EB-2025-0297

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Ontario Power Generation Inc. and DNNP LP for an order or orders approving payment amounts for prescribed generating facilities commencing January 1, 2027.

ONTARIO POWER GENERATION INC. AND DNNP LP

SETTLEMENT PROPOSAL

October 5, 2026

Ontario Power Generation Inc. and DNNP LP
EB-2025-0297
Settlement Proposal

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In addition to the Appendices listed above, the following live Excel models have been filed together with and form an integral part of this Settlement Proposal:

Revised Revenue Requirement Work Form

SECTION 1 – EB-2025-0297 SETTLEMENT PROPOSAL OVERVIEW

Filed with OEB: October 5, 2026

A. INTRODUCTION

This Settlement Proposal is filed with the Ontario Energy Board ("**OEB**") in connection with Ontario Power Generation Inc. ("**OPG**") and DNNP LP's (collectively the "**Applicants**") payment amounts application made under section 78.1 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B) (the "**Act**") seeking approval to set payment amounts for the output of OPG's regulated hydroelectric generating facilities and the output of the Applicants' respective nuclear generating facilities. The application covers the five-year term beginning January 1, 2027 through December 31, 2031. (OEB File Number EB-2025-0297) (the "**Application**").

As set forth herein, the Settlement Proposal contains a comprehensive settlement of all issues within the Application related to (i) OPG, with the exception of a partial settlement related to the clearance of balances recorded in the Capacity Refurbishment Variance Account ("**CRVA**"), which outstanding issue relates to the recovery of such balances with respect to the Darlington Refurbishment Program ("**DRP**") as detailed in Section 1, Part E below; and (ii) DNNP LP.

B. BACKGROUND

The OEB issued a Notice of Hearing on January 12, 2026, and Procedural Order No. 1 on February 5, 2026. A Pre-Hearing Conference was held on February 18 and 19, 2026 where there was agreement between the Applicants and the intervenors on certain revisions to the draft Issues List that was attached to Procedural Order No. 1. The final approved issues list (the "**Issues List**") is attached as Schedule A to Procedural Order No. 2 issued March 4, 2026. The interrogatories process took place between March and May 2026. Between May 27 and June 2, 2026, and on June 18, 2026, the Parties engaged in a Technical Conference. On June 22, 2026, the OEB issued a decision indicating that it was satisfied that the conditions set out in section 8 of *Ontario Regulation 53/05* ("**O. Reg. 53/05**"), relating to regulation of DNNP LP as a prescribed generator, had been met. On June 29, 2026, the parties proceeded to a Settlement Conference.

C. THE SETTLEMENT PROCESS

Pursuant to Procedural Order No. 2, a Settlement Conference was convened on June 29, 2026, was extended twice by the OEB at the request of the parties until July 29, 2026, with a final request from the parties to extend up to October 5, 2026. The Settlement Conference was conducted in accordance with the OEB's *Rules of Practice and Procedure* and the OEB's Practice Direction on Settlement Conferences (the "**Practice Direction**").

Ken Rosenberg acted as facilitator for the Settlement Conference.

OPG, DNNP LP, and the following Intervenors (the "**Intervenors**") participated in the Settlement Conference:

Association of Major Power Consumers in Ontario ("**AMPCO**")
Building Owners and Managers Association Toronto ("**BOMA**")
Coalition of Concerned Manufacturers and Businesses of Canada ("**CCMBC**")
Consumers Council of Canada ("**CCC**")
Energy Probe Research Foundation ("**Energy Probe**")
Environmental Defence Canada Inc. ("**Environmental Defence**")
Independent Electricity System Operator ("**IESO**")
Minogi Corp. ("**Minogi**")
Ontario Association of Physical Plant Administrators ("**OAPPA**")
Power Workers Union ("**PWU**")
Quinte Manufacturers Association ("**QMA**")
School Energy Coalition ("**SEC**")
Society of United Professionals ("**Society**")
Vulnerable Energy Consumers Coalition ("**VECC**").

WTFN Investment Holdings LP ("**WTFN**") and Mr. Keith Pinto[1] did not participate in the Settlement Conference.

The Society and PWU take no position on the settlements reached on each issue. Notwithstanding any other clause in this Settlement Proposal, in the interest of facilitating a settlement, Environmental Defence takes no position on any issues except for issues 20, 21, and 22. The IESO takes no position on any issues except Issue 20 and 22. Minogi takes no position on all components of the DNNP LP settlement set out in Section 3 of this Settlement Proposal.

OPG, DNNP LP, and the Intervenors are collectively referred to below as the "**Parties**" and each of them, a "**Party**".

OEB Staff also participated in the Settlement Conference. The role adopted by OEB Staff is set out in page 5 of the Practice Direction. Although OEB Staff is not a party to this Settlement Proposal, as noted in the Practice Direction, OEB Staff who participated in the Settlement Conference are bound by the same confidentiality and settlement privilege requirements that apply to the Parties to the proceeding.

[1] While Mr. Pinto initially attended the first day of the Settlement Conference, he did not attend any aspects thereafter notwithstanding receipt of calendar appointments and communication reach outs from the OEB appointed facilitator. As a result, he is not considered a Party for purposes of this Settlement Proposal.

D. SETTLEMENT PROPOSAL PREAMBLE

This document comprises the Settlement Proposal and is presented jointly to the OEB by the Parties. This document is called a "**Settlement Proposal**" because it is a proposal by the Parties to the OEB to settle the issues in this proceeding identified as settled in this Settlement Proposal. It is termed a proposal as between the Parties and the OEB. However, as between the Parties, and subject only to the OEB's approval of this Settlement Proposal, this document is intended to be a legal agreement, creating mutual obligations, and binding and enforceable in accordance with its terms. As set forth later in this preamble, this Settlement Proposal is subject to a condition subsequent: that if it is not accepted by the OEB in its entirety, then, unless amended by the Parties, it is null and void and of no further effect. In entering into this Settlement Proposal, the Parties understand and agree that, pursuant to the Act, the OEB has exclusive jurisdiction with respect to the interpretation and enforcement of the terms hereof.

The Parties acknowledge that this settlement proceeding is confidential and privileged in accordance with the Practice Direction. The Parties understand that confidentiality in that context does not have the same meaning as confidentiality in the OEB's Practice Direction on Confidential Filings, and the rules of that latter document do not apply. Instead, in this Settlement Conference, and in this Settlement Proposal, the Parties have interpreted "confidential" to mean that the documents and other information provided during the course of the settlement proceeding, the discussion of each issue, the offers and counter-offers, and the negotiations leading to the settlement – or not – of each issue during the Settlement Conference are strictly privileged and without prejudice. None of the foregoing is admissible as evidence in this proceeding, or otherwise, with one exception: the need to resolve a subsequent dispute over the interpretation of any provision of this Settlement Proposal. Further, the Parties shall not disclose those documents or other information to persons who were not attendees at the Settlement Conference. The Parties agree that "attendees" is deemed to include, in this context, persons who were not in attendance via video conference at the settlement conference but were (i) any persons or entities that the Parties engaged to assist them with the Settlement Conference, and (ii) any persons or entities from whom the Parties sought instructions with respect to the negotiations, in each case provided that any such persons or entities have agreed to be bound by the same confidentiality provisions as the Parties.

As per page 5 of the Practice Direction, OEB Staff will file a submission with the OEB commenting on two aspects of the Settlement Proposal: (i) whether the Settlement Proposal represents an acceptable outcome from a public interest perspective, and (ii) whether the accompanying explanation and rationale is adequate to support the Settlement Proposal.

This Settlement Proposal is in part organized in accordance with the Issues List. This Settlement Proposal provides a brief description of each of the settled and partially settled issues, together with references to the evidence submitted for the record in this proceeding. The Parties agree that references to the "evidence" in this Settlement Proposal shall, unless the context otherwise requires, include, in addition to the Application, the written responses to interrogatories and Technical Conference undertakings, and other components of the record up to and including the date hereof, including the Applicants' responses to certain Settlement Conference clarification questions and Excel versions of Ex. L-F4-CCC-084, Attachment 1, Tables 15-24 that the Parties have agreed to file on the record of this proceeding and additional information included by the Parties in this Settlement Proposal.

The supporting Parties for each settled and partially settled issue, as applicable, agree that the evidence in respect of that settled or partially settled issue, as applicable, is sufficient in the context of the overall settlement to support the proposed settlement, and the sum of the evidence in this proceeding provides an appropriate evidentiary record to support acceptance by the OEB of this Settlement Proposal.

There are Appendices to this Settlement Proposal which provide further support for the Settlement Proposal. The Parties acknowledge that the Appendices were prepared by the Applicants. While the Intervenors have reviewed the Appendices, the Intervenors are relying on the accuracy of those Appendices and the underlying evidence in entering into this Settlement Proposal.

The final agreements of the Parties following the Settlement Conference are set out below. The Parties explicitly request that the OEB consider and accept this Settlement Proposal as a package. None of the matters in respect of which a settlement has been reached is severable. Numerous compromises were made by the Parties with respect to various matters to arrive at this Settlement Proposal. Reductions or increases to the agreed-upon amounts may have financial consequences in other areas of this Settlement Proposal, which may be unacceptable to one or more of the Parties. If the OEB does not accept the Settlement Proposal in its entirety, then there is no agreement, unless the Parties agree, in writing, that the balance of this Settlement Proposal may continue as valid settlement subject to any revisions that may be agreed-upon by the Parties.

It is further acknowledged and agreed that none of the Parties will withdraw from this agreement under any circumstances, except as provided under Rule 30.05 of the OEB's *Rules of Practice and Procedure*.

In the event that the OEB directs the Parties to make reasonable efforts to revise the Settlement Proposal, the Parties agree to use reasonable efforts to discuss any potential revisions, but no Party will be obligated to accept any proposed revision. The Parties agree that all of the Parties must concur with any revised settlement proposal, or take no

position, prior to its resubmission to the OEB for its review and consideration as a basis for making a decision.

Unless otherwise expressly stated in this Settlement Proposal, the agreement by the Parties to the settlement of any item shall be interpreted as being for the purpose of settlement of this case only and not a statement or acknowledgement of principle applicable in any other situation. Where, if at all, the Parties have agreed that a particular principle should be applicable generally, this Settlement Proposal states so expressly. The Parties understand this to be consistent with OEB policy, under which settlements and their approval by the OEB are considered to be specific to the facts of a particular case, and not precedents or statements of principle unless clearly so stated.

In this Settlement Proposal, where any of the Parties "accept" the evidence of the Applicants, or "agree" to a revised term or condition, including a revised budget or forecast, then, unless expressly stated to the contrary, the words "for the purpose of settlement of the issues herein" shall be deemed to qualify that acceptance or agreement.

Except for those parts of this Settlement Proposal that are expressly agreed to apply for a period of time beyond the effective date of the payment amounts order for the Applicants' next rebasing application for the respective prescribed facilities, it is also acknowledged and agreed that this Settlement Proposal is without prejudice to any of the Parties or the OEB re-examining the items settled herein in any subsequent proceeding and taking positions or rendering decisions inconsistent with the resolution of these items in this Settlement Proposal. However, none of the Parties will, in any subsequent proceeding, take the position that the resolution therein of any issue settled in this Settlement Proposal, if contrary to the terms of this Settlement Proposal, should be applicable to the Applicants for any part of the 2027-2031 period, unless otherwise required by applicable laws.

E. SETTLEMENT PROPOSAL OVERVIEW

The Parties are pleased to advise the OEB that they have reached a substantial, but not a complete, agreement with respect to OPG and a complete settlement with respect to DNNP LP:

"**Complete Settlement**" means an issue for which complete settlement was reached by all Parties, and if this Settlement Proposal is accepted by the OEB, the Parties will not adduce any evidence or argument during the hearing in respect of these issues.	Issues settled: **Issues: 1, 3-39, 41-45**

"**Partial Settlement**" means an issue for which there is partial settlement, as the Applicants and the Intervenors who take any position on the issue were able to agree on some, but not all, aspects of the particular issue. If this Settlement Proposal is accepted by the OEB, the Parties who take any position on the issue will only adduce evidence and argument during the hearing on those portions of the issues not addressed in this Settlement Proposal.	Issue partially settled: **Issues: 2, 40**
"**No Settlement**" means an issue for which no settlement was reached. Unless otherwise noted in this Settlement Proposal, the Applicants and the Intervenors who take a position on the issue will adduce evidence and/or argument at the hearing on the issue.	Issues not settled: **None**

With respect to Issues 2 and 40, denoted as Partial Settlement, the Parties settled on all matters within these issues, with the exception of OPG's proposed recovery of a $170.2M debit balance in the CRVA related to the DRP[2], as at December 31, 2024. OPG and the Intervenors agree that this aspect should proceed by way of written hearing ("**Outstanding Issue**")[3].

The changes to components of OPG's proposed nuclear revenue requirements and production forecast for the 2027-2031 period agreed to by the Parties are as identified in Tables 1-5 below and changes to components of OPG's proposed regulated hydroelectric revenue requirement and production forecast for the 2027 test year (the only year for which an annual revenue requirement is requested in this Application) are as identified in Table 6 below. The changes to components of DNNP LP's proposed revenue requirements and production forecast for the 2027-2031 period agreed to by the Parties are as identified in Tables 7-11 below. The "Application Proposed" columns in the above noted tables, as well as any amounts identified in the Settlement Proposal as being proposed by the Applicants refer to the pre-filed evidence, subject to minor corrections identified by the Applicants in Ex. L-B1-CCC-019, Ex. L-A2-SEC-025, Ex. L-F3-SEC-174, and Ex. JT4.11. The Parties have agreed to these corrections, which are reflected in the settlement adjusted amounts in this Settlement Proposal. In addition, in taking a holistic approach to the revenue requirement totals, a "general revenue requirement adjustment"

[2] This balance resulted from historical variances in the amounts and/or timing of DRP capital in-service additions (and their tax effects) and certain non-capital project costs relative to forecasts reflected in OEB-approved revenue requirements (Ex. H1-1-1, p. 23, lines 5-6; Ex. H1-1-1, Table 1, line 21, col. (c)). In particular, this includes incremental amounts sought for recovery from customers due to the earlier inclusion in the rate base and the associated timing of depreciation and cost of capital impacts for Darlington Unit 1 and Unit 3 as a result of their earlier than planned return to service from refurbishment.

[3] See Section 2, Part J of this Settlement Proposal and Issue 44 below.

has been agreed to by the Parties for OPG's nuclear and regulated hydroelectric revenue requirements as part of this Settlement Proposal.

The Parties note that the settlement adjusted amounts identified in this Settlement Proposal, including "Settled Amounts" in Tables 1-11 below and the settlement adjusted payment amounts in Tables 12 and 13 below, where applicable, are subject to the agreement to update the Return on Equity ("**ROE**") rate for the 2027-2031 period using the prevailing ROE rate specified by the OEB as of the effective date of the final payment amounts order in this proceeding, as proposed by the Applicants and as discussed in Section 2, Part B, subpart (iii) and Section 3, Part B, subpart (ii), as well as the OEB's decision on the Outstanding Issue.

Table 1 –
Summary of 2027 OPG Nuclear Revenue Requirement, Production Forecast, and Deferral and Variance Account Amortization ($M)

Line	Component	Description	Application Proposed	Settlement Adjustment	Settled Amount [4]
1	Rate Base	Net Fixed Assets, Working Capital, and Cash Working Capital	15,749.4	(260.2)	15,489.2
2	Cost of Capital	Short and Long Term Debt, Return on Equity, Adjustment for lesser of UNL or ARC [5]	1,087.9	(67.8)	1,020.1
3	OM&A	Operations, Maintenance, and Administration Expenses	1,863.7	(90.0)	1,773.7
4	Other Expenses	Fuel, Depreciation & Amortization, Property Taxes and Income Tax	811.6	(7.1)	804.5
5	Other Revenues	Bruce Lease Net Revenues, and Ancillary and Other Revenue	1.1	0.0	1.1
6	Stretch Factor	Cumulative OPG Nuclear Stretch Factor Dollars	0.0	0.0	0.0
7	Concurrent Cost Recovery	Concurrent Cost Recovery – Pickering Refurbishment Program	297.6	(2.6)	295.0
8	General Revenue Requirement Adjustment	Reduction to Nuclear Revenue Requirement for Purposes of Settlement	0.0	(35.4)	(35.4)
9	Revenue Requirement Net of Stretch Factor	Sum of Line 2 to Line 8	4,059.7	(202.9)	3,856.8
10	Amortization of Deferral & Variance Account Amounts	Amortization of Deferral & Variance Account Balances (OPG Nuclear)	134.5	(59.5)	75.0
11	Production	Nuclear Production Forecast	18.7 TWh	0.65 TWh	19.3 TWh

[4] Numbers may not add due to rounding.
[5] UNL stands for unfunded nuclear liability. ARC stands for asset retirement costs.

Table 2 –
Summary of 2028 OPG Nuclear Revenue Requirement, Production Forecast, and Deferral and Variance Account Amortization ($M)

Line	Component	Description	Application Proposed	Settlement Adjustment	Settled Amount [6]
1	Rate Base	Net Fixed Assets, Working Capital, and Cash Working Capital	16,278.6	(487.0)	15,791.6
2	Cost of Capital	Short and Long Term Debt, Return on Equity, Adjustment for lesser of UNL or ARC	1,141.4	(84.2)	1,057.2
3	OM&A	Operations, Maintenance, and Administration Expenses	1,756.0	(125.0)	1,631.0
4	Other Expenses	Fuel, Depreciation & Amortization, Property Taxes and Income Tax	927.8	(17.5)	910.3
5	Other Revenues	Bruce Lease Revenues and Ancillary and Other Revenue	44.2	0.0	44.2
6	Stretch factor	Cumulative OPG Nuclear Stretch Factor Dollars	7.0	7.0	13.9
7	Concurrent Cost Recovery	Concurrent Cost Recovery – Pickering Refurbishment Program	479.9	(14.3)	465.5
8	General Revenue Requirement Adjustment	Reduction to Nuclear Revenue Requirement for Purposes of Settlement.	0.0	(35.4)	(35.4)
9	Revenue Requirement Net of Stretch Factor	Sum of Line 2 to Line 8	4,253.9	(283.4)	3,970.6
10	Amortization of Deferral & Variance Account Amounts	Amortization of Deferral & Variance Account Balances (OPG Nuclear)	134.5	(59.5)	75.0
11	Production	Nuclear Production Forecast	26.7 TWh	0.875 TWh	27.6TWh

[6] Numbers may not add due to rounding

Table 3 –
Summary of 2029 OPG Nuclear Revenue Requirement, Production Forecast, and Deferral and Variance Account Amortization ($M)

Line	Component	Description	Application Proposed	Settlement Adjustment	Settled Amount [7]
1	Rate Base	Net Fixed Assets, Working Capital, and Cash Working Capital	16,217.5	(583.3)	15,634.3
2	Cost of Capital	Short and Long Term Debt, Return on Equity, Adjustment for lesser of UNL or ARC	1,147.1	(90.4)	1,056.7
3	OM&A	Operations, Maintenance, and Administration Expenses	1,917.4	(130.0)	1,787.4
4	Other Expenses	Fuel, Depreciation & Amortization, Property Taxes and Income Tax	951.7	(25.9)	925.9
5	Other Revenues	Bruce Lease Revenues and Ancillary and Other Revenue	(4.3)	0.0	(4.3)
6	Stretch factor	Cumulative OPG Nuclear Stretch Factor Dollars	14.6	14.7	29.3
7	Concurrent Cost Recovery	Concurrent Cost Recovery – Pickering Refurbishment Program	667.7	(41.3)	626.4
8	General Revenue Requirement Adjustment	Reduction to Nuclear Revenue Requirement for Purposes of Settlement.	0.0	(35.4)	(35.4)
9	Revenue Requirement Net of Stretch Factor	Sum of Line 2 to Line 8	4,673.6	(337.7)	4,335.9
10	Amortization of Deferral & Variance Account Amounts	Amortization of Deferral & Variance Account Balances (OPG Nuclear)	134.5	(59.5)	75.0
11	Production	Nuclear Production Forecast	25.1 TWh	0.75 TWh	25.8 TWh

[7] Numbers may not add due to rounding

Table 4 –
Summary of 2030 OPG Nuclear Revenue Requirement, Production Forecast, and Deferral and Variance Account Amortization ($M)

Line	Component	Description	Application Proposed	Settlement Adjustment	Settled Amount [8]
1	Rate Base	Net Fixed Assets, Working Capital, and Cash Working Capital	16,807.3	(812.7)	15,994.5
2	Cost of Capital	Short and Long Term Debt, Return on Equity, Adjustment for lesser of UNL or ARC	1,193.8	(108.7)	1,085.1
3	OM&A	Operations, Maintenance, and Administration Expenses	1,854.9	(130.0)	1,724.9
4	Other Expenses	Fuel, Depreciation & Amortization, Property Taxes and Income Tax	1,039.2	(38.0)	1,001.2
5	Other Revenues	Bruce Lease Revenues and Ancillary and Other Revenue	20.8	0.0	20.8
6	Stretch factor	Cumulative OPG Nuclear Stretch Factor Dollars	22.5	22.9	45.4
7	Concurrent Cost Recovery	Concurrent Cost Recovery – Pickering Refurbishment Program	832.0	(77.1)	755.0
8	General Revenue Requirement Adjustment	Reduction to Nuclear Revenue Requirement for Purposes of Settlement.	0.0	(35.4)	(35.4)
9	Revenue Requirement Net of Stretch Factor	Sum of Line 2 to Line 8	4,876.7	(412.2)	4,464.5
10	Amortization of Deferral & Variance Account Amounts	Amortization of Deferral & Variance Account Balances (OPG Nuclear)	67.7	0.0	67.7
11	Production	Nuclear Production Forecast	26.8 TWh	0.85 TWh	27.7 TWh

[8] Numbers may not add due to rounding

Table 5 –
Summary of 2031 OPG Nuclear Revenue Requirement, Production Forecast, and Deferral and Variance Account Amortization ($M)

Line	Component	Description	Application Proposed	Settlement Adjustment	Settled Amount [9]
1	Rate Base	Net Fixed Assets, Working Capital, and Cash Working Capital	23,519.3	(1,575.4)	21,943.9
2	Cost of Capital	Short and Long Term Debt, Return on Equity, Adjustment for lesser of UNL or ARC	1,674.2	(183.2)	1,491.0
3	OM&A	Operations, Maintenance, and Administration Expenses	2,150.6	(140.0)	2,010.6
4	Other Expenses	Fuel, Depreciation & Amortization, Property Taxes and Income Tax	1,297.1	(64.1)	1,233.0
5	Other Revenues	Bruce Lease Revenues and Ancillary and Other Revenue	6.5	0.0	6.5
6	Stretch factor	Cumulative OPG Nuclear Stretch Factor Dollars	31.7	32.5	64.2
7	Concurrent Cost Recovery	Concurrent Cost Recovery – Pickering Refurbishment Program	646.2	(70.2)	576.0
8	General Revenue Requirement Adjustment	Reduction to Nuclear Revenue Requirement for Purposes of Settlement.	0.0	(50.4)	(50.4)
9	Revenue Requirement Net of Stretch Factor	Sum of Line 2 to Line 6	5,729.8	(540.4)	5,189.4
10	Amortization of Deferral & Variance Account Amounts	Amortization of Deferral & Variance Account Balances (OPG Nuclear)	67.7	0.0	67.7
11	Production	Nuclear Production Forecast	28.9 TWh	1.0 TWh	29.9 TWh

[9] Numbers may not add due to rounding

Table 6 –
Summary of 2027 OPG Regulated Hydroelectric Revenue Requirement, Production Forecast, and Deferral and Variance Account Amortization ($M)

Line	Component	Description	Application Proposed	Settlement Adjustment	Settled Amount [10]
1	Rate Base	Net Fixed Assets, Working Capital, and Cash Working Capital	9,135.1	(126.8)	9,008.4
2	Cost of Capital	Short and Long Term Debt, Return on Equity	634.2	(38.1)	596.1
3	OM&A	Operations, Maintenance, and Administration Expenses	499.3	(25.0)	474.3
4	Other Expenses	Gross Revenue Charge, Depreciation & Amortization, Property Taxes and Income Tax	597.0	(26.3)	570.7
5	Other Revenues	Ancillary and Other Revenue	62.2	29.4	91.6
6	General Revenue Requirement Adjustment	Reduction to Regulated Hydroelectric Revenue Requirement for Purposes of Settlement	0.0	(5.9)	(5.9)
7	Revenue Requirement	Sum of Line 2 to Line 6	1,668.3	(124.7)	1,543.6
8	Amortization of Deferral & Variance Account Amounts	Amortization of Deferral & Variance Account Balances (Regulated Hydroelectric)*	(37.9)	(12.3)	(50.3)
9	Production	Regulated Hydroelectric Production Forecast	32.5 TWh	0.45 TWh	32.9 TWh

* Settled amortization amounts for 2028 and 2029 are also equal to ($50.3M).

[10] Numbers may not add due to rounding

Table 7 –
Summary of 2027 DNNP LP Nuclear Revenue Requirement, Production Forecast, and Deferral and Variance Account Amortization ($M)

Line	Component	Description	Application Proposed	Settlement Adjustment	Settled Amount
1	Rate Base	Net Fixed Assets, Working Capital, and Cash Working Capital	0.0	0.0	0.0
2	Cost of Capital	Short and Long Term Debt, Return on Equity	0.0	0.0	0.0
3	OM&A	Operations, Maintenance, and Administration Expenses	77.0	(4.0)	73.0
4	Other Expenses	Fuel, Depreciation & Amortization, Property Taxes and Income Tax	9.1	0.0	9.1
5	Other Revenues	Ancillary and Other Revenue	0.0	0.0	0.0
6	Concurrent Cost Recovery	Concurrent Cost Recovery – Darlington New Nuclear Program	214.9	(0.8)	214.2
7	Revenue Requirement	Sum of Line 2 to Line 6	301.0	(4.8)	296.3
8	Amortization of Deferral & Variance Account Amounts	Amortization of Deferral & Variance Account Balances (DNNP LP)	0.0	0.0	0.0
9	Production	DNNP LP Production Forecast	0.0 TWh	0.0 TWh	0.0 TWh

Table 8 –
Summary of 2028 DNNP LP Nuclear Revenue Requirement, Production Forecast, and Deferral and Variance Account Amortization ($M)

Line	Component	Description	Application Proposed	Settlement Adjustment	Settled Amount
1	Rate Base	Net Fixed Assets, Working Capital, and Cash Working Capital	0.0	0.0	0.0
2	Cost of Capital	Short and Long Term Debt, Return on Equity	0.0	0.0	0.0
3	OM&A	Operations, Maintenance, and Administration Expenses	80.1	(4.0)	76.1
4	Other Expenses	Fuel, Depreciation & Amortization, Property Taxes and Income Tax	13.8	0.0	13.8
5	Other Revenues	Ancillary and Other Revenue	0.0	0.0	0.0
6	Concurrent Cost Recovery	Concurrent Cost Recovery – Darlington New Nuclear Program	284.8	(10.7)	274.2
7	Revenue Requirement	Sum of Line 2 to Line 6	378.8	(14.7)	364.1
8	Amortization of Deferral & Variance Account Amounts	Amortization of Deferral & Variance Accounts (DNNP LP)	0.0	0.0	0.0
9	Production	DNNP LP Production Forecast	0.0 TWh	0.0 TWh	0.0 TWh

Table 9 –
Summary of 2029 DNNP LP Nuclear Revenue Requirement, Production Forecast, and Deferral and Variance Account Amortization ($M)

Line	Component	Description	Application Proposed	Settlement Adjustment	Settled Amount
1	Rate Base	Net Fixed Assets, Working Capital, and Cash Working Capital	2.1	0.0	2.1
2	Cost of Capital	Short and Long Term Debt, Return on Equity	0.2	0.0	0.2
3	OM&A	Operating, Maintenance, and Administration Expenses	70.8	(4.0)	66.8
4	Other Expenses	Fuel, Depreciation & Amortization, Property Taxes and Income Tax	12.7	0.0	12.7
5	Other Revenues	Ancillary and Other Revenue	0.0	0.0	0.0
6	Concurrent Cost Recovery	Concurrent Cost Recovery – Darlington New Nuclear Program	321.2	(27.8)	293.4
7	Revenue Requirement	Sum of Line 2 to Line 6	404.9	(31.8)	373.1
8	Amortization of Deferral & Variance Account Amounts	Amortization of Deferral & Variance Accounts (DNNP LP)	0.0	0.0	0.0
9	Production	DNNP LP Production Forecast	0.0 TWh	0.0 TWh	0.0 TWh

Table 10 –
Summary of 2030 DNNP LP Nuclear Revenue Requirement, Production Forecast, and Deferral and Variance Account Amortization ($M)

Line	Component	Description	Application Proposed	Settlement Adjustment	Settled Amount
1	Rate Base	Net Fixed Assets, Working Capital, and Cash Working Capital	1,371.1	(134.2)	1,236.9
2	Cost of Capital	Short and Long Term Debt, Return on Equity	124.9	(12.2)	112.7
3	OM&A	Operations, Maintenance, and Administration Expenses	119.6	(4.0)	115.6
4	Other Expenses	Fuel, Depreciation & Amortization, Property Taxes and Income Tax	41.5	(2.2)	39.3
5	Other Revenues	Ancillary and Other Revenue	0.0	0.0	0.0
6	Concurrent Cost Recovery	Concurrent Cost Recovery – Darlington New Nuclear Program	274.2	(29.8)	244.4
7	Revenue Requirement	Sum of Line 2 to Line 6	560.2	(48.3)	512.0
8	Amortization of Deferral & Variance Account Amounts	Amortization of Deferral & Variance Accounts (DNNP LP)	0.0	0.0	0.0
9	Production	DNNP LP Production Forecast	0.5 TWh	0.0 TWh	0.5 TWh

Table 11 –
Summary of 2031 DNNP LP Nuclear Revenue Requirement, Production Forecast, and Deferral and Variance Account Amortization ($M)

Line	Component	Description	Application Proposed	Settlement Adjustment	Settled Amount
1	Rate Base	Net Fixed Assets, Working Capital, and Cash Working Capital	6,530.0	(641.9)	5,888.1
2	Cost of Capital	Short and Long Term Debt, Return on Equity	594.9	(58.5)	536.4
3	OM&A	Operations, Maintenance, and Administration Expenses	259.7	(8.0)	251.6
4	Other Expenses	Fuel, Depreciation & Amortization, Property Taxes and Income Tax	163.2	(9.4)	153.9
5	Other Revenues	Ancillary and Other Revenue	0.0	0.0	0.0
6	Concurrent Cost Recovery	Concurrent Cost Recovery – Darlington New Nuclear Program	24.6	(3.7)	20.9
7	Revenue Requirement	Sum of Line 2 to Line 6	1,042.4	(79.6)	962.8
8	Amortization of Deferral & Variance Account Amounts	Amortization of Deferral & Variance Accounts (DNNP LP)	0.0	0.0	0.0
9	Production	DNNP LP Production Forecast	1.9 TWh	0.1 TWh	2.0 TWh

In the Application, pursuant to s. 14(2)7 and 14(2)8 of O. Reg. 53/05, the Applicants sought an approval of blended payment amounts and blended deferral and variance account payment riders for OPG's nuclear facilities and DNNP LP's prescribed assets, effective January 1 of each year 2027 through 2031. The impacts of the Settlement Proposal on such proposed nuclear payment amounts and payment riders are identified in Tables 12 and 13 below, excluding from the settlement adjusted amounts OPG's proposed recovery of the CRVA balances related to the DRP comprising the Outstanding Issue.

In the Application, OPG made a payment amount shaping proposal as set out in Ex. I1-3-2 to help manage the 2027 ratepayer impacts. This involved recording $500.0M of OPG's proposed 2027 nuclear revenue requirement in a proposed Payment Amount Shaping Deferral Account, to be collected in 2028. Utilizing this mechanism, the Parties have agreed to a revised deferral amount of $350.0M of OPG's 2027 settlement adjusted nuclear revenue requirement, to be collected in 2028. The payment amounts shown in

Tables 12 and 13 below reflect the original and agreed to payment amount shaping proposals, as applicable.

Table 12 – Applicants' Proposed Nuclear Payment Amounts ($/MWh)

	2027	2028	2029	2030	2031
Applicants' Proposed Blended Nuclear Payment Amount After Shaping	206.70	192.42	202.74	199.16	219.60
Applicants' Proposed Nuclear Payment Rider	7.19	5.04	5.36	2.48	2.19
Applicants' Proposed Total Nuclear Payments	213.89	197.46	208.10	201.64	221.79

Table 13 – Settlement Adjusted Nuclear Payment Amounts ($/MWh)

	2027	2028	2029	2030	2031
Settlement Adjusted Blended Nuclear Payment Amount After Shaping	196.62	169.94	182.40	176.64	192.42
Settlement Adjusted Nuclear Payment Rider[11]	3.88	2.72	2.90	2.40	2.12
Settlement Adjusted Total Nuclear Payments	200.50	172.66	185.30	179.04	194.54

With respect to the regulated hydroelectric payment amount, OPG sought, effective January 1, 2027, the approval of a payment amount of $51.39/MWh, as set out in Ex. I1-2-1. The impacts of the Settlement Proposal reduce this proposed regulated hydroelectric payment amount to $46.90/MWh. OPG also sought approval of a custom price-cap index

[11] Subject to the OEB's decision on the Outstanding Issue, disposition of the $170.2M debit balance in the CRVA related to the DRP as at December 31, 2024 sought in the Application has been removed from the total recoverable amount reflected in the settlement adjusted nuclear payment riders. Including the amortization of such amount as sought in the Application would result in settlement adjusted nuclear payment riders of $6.81/MWh in 2027, $4.78/MWh in 2028, $5.10/MWh in 2029, $2.40/MWh in 2030, and $2.12/MWh in 2031.

that the OEB would use to set the regulated hydroelectric payment amounts effective January 1 of each year 2028 through 2031, and a hydroelectric incentive mechanism ("**HIM**") that adjusts OPG's revenues from the regulated hydroelectric payment amount.

OPG also sought approval of deferral and variance account payment riders for the regulated hydroelectric facilities, effective January 1 of each year 2027 through 2029. The impacts of the Settlement Proposal on these proposed and illustrative payment amounts and payment riders are identified in Table 14 below.

Table 14 – OPG's Proposed and Settlement Adjusted Regulated Hydroelectric Payment Amounts ($/MWh)

	2027	2028	2029	2030	2031
OPG's Proposed 2027 Regulated Hydroelectric Payment Amount and Illustrative 2028-2031 Payment Amounts [12]	51.39	54.89	59.04	61.77	63.87
OPG's Proposed Regulated Hydroelectric Payment Riders	(1.17)	(1.17)	(1.17)	0.00	0.00
Settlement Adjusted 2027 Regulated Hydroelectric Payment Amount and Illustrative 2028-2031 Payment Amounts	46.90	48.72	53.30	55.17	56.37
Settlement Adjusted Regulated Hydroelectric Payment Riders	(1.53)	(1.51)	(1.50)	0.00	0.00

The Parties agree that the payment amounts and payment riders arising from this proceeding shall be effective January 1, 2027.

[12] Exhibit JT4.13.

The estimated residential customer bill impacts from the Application as adjusted for the Settlement Proposal and excluding OPG's proposed recovery of the CRVA balances related to the DRP comprising the Outstanding Issue is shown in Table 15 below. These impacts are calculated in the same manner as set out in Ex. I1-1-2. Regulated hydroelectric payment amounts for the 2028-2031 period are included in these calculations for illustrative purposes based on the agreed-upon custom price-cap index as set out in this Settlement Proposal and assuming the most recent generation industry-weighted inflation factor applies in all years of the period. Further details on the settled custom price-cap index framework are provided in Section 2, Part A of this Settlement Proposal.

Table 15 – Estimated Residential Customer Bill Impacts ($/Month)

	2027	2028	2029	2030	2031	Average
Applicants' Original Proposal	7.93	2.44	1.33	0.69	4.62	3.40
Settlement Proposal	6.29	0.46	1.72	0.53	3.79	2.56
Difference	(1.64)	(1.98)	0.39	(0.16)	(0.83)	(0.84)

Revenue Requirements

This Settlement Proposal represents an overall reduction to OPG's proposed nuclear revenue requirements of $1.8B over the 2027-2031 period. Contributing to this overall reduction in revenue requirements is a decrease to the requested OM&A expenses of $615.0M over the period and a reduction to the requested nuclear rate base of $1.6B by 2031. In taking a holistic approach to the revenue requirement totals, the overall reduction in OPG's nuclear revenue requirements includes a general reduction of $192.0M over the 2027-2031 period.

With respect to the regulated hydroelectric facilities, this Settlement Proposal represents an overall reduction to OPG's proposed 2027 test year revenue requirement of $124.7M. Contributing to this overall reduction in revenue requirement is a decrease to the requested OM&A expenses of $25.0M, an increase in the other revenues amount applied to offset the revenue requirement of $29.4M, and a reduction to the requested regulated hydroelectric rate base of $126.8M for 2027. In addition to the reduction in the 2027 revenue requirement, the Settlement Proposal represents a reduction of $432.5M[13] in the regulated hydroelectric capital-related revenue requirement underpinning the Capital factor to be used as part of the rate setting formula over the 2028-2031 period.

[13] As compared against Ex. JT4.13, Attachment 1.

Contributing to this overall reduction in the capital-related revenue requirement is an increase in the stretch factor (from 0.15% to 0.30%) and the introduction of a supplemental stretch factor of 0.30% applied to the capital-related revenue requirement.

With respect to DNNP LP's prescribed assets, this Settlement Proposal represents an overall reduction to the proposed revenue requirements of $179.1M over the 2027-2031 period.

Production Forecasts

Over the 2027-2031 period, the Settlement Proposal reflects a total increase in forecast nuclear production of 4.125 TWh for OPG and a total increase in forecast production of 0.1 TWh for DNNP LP. For OPG's forecast regulated hydroelectric production, the Settlement Proposal reflects an increase of 0.45 TWh for the 2027 test year. The Parties have also agreed to the establishment of new production variance accounts. One account is to be established to enable the sharing with ratepayers of certain positive and negative OPG net revenue impacts resulting from variances to the forecast planned outage days at Darlington during the 2027-2031 period, as discussed in Section 2, Part C, subpart (i) of this Settlement Proposal. A second account is to be established to record any positive OPG net revenue impacts resulting from any of the Pickering Nuclear Generating Station ("**Pickering**") units returning to service from refurbishment in the 2027-2031 period earlier than reflected in OPG's nuclear production forecast as approved by the OEB in this proceeding, subject to a sharing mechanism, as discussed in Section 2, Part C, subpart (i) of this Settlement Proposal.

Clean Electricity Investment Tax Credits

At the time of filing the Application, federal legislation establishing the Clean Electricity Investment Tax Credits ("**CEITCs**") and the reinstatement of the accelerated investment incentive property rules enabling higher capital cost allowance ("**CCA**") deductions for tax purposes, was proposed but had not yet become law. As the Applicants expected that they would be eligible for these mechanisms with respect to their prescribed assets, if enacted, they proposed in the Application to pass through to customers the resulting revenue requirement impacts for the 2027-2031 period through associated deferral and variance accounts. Following these mechanisms becoming enacted on March 26, 2026, in Ex. L-F4-CCC-084, the Applicants provided an estimate of such forecasted impacts for OPG's nuclear facilities, OPG's regulated hydroelectric facilities, and DNNP LP ("**CCC-084 Impacts**"), which would have the effect of reducing the proposed payment amounts. In this Settlement Proposal, the Parties have agreed to apply these forecasted impacts to the revenue requirements in this proceeding, along with establishing new variance accounts to record any differences between the forecasted and actual revenue requirement impacts of the CEITCs to the extent such impacts would not otherwise be captured in another deferral or variance account.

The Parties have agreed that forecasted capital expenditures, financial commitments and in-service capital additions for the Pickering Refurbishment Program ("**PRP**") and Darlington New Nuclear Program ("**DNNP**") as set out in the Application and as adjusted for the CCC-084 Impacts are reasonable and form part of the respective settlement adjusted forecast rate base for the 2027-2031 period. The Parties have further agreed that the resulting forecast interest amounts for recovery prior to the assets being placed in service ("**Concurrent Cost Recovery**" or "**CCR**") for the 2027-2031 period associated with the PRP and the DNNP, as proposed in the Application and adjusted for the CCC-084 Impacts, meet the requirements set out in s. 6(2)12.1i and s. 14(2)5i of O. Reg. 53/05, and are correctly reflected in the nuclear revenue requirements on that basis. The CCR mechanism is further discussed in Section 4, Issue 42 of this Settlement Proposal.

Generating Asset Mix

The Parties acknowledge that the scope of this proceeding and this Settlement Proposal does not include the consideration of appropriateness of the generating asset mix for the Ontario electricity market and is limited to establishing the applicable revenue requirements and payment amounts. Agreement by the Parties on this Settlement Proposal and any approval by the OEB of this settlement should not be construed as an agreement by Intervenors to the need or preferable alternative(s) regarding the generating asset mix for the Ontario electricity system, including nuclear new builds or nuclear refurbishments.

Capital Structure

The Parties have agreed that for the purposes of determining the OPG revenue requirements and payment amounts for the 2027-2031 period, OPG's capital structure will remain unchanged from EB-2020-0290 and EB-2016-0152 at 45% equity and 55% debt. OPG had proposed a capital structure of 52% equity and 48% debt in the Application. With consideration of the DNNP Generator Capital Structure Variance Account established under s. 13(1) of O. Reg. 53/05, the Parties have agreed to DNNP LP's capital structure of 100% equity for the purposes of determining the nuclear revenue requirements for the 2027-2031 period, as proposed in the Application.

Rate-Setting Framework

With respect to the OPG nuclear rate-setting framework, the Parties have agreed to expand the scope of costs to which the nuclear stretch factor applies and increase the nuclear stretch factor, relative to the proposals in the Application.

With respect to the OPG regulated hydroelectric rate-setting framework, the Parties have agreed to an increase in the regulated hydroelectric stretch factor, the introduction of a supplemental stretch factor for capital-related revenue requirement and the addition of a

production growth factor to account for forecast production increases over the 2028-2031 period.

The Parties have agreed to the DNNP LP nuclear rate-setting framework as proposed in the Application.

Hydroelectric Incentive Mechanism

The Parties have agreed to continue the HIM as proposed in the Application, but not to discontinue the Hydroelectric Incentive Mechanism Variance Account ("**HIMVA**") that asymmetrically shares incremental HIM revenues with ratepayers as OPG had proposed in the Application. The Parties have also agreed that, as part of the next application seeking to clear the Hydroelectric Surplus Baseload Generation Variance Account ("**SBGVA**") or the HIMVA balances, OPG shall request that the issues list for that proceeding include a full review of the treatment of the SBGVA, the HIM and the make whole payments ("**MWPs**").

Earnings Sharing Mechanism

As part of the rate-setting frameworks, the Parties have agreed to continue the existing earnings sharing mechanism for the OPG prescribed assets as proposed in the Application, and agree to no earnings sharing mechanism for DNNP LP.

Off Ramp

The Parties have agreed that the actual annual regulatory return reporting requirement as proposed in the Application (Ex. A1-3-2, Section 4.2) shall be the basis for determining if OPG and/or DNNP LP's actual ROE is outside the +/-300 basis point trigger for determining whether a regulatory review may be initiated by the OEB for OPG and/or DNNP LP, as applicable.

Deferral and Variance Accounts

Excluding the Outstanding Issue, the Parties have agreed that OPG will recover or refund all deferral and variance account balances (as of December 31, 2024) as proposed in the Application, with the exception of certain debit balances totaling approximately $8.3M, which will not be recovered, and a $37.0M debit balance in respect of the SBGVA, which will be considered in a subsequent proceeding. The Application does not seek disposition of any deferral and variance account balances for DNNP LP as none were in existence as of December 31, 2024.

The Parties have agreed to continue existing deferral and variance accounts and establish new deferral and variance accounts for the Applicants, effective January 1, 2027, as proposed in the Application, with certain modifications, as described in Section

2, Part G of this Settlement Proposal. This includes the establishment of certain accounts for DNNP LP, which largely mirror similar OPG accounts.

Summary

This Settlement Proposal is the culmination of extensive discussion and consideration by the Parties which represent an array of interests affected by the Application. Based on the impacts of the settlement described above, together with the evidence and rationale provided below, the Parties agree that this Settlement Proposal is in the public interest and the Parties recommend its acceptance by the OEB. Subject to the update for the prevailing ROE rate specified by the OEB as of the effective date of the final payment amounts order in this proceeding, the Applicants have prepared a draft payment amounts order reflecting the Settlement Proposal that excludes recovery of the CRVA balances related to the DRP comprising the Outstanding Issue. The intervenors accept the draft payment amounts order for purposes of making a final OEB order establishing payment amounts and payment riders arising from this Settlement Proposal based on the process described in Section 2, Part J herein.

SECTION 2 – KEY COMPONENTS OF THE OPG SETTLEMENT

The subsections below summarize the key components of the OPG settlement reached by the Parties. The evidentiary basis upon which each specific issue was settled is summarized in Section 4 of this Settlement Proposal.

The settlement adjustments to OPG's nuclear revenue requirements are presented in Table 16 below.

Table 16 – 2027-2031 Settlement Adjusted OPG Nuclear Revenue Requirements ($M)

	2027	2028	2029	2030	2031
OPG's Proposed Revenue Requirement Net of Stretch Factor	4,059.7	4,253.9	4,673.6	4,876.7	5,729.8
Settled Revenue Requirement Net of Stretch Factor	3,856.8	3,970.6	4,335.9	4,464.5	5,189.4
Difference	(202.9)	(283.3)	(337.7)	(412.2)	(540.4)

With respect to the regulated hydroelectric facilities, the settlement adjustments to the revenue requirement for the 2027 test year total a reduction of $124.7M, from $1,668.3M to $1,543.6M.

A. RATE-SETTING FRAMEWORKS

The Parties agree to the application of OPG's proposed nuclear and regulated hydroelectric rate-setting frameworks for the five-year term from 2027-2031, with certain modifications as identified below. Table 17 below outlines modifications to OPG's proposed nuclear rate-setting framework and Table 19 below outlines modifications to OPG's proposed regulated hydroelectric rate-setting framework.

Table 17 – Modifications to Proposed OPG Nuclear Rate-Setting Framework

	OPG's Original Proposal	Settlement Proposal
Form	Custom IR framework	No change
Rate-Setting Mechanism	Individual annual revenue requirements with applied stretch factor reductions, and individual annual production forecasts	No change
Stretch Factor Scope	OM&A (Base, Project excluding Operations and Project Support, Outage, Pickering Cyclical Maintenance, and Allocation of Corporate Support Costs), Asset Service Fees, Nuclear Operations and Support Services Capital-Related Revenue Requirement	As originally proposed, plus: • Project OM&A (Operations and Project Support), Allocation of Centrally Held Costs, Nuclear Fuel Costs, Working Capital-Related Revenue Requirement, Property Tax, and Other Revenues
Stretch Factor	0.30%, cumulative reduction for 2028-2031	0.60%, cumulative reduction for 2028-2031

The annual stretch factor reductions to OPG's nuclear revenue requirements based on the settlement are set out in Table 18 below.

Table 18 – 2028-2031 Settlement Adjusted OPG Nuclear Stretch Factor Reduction Amounts ($M)*

	2028	2029	2030	2031
OPG's Proposed Stretch Reduction to OPG Nuclear Revenue Requirement	7.0	14.6	22.5	31.7
Settlement Adjusted Stretch Reduction to OPG Nuclear Revenue Requirement	13.9	29.3	45.4	64.2
Difference	7.0	14.7	22.9	32.5

* Calculated based on settlement adjusted revenue requirement components.

Table 19 – Modifications to Proposed Regulated Hydroelectric Rate-Setting Framework

	OPG's Original Proposal	Settlement Proposal
Form	Custom Price-cap Index	No change
Year 1 Rates	Cost of service rebasing based on 2027 test year	No change
Annual Adjustment Mechanism	1+(I-X+C-GRCF)	1+(I-X+C-GRCF-G)
Inflation ("I-Factor")	Composite Index Generation Industry-weighted Labour Index (Ontario AWE, updated annually) and Non-Labour Index (GDP-IPI-FDD, updated annually)	No change
X-Factor	0% productivity 0.15% stretch factor Stretch factor application to capital-related revenue requirement through Capital factor design	0% productivity 0.30% stretch factor 0.30% supplemental stretch factor applied to capital-related revenue requirement

	OPG's Original Proposal	Settlement Proposal
		Stretch factor application to capital-related revenue requirement through Capital factor design
Production Growth Factor	No proposal	Growth factor based on the year-over-year change in the settlement adjusted production forecast for the 2028-2031 period[14]
Capital Factor ("C-Factor")	Provides incremental funding required to recover capital-related revenue requirement, less 0.15% (stretch factor) applied cumulatively over 2028-2031 period	Provides incremental funding required to recover the settled capital-related revenue requirement, less 0.60% (sum of stretch and supplemental stretch factors) applied cumulatively over 2028-2031 period
GRC Factor ("GRCF")	Removes the (I-X) escalation of gross revenue charge and other water rental cost ("GRC") amounts embedded in payment amounts. Designed using the forecast 2027 GRC costs	Removes the (I-X) escalation of GRC amounts embedded in payment amounts. Designed using the forecast 2027-2031 GRC costs as adjusted to reflect the settlement adjusted production forecast
Global Hydroelectric Capital Variance Account	Records the difference, for the 2028-2031 period on a cumulative four-year basis and asymmetrically in favour of ratepayers, between (i) the forecast capital-related revenue requirement ("**CRRR**") that forms the basis of the C-factor, and (ii) the CRRR determined based on OPG's actual in-service capital additions for the regulated hydroelectric facilities	Records the difference, for the 2027-2031 period on a cumulative five-year basis and asymmetrically in favour of ratepayers, between (i) for 2027, the forecast CRRR that underpins the 2027 payment amount and, for the 2028-2031 period, the forecast CRRR that forms the basis of the C-factor, and (ii) the CRRR determined based on

[14] Incremental production increases are expected due to generating capacity additions from OPG's redevelopment and refurbishment projects, as described in Ex. D1-1-2 and Ex. L-E1-CCC-063.

	OPG's Original Proposal	Settlement Proposal
		OPG's actual in-service capital additions for the regulated hydroelectric facilities

Table 20 below shows the 2027-2031 regulated hydroelectric capital-related revenue requirement and the 2028-2031 incremental regulated hydroelectric capital funding requirement under the settled rate-setting framework parameters, on the same basis as Ex. A1-3-2, Chart 6. Table 21 below sets out the formula-derived non-capital regulated hydroelectric revenue requirement and Table 22 below provides the determination of the 2028-2031 Capital factor, as settled, on the same basis as Ex. A1-3-2, Charts 7 and 8, respectively. For comparison, Tables 20A, 21A, and 22A below set out the above calculations as proposed in the Application. Table 23 below sets out the determination of the 2028-2031 GRCF, as settled, on the same basis as Ex. A1-3-2, Chart 9. Table 24 below provides the determination of the settled production growth factor, on the same basis as Ex. JT5.14, Chart 1. Tables 20-24 below reflect the corresponding adjustments to the 2027 test year revenue requirement, the 2028-2031 capital-related revenue requirement, and the production forecast for the regulated hydroelectric facilities agreed to in this Settlement Proposal.

Table 20 – 2027-2031 Regulated Hydroelectric Capital-related Revenue Requirement and the 2028-2031 Incremental Regulated Hydroelectric Capital Funding Requirement per Settlement Proposal ($M)

Line No.	Description	Note	2027	2028	2029	2030	2031
1	Depreciation	Determined on a cost-of-service basis	213.2	223.8	241.6	252.8	259.0
2	Cost of Capital		596.1	632.4	701.0	737.6	767.5
3	Income Tax		(3.3)	15.0	86.5	100.1	96.5
4	**Capital-Related Revenue Requirement**	Sum lines 1 to 3	**806.0**	**871.1**	**1,029.1**	**1,090.6**	**1,123.0**
5	Stretch Factor	0.3% stretch + 0.3% supplemental capital stretch	-	0.6%	0.6%	0.6%	0.6%
6	Capital-Related Revenue Requirement Stretch Adjustment	line 4 x line 5 (cumulative)	-	5.2	11.4	17.9	24.7
7	**Capital-Related Revenue Requirement (after stretch adjustment)**	line 4 - line 6	**806.0**	**865.9**	**1,017.7**	**1,072.6**	**1,098.3**
8	Capital Funding Provided through (I-X), *assuming C-Factor application in preceding years*	(line 8_{t-1} + line 9_{t-1}) x (I-X)	806.0	827.2	888.6	1,044.5	1,100.8

Line No.	Description	Note	2027	2028	2029	2030	2031
9	**Incremental Capital Funding Requirement**	line 7 - line 8	**-**	**38.7**	**129.1**	**28.2**	**(2.4)**

Table 20A – 2027-2031 Regulated Hydroelectric Capital-related Revenue Requirement and the 2028-2031 Incremental Regulated Hydroelectric Capital Funding Requirement per Application[15] ($M)

Line No.	Description	Note	2027	2028	2029	2030	2031
1	Depreciation	Determined on a cost-of-service basis	215.4	228.4	249.6	263.6	271.7
2	Cost of Capital		634.2	681.2	766.6	816.3	855.8
3	Income Tax		27.3	70.3	87.6	101.6	110.7
4	**Capital-Related Revenue Requirement**	Sum lines 1 to 3	**876.9**	**979.9**	**1,103.8**	**1,181.5**	**1,238.1**
5	Stretch Factor	0.15% stretch	-	0.15%	0.15%	0.15%	0.15%
6	Capital-Related Revenue Requirement Stretch Adjustment	line 4 x line 5 (cumulative)	-	1.5	3.1	4.9	6.8
7	**Capital-Related Revenue Requirement (after stretch adjustment)**	line 4 - line 6	**876.9**	**978.5**	**1,100.7**	**1,176.6**	**1,231.4**
8	Capital Funding Provided through (I-X), *assuming C-Factor application in preceding years*	(line 8_{t-1} + line 9_{t-1}) x (I-X)	876.9	901.3	1,005.6	1,131.2	1,209.2
9	**Incremental Capital Funding Requirement**	line 7 - line 8	**-**	**77.2**	**95.1**	**45.3**	**22.2**

Table 21 – 2027-2031 Formula-Derived Non-Capital Regulated Hydroelectric Revenue Requirement per Settlement Proposal ($M)

Line No.	Description	Note	2027	2028	2029	2030	2031
1	OM&A (incl. Property Tax)	Inclusive of settlement adjustments, escalated by (I-X)	476.4	488.9	501.8	514.9	528.5
2	GRC	Per Ex. L-A1-SEC-012, Attachment 1, Table 1, line 7, as increased to reflect 0.45 TWh increase in production forecast	358.7	361.0	362.0	360.7	361.3
3	Other Revenues	Escalated by (I-X)	(91.6)	(94.0)	(96.5)	(99.0)	(101.6)
4	Settlement Adjustment	Escalated by (I-X)	(5.9)	(6.1)	(6.3)	(6.4)	(6.6)
5	**Total Non-Capital Revenue Requirement**	Sum lines 1 to 4	**737.6**	**749.8**	**761.0**	**770.2**	**781.6**

[15] Exhibit JT4.13, Attachment 1, Table 2.

Table 21A – 2027-2031 Formula-Derived Non-Capital Regulated Hydroelectric Revenue Requirement per Application[16] ($M)

Line No.	Description	Note	2027	2028	2029	2030	2031
1	OM&A (incl. Property Tax)	Escalated by (I-X)	501.4	515.3	529.6	544.3	559.5
2	GRC	Fixed at 2027 amount	352.2	352.2	352.2	352.2	352.2
3	Other Revenues	Escalated by (I-X)	(62.2)	(64.0)	(65.7)	(67.6)	(69.4)
4	**Total Non-Capital Revenue Requirement**	Sum lines 1 to 3	**791.4**	**803.6**	**816.1**	**829.0**	**842.2**

Table 22 – Determination of 2028-2031 Regulated Hydroelectric Capital Factor per Settlement Proposal

Line No.	Description	Note	2027	2028	2029	2030	2031
1	Capital-Related Revenue Requirement (after stretch adjustment) ($M)	Table 20, line 7	806.0	865.9	1,017.7	1,072.6	1,098.3
2	Total Non-Capital Revenue Requirement ($M)	Table 21, line 5	737.6	749.8	761.0	770.2	781.6
3	**Total Revenue Requirement ($M)**	line 1 + line 2	**1,543.6**	**1,615.8**	**1,778.8**	**1,842.8**	**1,879.9**
4	Incremental Capital Funding Requirement ($M)	Table 20, line 9	-	38.7	129.1	28.2	(2.4)
5	**Custom Capital Factor (%)**	line 4 / line 3_{t-1}		**2.5%**	**8.0%**	**1.6%**	**-0.1%**

Table 22A – Determination of 2028-2031 Regulated Hydroelectric Capital Factor per Application[17]

Line No.	Description	Note	2027	2028	2029	2030	2031
1	Capital-Related Revenue Requirement (after stretch adjustment) ($M)	Table 20a, line 7	**876.9**	**978.5**	**1,100.7**	**1,176.6**	**1,231.4**
2	Total Non-Capital Revenue Requirement ($M)	Table 21a, line 4	**791.4**	**803.6**	**816.1**	**829.0**	**842.2**
3	**Total Revenue Requirement ($M)**	line 1 + line 2	**1,668.3**	**1,782.0**	**1,916.8**	**2,005.6**	**2,073.6**
4	Incremental Capital Funding Requirement ($M)	Table 20a, line 9	-	**77.2**	**95.1**	**45.3**	**22.2**
5	**Custom Capital Factor (%)**	line 4 / line 3_{t-1}		**4.6%**	**5.3%**	**2.4%**	**1.1%**

[16] *Ibid*.

[17] *Ibid*.

Table 23 – Determination of 2028-2031 Regulated Hydroelectric GRC Factor per Settlement Proposal

Line No.	Description	Note	2027	2028	2029	2030	2031
1	GRC Provided through (I-X) ($M)	(line 1 + line 2) x (I-X)	358.7	368.1	370.5	371.5	370.1
2	Variance to Forecast GRC ($M)	Table 21, line 2 - line 1	0	(7.1)	(8.5)	(10.8)	(8.9)
3	Total Revenue Requirement ($M)	Table 22, line 3	1,543.6	1,615.8	1,778.8	1,842.8	1,879.9
4	**GRCF (%)**	-(line 2 / line 3_{t-1})	**0%**	**0.5%**	**0.5%**	**0.6%**	**0.5%**

Table 24 – Determination of 2028-2031 Regulated Hydroelectric Production Growth Factor per Settlement Proposal

Line No.	Description	Note	2027	2028	2029	2030	2031
1	Production Forecast (TWh)	Ex. L-A1-SEC-011 + 0.45TWh	32.9	33.2	33.4	33.4	33.4
2	**Production Growth Factor (%)**	line 2 / Table 23, line 3_{t-1}		**0.8%**	**0.7%**	**0.1%**	**-0.2%**

The calculations of revenue requirement and payment amount adjustment factors determined in Tables 20-24 above result in the price cap indices and illustrative 2028-2031 regulated hydroelectric payment amounts presented in Table 24A below. For comparison, the price cap indices and illustrative 2028-2031 regulated hydroelectric payment amounts associated with OPG's original proposal are presented in Table 24B below.

Table 24A – Determination of 2028-2031 Price Cap Index and Illustrative Regulated Hydroelectric Payment Amounts – Settlement Proposal

Line No.	Description	Note	2027	2028	2029	2030	2031
1	I-Factor (%)	Ex. JT4.13, Att. 1, Table 1, line 1		2.9%	2.9%	2.9%	2.9%
2	Stretch Factor (%)			0.3%	0.3%	0.3%	0.3%
3	Custom Capital Factor (%)	Table 22, line 5		2.5%	8.0%	1.6%	-0.1%
4	GRCF (%)	Table 23, line 4		0.5%	0.5%	0.6%	0.5%
5	Production Growth Factor (%)	Table 24, line 2		0.8%	0.7%	0.1%	-0.2%
6	**Price Cap Index (%)**	Line 1 – line 2 + line 3 – line 4 – line 5		**3.9%**	**9.4%**	**3.5%**	**2.2%**
7	**Price Cap Adjusted Regulated Hydroelectric Payment Amount ($/MWh)**	Illustrative for 2028-2031 based on current I-Factor	**46.90**	**48.72**	**53.30**	**55.17**	**56.37**

Table 24B – Determination of 2028-2031 Price Cap Index and Illustrative Regulated Hydroelectric Payment Amounts – Application

Line No.	Description	Note	2027	2028	2029	2030	2031
1	I-Factor (%)	Ex. JT4.13, Att. 1, Table 1, line 1		2.9%	2.9%	2.9%	2.9%
2	Stretch Factor (%)			0.15%	0.15%	0.15%	0.15%
3	Custom Capital Factor (%)	Ex. JT4.13, Att. 1, Table 1, line 7		4.6%	5.3%	2.4%	1.1%
4	GRCF (%)	Ex. JT4.13, Att. 1, Table 1, line 8		0.6%	0.6%	0.5%	0.5%
5	Production Growth Factor (%)	Not proposed		N/A	N/A	N/A	N/A
6	**Price Cap Index (%)**	Line 1 – line 2 + line 3 – line 4 – line 5		**6.8%**	**7.6%**	**4.6%**	**3.4%**
7	**Price Cap Adjusted Regulated Hydroelectric Payment Amount ($/MWh)**	Illustrative for 2028-2031 based on current I-Factor	**51.39**	**54.89**	**59.04**	**61.77**	**63.87**

As part of OPG's rate-setting frameworks, the Parties have agreed (i) to the continuation of the existing asymmetrical earnings sharing mechanism, whereby 50% of any regulated earnings for OPG's combined nuclear and regulated hydroelectric business that exceed 100 basis points above the OEB approved ROE rate, as assessed over a cumulative five-year period, is shared with ratepayers[18], and (ii) that unforeseen events affecting OPG's regulated hydroelectric and nuclear businesses continue to be addressed through an accounting order process, subject to a $20M annual regulatory materiality threshold.

B. RATE BASE, COST OF CAPITAL AND CONCURRENT COST RECOVERY

(i) OPG Nuclear Rate Base and Concurrent Cost Recovery Amounts

The Parties agree to the opening 2027 rate base values for OPG nuclear facilities as proposed by OPG and adjusted for the CCC-084 Impacts, other than a permanent reduction of $40.0M and an adjustment to the DRP rate base to reflect OPG's updated forecast of the DRP's total forecast cost of $12.65B since the Application was filed, which represents a reduction of $50.0M from the pre-filed evidence.

The Parties further agree to the forecast rate base for OPG nuclear facilities for the 2027-2031 period as set out in Table 25 below. The reduction in the rate base relative to OPG's request relates to the agreed-upon adjustments to the opening 2027 rate base values, the CCC-084 Impacts and adjustments to the proposed 2027-2031 forecast in-service capital additions for Nuclear Operations and Corporate Support Services projects

[18] Exhibit A1-3-2, Section 4.1

discussed below. The agreed-upon rate base values also reflect the corresponding adjustments to the forecast depreciation and amortization expenses.

Table 25 – 2027-2031 Settlement Adjusted OPG Nuclear Rate Base ($M)

	2027	2028	2029	2030	2031
Proposed OPG Nuclear Rate Base	15,749.4	16,278.6	16,217.5	16,807.3	23,519.3
Settlement Adjusted OPG Nuclear Rate Base	15,489.2	15,791.6	15,634.3	15,994.5	21,943.9
Difference	(260.2)	(487.0)	(583.3)	(812.7)	(1,575.4)

OPG's proposed forecast nuclear in-service capital additions for the 2027-2031 period are set out in Table 26 below.

Table 26 – Proposed Forecast OPG Nuclear In-service Capital Additions ($M)

	Reference	2027	2028	2029	2030	2031
Nuclear Operations Capital Projects	Ex. D2-1-3, Tables 4a, line 50 and 4b, line 76	848.0	799.8	1,004.6	1,408.0	958.6
Pickering Refurbishment Program	Ex. D2-3-8, Table 5, line 11	20.6	0.0	0.0	0.0	9,688.0
Corporate Support Services Projects Entering OPG Nuclear Rate Base	Ex. D3-1-2, Tables 5a, line 22 + line 27 and 5b, line 1 + line 6	133.9	62.1	67.1	71.4	39.7
Total Proposed OPG Nuclear In-service Additions		1,002.5	861.9	1,071.7	1,479.4	10,686.3

The Parties agree that the forecasted capital expenditures, financial commitments and in-service capital additions for the PRP as set out in the Application are reasonable and form part of OPG's settlement adjusted nuclear rate base for the 2027-2031 period without adjustments.

With respect to the Nuclear Operations capital projects, the Parties agree to reduce, relative to OPG's proposal in the Application as adjusted for the CCC-084 Impacts, the forecast in-service capital additions to rate base by 10% per year for the 2027-2031 period. With respect to the Corporate Support Services capital projects entering OPG's nuclear rate base, the Parties agree to reduce, relative to OPG's proposal in the Application, the forecast in-service capital additions by 11% per year for the 2027-2031 period.

For purposes of settlement, the Parties also agree to a change in the forecast timing in which certain Nuclear Operations in-service capital amounts related to Pickering are included in the forecast rate base for the 2027-2031 period. Specifically, the following amounts are removed from the 2027-2030 period and added to 2031: $0.5M in 2027, $15.7M in 2028, $17.6M in 2029, and $220.2M in 2030. The total adjustment to 2031 is therefore an increase in the settled in-service capital additions by $254.0M. The above modifications have been reflected at the mid-year average in the settlement adjusted forecast rate base.

The adjustments associated with the above in-service capital reductions and modifications, together with the gross plant reductions arising from the CCC-084 Impacts, are set out in Table 27 below. These adjustments associated with the above in-service adjustments and modifications apply to CRVA non-eligible projects.

Table 27 – Settlement Adjustments to Forecast OPG Nuclear In-service Capital Additions ($M)

	2027	2028	2029	2030	2031
OPG Nuclear Operations Projects	(94.2)	(108.7)	(140.6)	(388.5)	77.6
Darlington Refurbishment Program	(249.1)	0.0	0.0	0.0	0.0
Pickering Refurbishment Program	(0.4)	0.0	0.0	0.0	(1,005.3)
Corporate Support Services Projects	(14.7)	(6.8)	(7.4)	(7.9)	(4.4)

	2027	2028	2029	2030	2031
Entering OPG Nuclear Rate Base					
Total Settlement Adjustments to OPG Nuclear in-service Additions and CEITC Adjustments	(358.5)	(115.6)	(148.0)	(396.4)	(932.0)

The settlement adjusted forecasted OPG nuclear in-service capital additions for the 2027-2031 period are set out in Table 28 below.

Table 28 – Settlement Adjusted Forecast OPG Nuclear In-service Capital Additions Net of CEITC Adjustments ($M)

	2027	2028	2029	2030	2031
OPG Nuclear Operations Projects	753.8	691.1	864.0	1,019.5	1,036.3
Darlington Refurbishment Program	(249.1)	0.0	0.0	0.0	0.0
Pickering Refurbishment Program	20.2	0.0	0.0	0.0	8,682.7
Corporate Support Services Projects Entering OPG Nuclear Rate Base	119.2	55.3	59.7	63.5	35.3
Total Settlement Adjusted OPG Nuclear In-service Additions Net of CEITC Adjustments	664.0	746.4	923.7	1,083.1	9,754.3

The Parties agree to the treatment as CRVA eligible of the regulated nuclear projects and initiatives as identified in Section 4, Issue 13 of this Settlement Proposal.

The Parties agree that the forecast CCR interest amounts of $2.7B over the 2027-2031 period associated with the PRP, as proposed in the Application and adjusted for the CCC-084 Impacts, meet the requirements set out in s. 6(2)12.1i of O. Reg. 53/05 and are correctly reflected in OPG's nuclear revenue requirements on that basis. These CCR interest amounts are set out in Table 29 below.

Table 29 – 2027-2031 Settlement Adjusted OPG CCR Interest Amounts ($M)

	2027	2028	2029	2030	2031
Proposed OPG CCR Interest Amounts	297.6	479.9	667.7	832.0	646.2
Settlement Adjusted OPG CCR Interest Amounts	295.0	465.5	626.4	755.0	576.0
Difference	(2.6)	(14.3)	(41.3)	(77.1)	(70.2)

(ii) Regulated Hydroelectric Rate Base

The Parties agree to the opening 2027 rate base values for regulated hydroelectric facilities as proposed by OPG and adjusted for the CCC-084 Impacts, other than a permanent reduction of $40.0M and an adjustment to reflect lower than forecast actual in-service capital additions for 2025 in the amount of $19.5M as shown in Ex. L-A1-CCC-001, Attachment 1, Table 1.

The Parties further agree to the forecast rate base for the regulated hydroelectric facilities for the 2027-2031 period as set out in Table 30 below. The reduction in the rate base relative to OPG's request relates to the agreed-upon adjustments to the opening 2027 rate base values, the CCC-084 Impacts and adjustments to the proposed 2027-2031 forecasted in-service capital additions for the regulated hydroelectric facilities discussed below. The agreed-upon forecast rate base values also reflect the corresponding adjustments to the forecast depreciation and amortization expenses. These adjustments are reflected in the calculation of the Capital factor in Table 22 above, to be used as part of the regulated hydroelectric rate setting formula over the 2028-2031 period.

Table 30 – 2027-2031 Settlement Adjusted Regulated Hydroelectric Rate Base ($M)

	2027	2028	2029	2030	2031
Proposed Regulated Hydroelectric Rate Base	9,135.1	9,687.1	10,814.1	11,471.1	12,007.4
Settlement Adjusted Regulated Hydroelectric Rate Base	9,008.4	9,419.3	10,350.5	10,853.1	11,282.7
Difference	(126.8)	(267.8)	(463.6)	(618.0)	(724.7)

The Parties agree to reduce, relative to OPG's proposal in the Application, the forecast regulated hydroelectric in-service capital additions to rate base as adjusted for the CCC-084 Impacts, excluding those with respect to the Corporate Support Services capital projects, by 13% per year for the 2027-2031 period. With respect to the Corporate Support Services capital projects entering the regulated hydroelectric rate base, the Parties agree to reduce, relative to OPG's proposal in the Application, the forecast in-service capital additions by 11% per year for the 2027-2031 period. The adjustments associated with these reductions, together with the gross plant reductions arising from the CCC-084 Impacts, are set out in Table 31 below. The adjustments associated with the above in-service capital reductions apply to CRVA non-eligible projects.

Table 31 – Proposed and Settlement Adjusted Forecast Regulated Hydroelectric In-service Capital Additions Net of CEITC Adjustments ($M)

	Reference	2027	2028	2029	2030	2031
Proposed Forecast Regulated Hydroelectric						
Regulated Hydroelectric Projects	Ex. D1-1-2, Table 4	841.5	1,104.7	1,115.5	938.5	627.1
Corporate Support Services Projects Entering Regulated Hydroelectric Rate Base	Ex. D3-1-2, Table 4	1.5	1.5	1.5	1.5	1.5
Total Proposed Regulated Hydroelectric In-Service Additions		843.0	1,106.2	1,117.0	940.0	628.6
Settlement Adjustments to Forecast Regulated Hydroelectric						
Regulated Hydroelectric Projects		(131.5)	(184.5)	(186.7)	(143.9)	(95.7)
Corporate Support Services Projects Entering Regulated Hydroelectric Rate Base		(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
Total Settlement Adjustments to Regulated Hydroelectric In-Service Additions and CEITC Adjustments		(131.6)	(184.7)	(186.8)	(144.1)	(95.8)
Settlement Adjusted Forecast Regulated Hydroelectric						
Regulated Hydroelectric Projects		710.1	920.2	928.8	794.5	531.4
Corporate Support Services Projects		1.3	1.3	1.3	1.3	1.3

	Reference	2027	2028	2029	2030	2031
Entering Regulated Hydroelectric Rate Base						
Total Settlement Adjusted Regulated Hydroelectric In-Service Additions Net of CEITC Adjustments		711.4	921.5	930.2	795.8	532.8

The Parties agree to the treatment as CRVA eligible of the regulated hydroelectric projects and initiatives as identified in Section 4, Issue 11 of this Settlement Proposal.

(iii) OPG Cost of Capital and Capital Structure

For purposes of settlement, the Parties agree for OPG's capital structure to remain unchanged from EB-2016-0152 and EB-2020-0290 at 45% equity and 55% debt for the purposes of determining its 2027-2031 revenue requirements and payment amounts. OPG had proposed a capital structure of 52% equity and 48% debt in the Application.

The Parties also agree to set the ROE rate, long-term cost of debt rate and short-term cost of debt rate for the purposes of determining OPG's 2027-2031 revenue requirements and payment amounts as proposed in the Application and as adjusted for the CCC-084 Impacts.

Based on the above parameters and subject to the update for the prevailing ROE rate specified by the OEB as of the effective date of the final payment amounts order in this proceeding, Tables 32 and 33 below set out the settlement adjusted OPG cost of capital amounts for the 2027-2031 period. These cost of capital amounts reflect the corresponding forecast rate base values and revenue requirement impacts of OPG's nuclear liabilities agreed to in this Settlement Proposal.

Table 32 – 2027-2031 Settlement Adjusted OPG Nuclear Cost of Capital Amounts ($M)

	2027	2028	2029	2030	2031
Proposed OPG Nuclear Cost of Capital	1,087.9	1,141.4	1,147.1	1,193.8	1,674.2
Settlement Adjusted OPG Nuclear Cost of Capital	1,020.1	1,057.2	1,056.7	1,085.1	1,491.0
Difference	(67.8)	(84.2)	(90.4)	(108.7)	(183.2)

Table 33 – 2027-2031 Settlement Adjusted Regulated Hydroelectric Cost of Capital Amounts ($M)

	2027	2028	2029	2030	2031
Proposed Regulated Hydroelectric Cost of Capital[19]	634.2	681.2	766.6	816.3	855.8
Settlement Adjusted Regulated Hydroelectric Cost of Capital	596.1	632.4	701.0	737.6	767.5
Difference	(38.1)	(48.8)	(65.6)	(78.7)	(88.3)

C. PRODUCTION FORECAST

(i) OPG Nuclear Production Forecast

The Parties agree to a modified 2027-2031 OPG nuclear production forecast compared to OPG's original proposal, as set out in Table 34 below.

Table 34 – 2027-2031 Settlement Adjusted OPG Nuclear Production Forecast (TWh)

	2027	2028	2029	2030	2031
Proposed OPG Nuclear Production Forecast	18.7	26.7	25.1	26.8	28.9
Settlement Adjusted OPG Nuclear Production Forecast	19.3	27.6	25.8	27.7	29.9
Difference	0.65	0.875	0.75	0.85	1.0

[19] Exhibit JT4.13, Att. 1, Table 2: line 2 + line 3.

The Parties have also agreed to establish a new symmetrical planned outage days settlement variance account to share net revenue impacts with ratepayers resulting from certain variances to the forecast planned outage days at the Darlington Nuclear Generating Station ("**Darlington**") over a cumulative basis over the 2027-2031 period. For settlement purposes, including the operation of this variance account, the Parties have agreed to attribute the settlement adjustment increasing the OPG nuclear production forecast by an average of 0.825 TWh per year (4.125 TWh over the rate period), as set out in Table 34 above, to planned outage days at Darlington[20]. Under the agreed terms of this account, OPG will be permitted to recover 50% of foregone revenues, net of associated nuclear fuel costs, over the 2027-2031 period that result from higher planned outage days at Darlington compared to such settlement adjusted forecast planned outages days reflected in this Settlement Proposal with respect to foregone revenues not cumulatively exceeding an equivalent of 4.125 TWh in OPG's nuclear production at Darlington over the period. In the event the actual planned outage days at Darlington over the 2027-2031 period are lower than such settlement adjusted planned outage days reflected in this Settlement Proposal, OPG will credit ratepayers with 50% of the resulting incremental revenues, net of associated nuclear fuel costs, with respect to incremental revenues not cumulatively exceeding an equivalent of 2.675 TWh of OPG's nuclear production at Darlington over the period, and 75% of the resulting incremental revenues, net of associated nuclear fuel costs, with respect to incremental revenues cumulatively exceeding an equivalent of 2.675 TWh of OPG's nuclear production at Darlington over the period.

The Parties have also agreed to establish the Pickering Refurbishment 2027-2031 Early Return to Service Variance Account to return to ratepayers 75% of OPG's incremental revenues, net of associated nuclear fuel costs, resulting from any of the Pickering units returning to service from refurbishment during the 2027-2031 period earlier than reflected in OPG's nuclear production forecast as approved by the OEB in this proceeding.

For clarity, OPG's earnings sharing mechanism calculation will be performed after any positive or negative amounts recorded in the above accounts, to avoid duplication.

(ii) Regulated Hydroelectric Production Forecast

The Parties agree to modify the regulated hydroelectric production forecast from OPG's original proposal, as set out in Table 35 below, (i) by increasing the 2027 forecast production (for purposes of the 2027 payment amount) by 0.45 TWh, and (ii) by reflecting a settlement adjusted forecast production for the 2028-2031 period (for purposes of

[20] The Parties agree that the settlement adjustment increasing the OPG nuclear production forecast over the 2027-2031 period corresponds to the following decreases in the forecasted planned outage days at Darlington set out at Ex. E2-1-2, Table 1b, lines 3 and 32: 30.8 days in 2027, 41.5 days in 2028, 35.6 days in 2029, 40.3 days in 2030, and 47.5 days in 2031. Darlington planned outage days are converted to TWh at a rate of 0.021072 TWh per planned outage day, as reflected in Ex. JT3.20, Attachment 1.

modifying OPG's proposed regulated hydroelectric rate-setting framework to account for the expected year-over-year changes in the 2028-2031 production forecast through the production growth factor, which, on average, has the effect of reducing payment amounts). The settlement adjusted production forecast for each of the 2028-2031 years represents the regulated hydroelectric production forecast for those years set out in Ex. L-A1-SEC-011, as increased by 0.45 TWh.

Table 35 – 2027-2031 Settlement Adjusted Regulated Hydroelectric Production Forecast (TWh)

	2027	2028	2029	2030	2031
Proposed Regulated Hydroelectric Production Forecast	32.5	n/a	n/a	n/a	n/a
Settlement Adjusted Regulated Hydroelectric Production Forecast	32.9	33.2	33.4	33.4	33.4
Difference	0.45	n/a	n/a	n/a	n/a

D. OPERATING COSTS

(i) OPG Nuclear OM&A Expenses

The Parties agree to reduce the proposed forecast total OM&A expenses for OPG nuclear facilities, excluding Pickering Refurbishment OM&A expenses and including associated Allocation of Corporate Costs, Allocation of Centrally Held Costs and Asset Service Fees, for the 2027-2031 period as follows: $90.0M in 2027, $125.0M in 2028, $130.0M in 2029, $130.0M in 2030, $140.0M in 2031, which represents an average reduction of 6.7% over the period. The Parties agree to the forecast Pickering Refurbishment OM&A expenses as proposed by OPG in the Application. The resulting settlement adjusted total OM&A expenses for OPG nuclear facilities are set out in Table 36 below.

Table 36 – 2027-2031 Settlement Adjusted Total OPG Nuclear OM&A Expenses ($M)

	2027	2028	2029	2030	2031
Proposed Total OPG Nuclear OM&A	1,863.7	1,756.0	1,917.4	1,854.9	2,150.6
Settlement Adjusted Total OPG Nuclear OM&A	1,773.7	1,631.0	1,787.4	1,724.9	2,010.6
Difference	(90.0)	(125.0)	(130.0)	(130.0)	(140.0)

(ii) OPG Nuclear Fuel Costs

OPG's nuclear fuel costs consist of the following:

- The weighted average cost of manufactured uranium fuel bundles loaded into a reactor ("**nuclear fuel bundle cost**");
- Used nuclear fuel storage and disposal costs; and
- Fuel oil used to run stand-by generators at OPG's nuclear stations.

The Parties agree to reduce the nuclear fuel bundle cost forecast by replacing the high-price midpoint uranium forecast reflected in OPG's proposal with the mid-price midpoint uranium forecast as set out in Ex. L-F2-SEC-171. The Parties also agree to establish a symmetrical fuel cost variance account for OPG's nuclear facilities. For purposes of account entries, variances will be determined on an annual $/MWh basis, relative to the settlement adjusted values, as applied to the forecast OPG nuclear production underpinning the nuclear payment amounts. The settlement adjusted fuel costs also reflect the impacts of the settlement adjustments to OPG's nuclear production forecast. The settlement adjusted OPG nuclear fuel costs are set out in Table 37 below.

Table 37 – 2027-2031 Settlement Adjusted OPG Nuclear Fuel Costs ($M)

	2027	2028	2029	2030	2031
Proposed OPG Nuclear Fuel Costs	150.9	221.7	223.6	261.2	306.1
Settlement Adjusted OPG Nuclear Fuel Costs	154.6	225.2	224.0	259.3	302.6
Difference	3.7	3.5	0.5	(1.9)	(3.6)

(iii) Regulated Hydroelectric OM&A Expenses

The Parties agree to reduce the proposed forecast total OM&A expenses for OPG's regulated hydroelectric facilities by $25.0M for the 2027 test year, inclusive of associated

Allocation of Corporate Costs, Allocation of Centrally Held Costs and Asset Service Fees, which represents a reduction of approximately 5%. The resulting settlement adjusted total OM&A expenses for OPG's regulated hydroelectric facilities for the 2027 test year are $474.3M.

(iv) Regulated Hydroelectric GRC Costs

The Parties agree to modify the regulated hydroelectric GRC costs forecasts from OPG's original proposal, as set out in Table 38 below, by (i) increasing the 2027 GRC costs for the impact of the settlement adjustments to the 2027 regulated hydroelectric production forecast (for purposes of the 2027 payment amount), and (ii) reflecting a settlement adjusted GRC costs forecast for the 2028-2031 period (for purposes of determining the GRCF) in conjunction with modifying OPG's proposed regulated hydroelectric rate-setting framework to account for year-over-year changes in the 2028-2031 production forecast through the production growth factor. The settlement adjusted GRC costs forecast for the 2028-2031 years represents such forecast set out in Ex. L-A1-SEC-012, Attachment 1, Table 1, line 7, as increased to reflect an additional 0.45 TWh in forecast annual production at the $14.40/MWh GRC tier.

Table 38 – 2027-2031 Settlement Adjusted Regulated Hydroelectric GRC Costs ($M)

	2027	2028	2029	2030	2031
Proposed GRC Costs	352.2	n/a	n/a	n/a	n/a
Settlement Adjusted GRC Costs	358.7	361.0	362.0	360.7	361.3
Difference	6.5	n/a	n/a	n/a	n/a

(v) OPG Nuclear Depreciation and Amortization Expenses

Subject to the impact of settlement adjustments to the rate base values and the forecast in-service capital additions and the CCC-084 Impacts, the Parties agree to the proposed OPG nuclear and regulated hydroelectric depreciation and amortization expenses for the 2027-2031 period as set out in the Application. The settlement adjusted forecast depreciation and amortization expenses for OPG nuclear and regulated hydroelectric facilities are set out in Table 39 and Table 40, respectively, below.

Table 39 – 2027-2031 Settlement Adjusted OPG Nuclear Depreciation and Amortization Expenses ($M)

	2027	2028	2029	2030	2031
Proposed OPG Nuclear Depreciation and Amortization	663.3	708.5	730.3	779.8	992.6
Settlement Adjusted OPG Nuclear Depreciation and Amortization	652.5	687.5	704.0	743.7	932.0
Difference	(10.8)	(21.0)	(26.3)	(36.2)	(60.6)

Table 40 – 2027-2031 Settlement Adjusted Regulated Hydroelectric Depreciation and Amortization Expenses ($M)

	2027	2028	2029	2030	2031
Proposed Regulated Hydroelectric Depreciation and Amortization	215.4	228.4	249.6	263.6	271.7
Settlement Adjusted Regulated Hydroelectric Depreciation and Amortization	213.2	223.8	241.6	252.8	259.0
Difference	(2.2)	(4.6)	(8.0)	(10.7)	(12.8)

(vi) OPG Income and Property Taxes

Subject to the impact of settlement adjustments to other components of OPG's revenue requirements and the CCC-084 Impacts, the Parties agree to the proposed OPG nuclear and regulated hydroelectric regulatory income tax and property tax amounts for the 2027-2031 period as set out in the Application. The settlement adjusted forecast regulatory income tax expenses for the regulated hydroelectric facilities are set out in Table 41 below.[21] There are no settlement adjustments to OPG's forecast property tax expenses.

[21] For OPG nuclear facilities, the settlement adjustments do not impact OPG's regulatory income tax expenses as proposed in the Application for revenue requirement purposes due to the forecast regulatory tax loss position (Ex. F4-2-1, Section 3.1); instead, these adjustments affect the nuclear regulatory tax loss balance carried forward to the next rate-setting period.

Table 41 – 2027-2031 Settlement Adjusted Regulated Hydroelectric Regulatory Income Tax Expenses ($M)

	2027	2028	2029	2030	2031
Proposed Regulated Hydroelectric Income Taxes	27.3	70.3	87.6	101.6	110.7
Settlement Adjusted Regulated Hydroelectric Income Taxes	(3.3)	15.0	86.5	100.1	96.5
Difference	(30.6)	(55.3)	(1.1)	(1.5)	(14.2)

E. OTHER REVENUES

The Parties agree to the forecast other revenues for OPG nuclear facilities for the 2027-2031 period as proposed in the Application, including Bruce lease net revenues.

Regarding forecast other revenues for the regulated hydroelectric facilities, the Parties agree to increase the amount applied to offset the revenue requirement by $29.4M for the 2027 test year, of which $18.4M is associated with HIM revenues, $8.0M with ancillary services and $3.0M with other revenue categories (i.e., Segregated Mode of Operation, Water Transactions, and Capacity Exports). The resulting settlement adjusted other revenues for regulated hydroelectric facilities are $91.6M for the 2027 test year.

F. GENERAL REVENUE REQUIREMENT ADJUSTMENTS

In addition to the basis and mechanisms agreed to by the Parties herein related to the determination of OPG's nuclear and regulated hydroelectric revenue requirements, the Parties also took a holistic approach to the revenue requirement totals and, in this regard, have agreed to reduce OPG's proposed 2027 regulated hydroelectric revenue requirement by $5.9M and reduce OPG's proposed nuclear revenue requirements over the 2027-2031 period as follows: $35.4M in 2027, $35.4M in 2028, $35.4M in 2029, $35.4M in 2030, and $50.4M in 2031.

G. DEFERRAL AND VARIANCE ACCOUNTS

The Application proposes to clear the audited balances in all of OPG's deferral and variance accounts as at December 31, 2024, less amortization amounts previously approved by the OEB, with certain exceptions. With the exception of the Rate Smoothing Deferral Account, OPG proposed to recover or refund the balances over a three-year period from January 1, 2027 to December 31, 2029. OPG proposed to recover the balance in the Rate Smoothing Deferral Account over the ten-year period from January

1, 2027 to December 31, 2036, being such maximum period permissible pursuant to s. 6(2)12iv of O. Reg. 53/05.

Excluding to the Outstanding Issue, the Parties agree that OPG shall recover or refund all deferral and variance account balances as proposed in the Application, with the exception of (i) the $7.7M debit balance in the Clarington Corporate Campus Deferral Account and an agreed upon $575,000 debit balance in respect of the CRVA (Nuclear – Non-DRP), both of which will not be recovered, and (ii) an agreed upon $37.0M debit balance in respect of the SBGVA, the consideration of which will be deferred to a subsequent proceeding.

The Parties agree to continue or discontinue existing deferral and variance accounts for OPG, effective January 1, 2027 unless otherwise noted, as proposed in the Application, including the methodologies that will be used to record entries into these accounts, with the following modifications:

- **Pension and OPEB Cost Variance Account (OPG)** will record the difference between (i) the pension and other post employment benefit ("**OPEB**") non-capital costs, plus related income tax PILs, reflected in the revenue requirement approved by the OEB; and (ii) OPG's actual pension and OPEB non-capital costs, and associated tax impacts, for the prescribed generation facilities, excluding any variances arising from differences in staffing levels (other than changes in long-term disability benefit plan data) and compensation levels including pension and benefit plan provisions. Actual pension and OPEB non-capital costs used in the calculation of the difference shall be calculated on an accrual basis using the same accounting standards as those used to derive the reference amount and holding constant staffing levels (other than changes in long-term disability benefit plan data) and compensation levels including pension and benefit plan provisions that are reflected in the reference amount;

- **Hydroelectric Surplus Baseload Generation Variance Account** shall only record amounts relating to global SBG spill and not local SBG spill, where the global SBG spill calculation methodology will be as described below, for the period until the effective date of the payment amounts order in OPG's next application seeking to clear the SBGVA balances, at which time a determination with respect to the treatment of local SBG spill in the SBGVA will be made on a then go-forward basis:

    - OPG will calculate global SBG spill using the general principles in the IESO's proposed methodology, introduced through IESO Pre-Settlement Question #1 in EB-2025-0297 and provided in Attachment 1, particularly as described in Condition 1, by categorizing spill consistent

with the basis and methodology used in OPG's existing SBGVA algorithm. Specifically, OPG will modify the IESO's proposal as follows:

- OPG will use an hourly average for the Energy Reference Price[22]; and
- OPG will compare the applicable GRC against the Energy Reference Price as identified in the IESO's proposal's Condition 1. Spill amounts when the Energy Reference Price is less than or equal to GRC will be categorized as global SBG spill.

- **Ancillary Services Net Revenue Variance Account – Nuclear Sub-Account** and **Hydroelectric Incentive Mechanism Variance Account** will continue, using the methodologies previously approved by the OEB. The HIM is discussed in Section 4, Issue 21 of this Settlement Proposal;
- **Nuclear Development Variance Account** will not accrue interest on the existing December 31, 2024 debit balance of $23.5M not related to the DNNP;
- **Clarington Corporate Campus Deferral Account** will be terminated effective January 1, 2027; and
- Any changes in the CCA rules or rates, including immediate expensing for tax purposes, will be recorded in a newly established account as described below, rather than the existing deferral and variance accounts.

The Parties agree to establish new deferral and variance accounts for OPG, effective January 1, 2027 unless otherwise noted, including the Clean Electricity ITC Variance Account (OPG) and the DNNP Nuclear Liability Deferral Account, as proposed in the Application, including the methodologies that will be used to record entries into these accounts, with the following modifications:

- **Nuclear Security Regulation and American Eel Impact Deferral Account (OPG)** will record the impacts for OPG's prescribed facilities associated with the following, replacing OPG's proposed Change of Laws Deferral Account (OPG):
  - Canadian Nuclear Safety Commission ("**CNSC**") Security Regulations (identified at Ex. JT5.18), for which the account will capture the revenue requirement impacts for the nuclear facilities

[22] The Energy Reference Price is the locational marginal price at the RICHVIEW-230. REFERENCE pricing location identified in the IESO's Real-Time 5 Min Energy LMP Report.

resulting from increased security requirements for high security nuclear sites, to the extent such impacts are not reflected in OPG's payment amounts; and

- Provincial and federal changes in law pertaining to the American eel (Ex. H1-1-1, Section 7.1.2), for which the account will capture the revenue requirement impacts resulting from compliance activities, as well as any resulting foregone production revenue impacts, net of associated GRC costs, with respect to the regulated hydroelectric facilities, to the extent such impacts are not reflected in OPG's payment amounts;

- **Global Hydroelectric Capital Variance Account** will have an expanded scope that includes the 2027 year, in addition to the 2028-2031 period. The account is discussed in Section 2, Part A, Table 19 of this Settlement Proposal;

- **Nuclear Fuel Cost Variance Account (OPG)** will be established to record nuclear fuel bundle cost variances (on a $/MWh basis) applicable to OPG's nuclear facilities, as discussed in Section 2, Part D, subsection (ii) of this Settlement Proposal;

- **Darlington Planned Outage Days (2027-2031) Settlement Variance Account** will be established to share certain positive and negative OPG net revenue impacts with ratepayers, on a cumulative basis with respect to the 2027-2031 period, resulting from variances to the forecast planned outage days at Darlington as reflected in this Settlement Proposal, as further detailed in Section 2, Part C, subpart (i) of this Settlement Proposal;

- **Pickering Refurbishment 2027-2031 Early Return to Service Variance Account** will be established to share positive OPG net revenue impacts with ratepayers resulting from any of the Pickering units returning to service from refurbishment in the 2027-2031 period earlier than reflected in OPG's nuclear production forecast as approved by the OEB in this proceeding, as further detailed in Section 2, Part C, subpart (i) of this Settlement Proposal; and

- **Change in CCA Rules or Rates Variance Account (OPG)** will be established effective September 15, 2026, to record, on a without prejudice basis as stated below, the revenue requirement impact for OPG's prescribed facilities of any changes to the CCA rules or rates. OPG shall record such impacts based on the actual undepreciated capital cost and CCA schedules for OPG's prescribed assets, determined with and without

the change, for the period until the effective date of the payment amounts order in OPG's next application seeking to clear the Change in CCA Rules or Rates Variance Account (OPG) balances, at which time a determination with respect to the methodology for determining the entries in the account effective September 15, 2026 will be made. The recording of entries in the account based on the actual undepreciated capital cost and CCA schedules for OPG's prescribed assets, determined with and without the change, up until the date of the payment amounts order in the above proceeding, shall be without prejudice to positions that Parties may take in that proceeding in relation to the methodology for determining entries in the account.

- **Payment Amount Shaping Deferral Account**, which is discussed in Section 4, Issue 3 of this Settlement Proposal.

The Parties also agree, effective January 1, 2027, to expand the scope of the existing Gross Revenue Charge Variance Account to apply to all of OPG's regulated hydroelectric facilities, along with expanding the account's scope to capture the revenue requirement impact of any legislated or regulatory changes to the GRC construct, and to extend the existing SR&ED ITC Variance Account (OPG) to include OPG's regulated hydroelectric facilities on the same basis as it applies to OPG's nuclear facilities, all as proposed in the Application.

H. PAYMENT AMOUNTS SHAPING

The Parties have agreed to the deferral of $350.0M of OPG's 2027 settlement adjusted nuclear revenue requirement to 2028, using a newly established Payment Amount Shaping Deferral Account as proposed by OPG, as discussed further in Section 4, Issue 3 of this Settlement Proposal.

I. REPORTING AND RECORD KEEPING REQUIREMENTS

The Parties agree to the reporting and record keeping requirements for the Applicants as set out in Appendix A hereto. The Parties also agree that the Applicants will undertake certain independent studies, reports, and other filings as set out in Appendix A hereto.

J. IMPLEMENTATION

The Parties agree that the effective date for the blended nuclear payment amounts and payment riders and the regulated hydroelectric payment amounts and payment riders arising from this proceeding shall be January 1, 2027.

Subject to the OEB's consideration and determination, if this Settlement Proposal is approved by the OEB, the Parties agree that they are amenable to the OEB bifurcating

the consideration of the issues settled pursuant to this Settlement Proposal and the Outstanding Issue by:

- the OEB issuing a final decision and order on the draft Payment Amounts Order set out in Appendix B (subject to the update for the prevailing ROE rate specified by the OEB as discussed in Section 2, Part B, subpart (iii) and Section 3, Part B, subpart (ii)) to permit such payment amounts and payment riders to be effective and implemented for January 1, 2027, and

- the OEB hearing the Outstanding Issue by way of written hearing, to establish a separate order setting a corresponding payment rider, commencing no earlier than July 1, 2027, to the extent recorded amounts in respect of the Outstanding Issue are approved, in whole or in part, for disposition by the OEB.

SECTION 3 – KEY COMPONENTS OF THE DNNP LP SETTLEMENT

The subsections below summarize the key components of the DNNP LP settlement reached by the Parties. Unless identified below or under a specific issue set out in Section 4 of this Settlement Proposal, the Parties agree to the application made by DNNP LP. The evidentiary basis upon which each specific issue was settled is summarized in Section 4 of this Settlement Proposal. The settlement adjustments to DNNP LP's revenue requirements are presented in Table 42 below.

Table 42 – 2027-2031 Settlement Adjusted DNNP LP Revenue Requirements ($M)

	2027	2028	2029	2030	2031
DNNP LP's Proposed Revenue Requirement	301.0	378.8	404.9	560.2	1,042.4
Settlement Adjusted Revenue Requirement	296.3	364.1	373.1	512.0	962.8
Difference	(4.8)	(14.7)	(31.8)	(48.3)	(79.6)

A. RATE SETTING FRAMEWORK

The Parties agree to the application of DNNP LP's proposed Custom IR rate-setting framework for the five-year term from 2027-2031. As part of the framework, the Parties have agreed (i) to no earnings sharing mechanism for DNNP LP, and (ii) that unforeseen events affecting DNNP LP will be addressed through an accounting order process, subject to a $10M annual regulatory materiality threshold.

B. RATE BASE, COST OF CAPITAL AND CONCURRENT COST RECOVERY

(i) DNNP LP Rate Base and Concurrent Cost Recovery Amounts

The Parties agree to the forecast rate base for DNNP LP's prescribed assets for the 2027-2031 period as set out in Table 43 below. The reduction in the rate base relative to DNNP LP's request relates to the CCC-084 Impacts, including the corresponding adjustments to the forecast depreciation and amortization expenses.

Table 43 – 2027-2031 Settlement Adjusted DNNP LP Rate Base ($M)

	2027	2028	2029	2030	2031
Proposed DNNP LP Rate Base	0.0	0.0	2.1	1,371.1	6,530.0
Settlement Adjusted DNNP LP Rate Base	0.0	0.0	2.1	1,236.9	5,888.1
Difference	0.0	0.0	0.0	(134.2)	(641.9)

The Parties agree that the forecasted capital expenditures, financial commitments and in-service capital additions for the DNNP as set out in the Application are reasonable and form part of DNNP LP's settled forecast rate base for the 2027-2031 period without adjustments.

The Parties agree that the forecast CCR interest amounts of $1.0B over the 2027-2031 period associated with the DNNP, as proposed in the Application and adjusted for the CCC-084 Impacts, meet the requirements set out in s. 14(2)5i of O. Reg. 53/05 and are correctly reflected in DNNP LP's revenue requirements on that basis. These CCR amounts are set out in Table 44 below.

Table 44 – 2027-2031 Settlement Adjusted DNNP LP CCR Interest Amounts ($M)

	2027	2028	2029	2030	2031
Proposed DNNP LP CCR Interest Amounts	214.9	284.8	321.2	274.2	24.6
Settlement Adjusted DNNP LP CCR Interest Amounts	214.2	274.2	293.4	244.4	20.9
Difference	(0.8)	(10.7)	(27.8)	(29.8)	(3.7)

(ii) DNNP LP Cost of Capital and Capital Structure

For purposes of setting payment amounts in this proceeding, the Parties agree to DNNP LP's capital structure of 100% equity in determining DNNP LP's revenue requirements for the 2027-2031 period. The Parties acknowledge that the foregoing is subject to any true-up arising from the DNNP Generator Capital Structure Variance Account established under s. 13(1) O. Reg 53/05.

The Parties also agree to set the ROE rate as proposed in the Application.

Based on the above parameters and subject to the update for the prevailing ROE rate specified by the OEB as of the effective date of the final payment amounts order in this proceeding, Table 45 below sets out the settlement adjusted DNNP LP cost of capital amounts for the 2027-2031 period. These cost of capital amounts reflect the corresponding forecast rate base values agreed to in this Settlement Proposal.

Table 45 – 2027-2031 Settlement Adjusted DNNP LP Cost of Capital Amounts ($M)

	2027	2028	2029	2030	2031
Proposed DNNP LP Cost of Capital	0.0	0.0	0.2	124.9	594.9
Settlement Adjusted DNNP LP Cost of Capital	0.0	0.0	0.2	112.7	536.4
Difference	0.0	0.0	0.0	(12.2)	(58.5)

C. PRODUCTION FORECAST

The Parties agree to a modified 2027-2031 DNNP LP nuclear production forecast compared to DNNP LP's original proposal, as set out in Table 46 below.

Table 46 – 2027-2031 Settlement Adjusted DNNP LP Production Forecast (TWh)

	2027	2028	2029	2030	2031
Proposed DNNP LP Production Forecast	0.0	0.0	0.0	0.5	1.9
Settlement Adjusted DNNP LP Production Forecast	0.0	0.0	0.0	0.5	2.0
Difference	0.0	0.0	0.0	0.0	0.1

D. OPERATING COSTS

(i) DNNP LP OM&A Expenses

The Parties agree to reduce the proposed forecast OM&A expenses for DNNP LP's prescribed assets, excluding DNNP Operational Readiness OM&A expenses and including associated Allocation of Corporate Costs, Allocation of Centrally Held Costs and Asset Service Fees as follows: $4.0M in 2027, $4.0M in 2028, $4.0M in 2029, $4.0M in 2030, and $8.0M in 2031. The Parties agree to the forecast DNNP Operational Readiness OM&A expenses as proposed by DNNP LP in the Application. The resulting settlement adjusted total OM&A expenses for DNNP LP's prescribed assets are set out in Table 47 below.

Table 47 – 2027-2031 Settlement Adjusted Total DNNP LP OM&A Expenses ($M)

	2027	2028	2029	2030	2031
Proposed Total DNNP LP OM&A	77.0	80.1	70.8	119.6	259.7
Settlement Adjusted Total DNNP LP OM&A	73.0	76.1	66.8	115.6	251.6
Difference	(4.0)	(4.0)	(4.0)	(4.0)	(8.0)

(ii) DNNP LP Nuclear Fuel Costs

DNNP LP's nuclear fuel costs consist of service fees payable to OPG for the costs of the nuclear fuel inventory and its consumption (as well as a minimal amount of fuel oil). The Parties agree to DNNP LP's nuclear fuel costs as proposed in the Application, subject to the impacts of the settlement adjustment to DNNP LP's production forecast. The settlement adjusted DNNP LP nuclear fuel costs are set out in Table 48 below.

Table 48 – 2027-2031 Settlement Adjusted DNNP LP Nuclear Fuel Costs ($M)

	2027	2028	2029	2030	2031
Proposed DNNP LP Nuclear Fuel Costs	9.1	13.8	12.7	18.1	49.8
Settlement Adjusted DNNP LP Nuclear Fuel Costs	9.1	13.8	12.7	18.1	51.2
Difference	0.0	0.0	0.0	0.0	1.4

(iii) DNNP LP Depreciation and Amortization Expenses

The Parties agree to the proposed DNNP LP depreciation and amortization expenses for the 2027-2031 period as set out in the Application and adjusted for the CCC-084 Impacts. The settlement adjusted forecast depreciation and amortization expenses for DNNP LP are set out in Table 49 below.

Table 49 – 2027-2031 Settlement Adjusted DNNP LP Depreciation and Amortization Expenses ($M)

	2027	2028	2029	2030	2031
Proposed DNNP LP Depreciation and Amortization	0.0	0.0	0.0	22.6	109.7
Settlement Adjusted DNNP LP Depreciation and Amortization	0.0	0.0	0.0	20.4	98.9
Difference	0.0	0.0	0.0	(2.2)	(10.8)

(iv) DNNP LP Income and Property Taxes

Subject to the impact of settlement adjustments to other components of DNNP LP's revenue requirements and the CCC-084 Impacts, the Parties agree to DNNP LP's proposed regulatory income tax and property tax amounts for the 2027-2031 period as set out in the Application. The settlement adjustments do not impact DNNP LP's regulatory income tax expenses as proposed in the Application for revenue requirement purposes due to the forecast regulatory tax loss position; instead, these adjustments affect DNNP LP's regulatory tax loss balance carried forward to the next rate-setting period. There are no settlement adjustments to DNNP LP's forecast property tax expenses.

E. DEFERRAL AND VARIANCE ACCOUNTS

Subject to the establishment of the Change in CCA Rates or Rules Variance Account (DNNP) as described below, the Parties agree to continue or discontinue existing deferral and variance accounts for DNNP LP, effective January 1, 2027 unless otherwise noted, as proposed in the Application, including the methodologies that will be used to record entries into these accounts, without modifications.

The Parties agree to establish new deferral and variance accounts for DNNP LP, effective January 1, 2027 unless otherwise noted, including the methodologies that will be used to record entries into these accounts, with the following modifications:

- **Pension and OPEB Cost Variance Account (DNNP)** will record the difference between (i) the pension and other post employment benefit ("**OPEB**") non-capital costs reflected in the revenue requirement approved by the OEB; and (ii) DNNP LP's actual pension and OPEB non-capital costs, excluding any variances arising from differences in staffing levels (other than changes in long-term disability benefit plan data) and compensation levels including pension and benefit plan provisions. Actual pension and OPEB non-capital costs used in the calculation of the difference shall be calculated on an accrual basis using the same accounting standards as those used to derive the reference amount and holding constant staffing levels (other than changes in long-term disability benefit plan data) and compensation levels including pension and benefit plan provisions that are reflected in the reference amount;

- **Nuclear Security Regulation Deferral Account (DNNP)** will record the revenue requirement impacts for DNNP LP's prescribed facilities associated with CNSC Security Regulations (identified at Ex. JT5.18), for which the account will capture revenue requirement impacts resulting from increased security requirements for high security nuclear sites, to the extent such impacts are not reflected in DNNP LP's payment amounts, replacing DNNP LP's proposed Change of Laws Deferral Account (DNNP);

- **Clean Electricity ITC and Other Benefits Variance Accounts (DNNP)** will replace DNNP LP's proposed Clean Electricity ITC Variance Account (DNNP) and will record (i) in the Clean Electricity ITC Sub-Account, the differences between the forecast and actual revenue requirement impacts of the CEITCs for DNNP LP's prescribed assets to the extent they are not otherwise captured in another deferral or variance account, as proposed by DNNP LP for the Clean Electricity ITC Variance Account (DNNP), as well as (ii) in the Other Benefits Sub-Account, the revenue requirement impacts of reflecting the mechanism described in section 5.14 of the Management, Operations, Maintenance and Administration Services Agreement between DNNP LP and OPG dated April 20, 2026. A copy of this agreement can be found at Ex. L-A1-CCC-010, Attachment 4, with further details described in Ex. JTX 3.21. The Parties further agree that any documentation with respect to the foregoing subpart (ii) shall be treated confidentially; and

- **Change in CCA Rules or Rates Variance Account (DNNP)** will be established effective September 15, 2026, to record, on a without prejudice basis as stated below, the revenue requirement impact for DNNP LP's prescribed facilities of any changes to the CCA rules or rates. DNNP LP shall record such impacts based on the actual undepreciated capital cost and CCA schedules for DNNP LP's prescribed assets, determined with and

without the change, for the period until the effective date of the payment amounts order in DNNP LP's next application seeking to clear the Change in CCA Rules or Rates Variance Account (DNNP) balances, at which time a determination with respect to the methodology for determining the entries in the account effective September 15, 2026 will be made. The recording of entries in the account based on the actual undepreciated capital cost and CCA schedules for DNNP LP's prescribed assets, determined with and without the change, up until the date of the payment amounts order in the above proceeding, shall be without prejudice to positions that Parties may take in that proceeding in relation to the methodology for determining entries in the account.

F. REPORTING AND RECORD KEEPING REQUIREMENTS

As noted in Section 2, Part I of this Settlement Proposal, the Parties agree to the reporting and record keeping requirements for the Applicants and that the Applicants will undertake certain independent studies, reports, and other filings, all as set out in Appendix A hereto.

G. IMPLEMENTATION DATE

As noted in Section 2, Part J of this Settlement Proposal, the Parties agree that the effective date for the blended nuclear payment amounts and payment riders arising from this proceeding shall be January 1, 2027.

SECTION 4 – SETTLEMENT BY ISSUE

Issue 1

Are the 2027 hydroelectric payment amount and rate riders reasonable given the overall bill impact to customers?

Settlement Status: Complete Settlement

Subject to the terms of this Settlement Proposal, the Parties accept that the 2027 regulated hydroelectric payment amount and payment riders arising from the Settlement Proposal are reasonable given the overall bill impact to customers.

Parties in Support:	OPG, AMPCO, BOMA, CCMBC, CCC, Energy Probe, Minogi, OAPPA, QMA, SEC, VECC
Parties Taking no Position:	PWU, Society, Environmental Defence, IESO

Evidence

Exhibits	Ex. I1-1-2 (Consumer Impact), Ex. A1-3-2 (Rate-Setting Framework and Performance Reporting), Ex. H1-2-1 (Clearance of Deferral and Variance Accounts), Ex. I1-2-1 (Regulated Hydroelectric Payment Amount), Ex. I1-3-2 (Payment Amount Shaping)
Interrogatories	Ex. L-A1-SEC-005, Ex. L-I1-CCC-109, Ex. L-I1-SEC-215, Ex. L-H1-Staff-055, Ex. L-H1-Staff-255, Ex. L-H1-Staff-256, Ex. L-I1-AMPCO-126
Undertakings	Ex. JT5.1

Issue 2

Are the 2027-2031 nuclear payment amounts and rate riders reasonable given the overall bill impact to customers?

Settlement Status: Partial Settlement

Subject to the terms of this Settlement Proposal and the OEB's decision on the Outstanding Issue, the Parties accept that the 2027-2031 nuclear payment amounts and payment riders arising from the Settlement Proposal are reasonable given the overall bill impact to customers.

Parties in Support:	Applicants, AMPCO, BOMA, CCMBC, CCC, Energy Probe, OAPPA, QMA, SEC, VECC
Parties Taking no Position:	PWU, Society, Environmental Defence, IESO, Minogi (as it relates to DNNP)

Evidence

Exhibits	Ex. I1-1-2 (Consumer Impact), Ex. A1-3-2 (Rate-Setting Framework and Performance Reporting), Ex. H1-2-1 (Clearance of Deferral and Variance Accounts), Ex. I1-3-1 (Nuclear Payment Amounts), Ex. I1-3-2 (Payment Amount Shaping)
Interrogatories	Ex. L-A1-SEC-005, Ex. L-I1-CCC-109, Ex. L-I1-SEC-215, Ex. L-H1-Staff-055, Ex. L-H1-Staff-255, Ex. L-H1-Staff-256, Ex. L-I1-AMPCO-126
Undertakings	Ex. JT5.1

Issue 3

Is the Applicants' proposal for intra-period payment amount shaping an appropriate form of rate mitigation?

Settlement Status: Complete Settlement

The Parties accept OPG's proposed payment amount shaping approach to help manage the 2027 ratepayer impacts. Using this approach, the Parties have agreed to the deferral of $350.0M of OPG's 2027 settlement adjusted nuclear revenue requirement to 2028, with resulting entries of $350.0M in 2027, ($350.0M) in 2028, $0 in 2029, $0 in 2030, and $0 in 2031 in the newly established Payment Amount Shaping Deferral Account. The Parties have further agreed that the account balance will attract interest at the rate set by the OEB from time to time pursuant to its interest policy for deferral and variance accounts as compared to OPG's proposal in the Application to apply its OEB approved long-term debt rate.

Parties in Support:	Applicants, AMPCO, BOMA, CCMBC, CCC, Energy Probe, OAPPA, QMA, SEC, VECC
Parties Taking no Position:	PWU, Society, Environmental Defence, IESO, Minogi (as it relates to DNNP)

Evidence

Exhibits	Ex. I1-1-2 (Consumer Impact), Ex. A1-3-2 (Rate-Setting Framework and Performance Reporting), Ex. H1-2-1 (Clearance of Deferral and Variance Accounts), Ex. I1-3-1 (Nuclear Payment Amounts), Ex. I1-3-2 (Payment Amount Shaping)
Interrogatories	Ex. L-H1-CCC-107, Ex. L-H1-SEC-204, Ex. L-H1-Staff-254, Ex. L-H1-Staff-257, Ex. L-I1-CCC-109, Ex. L-I1-SEC-216, Ex. L-I1-Staff-267
Undertakings	Ex. JT5.1

Issue 4

Is the proposed Custom IR framework for setting the 2027-2031 hydroelectric payment amounts appropriate?

Settlement Status: Complete Settlement

The Parties agree to the application of OPG's proposed regulated hydroelectric rate-setting framework for the five-year term from 2027-2031, subject to the following modifications:

- Increasing the stretch factor from 0.15% to 0.30%;
- Addition of a supplemental stretch factor of 0.30% on capital-related revenue requirement;
- Addition of a production growth factor based on the year-over-year changes in the settlement adjusted production forecast over the 2028-2031 period, together with corresponding adjustments to the GRCF; and
- Expanding the scope of the newly established Global Hydroelectric Capital Variance Account to include the 2027 year, in addition to the 2028-2031 period.

Parties in Support:	OPG, AMPCO, BOMA, CCMBC, CCC, Energy Probe, Minogi, OAPPA, QMA, SEC, VECC
Parties Taking no Position:	PWU, Society, IESO, Environmental Defence

Evidence

Exhibits	Ex. A1-3-2 (Rate-Setting Framework and Performance Reporting), Ex. H1-1-1 (Deferral and Variance Accounts), Ex. I1-2-1 (Regulated Hydroelectric Payment Amount), Ex. F1-4-1 (Gross Revenue Charge and Other Water Agreement Costs – Regulated Hydroelectric), Ex. F1-4-2 (Comparison of Gross Revenue Charge and Other Water Agreement Costs – Regulated Hydroelectric)
Interrogatories	Ex. L-A1-CCC-003, Ex. L-A1-CCC-004, Ex. L-A1-CCC-006, Ex. L-A1-CCC-007, Ex. L-A1-EP-002, Ex. L-A1-EP-003, Ex. L-A1-SEC-010, Ex. L-A1-SEC-011, Ex. L-A1-SEC-012, Ex. L-A1-SEC-013, Ex. L-A1-SEC-016, Ex. A1-Staff-003, Ex. L-A1-Staff-004, Ex. L-A1-Staff-269, Ex. L-A1-Staff-270, Ex. L-A1-Staff-271, Ex. L-A1-Staff-272, Ex. L-A1-Staff-280, Ex. L-A1-Staff-285, Ex. L-A1-Staff-289, Ex. L-A1-Staff-291, Ex. L-A1-Staff-292, Ex. L-A1-Staff-330, Ex. L-A1-Staff-331, Ex. L-A1-Staff-332, Ex. L-A1-Staff-334, Ex. L-A1-VECC-001, Ex. L-A1-VECC-002, Ex. L-C1-Staff-021, Ex. L-A1-CCC-008, Ex. L-A1-SEC-017, Ex. L-A1-SEC-018, Ex. L-A1-SEC-019, Ex. L-A1-SEC-020, Ex. L-A1-SEC-021, Ex. L-A1-SEC-022, Ex. L-A1-Staff-277, Ex. L-A1-Staff-278, Ex. L-A1-Staff-279, Ex. L-A1-Staff-280, Ex. L-A1-Staff-281, Ex. L-A1-Staff-282, Ex. L-A1-Staff-283, Ex. L-A1-Staff-284, Ex. L-A1-Staff-286, Ex. L-A1-Staff-287, Ex. L-A1-Staff-

	288, Ex. L-A1-Staff-290, Ex. L-A1-Staff-335, Ex. L-A1-Staff-336, Ex. L-A1-Staff-337, Ex. L-A1-Staff-338, Ex. L-A1-Staff-339, Ex. L-A1-Staff-340, Ex. L-A1-Staff-341, Ex. L-A1-Staff-342, Ex. L-A1-Staff-344, Ex. L-A1-Staff-273, Ex. L-A1-Staff-274, Ex. L-E1-ED-016, Ex. L-F1-Staff-176, Ex. L-F1-CCC-068, Ex. L-F1-VECC-011, Ex. L-A1-SEC-014, Ex. L-F1-Staff-161, Ex. L-F1-Staff-168, Ex. L-F1-AMPCO-097, Ex. L-F1-AMPCO-098, Ex. L-F1-SEC-150, Ex. L-F1-SEC-151, Ex. L-F1-SEC-152 Ex. L-A1-Staff-285, Ex. L-A1-Staff-287, Ex. L-A1-Staff-329, Ex. L-A1-Staff-333
Undertakings	Ex. JT4.13, Ex. JT5.3, Ex. JT5.4, Ex. JT5.7, Ex. JT5.13, Ex. JT5.14

Issue 5

Is the proposed Custom IR framework for setting the 2027-2031 nuclear payment amounts appropriate?

Settlement Status: Complete Settlement

The Parties agree to the application of OPG's proposed nuclear rate-setting framework for the five-year term from 2027 to 2031, subject to the following modifications:

- Increasing the stretch factor from 0.30% to 0.60%; and
- Expanding the scope of the stretch factor to include Project OM&A (Operations and Project Support), Allocation of Centrally Held Costs, Nuclear Fuel Costs, Working Capital-Related Revenue Requirement, Property Tax, and Other Revenues.

Parties in Support:	Applicants, AMPCO, BOMA, CCMBC, CCC, Energy Probe, OAPPA, QMA, SEC, VECC
Parties Taking no Position:	PWU, Society, IESO, Environmental Defence, Minogi (as it relates to DNNP)

Evidence

Exhibits	Ex. A1-3-2 (Rate-setting Framework and Performance Reporting), Ex. F2-1-1 (Business Planning and Benchmarking – Nuclear)
Interrogatories	Ex. L-A1-CCC-005, Ex. L-A1-Staff-294, Ex. L-A1-Staff-295, Ex. L-A1-Staff-296, Ex. L-A1-Staff-297, Ex.

	L-A1-Staff-345, Ex. L-A1-Staff-349, Ex. L-A1-SEC-014, Ex. L-A1-Staff-346, Ex. L-A1-VECC-004, Ex. L-F2-CCC-071, Ex. L-F2-SEC-157, Ex. L-F2-SEC-162, Ex. L-F2-SEC-163, Ex. L-F2-Staff-179, Ex. L-F2-Staff-182, Ex. L-F2-Staff-183, Ex. L-F2-Staff-186, Ex. L-F2-Staff-322, Ex. L-F2-Staff-323, Ex. L-F2-Staff-324, Ex. L-F2-Staff-325, Ex. L-F2-Staff-326, Ex. L-F2-Staff-327, Ex. L-F2-Staff-328
Undertakings	Ex. JT3.4, Ex. JT3.5, Ex. JT3.11, Ex. JT5.2, Ex. JT5.15

Issue 6

Are the amounts proposed for the prescribed hydroelectric facilities rate base appropriate?

Settlement Status: Complete Settlement

The Parties agree to the 2027 rate base value for the regulated hydroelectric facilities as proposed by OPG, adjusted for:

- The CCC-084 Impacts;
- An agreed permanent reduction to the opening 2027 rate base value of $40.0M;
- A reduction to reflect lower than forecast actual in-service capital additions for 2025 in the amount of $19.5M;
- The reductions and adjustments to proposed in-service capital additions discussed under Issue 12 below; and
- The adjustments to the proposed depreciation and amortization expenses discussed under Issue 27 below.

Parties in Support:	OPG, AMPCO, BOMA, CCMBC, CCC, Energy Probe, Minogi, OAPPA, QMA, SEC, VECC
Parties Taking no Position:	PWU, Society, IESO, Environmental Defence

Evidence

Exhibits	Ex. B1-1-1 (Rate Base), Ex. B1-1-2 (Cash Working Capital), Ex. B2-1-1 (Prescribed Facility Rate Base – Regulated Hydroelectric), Ex. B2-2-1 (Comparison of Prescribed Facility Rate Base – Regulated

	Hydroelectric), Ex. B2-3-1 (Continuity of Gross Property, Plant and Equipment – Regulated Hydroelectric), Ex. B2-4-1 (Continuity of Accumulated Depreciation and Amortization – Regulated Hydroelectric), Ex. B2-5-1 (Working Capital Summary – Regulated Hydroelectric)
Interrogatories	Ex. L-B1-CCC-018, Ex. L-B1-SEC-028, Ex. L-B1-Staff-017, Ex. L-B1-Staff-019, Ex. L-B2-Staff-018
Undertakings	N/A

Issue 7

Are the amounts proposed for the OPG nuclear facilities rate base appropriate?

Settlement Status: Complete Settlement

The Parties agree to the rate base values for OPG nuclear facilities for the 2027-2031 period as proposed by OPG, adjusted for:

- The CCC-084 Impacts;
- An agreed permanent reduction to the opening 2027 rate base value of $40.0M;
- An adjustment to the DRP rate base to reflect OPG's updated forecast of the DRP's total forecast cost of $12.65B since the Application was filed, which represents a reduction of $50.0M from the pre-filed evidence;
- The reductions to proposed in-service capital additions discussed under Issue 14 below; and
- The adjustments to the proposed depreciation and amortization expenses discussed under Issue 28 below.

The Parties also agree that OPG will not seek recovery of any final costs of the DRP that exceed the $12.8B approved budget and that, subject to this commitment, effective January 1, 2027, OPG would record in the CRVA the revenue requirement of any differences between the amount and timing of the remaining actual expenditures and in-service amounts for the DRP and such forecasts reflected in the revenue requirements approved in this proceeding, with any such CRVA amounts to be dispositioned in a future application on a mechanical basis (subject to the amounts being accurately recorded).

Parties in Support:	OPG, AMPCO, BOMA, CCMBC, CCC, Energy Probe, Minogi, OAPPA, QMA, SEC, VECC

Parties Taking no Position:	PWU, Society, IESO, Environmental Defence, Minogi (as it relates to DNNP)

Evidence

Exhibits	Ex. B1-1-1 (Rate Base), Ex. B1-1-2 (Cash Working Capital), Ex. B3-1-1 (Prescribed Facility Rate Base – Combined Nuclear), Ex. B3-2-1 (Comparison of Prescribed Facility Rate Base – Combined Nuclear), Ex. B3-3-1 (Continuity of Property, Plant and Equipment – Combined Nuclear), Ex. B3-4-1 (Continuity of Accumulated Depreciation and Amortization – OPG Nuclear Facilities and Combined Nuclear), Ex. B3-5-1 (Working Capital Summary – OPG Nuclear Facilities and Combined Nuclear)
Interrogatories	Ex. L-B1-SEC-028, Ex. L-B1-CCC-018, Ex. L-B1-CCC-019, Ex. L-B1-Staff-020
Undertakings	Ex. JT5.10

Issue 8

Are the amounts proposed for the Darlington New Nuclear Program (DNNP) facilities rate base appropriate?

Settlement Status: Complete Settlement

The Parties agree to the rate base values for DNNP for the 2027-2031 period as proposed by DNNP LP, adjusted for the CCC-084 Impacts including the adjustments to the proposed depreciation and amortization expenses discussed under Issue 29 below.

Parties in Support:	DNNP LP, AMPCO, BOMA, CCMBC, CCC, Energy Probe, OAPPA, QMA, SEC, VECC
Parties Taking no Position:	PWU, Society, Minogi, IESO, Environmental Defence

Evidence

Exhibits	Ex. B1-1-1 (Rate Base), Ex. B1-1-2 (Cash Working Capital), Ex. B3-1-1 (Prescribed Facility Rate Base – Combined Nuclear), Ex. B3-2-1 (Comparison of Prescribed Facility Rate Base – Combined Nuclear), Ex. B3-3-1 (Continuity of Property, Plant and Equipment – Combined Nuclear), Ex. B3-4-1 (Continuity of Accumulated Depreciation and

	Amortization – OPG Nuclear Facilities and Combined Nuclear), Ex. B3-5-1 (Working Capital Summary – OPG Nuclear Facilities and Combined Nuclear)
Interrogatories	Ex. L-B1-SEC-028
Undertakings	N/A

Issue 9

Are OPG's proposed capital structure, rate of return on equity, and proposed costs for the long-term and short-term debt components of its capital structure for the 2027-2031 term appropriate?

Settlement Status: Complete Settlement

For purposes of settlement, the Parties agree for OPG's deemed capital structure to remain unchanged from EB-2016-0152 and EB-2020-0290 at 45% equity and 55% debt for the purposes of determining OPG's revenue requirements for the 2027-2031 period.

The Parties also agree to set the ROE rate, long-term cost of debt rate and short-term cost of debt rate for the 2027-2031 period as proposed by the Applicants and adjusted for the CCC-084 Impacts. With respect to the ROE rate, the Parties specifically agree to update the rate for the 2027-2031 period using the prevailing ROE rate specified by the OEB as of the effective date of the final payment amounts order in this proceeding, as discussed in Section 2, Part B, subpart (iii) of this Settlement Proposal. The agreement on the long-term cost of debt rate is without prejudice to positions that Parties may take in future proceedings in relation to the applicable forecasting methodology for the credit spread component of the rate as it relates to planned debt issues.

Parties in Support:	OPG, AMPCO, BOMA, CCMBC, CCC, Energy Probe, Minogi, OAPPA, QMA, SEC, VECC
Parties Taking no Position:	PWU, Society, IESO, Environmental Defence, Minogi (as it relates to DNNP)

Evidence

Exhibits	Ex. C1-1-1 (Capital Structure and Return on Equity), Ex. C1-1-2 (Cost of Long-Term Debt), Ex. C1-1-3 (Cost of Short-Term Debt)
Interrogatories	Ex. L-C1-EP-004, Ex. L-C1-EP-005, Ex. L-C1-EP-006, Ex. L-C1-EP-024, Ex. L-C1-Staff-034, Ex. L-C1-SEC-033, Ex. L-C1-Staff-027, Ex. L-C1-Staff-266, Ex. L-H1-Staff-247, Ex. L-I1-AMPCO-125, Ex. L-C1-Ex. L-C1-CCC-020, Ex. L-C1-Staff-025, Ex. L-C1-SEC-

	034, Ex. L-C1-CCC-035, Ex. L-C1-CCC-036, Ex. L-C1-Staff-028, Ex. L-C1-Staff-029, Ex. L-C1-Staff-030, Ex. L-C1-Staff-031, Ex. L-C1-Staff-033, Ex. L-C1-Staff-035, Ex. L-C1-Staff-036, Ex. L-C1-Staff-037, Ex. L-C1-Staff-038, Ex. L-C1-CCC-022, Ex. L-C1-CCC-025, Ex. L-C1-CCC-026, Ex. L-C1-CCC-028, Ex. L-C1-CCC-029, Ex. L-C1-EP-007, Ex. L-C1-EP-009, Ex. L-C1-EP-010, Ex. L-C1-EP-011, Ex. L-C1-EP-012, Ex. L-C1-EP-013, Ex. L-C1-EP-023, Ex. L-C1-SEC-031, Ex. L-C1-Staff-040, Ex. L-C1-Staff-052
Undertakings	Ex. JT4.14

Issue 10

Are DNNP LP's proposed capital structure, rate of return on equity, and proposed costs for the long-term and short-term debt components of its capital structure for the 2027-2031 term appropriate?

Settlement Status: Complete Settlement

For purposes of setting blended nuclear payment amounts, and with consideration of the DNNP Generator Capital Structure Variance Account established under s. 13(1) of O. Reg 53/05, the Parties agree to the capital structure of 100% equity in determining DNNP LP's revenue requirements for the 2027-2031 period. The Parties acknowledge that the foregoing is subject to any true-up arising from the DNNP Generator Capital Structure Variance Account established under s. 13(1) of O. Reg 53/05.

The Parties also agree to set the ROE rate as proposed by the Applicants; specifically that the rate for the 2027-2031 period would be updated using the prevailing ROE rate specified by the OEB as of the effective date of the final payment amounts order in this proceeding, as discussed in Section 2, Part B, subpart (iii) and Section 3, Part B, subpart (ii) of this Settlement Proposal.

Parties in Support:	DNNP LP, AMPCO, BOMA, CCMBC, CCC, Energy Probe, OAPPA, QMA, SEC, VECC
Parties Taking no Position:	PWU, Society, Minogi, IESO, Environmental Defence

Evidence

Exhibits	Ex. C1-1-1 (Capital Structure and Return on Equity)
Interrogatories	Ex. L-C1-CCC-021, Ex. L-C1-Staff-039, Ex. L-C1-Staff-023, Ex. L-C1-VECC-006, Ex. L-C1-VECC-007, Ex. L-C1- SEC-037, Ex. L-C1-SEC-038, Ex. L-C1-EP-

	025, Ex. L-C1-EP-026, Ex. L-C1-EP-027, Ex. L-C1-SEC-040, Ex. L-C1-SEC-036, Ex. L-C1-Staff-041, Ex. L-C1-Staff-042, Ex. L-C1-Staff-043, Ex. L-C1-Staff-044, Ex. L-C1-Staff-045, Ex. L-C1-Staff-046, Ex. L-C1-Staff-047, Ex. L-C1-Staff-048
Undertakings	Ex. JT4.14, Ex. JT4.15

Issue 11

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

Settlement Status: Complete Settlement

The Parties agree that the regulated hydroelectric capital and non-capital projects and initiatives identified in the pre-filed evidence as eligible for CRVA treatment are subject to section 6(2)4 of O. Reg. 53/05 and meet the requirements of that section, with the exception of Project #83194 Frederick House Lake Dam Upgrades (Ex. D1-1-2, Table 1, line 11) and the unallocated investment related to Mistinikon Control Dam Upgrades (Ex. D1-1-2, Table 5b, line 44).

The Parties agree that the projects and initiatives agreed to for the purposes of this Issue 11 will form the basis of the regulated hydroelectric reference amounts for recording entries in the CRVA effective January 1, 2027. The Parties acknowledge that this represents an approved envelope with respect to CRVA eligible in-service capital additions included in the payment amounts arising from this proceeding but is not an approval of the prudence of any specific project or initiative included in the Application. The prudence of any specific project or initiative will be determined at the time of any applicable disposition of the CRVA or upon an applicable rebasing application.

Parties in Support:	OPG, AMPCO, BOMA, CCMBC, CCC, Energy Probe, Minogi, OAPPA, QMA, SEC, VECC
Parties Taking no Position:	PWU, Society, IESO, Environmental Defence

Evidence

Exhibits	Ex. D1-1-1 (Capital Expenditures – Regulated Hydroelectric), Ex. D1-1-2 (Capital Projects – Regulated Hydroelectric Operations), Ex. H1-1-1 (Deferral & Variance Accounts)
Interrogatories	Ex. L-D1-Staff-061, Ex. L-H1-CCC-100
Undertakings	Ex. JT1.16

Issue 12

Are the proposed hydroelectric capital expenditures and/or financial commitments and proposed in-service additions reasonable?

Settlement Status: Complete Settlement

The Parties agree that the proposed regulated in-service capital additions to rate base are reasonable, subject to a reduction of the proposed in-service capital additions as adjusted for the CCC-084 Impacts, excluding those with respect to Corporate Support Services, of 13% per year for the 2027-2031 period and, with respect to the Corporate Support Services capital projects entering rate base, of 11% per year for the 2027-2031 period. The above reductions are applied to CRVA non-eligible projects.

The consideration of OPG's proposed regulated hydroelectric capital expenditures and financial commitments was made in the context of the settlement adjustments to the in-service capital additions.

Parties in Support:	OPG, AMPCO, BOMA, CCMBC, CCC, Energy Probe, Minogi, OAPPA, QMA, SEC, VECC
Parties Taking no Position:	PWU, Society, IESO, Environmental Defence

Evidence

Exhibits	Ex. D1-1-1 (Capital Expenditures – Regulated Hydroelectric), Ex. D1-1-2 (Capital Projects – Regulated Hydroelectric), Ex. D2-1-1 (Project and Portfolio Management), Ex. F1-1-1 (Business Planning and Benchmarking – Regulated Hydroelectric)
Interrogatories	Ex. A1-AMPCO-003, Ex. A1-CCC-009, Ex. A1-Staff-007, Ex. A1-Staff-015, Ex. A1-SUP-003, Ex. L-B1-Staff-019, Ex. L-B2-Staff-018, Ex. L-D1-AMPCO-008, Ex. L-D1-AMPCO-009, Ex. L-D1-AMPCO-010, Ex. L-D1-AMPCO-013, Ex. L-D1-AMPCO-014, Ex. L-D1-AMPCO-015, Ex. L-D1-AMPCO-016, Ex. L-D1-AMPCO-017, Ex. L-D1-AMPCO-018, Ex. D1-CCC-039, Ex. L-D1-CCC-040, Ex. L-D1-ED-006, Ex. L-D1-SEC-041, Ex. L-D1-SEC-043, Ex. L-D1-SEC-044, Ex. L-D1-SEC-045, Ex. L-D1-SEC-048, Ex. L-D1-SEC-049, Ex. L-D1-SEC-051, Ex. L-D1-SEC-052, Ex. L-D1-SEC-053, Ex. L-D1-Staff-059, Ex. L-D1-Staff-062, Ex. L-D1-Staff-064, Ex. L-D1-Staff-066, Ex. L-D1-

	Staff-067, Ex. L-D1-Staff-068, Ex. L-D1-Staff-069, Ex. L-D1-Staff-070, Ex. L-D1-Staff-071, Ex. L-D1-Staff-072, Ex. L-D1-Staff-074, Ex. L-D1-Staff-075, Ex. L-D1-Staff-076, Ex. L-D1-Staff-077, Ex. L-D1-Staff-309, Ex. L-D1-Staff-310, Ex. L-D1-Staff-311, Ex. L-D1-Staff-312, Ex. L-D1-Staff-314, Ex. L-D1-Staff-316, Ex. L-D1-Staff-317, Ex. L-D1-Staff-318, Ex. L-D1-Staff-319, Ex. L-D1-Staff-0320, Ex. L-D2-AMPCO-022, Ex. L-D2-AMPCO-023, Ex. L-D2-SEC-056, Ex. L-F1-AMPCO-091, Ex. L-F1-AMPCO-093, Ex. L-F1-SEC-146, Ex. L-A1-SEC-014, Ex. L-F1-Staff-161, Ex. L-F1-Staff-168, Ex. L-F1-AMPCO-097, Ex. L-F1-AMPCO-098, Ex. L-F1-SEC-150, Ex. L-F1-SEC-151, Ex. L-F1-SEC-152
Undertakings	Ex. JT1.5, Ex. JT1.6, Ex. JT1.7, Ex. JT1.8, Ex. JT1.9, Ex. JT1.10, Ex. JT1.11, Ex. JT1.17, Ex. JT1.18, Ex. JT1.20, Ex. JT2.2, Ex. JT2.3, Ex. JT2.5, Ex. JT2.6, Ex. JT2.7, Ex. JT2.8, Ex. JT2.9, Ex. JT2.10, Ex. JT2.11, Ex. JT2.12, Ex. JT2.13, Ex. JT2.14

Issue 13

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?

Settlement Status: Complete Settlement

The Parties agree that OPG's nuclear capital and non-capital projects and initiatives identified in the pre-filed evidence as eligible for CRVA treatment are subject to section 6(2)4 of O. Reg. 53/05 and meet the requirements of that section, with the exception of Project #89462 DN Steam Generator Soft Chemical Clean project (Ex. D2-1-3, Table 1c, line 54).

The Parties agree that the projects and initiatives agreed for the purposes of this Issue 13 will form the basis of the nuclear reference amounts for recording entries in the CRVA effective January 1, 2027. The Parties acknowledge that, other than the PRP and the DRP, this represents an approved envelope with respect to CRVA eligible in-service capital additions included in the payment amounts arising from this proceeding but is not an approval of the prudence of any specific project or initiative included in the Application. The prudence of any specific project or initiative, other than the PRP and the DRP, will be determined at the time of any applicable disposition of the CRVA or upon an applicable rebasing application. The Parties' agreement with respect to the prudence review of the PRP and the DRP is discussed under Issue 15 and Issue 7, respectively.

Parties in Support:	OPG, AMPCO, BOMA, CCMBC, CCC, Energy Probe, Minogi, OAPPA, QMA, SEC, VECC
Parties Taking no Position:	PWU, Society, IESO, Environmental Defence, Minogi (as it relates to DNNP)

Evidence

Exhibits	Ex. D2-1-2 (Capital Expenditures – Nuclear Operations), Ex. D2-1-3 (Capital Projects – Nuclear Operations), Ex. H1-1-1 (Deferral & Variance Accounts)
Interrogatories	Ex. L-D2-CCC-041, Ex. L-D2-Staff-081
Undertakings	N/A

Issue 14

Are OPG's proposed nuclear capital expenditures and/or financial commitments and proposed in-service additions (excluding those for the PRP and the DNNP) reasonable?

Settlement Status: Complete Settlement

The Parties agree that OPG's in-service capital additions to rate base (excluding those for the PRP and the DNNP) are reasonable, subject to following adjustments:

- With respect to the Nuclear Operations capital projects, a reduction to the proposed in-service capital additions, as adjusted for the CCC-084 Impacts, of 10% per year for the 2027-2031 period;

- A change in the forecast timing that certain Nuclear Operations in-service capital amounts related to Pickering, are included in the rate base for the 2027-2031 period, resulting in the following amounts being deferred from the 2027-2030 period into 2031: $0.5M 2027, $15.7M 2028, $17.7M 2029, and $220.2M 2030, for a total increase in the in-service capital additions in 2031 of $254.1M. The Parties agree that the opening accumulated depreciation and amortization amount reflected in the nuclear rate base for 2032 will be decreased by $7.4M to reflect the impact of the above timing adjustments for purposes of OPG's next rebasing application for OPG's nuclear facilities and that this adjustment would then be drawn down through an adjustment to the depreciation and amortization expense on a straight-line basis over the remaining station life of Pickering; and

- A reduction to the proposed in-service capital additions for Corporate Support Services projects entering rate base of 11% per year for the 2027-2031 period.

The consideration of OPG's proposed nuclear capital expenditures and financial commitments was made in the context of the settlement adjustments to the in-service capital additions.

The above reductions are applied to CRVA non-eligible projects.

Parties in Support:	OPG, AMPCO, BOMA, CCMBC, CCC, Energy Probe, Minogi, OAPPA, QMA, SEC, VECC
Parties Taking no Position:	PWU, Society, IESO, Environmental Defence

Evidence

Exhibits	Ex. D2-1-1 (Project and Portfolio Management), Ex. D2-1-2 (Capital Expenditures – Nuclear Operations), Ex. D2-1-3 (Capital Projects – Nuclear Operations), Ex. D2-2-1 – D2-2-3 (Darlington Refurbishment Program Overview, Performance and In-Service Amounts), Ex. F2-7-1 (Darlington Refurbishment Program – OM&A), Ex. D3-1-1 (Capital Budget - Support Services), Ex. D3-1-2 (Capital Projects – Support Services)
Interrogatories	Ex. L-A1-Staff-013, Ex. L-D2-AMPCO-021, Ex. L-D2-AMPCO-022, Ex. L-D2-AMPCO-023, Ex. L-D2-AMPCO-024, Ex. L-D2-AMPCO-025, Ex. L-D2-AMPCO-026, Ex. L-D2-AMPCO-027, Ex. L-D2-AMPCO-028, Ex. L-D2-AMPCO-029, Ex. L-D2-AMPCO-030, Ex. L-D2-AMPCO-031, Ex. L-D2-AMPCO-032, Ex. L-D2-AMPCO-033, Ex. L-D2-AMPCO-034, Ex. L-D2-AMPCO-035, Ex. L-D2-AMPCO-036, Ex. L-D2-AMPCO-037, Ex. L-D2-AMPCO-038, Ex. L-D2-AMPCO-039, Ex. L-D2-AMPCO-040, Ex. L-D2-AMPCO-041, Ex. L-D2-AMPCO-042, Ex. L-D2-AMPCO-043, Ex. L-D2-AMPCO-044, Ex. L-D2-AMPCO-045, Ex. L-D2-AMPCO-046, Ex. L-D2-AMPCO-047, Ex. L-D2-AMPCO-048, Ex. L-D2-AMPCO-049, Ex. L-D2-AMPCO-050, Ex. L-D2-AMPCO-051, Ex. L-D2-AMPCO-052, Ex. L-D2-AMPCO-053, Ex. L-D2-AMPCO-054, Ex. L-D2-AMPCO-055, Ex. L-D2-AMPCO-056, Ex. L-D2-AMPCO-057, Ex. L-D2-AMPCO-058, Ex. L-D2-AMPCO-059, Ex. L-D2-AMPCO-060, Ex. L-D2-AMPCO-061, Ex. L-D2-AMPCO-062, Ex. L-D2-AMPCO-063, Ex. L-D2-

	AMPCO-064, Ex. L-D2-AMPCO-065, Ex. L-D2-AMPCO-066, Ex. L-D2-AMPCO-067, Ex. L-D2-AMPCO-068, Ex. L-D2-AMPCO-069, Ex. L-A1-CCC-001, Ex. L-D2-CCC-041, Ex. L-D2-CCC-042, Ex. L-D2-CCC-044, Ex. L-D2-ED-005, Ex. L-D2-ED-008, Ex. L-D2-OAPPA-002, Ex. L-D2-PWU-002, Ex. L-D2-PWU-003, Ex. L-D2-PWU-004, Ex. L-D2-PWU-005, Ex. L-D2-PWU-006, Ex. L-D2-SEC-056, Ex. L-D2-SEC-057, Ex. L-D2-SEC-058, Ex. L-D2-SEC-059, Ex. L-D2-SEC-060, Ex. L-D2-SEC-061, Ex. L-A1-Staff-015, Ex. L-D2-Staff-081, Ex. L-D2-Staff-082, Ex. L-D2-Staff-083, Ex. L-D2-Staff-084, Ex. L-D2-Staff-085, Ex. L-D2-Staff-086, Ex. L-D2-Staff-087, Ex. L-D2-Staff-088, Ex. L-D2-Staff-089, Ex. L-D2-Staff-090, Ex. L-D2-Staff-091, Ex. L-D2-Staff-092, Ex. L-D2-Staff-093, Ex. L-D2-Staff-094, Ex. L-D2-Staff-095, Ex. L-D2-Staff-096, Ex. L-A1-Staff-008, Ex. L-A1-Staff-011, Ex. L-D2-CCC-045, Ex. L-D2-CCC-046, Ex. L-D2-SEC-062, Ex. L-D2-SEC-063, Ex. L-D2-SEC-064, Ex. L-D2-SEC-065, Ex. L-F2-CCC-079, Ex. L-A1-CCC-009, Ex. L-D3-CCC-060, Ex. L-D3-CCC-061, Ex. L-D3-CCC-060, Ex. L-D3-CCC-062, Ex. L-D3-SUP-009, Ex. L-D3-SEC-118, Ex. L-D3-SEC-119, Ex. L-D3-SEC-120, Ex. L-D3-SEC-122, Ex. L-D3-SEC-123, Ex. L-D3-SEC-124, Ex. L-D3-SEC-125, Ex. L-D3-SEC-126, Ex. L-D3-SEC-127, Ex. L-D3-SEC-211, Ex. L-D3-Staff-085, Ex. L-D3-Staff-133, Ex. L-D3-Staff-134
Undertakings	Ex. JT2.6, Ex. JT2.22, Ex. JT2.23, Ex. JT3.2, Ex. JT3.3, Ex. JT3.8, Ex. JT3.9, Ex. JT3.17, Ex. JT4.1, Ex. JT5.6, Ex. JT5.9, Ex. JT5.19

Issue 15

Are OPG's proposed nuclear capital expenditures and/or financial commitments and proposed in-service additions for the PRP reasonable?

Settlement Status: Complete Settlement

The Parties agree that OPG's proposed capital expenditures, financial commitments and in-service capital additions of $9.9B[23] for the PRP are reasonable.

The Parties acknowledge that, to the extent there are any deviations from the aforementioned in-service capital additions, including any in-service timing, OPG will record the resulting revenue requirement impacts (excluding CCR interest impacts) in the CRVA and that OPG will be eligible to recover any such revenue requirement impacts of any prudently incurred PRP costs (subject to the amounts being accurately recorded).

Parties in Support:	OPG, AMPCO, BOMA, CCMBC, CCC, Energy Probe, Minogi, OAPPA, QMA, SEC, VECC
Parties Taking no Position:	PWU, Society, IESO, Environmental Defence

Evidence

Exhibits	Ex. D2-3-1 to Ex. D2-3-10 (Pickering Refurbishment Program)
Interrogatories	Ex. L-A1-CCC-001, Ex. L-D2-CCC-047, Ex. L-D2-CCC-048, Ex. L-D2-CCC-049, Ex. L-D2-CCC-050, Ex. L-D2-CCC-051, Ex. L-D2-CCC-052, Ex. L-D2-CCC-053, Ex. L-D2-SEC-066, Ex. L-D2-SEC-067, Ex. L-D2-SEC-068, Ex. L-D2-SEC-069, Ex. L-D2-SEC-070, Ex. L-D2-SEC-071, Ex. L-D2-SEC-072, Ex. L-D2-SEC-073, Ex. L-D2-SEC-074, Ex. L-D2-SEC-075, Ex. L-D2-SEC-076, Ex. L-D2-SEC-077, Ex. L-D2-SEC-078, Ex. L-D2-SEC-079, Ex. L-D2-SEC-080, Ex. L-D2-SEC-081, Ex. L-D2-SEC-082, Ex. L-D2-SEC-083, Ex. L-D2-SEC-084, Ex. L-D2-SEC-085, Ex. L-D2-SEC-086, Ex. L-D2-SEC-087, Ex. L-D2-SEC-088, Ex. L-D2-SEC-089, Ex. L-D2-SEC-090, Ex. L-D2-SEC-091, Ex. L-D2-SEC-092, Ex. L-D2-SEC-093, Ex. L-D2-SEC-094, Ex. L-D2-SEC-095, Ex. L-D2-

[23] The forecast in-service additions of $9.9B for the PRP comprise $0.2B in 2026, $0.02B in 2027, and $9.7B in 2031, as set out in Ex. D2-3-8, Table 5, line 11.

	SEC-096, Ex. L-H1-SEC-206, Ex. L-D2-Staff-096, Ex. L-D2-Staff-097, Ex. L-D2-Staff-098, Ex. L-D2-Staff-099, Ex. L-D2-Staff-100, Ex. L-D2-Staff-101, Ex. L-D2-Staff-102, Ex. L-D2-Staff-103, Ex. L-D2-Staff-104, Ex. L-D2-Staff-105, Ex. L-D2-Staff-106, Ex. L-D2-Staff-107, Ex. L-D2-Staff-108, Ex. L-D2-Staff-109, Ex. L-D2-Staff-110, Ex. L-D2-Staff-111, Ex. L-D2-Staff-112, Ex. L-D2-Staff-113, Ex. L-D2-Staff-114, Ex. L-D2-Staff-115, Ex. L-D2-Staff-116, Ex. L-D2-OAPPA-003, Ex. L-D2-OAPPA-004, Ex. L-D2-OAPPA-005, Ex. L-D2-ED-009, Ex. L-D2-PWU-008, Ex. L-D2-PWU-009, Ex. L-D2-AMPCO-069
Undertakings	Ex. JT2.15, Ex. JT2.16, Ex. JT2.17, Ex. JT3.12, Ex. JT3.13, Ex. JT3.14, Ex. JT3.15, Ex. JT3.16, Ex. JT3.19

Issue 16

Are DNNP's proposed nuclear capital expenditures and/or financial commitments and proposed in-service additions reasonable?

Settlement Status: Complete Settlement

The Parties agree DNNP LP's proposed capital expenditures, financial commitments and in-service capital additions of $6.6B[24] for the DNNP are reasonable.

The Parties acknowledge that, to the extent there are any deviations from the aforementioned in-service capital additions, including any in-service timing, DNNP LP will record the resulting revenue requirement impacts (excluding CCR interest impacts) in the Darlington New Nuclear Project Variance Account Re Development ("**DNNPVARD**") and that DNNP LP will be eligible to recover any such revenue requirements impacts of any prudently incurred DNNP costs (subject to the amounts being accurately recorded).

Parties in Support:	DNNP LP, AMPCO, BOMA, CCMBC, CCC, Energy Probe, OAPPA, QMA, SEC, VECC
Parties Taking no Position:	PWU, Society, Minogi, IESO, Environmental Defence

[24] The forecast in-service additions of $6.6B for the DNNP are in 2030, as set out in Ex. D2-4-8, Table 3.

Evidence

Exhibits	Ex. D2-4-1 to Ex. D2-4-10 (Darlington New Nuclear Program)
Interrogatories	Ex. L-A1-CCC-011, Ex. L-A1-CCC-012, Ex. L-D2-AMPCO-070, Ex. L-D2-AMPCO-071, Ex. L-D2-AMPCO-072, Ex. L-D2-AMPCO-073, Ex. L-D2-AMPCO-074, Ex. L-D2-AMPCO-075, Ex. L-D2-AMPCO-076, Ex. L-D2-AMPCO-077, Ex. L-D2-AMPCO-078, Ex. L-D2-AMPCO-079, Ex. L-D2-AMPCO-080, Ex. L-D2-AMPCO-081, Ex. L-D2-AMPCO-082, Ex. L-D2-AMPCO-083, Ex. L-D2-AMPCO-084, Ex. L-D2-AMPCO-086, Ex. L-D2-AMPCO-087, Ex. L-D2-AMPCO-088, Ex. L-D2-AMPCO-089, Ex. L-D2-CCC-055, Ex. L-D2-CCC-056, Ex. L-D2-CCC-057, Ex. L-D2-CCC-058, Ex. L-D2-CCC-059, Ex. L-D2-OAPPA-006, Ex. L-D2-OAPPA-007, Ex. L-D2-OAPPA-008, Ex. L-D2-SEC-097, Ex. L-D2-SEC-098, Ex. L-D2-SEC-099, Ex. L-D2-SEC-101, Ex. L-D2-SEC-102, Ex. L-D2-SEC-103, Ex. L-D2-SEC-104, Ex. L-D2-SEC-105, Ex. L-D2-SEC-106, Ex. L-D2-SEC-107, Ex. L-D2-SEC-108, Ex. L-D2-SEC-109, Ex. L-D2-SEC-110, Ex. L-D2-SEC-111, Ex. L-D2-SEC-112, Ex. L-D2-SEC-113, Ex. L-D2-SEC-114, Ex. L-D2-SEC-115, Ex. L-D2-SEC-116, Ex. L-D2-SEC-117, Ex. L-D2-Staff-117, Ex. L-D2-Staff-118, Ex. L-D2-Staff-119, Ex. L-D2-Staff-120, Ex. L-D2-Staff-121, Ex. L-D2-Staff-122, Ex. L-D2-Staff-123, Ex. L-D2-Staff-124, Ex. L-D2-Staff-125, Ex. L-D2-Staff-126, Ex. L-D2-Staff-127, Ex. L-D2-Staff-128, Ex. L-D2-Staff-129, Ex. L-D2-Staff-131,
Undertakings	Ex. JTX3.21, Ex. JT3.22, Ex. JT3.24, Ex. JT3.25, Ex. JT3.26, Ex. JT3.27, Ex. JT4.2, Ex. JT4.6, Ex. JT4.7, Ex. JT4.8, Ex. JT4.9

Issue 17

Is the proposed hydroelectric production forecast appropriate?

Settlement Status: Complete Settlement

The Parties agree to the modified regulated hydroelectric production forecast for the 2027-2031(i) by increasing the 2027 forecast production (for purposes of the 2027

payment amount) by 0.45 TWh, and (ii) by reflecting a settlement adjusted forecast production for the 2028-2031 period; as set out in Section 2, Part C, subpart (ii) of this Settlement Proposal. The Parties also agree that the increase in the regulated hydroelectric production forecast as a result of the above modification will be reflected in the production forecast models used to derive entries in the Hydroelectric Water Conditions Variance Account, as described in Ex. H1-1-1, Section 5.1. For this purpose, the Parties agree that this modification be applied to the regulated hydroelectric stations in the Niagara Region.

Parties in Support:	OPG, AMPCO, BOMA, CCMBC, CCC, Energy Probe, Minogi, OAPPA, QMA, SEC, VECC
Parties Taking no Position:	PWU, Society, IESO, Environmental Defence

Evidence

Exhibits	Ex. E1-1-1 (Production Forecast and Methodology – Regulated Hydroelectric), Ex. E1-1-2 (Comparison of Production Forecast – Regulated Hydroelectric), Ex. A1-3-2 (Rate-Setting Framework and Performance Reporting), Ex. I1-2-1 (Regulated Hydroelectric Payment Amount)
Interrogatories	Ex. L-A1-AMPCO-004, Ex. L-A1-CCC-001, Ex. L-A1-SEC-011, Ex. L-D1-ED-006, Ex. L-E1-CCC-063, Ex. L-E1-SEC-128, Ex. L-E1-Staff-135, Ex. L-E1-Staff-136, Ex. L-E1-Staff-0137, Ex. L-E1-Staff-138, Ex. L-E1-Staff-140, Ex. L-E1-Staff-141, Ex. L-A1-CCC-003, Ex. L-A1-Staff-334
Undertakings	Ex. JT1.12, Ex. JT1.13, Ex. JT2.1, Ex. JT5.13, Ex. JT5.14

Issue 18

Is the proposed OPG nuclear facilities production forecast appropriate?

Settlement Status: Complete Settlement

The Parties agree to the modified OPG nuclear production forecast for the 2027-2031 period, along with the establishment of new variance accounts to enable the sharing with ratepayers of certain positive and negative OPG net revenue impacts resulting from variances to the forecast planned outage days at Darlington during the 2027-2031 period and OPG's positive net revenue impacts resulting from any of the Pickering units returning to service from refurbishment in the 2027-2031 period earlier than reflected in OPG's

nuclear production forecast as approved by the OEB in this proceeding, as set out in Section 2, Part C, subpart (i) of this Settlement Proposal.

Parties in Support:	OPG, AMPCO, BOMA, CCMBC, CCC, Energy Probe, Minogi, OAPPA, QMA, SEC, VECC
Parties Taking no Position:	PWU, Society, IESO, Environmental Defence, Minogi (as it relates to DNNP)

Evidence

Exhibits	Ex. E2-1-1 (Production Forecast and Methodology – Nuclear), Ex. E2-1-2 (Comparison of Production Forecasts – Nuclear)
Interrogatories	Ex. L-A1-CCC-001, Ex. L-A2-CCC-014, Ex. L-E2-CCC-065, Ex. L-E2-OAPPA-010, Ex. L-E2-OAPPA-011, Ex. L-E2-SEC-137, Ex. L-E2-SEC-138, Ex. L-E2-SEC-139, Ex. L-E2-SEC-140, Ex. L-E2-SEC-141, Ex. L-E2-SEC-142, Ex. L-E2-SEC-143, Ex. L-E2-SEC-144, Ex. L-D2-Staff-082, Ex. L-D2-Staff-084, Ex. L-D2-Staff-086, Ex. L-E2-Staff-153, Ex. L-E2-Staff-154, Ex. L-E2-Staff-155, Ex. L-E2-Staff-156, Ex. L-E2-Staff-157, Ex. L-E2-Staff-158, Ex. L-E2-Staff-159, Ex. L-E2-VECC-009, Ex. L-E2-VECC-010, Ex. L-D2-ED-005, Ex. L-D2-ED-008
Undertakings	Ex. JT3.6, Ex. JT3.7, Ex. JT3.10, Ex. JT3.20

Issue 19

Is the proposed DNNP facilities production forecast appropriate?

Settlement Status: Complete Settlement

The Parties agree to the modify DNNP LP's proposed production forecast for the 2027-2031 period with an increase of 0.1 TWh in 2031, as set out in Section 3, Part C of this Settlement Proposal.

The Parties acknowledge that, pursuant to O. Reg. 53/05, s. 11(1), the DNNPVARD will record DNNP LP's revenue impacts, net of production costs, resulting from DNNP Unit 1 entering service earlier or later than the forecast in-service date of October 17, 2030 as set out at Ex. D2-4-8 and reflected in this Settlement Proposal.

The Parties also agree that, for the purpose of deriving entries in the DNNPVARD as described in Ex. H1-1-1, Section 6.1, the increase in the DNNP LP's production forecast as a result of the above modification will be reflected in the month of April 2031.

Parties in Support:	DNNP LP, AMPCO, BOMA, CCMBC, CCC, Energy Probe, OAPPA, QMA, SEC, VECC
Parties Taking no Position:	PWU, Society, Minogi, IESO, Environmental Defence

Evidence

Exhibits	Ex. E2-1-1 (Production Forecast and Methodology - Nuclear), Ex. E2-1-2 (Comparison of Production Forecasts – Nuclear)
Interrogatories	Ex. L-E2-SEC-145, Ex. L-F2-Staff-206
Undertakings	N/A

Issue 20

Is the proposed Hydroelectric Surplus Baseload Generation Variance Account spill calculation methodology appropriate?

Settlement Status: Complete Settlement

The Parties agree that OPG will continue to use the methodology for calculating SBGVA spill as described in Ex. E1-2-1, Section 4.0, as modified with respect to the treatment of global and local SBG spill as set out in Section 2, Part G of this Settlement Proposal.

The Parties also agree that, as part of the next application seeking to clear the SBGVA or HIMVA balances, OPG shall request that the issues list for that proceeding include a full review of the treatment of the SBGVA, the HIM and the MWPs, as discussed in Appendix A, Section 4.0 of this Settlement Proposal.

Parties in Support:	OPG, AMPCO, BOMA, CCMBC, CCC, Energy Probe, Environmental Defence, IESO, Minogi, OAPPA, QMA, SEC, VECC
Parties Taking no Position:	PWU, Society

Evidence

Exhibits	Ex. E1-2-1 (Hydroelectric Incentive Mechanism, Surplus Baseload Generation and Make Whole Payments), Ex. H1-1-1 (Deferral and Variance Accounts)

Interrogatories	Ex. L-E1-CCC-063, Ex. L-E1-ED-010, Ex. L-E1-ED-011, Ex. L-E1-ED-012, Ex. L-E1-ED-013, Ex. L-E1-ED-014, Ex. L-E1-ED-015, Ex. L-E1-IESO-001, Ex. L-E1-SEC-129, Ex. L-E1-SEC-130, Ex. L-E1-SEC-132, Ex. L-E1-SEC-134, Ex. L-E1-Staff-137, Ex. L-E1-Staff-147, Ex. L-E1-Staff-148, Ex. L-E1-Staff-149, Ex. L-E1-Staff-150, Ex. L-E1-Staff-151
Undertakings	N/A

Issue 21

Is the proposed Hydroelectric Incentive Mechanism ("HIM") methodology and HIM adjustment for spill appropriate?

Settlement Status: Complete Settlement

The Parties agree that OPG will continue to be settled according to the HIM methodology and HIM adjustment for spill ("**unintended benefit**") as described in Ex. E1-2-1, Section 5.0.

The Parties also agree that, as part of the next application seeking to clear the SBGVA or HIMVA balances, OPG shall request that the issues list for that proceeding include a full review of the treatment of the SBGVA, the HIM and the MWPs, as discussed in Appendix A, Section 4.0 of this Settlement Proposal. The implementation of any changes to the HIM methodology and/or the HIM adjustment for spill arising from such a review would be effective as of the effective date of the payment amount order in OPG's next rebasing application for the regulated hydroelectric facilities.

Parties in Support:	OPG, AMPCO, BOMA, CCMBC, CCC, Energy Probe, Environmental Defence, Minogi, OAPPA, QMA, SEC, VECC
Parties Taking no Position:	PWU, Society, IESO

Evidence

Exhibits	Ex. E1-2-1 (Hydroelectric Incentive Mechanism, Surplus Baseload Generation and Make Whole Payments), Ex. G1-1-1 (Other Revenues – Regulated Hydroelectric), Ex. H1-1-1 (Deferral and Variance Accounts)
Interrogatories	Ex. L-E1-CCC-064, Ex. L-E1-ED-016, Ex. L-E1-IESO-002, Ex. L-E1-SEC-131, Ex. L-E1-SEC-132, Ex. L-E1-SEC-143, Ex. L-E1-Staff-144, Ex. L-E1-

	Staff-145, Ex. L-E1-Staff-146, Ex. L-E1-Staff-147, Ex. L-G1-CCC-096, Ex. L-G1-Staff-242
Undertakings	Ex. JT1.21

Issue 22

Is the proposed treatment of make whole payments appropriate?

Settlement Status: Complete Settlement

The Parties agree that OPG will continue to retain Real-Time Energy MWPs and forgo receiving all Day-Ahead Energy and Day-Ahead Operating Reserve MWPs during the 2027-2031 period, while maintaining the ability to monitor such amounts, as described in Ex. E1-2-1, Section 6.2.

The Parties also agree that, as part of the next application seeking to clear the SBGVA or HIMVA balances, OPG shall request that the issues list for that proceeding include a full review of the treatment of the SBGVA, the HIM, and the MWPs, as discussed in Appendix A, Section 4.0 of this Settlement Proposal.

Parties in Support:	OPG, AMPCO, BOMA, CCMBC, CCC, Energy Probe, Environmental Defence, IESO, Minogi, OAPPA, QMA, SEC, VECC
Parties Taking no Position:	PWU, Society

Evidence

Exhibits	Ex. E1-2-1 (Hydroelectric Incentive Mechanism, Surplus Baseload Generation and Make Whole Payments), Ex. G1-1-1 (Other Revenues – Regulated Hydroelectric)
Interrogatories	Ex. L-E1-Staff-142, Ex. L-E1-Staff-143, Ex. L-E1-Staff-152
Undertakings	N/A

OM&A Costs

Issue 23

Is the 2027 base and project Operations, Maintenance and Administration ("OM&A") budget for the hydroelectric facilities appropriate?

Issue 24

Is the 2027-2031 base, project, outage and Pickering cyclical maintenance OM&A budget for OPG's nuclear facilities appropriate?

Issue 26

Are the allocated corporate costs, centrally held costs, and asset service fees to (1) OPG's nuclear business, (2) OPG's hydroelectric business, and (3) DNNP LP, appropriate?

Issue 33

Are the IR term human resource related costs (including wages, salaries, payments under contractual work arrangements, benefits, incentive payments, overtime FTEs and pension costs) appropriate?

Settlement Status: Complete Settlement

In respect of Issues 23, 24, 26, and 33, the Parties agree that the budgeted costs applicable to the respective issues for the 2027-2031 period are appropriate, subject to the following adjustments:

- A reduction to the proposed total OM&A expenses for the regulated hydroelectric facilities of $25.0M for the 2027 test year, inclusive of associated Allocation of Corporate Costs, Allocation of Centrally Held Costs and Asset Service Fees, which represents a reduction of approximately 5%; and

- A reduction to the proposed total OM&A expenses for the OPG nuclear facilities, excluding Pickering Refurbishment OM&A expenses and including associated Allocation of Corporate Costs, Allocation of Centrally Held Costs and Asset Service Fees, for the 2027-2031 period, as follows: $90.0M in 2027, $125.0M in 2028, $130.0M in 2029, $130.0M in 2030, and $140.0M in 2031, which represents an average reduction of 6.7% over the period.

Parties in Support:	Applicants, AMPCO, BOMA, CCMBC, CCC, Energy Probe, Minogi, OAPPA, QMA, SEC, VECC
Parties Taking no Position:	PWU, Society, IESO, Environmental Defence, Minogi (as it relates to DNNP)

Evidence

Exhibits	Regulated Hydroelectric:

	Ex. F1-1-1 (Business Planning and Benchmarking – Regulated Hydroelectric), Ex. F1-2-1 (Base OM&A – Regulated Hydroelectric), Ex. F1-2-2 (Comparison of Base OM&A – Regulated Hydroelectric), Ex. F1-3-1 (Project OM&A – Regulated Hydroelectric), Ex. F1-3-2, (Comparison of Project OM&A – Regulated Hydroelectric), Ex. F1-3-3 (Details of OM&A Projects – Regulated Hydroelectric), Ex. F1-5-1 (OM&A Purchased Services – Regulated Hydroelectric) Nuclear: Ex. F2-1-1 (Business Planning and Benchmarking – Nuclear), Ex. F2-2-1 (Nuclear Base and DNNP Operational Readiness OM&A Costs), Ex. F2-2-2 (Comparison of Nuclear Base and DNNP Operational Readiness OM&A Costs), Ex. F2-3-1 (Project OM&A Costs – Nuclear), Ex. F2-3-2 (Comparison of Project OM&A Costs - Nuclear), Ex. F2-3-3 (Details of OM&A Projects – Nuclear), Ex. F2-4-1 (Nuclear Outage and Pickering Cyclical Maintenance OM&A Costs), Ex. F2-4-2 (Comparison of Nuclear Outage and Pickering Cyclical Maintenance OM&A Costs), Ex. F2-5-1 (Nuclear Fuel Costs), Ex. F2-5-2 (Comparison of Nuclear Fuel Costs), Ex. F2-6-1 (OM&A Purchased Services - Nuclear Operations), Ex. F2-7-1 (Darlington Refurbishment Program - OM&A), Ex. F2-8-1 (Pickering Refurbishment Program Project OM&A), Corporate/Compensation: Ex. F3-1-1 (Allocation of Support Services Costs), Ex. F3-1-2 (Comparison of Allocation of Support Services Costs), Ex. F3-1-4 (Cost Allocation Methodology), Ex. F3-2-1 (Asset Service Fees), Ex, F3-2-2 (Comparison of Asset Service Fees), Ex. F4-3-1 (Compensation and Benefits), Ex. F4-3-2 (Pension and OPEB Benefits), Ex. F4-4-1 (Centrally Held Costs)
Interrogatories	Regulated Hydroelectric: Ex. L-A1-CCC-001, Ex. D1-Staff-060, Ex. L-D1-Staff-070, Ex. L-F1-AMPCO-092, Ex. L-F1-AMPCO-100, Ex. L-F1-AMPCO-101, Ex. L-F1-AMPCO-102, Ex. L-F1-AMPCO-103, Ex. L-F1-CCC-067, Ex. L-F1-CCC-069, Ex. L-F1-CCMBC-001,

	Ex. L-F1-CCMBC-002, Ex. L-F1-SEC-149, Ex. L-F1-SEC-154, Ex. L-F1-SEC-156, Ex. L-F1-Staff-160, Ex. L-F1-Staff-164, Ex. L-F1-Staff-169, Ex. L-F1-Staff-170, Ex. L-F1-Staff-172, Ex. F1-Staff-173, Ex. L-F1-Staff-174, Ex. L-F1-Staff-175, Ex. L-F1-Staff-177, Ex. L-F1-Staff-321, Ex. L-A1-SEC-014, Ex. L-F1-Staff-161, Ex. L-F1-Staff-168, Ex. L-F1-AMPCO-097, Ex. L-F1-AMPCO-098, Ex. L-F1-SEC-150, Ex. L-F1-SEC-151, Ex. L-F1-SEC-152 Nuclear: Ex. L-F2-AMPCO-104, Ex. L-F3-AMPCO-105, Ex. L-F3-AMPCO-107, Ex. L-A1-CCC-001, Ex. L-F2-CCC-070, Ex. L-F2-CCC-071, Ex. L-F2-CCC-072, Ex. L-F2-CCC-073, Ex. L-F2-CCC-074, Ex. L-F2-CCC-075, Ex. L-F2-CCC-076, Ex. L-F2-CCC-077, Ex. L-F2-CCC-078, Ex. L-F2-OAPPA-012, Ex. L-F2-OAPPA-014, Ex. L-F2-SEC-157, Ex. L-F2-SEC-158, Ex. L-F2-SEC-159, Ex. L-F2-SEC-160, Ex. L-F2-SEC-161, Ex. L-F2-SEC-162, Ex. L-F2-SEC-163, Ex. L-F2-SEC-164, Ex. L-F2-SEC-165, Ex. L-F2-SEC-166, Ex. L-F2-SEC-167, Ex. L-F2-SEC-168, Ex. L-F2-SEC-170 Ex. L-F2-Staff-171, Ex. L-F2-Staff-178, Ex. L-F2-Staff-179, Ex. L-F2-Staff-180, Ex. L-F2-Staff-181, Ex. L-F2-Staff-182, Ex. L-F2-Staff-183, Ex. L-F2-Staff-184, Ex. L-F2-Staff-185, Ex. L-F2-Staff-186, Ex. L-F2-Staff-188, Ex. L-F2-Staff-189, Ex. L-F2-Staff-190, Ex. L-F2-Staff-191, Ex. L-F2-Staff-195 Ex. L-F2-Staff-196, Ex. L-F2-Staff-197, Ex. L-F2-Staff-198, Ex. L-F2-Staff-202, Ex. L-F2-Staff-203, Ex. L-F2-Staff-204, Ex. L-F2-Staff-205, Ex. L-F2-Staff-206, Ex. L-F2-Staff-207, Ex. L-F2-Staff-208, Ex. F2-Staff-210, Ex. L-F2-Staff-211, Ex. L-F2-Staff-212, Ex. L-F2-Staff-213, Ex. L-F2-Staff-215, Ex. L-F2-Staff-216, Ex. L-F2-Staff-322, Ex. L-F2-Staff-323, Ex. L-F2-Staff-324, Ex. L-F2-Staff-325, Ex. L-F2-Staff-326, Ex. L-F2-Staff-327, Ex. L-F2-Staff-328, Ex. L-F2-SUP-010, Ex. L-F2-SUP-011, Ex. L-F2-SUP-012 Corporate Support: Ex. L-A1-CCC-009, Ex. L-F3-CCC-082, Ex. L-F4-AMPCO-124, Ex. L-F4-CCC-088, Ex. L-F4-CCC-089,

	Ex. L-F3-CCMBC-003, Ex. L-F4-CCMBC-007, Ex. L-F3-SEC-178, Ex. L-F3-SEC-181, Ex. L-F4-SEC-196, Ex. L-F4-SEC-198, Ex. L-F4-Staff-192, Ex. L-F4-Staff-229, Ex. L-F3-SUP-013, Ex. L-F4-SUP-014, Ex. L-F3-Staff-218, Ex. L-F3-SEC-175, Ex. F3-CCC-081, Ex. L-F3-CCC-082, Ex. L-F2-MC-008 Ex. L-F3-SEC-172, Ex. L-F3-SEC-173. Ex. L-F3-SEC-174, Ex. L-F3-SEC-176, Ex. L-F3-SEC-177, Ex. L-F3-SEC-178, Ex. L-F3-SEC-179, Ex. L-F3-SEC-180, Ex. L-F3-SEC-181, Ex. L-F3-SEC-182, Ex. L-F3-SEC-183, Ex. L-F3-VECC-013, Ex. L-F3-VECC-014, Ex. L-G2-Staff-243. Human Resources Related Costs (Overall): Ex. L-D2-PWU-011, Ex. L-D2-SEC-103, Ex. L-F2-SUP-011, Ex. L-F4-AMPCO-110, Ex. L-F4-AMPCO-111, Ex. L-F4-AMPCO-112, Ex. L-F4-AMPCO-113, Ex. L-F4-AMPCO-114, Ex. L-F4-AMPCO-115, Ex. L-F4-AMPCO-115, Ex. L-F4-AMPCO-116, Ex. L-F4-AMPCO-117, Ex. L-F4-AMPCO-118, Ex. L-F4-AMPCO-119, Ex. L-F4-AMPCO-120, Ex. L-F4-AMPCO-121, Ex. L-F4-AMPCO-122, Ex. L-F4-AMPCO-123, Ex. L-F4-AMPCO-124, Ex. L-F4-AMPCO-127, Ex. L-F4-CCC-085, Ex. L-F4-CCC-086, Ex. L-F4-CCC-087, Ex. L-F4-CCC-088, Ex. L-F4-CCC-089, Ex. L-F4-CCC-090, Ex. L-F4-CCC-091, Ex. L-F4-CCC-092, Ex. L-F4-CCC-093, Ex. L-F4-CCMBC-004, Ex. L-F4-CCMBC-005, Ex. L-F4-CCMBC-006, Ex. L-F4-CCMBC-007, Ex. L-F4-CCMBC-008, Ex. L-F4-CCMBC-009, Ex. L-F4-CCMBC-010, Ex. L-F4-CCMBC-011, Ex. L-F4-PWU-010, Ex. L-F4-PWU-012, Ex. L-F4-PWU-014, Ex. L-F4-SEC-189, Ex. L-F4-SEC-190, Ex. L-F4-SEC-191, Ex. L-F4-SEC-192, Ex. L-F4-SEC-193, Ex. L-F4-SEC-194, Ex. L-F4-SEC-195, Ex. L-F4-SEC-196, Ex. L-F4-SEC-197, Ex. L-F4-SEC-198, Ex. L-F4-Staff-192, Ex. L-F4-Staff-221, Ex. L-F4-Staff-222, Ex. L-F4-Staff-223, Ex. L-F4-Staff-224, Ex. L-F4-Staff-225, Ex. L-F4-Staff-226 Ex. L-F4-Staff-227, Ex. L-F4-Staff-228, Ex. L-F4-Staff-229, Ex. L-F4-Staff-230, Ex. L-F4-Staff-231, Ex. L-F4-Staff-232, Ex. L-F4-Staff-233, Ex. L-F4-Staff-234, Ex. L-F4-Staff-235, Ex. L-F4-SUP-014, Ex. L-F4-SUP-015, Ex. L-F4-SUP-016, Ex. L-F4-

	SUP-017, Ex. L-F4-SUP-018, Ex. L-F4-SUP-019, Ex. L-F4-SUP-020, Ex. L-F4-SUP-021, Ex. L-F4-SUP-022, Ex. L-F4-SUP-023, Ex. L-F4-SUP-025, Ex. L-F4-SUP-026, Ex. L-F4-SUP-027, Ex. L-F4-SUP-028, Ex. L-H1-SEC-207
Undertakings	Regulated Hydroelectric: Ex. JT1.14, Ex. JT1.15, Ex. JT1.19, Ex. JT1.22 Nuclear: Ex. JT2.18, Ex. JT2.19, Ex. JT2.20, Ex. JT34, Ex. JT3.5, Ex. JT3.11, Ex. JT4.11, Ex. JT5.2 Corporate: Ex. JT3.1, Ex. JT4.16, Ex. JT4.17, Ex. JT4.18, Ex. JT4.19, Ex. JT5.21

Issue 25

Is the 2027-2031 base outage and operational readiness OM&A budget for the DNNP facilities appropriate?

Settlement Status: Complete Settlement

The Parties agree that DNNP LP's budgeted OM&A costs for the 2027-2031 period are appropriate, subject to a reduction to such proposed total OM&A expenses, excluding DNNP Operational Readiness OM&A expense and including associated Allocation of Corporate Costs, Allocation of Centrally Held Costs and Asset Service Fees, for the 2027-2031 period, as follows: $4.0M in 2027, $4.0M in 2028, $4.0M in 2029, $4.0M in 2030, and $8.0M in 2031.

The Parties also agree that, for the purposes of the DNNPVARD, $1.5M of the above reduction to the proposed total OM&A expenses in 2031 shall be applied to the outage expenses.

Parties in Support:	Applicants, AMPCO, BOMA, CCMBC, CCC, Energy Probe, OAPPA, QMA, SEC, VECC
Parties Taking no Position:	PWU, Society, Minogi (as it relates to DNNP), IESO, Environmental Defence

Evidence

Exhibits	Ex. F2-1-1 (Business Planning and Benchmarking – Nuclear), Ex. F2-2-1 (Nuclear Base and DNNP

	Operational Readiness OM&A Costs), Ex. F2-2-2 (Comparison of Nuclear Base and DNNP Operational Readiness OM&A Costs) Ex. F3-1-1 (Allocation of Support Services Costs), Ex. F3-1-2 (Comparison of Allocation of Support Services Costs), Ex. F3-1-4 (Cost Allocation Methodology), Ex. F3-2-1 (Asset Service Fees), Ex, F3-2-2 (Comparison of Asset Service Fees), Ex. F4-3-1 (Compensation and Benefits), Ex. F4-3-2 (Pension and OPEB Benefits), Ex. F4-4-1 (Centrally held Costs)
Interrogatories	Ex. L-F2-Staff-194, Ex. L-F2-Staff-200, Ex. L-F2-Staff-201, Ex. L-D4-OAPPA-009, Ex. L-D3-CCC-060
Undertakings	

Depreciation Expenses

Issue 27

Is the proposed 2027 hydroelectric depreciation expense appropriate?

Issue 28

Is the proposed 2027-2031 OPG facilities nuclear depreciation expense appropriate?

Issue 29

Is the proposed 2027-2031 DNNP facilities depreciation expense appropriate?

Settlement Status: Complete Settlement

In respect of Issues 27, 28, and 29, the Parties agree that the amounts applicable to the respective issues are appropriate, subject to the applicable adjustments in connection with the CCC-084 Impacts and the modifications to the rate base values and forecast in-service capital additions as agreed to in this Settlement Proposal.

Parties in Support:	Applicants, AMPCO, BOMA, CCMBC, CCC, Energy Probe, OAPPA, QMA, SEC, VECC
Parties Taking no Position:	PWU, Society, Minogi (as it relates to DNNP), IESO, Environmental Defence

Evidence

Exhibits	Ex. F4-1-1 (Depreciation and Amortization)

Interrogatories	Ex. L-F4-AMPCO-108, Ex. L-F4-CCC-083, Ex. L-F4-SEC-185, Ex. L-F4-SEC-187, Ex. L-F4-SEC-188, Ex. L-F4-AMPCO-109, Ex. L-F4-CCC-083, Ex. L-F4-SEC-184, Ex. L-F4-SEC-186
Undertakings	N/A

Income and Property Taxes

Issue 30

Are the amounts proposed to be included in the 2027 hydroelectric revenue requirement for income and property taxes appropriate?

Issue 31

Are the amounts proposed to be included in the 2027-2031 OPG facilities nuclear revenue requirement for income and property taxes appropriate?

Issue 32

Are the amounts proposed to be included in the 2027-2031 DNNP facilities revenue requirement for income and property taxes appropriate?

Settlement Status: Complete Settlement

In respect of Issues 30, 31, and 32, the Parties agree that the amounts applicable to the respective issues are appropriate, subject to the applicable adjustments to regulatory income tax amounts in connection with (i) the CCC-084 Impacts, (ii) the modifications to the rate base values, forecast in-service capital additions, forecast depreciation and amortization expenses and OPG's proposed capital structure as agreed to in this Settlement Proposal, and (iii) the update of the prevailing ROE rate by the OEB as of the effective date of the final payment amounts order in this proceeding. The Parties acknowledge that the adjustments referred to in the foregoing subparts (i) and (ii) include modifications to the forecast capital cost allowance amounts from those proposed in the Application.

The Parties also agree that any differences between the forecasted impacts of the CEITCs included in the settlement adjusted revenue requirements and such actual impacts during the 2027-2031 period will be recorded in the respective deferral and variance accounts, including the following, with any such differences not otherwise captured in another deferral or variance account recorded in the newly established Clean Electricity ITC Variance Account (OPG) or Clean Electricity ITC and Other Benefits Variance Account (DNNP), as applicable:

- Differences related to OPG's expenditures eligible for the CRVA, including for the PRP (other than CCR interest amounts), will be recorded in the CRVA;

- Differences related to the DNNP (other than CCR interest amounts) will be recorded in the DNNPVARD; and

- Differences related to CCR interest amounts will be recorded in the respective CCR DVAs.

Parties in Support:	Applicants, AMPCO, BOMA, CCMBC, CCC, Energy Probe, OAPPA, QMA, SEC, VECC
Parties Taking no Position:	PWU, Society, Minogi (as it relates to DNNP), IESO, Environmental Defence

Evidence

Exhibits	Ex. F4-2-1 (Taxes)
Interrogatories	Ex. L-F4-CCC-084, Ex. L-F4-SEC-199, Ex. L-F4-SEC-200, Ex. L-F4-Staff-219, Ex. L-F4-Staff-220
Undertakings	Ex. JT5.17

Issue 34

Are the forecasts of hydroelectric non-energy revenues appropriate?

Settlement Status: Complete Settlement

The Parties agree that OPG's forecasts of regulated hydroelectric non-energy revenues for the 2027 test year are appropriate, subject to following adjustments:

- An increase to the forecast HIM revenues of $18.4M;

- An increase to the ancillary services revenues of $8.0M; and

- An increase to the remaining other revenue categories totaling $3.0M.

The Parties further agree that the $8.0M increase to the forecast ancillary services revenues will be subject to the Ancillary Services Net Revenue Variance Account and that the reference amount for recording entries in this account will be correspondingly increased from the amount proposed in the Application.

The Parties also agree that the HIMVA will have a reference amount for recording entries in the account of $54.5M.

Parties in Support:	OPG, AMPCO, BOMA, CCMBC, CCC, Energy Probe, Minogi, OAPPA, QMA, SEC, VECC
Parties Taking no Position:	PWU, Society, IESO, Environmental Defence

Evidence

Exhibits	Ex. G1-1-1 (Other Revenues – Regulated Hydroelectric), Ex. G1-1-2 (Comparison of Other Revenues – Regulated Hydroelectric)
Interrogatories	Ex. L-A1-CCC-001, Ex. L-G1-SEC-201, Ex. L-G1-Staff-238, Ex. L-G1-Staff-239, Ex. L-G1-Staff-240, Ex. L-G1-Staff-241, Ex. L-G1-Staff-242
Undertakings	Ex. JT2.4

Issue 35

Are the forecasts of nuclear non-energy revenues appropriate?

Settlement Status: Complete Settlement

The Parties agree that OPG's forecasts of nuclear non-energy revenues for the 2027-2031 period are appropriate.

Parties in Support:	OPG, AMPCO, BOMA, CCMBC, CCC, Energy Probe, Minogi, OAPPA, QMA, SEC, VECC
Parties Taking no Position:	PWU, Society, IESO, Environmental Defence

Evidence

Exhibits	Ex. G2-1-1 (Nuclear Non-Energy Revenues), Ex. G2-1-2 (Comparison of Non-Energy Revenues – Nuclear)
Interrogatories	Ex. L-G2-CCC-097, Ex. L-G2-Staff-244, Ex. L-G2-Staff-245, Ex. L-A1-CCC-001
Undertakings	N/A

Issue 36

Are the IR term costs related to the Bruce Nuclear Generating Station, and costs and revenues related to the Bruce lease appropriate?

Settlement Status: Complete Settlement

The Parties agree that OPG's forecasts of costs related to the Bruce Nuclear Generating Stations and costs and revenues related to the Bruce lease, for the 2027-2031 period, are appropriate.

Parties in Support:	OPG, AMPCO, BOMA, CCMBC, CCC, Energy Probe, Minogi, OAPPA, QMA, SEC, VECC
Parties Taking no Position:	PWU, Society, IESO, Environmental Defence

Evidence

Exhibits	Ex. G2-1-1 (Bruce Generating Stations – Revenues and Costs), Ex. G2-1-2 (Comparison of Non-Energy Revenues – Nuclear)
Interrogatories	Ex. L-A1-CCC-001, Ex. L-F4-SEC-186, Ex. L-G2-CCC-097, Ex. L-G2-CCC-098
Undertakings	N/A

Issue 37

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

Settlement Status: Complete Settlement

The Parties agree that the revenue requirement impacts of OPG's nuclear liabilities for OPG's nuclear facilities for the 2027-2031 period have been appropriately determined, subject to reflecting the impacts of the settlement adjustments to OPG's nuclear production forecast on used fuel variable costs. The Parties also agree with OPG's proposed treatment of OPG's nuclear liabilities for the DNNP facilities, including the methodology for determining the cost impacts of such liabilities.

The Parties also agree to continue OPG's EB-2020-0290 accounting order application requirement related to accounting changes impacting the calculation of OPG's nuclear liabilities and changes in depreciation end-of-life dates for its prescribed nuclear facilities, subject to the updated annual regulatory materiality threshold of $20M, and to extend this requirement to DNNP LP in respect of changes in depreciation end-of-life dates for its prescribed facilities, subject to an annual regulatory materiality threshold of $10M, all as proposed in the Application.

Parties in Support:	Applicants, AMPCO, BOMA, CCMBC, CCC, Energy Probe, OAPPA, QMA, SEC, VECC
Parties Taking no Position:	PWU, Society, Minogi (as it relates to DNNP), IESO, Environmental Defence

Evidence

Exhibits	Ex. C2-1-1 (Nuclear Waste Management and Decommissioning – Revenue Requirement Impact of Nuclear Liabilities)
Interrogatories	Ex. L-C2-CCC-037, Ex. L-C2-MC-003, Ex. L-C2-OAPPA-001, Ex. L-C2-Staff-056, Ex. L-C2-Staff-057, Ex. L-C2-Staff-058
Undertakings	N/A

Deferral and Variance Accounts

Issue 38

Are the deferral and variance accounts that OPG and DNNP LP propose to continue, establish, and discontinue appropriate?

Issue 39

Are the methodologies used to determine additions to the deferral and variance accounts appropriate?

Settlement Status: Complete Settlement

The Parties agree to continue or discontinue existing deferral and variance accounts for the Applicants, effective January 1, 2027 unless otherwise noted, as proposed in the Application, including the methodologies that will be used to record entries into these accounts, subject to the modifications with respect to the Pension and OPEB Cost Variance Account (OPG), the Nuclear Development Variance Account, the SBGVA, the Ancillary Services Net Revenue Variance Account – Nuclear Sub-Account the HIMVA and the Clarington Corporate Campus Deferral Account and the modifications arisings from the establishment of the Change in CCA Rules or Rates Variance Account (OPG) and the Change in CCA Rules or Rates Variance Account (DNNP), as described in Section 2, Part G and Section 3, Part F of this Settlement Proposal.

The Parties also agree that the Applicants will establish new accounts, effective January 1, 2027 unless otherwise noted, as proposed in the Application, subject to the modifications with respect to the respective proposals for the Change of Laws Deferral Accounts (which will be renamed to the Nuclear Security Regulation and American Eel Impact Deferral Account (OPG) and, Nuclear Security Regulation Deferral Account (DNNP)), the Global Hydroelectric Capital Variance Account, the Clean Electricity ITC Variance Account (DNNP) (which will be renamed to the Clean Electricity ITC and Other Benefits Variance Account (DNNP)), the Pension and OPEB Cost Variance Account

(DNNP), and the Payment Amount Shaping Deferral Account, and the modifications arising from the establishment of the Change in CCA Rules or Rates Variance Account (OPG) and the Change in CCA Rules or Rates Variance Account (DNNP), as described in Section 2, Part G and Section 3, Part F of this Settlement Proposal. In addition to the foregoing, the Parties agree that the Applicants shall establish three new accounts – the Nuclear Fuel Cost Variance Account (OPG), the Darlington Planned Outage Days (2027-2031) Settlement Variance Account and the Pickering Refurbishment 2027-2031 Early Return to Service Variance Account, as described in Section 2, Part G of this Settlement Proposal.

The Parties also agree to corresponding adjustments to the reference amounts for recording entries in the applicable accounts effective January 1, 2027, relative to the Applicants' proposals, to reflect the impacts of the Settlement Proposal.

The Parties further agree that the terms of any existing or new deferral and variance accounts established for the Applicants shall be implemented and interpreted in a manner that avoids duplication of amounts recorded amongst the accounts during the 2027-2031 period.

Additional details with respect to the agreed terms and scope of certain deferral and variance accounts are provided in Section 5, Issues 3, 11, 13, 15, 16, 17, 19, 20, 30, 31, 32, 34, and 43 of this Settlement Proposal.

Parties in Support:	Applicants, AMPCO, BOMA, CCMBC, CCC, Energy Probe, OAPPA, QMA, SEC, VECC
Parties Taking no Position:	PWU, Society, Minogi (as it relates to DNNP), IESO, Environmental Defence

Evidence

Exhibits	Ex. H1-1-1 (Deferral and Variance Accounts), Ex. F2-5-1 (Nuclear Fuel Costs), Ex. F2-5-2 (Comparison of Nuclear Fuel Costs)
Interrogatories	Ex. L-F1-SEC-149, Ex. L-D1-Staff-073, Ex. L-F2-CCC-077, Ex. L-F2-SEC-170, Ex. L-F2-Staff-211, Ex. L-F2-Staff-212, Ex. L-F2-Staff-213, Ex. L-F2-OAPPA-014 Ex. L-H1-CCC-099, Ex. L-H1-CCC-100, Ex. L-H1-CCC-102, Ex. L-H1-CCC-106, Ex. L-H1-CCC-107, Ex. L-H1-CCC-108, Ex. L-H1-SEC-204, Ex. L-H1-SEC-209, Ex. L-H1-SEC-214, Ex. L-H1-Staff-055, Ex. L-H1-Staff-139, Ex. L-H1-Staff-246, Ex. L-H1-Staff-

	247, Ex. L-H1-Staff-248, Ex. L-H1-Staff-253, Ex. L-H1-Staff-254, Ex. L-H1-Staff-257, Ex. L-H1-Staff-259, Ex. L-H1-Staff-261, Ex. L-H1-Staff-262, Ex. L-H1-Staff-263, Ex. L-H1-Staff-264
Undertakings	Ex. JT5.1, Ex. JT5.3, Ex. JT5.12, Ex. JT5.18

Issue 40

Are the balances for recovery and the proposed disposition amounts in each of the deferral and variance accounts appropriate?

Settlement Status: Partial Settlement

Excluding the Outstanding Issue, the Parties agree that OPG shall recover or refund all deferral and variance account balances as proposed, with the exceptions of the Clarington Corporate Campus Deferral Account, the CRVA (Nuclear – Non-DRP) and the SBGVA, as set out in Section 2, Part G of this Settlement Proposal.

The Parties were not able to reach agreement on the Outstanding Issue, being OPG's proposed recovery of the $170.2M debit balance in the CRVA related to the DRP – Excluding D2O Storage Project, as at December 31, 2024. This balance resulted from historical variances in the amounts and/or timing of DRP in-service capital additions (and their tax effects) and certain non-capital project costs relative to forecasts reflected in OEB-approved revenue requirements (Ex. H1-1-1, p. 23, lines 5-6 and Ex. H1-1-1, Table 1, line 21, col. (c)). In particular, this includes incremental amounts sought for recovery from customers due to the earlier inclusion in the rate base and the associated timing of depreciation and cost of capital impacts for Darlington Unit 1 and Unit 3 as a result of their earlier than planned return to service from refurbishment.

The Parties agree that the Outstanding Issue should proceed by way of written hearing as discussed further under Issue 44.

Parties in Support:	Applicants, AMPCO, BOMA, CCMBC, CCC, Energy Probe, OAPPA, QMA, SEC, VECC
Parties Taking no Position:	PWU, Society, Minogi (as it relates to DNNP), IESO, Environmental Defence

Evidence

Exhibits	Ex. H1-1-1 (Deferral and Variance Accounts), Ex. H1-2-1 (Clearance of Deferral and Variance Accounts)

Interrogatories	Ex. L-H1-CCC-101, Ex. L-H1-CCC-103, Ex. L-H1-CCC-104, Ex. L-H1-CCC-105, Ex. L-H1-SEC-205, Ex. L-H1-SEC-206, Ex. L-H1-SEC-207, Ex. L-H1-SEC-208, Ex. L-H1-SEC-210, Ex. L-H1-SEC-211, Ex. L-H1-SEC-212, Ex. L-H1-SEC-213, Ex. L-H1-Staff-249, Ex. L-H1-Staff-250, Ex. L-H1-Staff-251, Ex. L-H1-Staff-252, Ex. L-H1-Staff-255, Ex. L-H1-Staff-256, Ex. L-H1-Staff-260, Ex. L-H1-VECC-015
Undertakings	N/A

Issue 41

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

Settlement Status: Complete Settlement

The Parties agree to the reporting and record keeping requirements for OPG and DNNP LP set out in Appendix A hereto. The Parties also agree that the Applicants will undertake certain independent studies, reports, and other filings as set out in Appendix A hereto.

Parties in Support:	Applicants, AMPCO, BOMA, CCMBC, CCC, Energy Probe, OAPPA, QMA, SEC, VECC
Parties Taking no Position:	PWU, Society, IESO, Environmental Defence, Minogi (as it relates to DNNP)

Evidence

Exhibits	Ex. A1-3-2 (Rate-setting Framework and Performance Reporting), Ex. F1-1-1 (Business Planning and Benchmarking – Regulated Hydroelectric), Ex. F2-1-1 (Business Planning and Benchmarking – Nuclear), Ex. D2-4-9 (Darlington New Nuclear Program Execution), Ex. D2-3-9 (Pickering Refurbishment Program Execution), Ex. F3-3-1 (OPG Procurement Process)
Interrogatories	Ex. L-A1-AMPCO-001, Ex. L-A1-SEC-014, Ex. L-A1-VECC-003, Ex. L-F1-AMPCO-097, Ex. L-F1-AMPCO-098, Ex. L-F1-SEC-153, Ex. L-F1-Staff-161, Ex. L-F1-Staff-162, Ex. L-F1-Staff-163, Ex. L-F1-Staff-166, Ex. L-F1-Staff-168, Ex. L-F1-Staff-170, Ex. L-D2-AMPCO-085, Ex. L-A1-AMPCO-001, Ex. L-A1-

	SEC-014, Ex. L-A1-VECC-004, Ex. L-D3-MC-006, Ex. L-F3-MC-009, Ex. L-F3-MC-011
Undertakings	Ex. JT3.22, Ex. JT4.4, Ex. JT1.1, Ex. JT1.2b, Ex. JT1.2d, Ex. JT.1.2e, Ex. JT1.2f, Ex. JT1.2j

Issue 42

What should be the scope and filing requirements of OPG and DNNP LP's annual applications during the IR Term?

Settlement Status: Complete Settlement

The Parties agree that the Applicants will file applications on an annual basis to clear the year-end balances in the Darlington New Nuclear Project Variance Account re Capital Cost Amounts and the Pickering B Refurbishment Project Variance Account (collectively, "**CCR DVAs**") on an audited, actual basis. Such annual applications will include an annual continuity schedule with the opening balance, transactions, interest and closing balance for each of the CCR DVAs, and tables showing the calculations of the additions to each of the accounts in a format similar to Ex. I1-1-1, Tables 6 and 7 in order to demonstrate the underlying calculations, including the variances relative to the forecast amounts reflected in the payment amounts. The Applicants will also file an auditor's report with respect to the balances being cleared The Parties acknowledge that the above process will meet the requirements of s. 6(2)12.1ii and s. 14(2)5ii, O. Reg. 53/05.

The Parties also agree that OPG will file applications on an annual basis to adjust OPG's regulated hydroelectric payment amounts according to the Custom IR framework formula as settled under Issue 4 of this Settlement Proposal. Such annual applications will set out the calculation of the adjusted regulated hydroelectric payment amounts in a format similar to Ex. I1-2-1, Table 1, and any additional evidence necessary to support the calculation of the regulated hydroelectric payment amounts. The table will include actual historical OEB-approved values from previous proceedings related to the 2027-2031 rate term.

OPG and DNNP LP's annual applications will also set out the estimated bill impacts of any proposed adjustments to payment amounts or payment riders. Bill impacts should show the monthly impact for residential customers consistent with the methodology in Ex. I1-1-2.

Parties in Support:	Applicants, AMPCO, BOMA, CCMBC, CCC, Energy Probe, OAPPA, QMA, SEC, VECC
Parties Taking no Position:	PWU, Society, Minogi (as it relates to DNNP), IESO, Environmental Defence

Evidence

Exhibits	Ex. I1-1-3 (Concurrent Cost Recovery), Ex. A1-2-2 (Approvals)
Interrogatories	Ex. L-I1-Staff-258
Undertakings	N/A

Issue 43

Do the Concurrent Cost Recovery amounts proposed meet the requirements set out in s. 6(2)12.1i and 14(2)5i of O. Reg. 53/05?

Settlement Status: Complete Settlement

The Parties agree that the forecast CCR interest amounts for the 2027-2031 period associated with the PRP and the DNNP, as proposed in the Application and adjusted for the CCC-084 Impacts, meet the requirements set out in s. 6(2)12.1i and s. 14(2)5i of O. Reg. 53/05, and are correctly reflected in the respective nuclear revenue requirements on that basis.

Agreement by the Parties on this settlement should not be construed as an agreement by Intervenors to the appropriateness of the CCR mechanism in the absence of the O. Reg. 53/05 requirements, and is without prejudice to any Party to argue for or against an adjustment to recovered CCR interest amounts when the OEB considers actual in-service amounts for purposes of rebasing the payment amounts and where those actual in-service amounts are underpinned by capital expenditures to which the CCR mechanism applied.

Parties in Support:	Applicants, AMPCO, BOMA, CCMBC, CCC, Energy Probe, OAPPA, QMA, SEC, VECC
Parties Taking no Position:	PWU, Society, Minogi (as it relates to DNNP), IESO, Environmental Defence

Evidence

Exhibits	Ex. I1-1-3, Ex. A1-2-2, Ex. D2-4-1, Ex. D2-3-1
Interrogatories	Ex. L-D4-Staff-134, Ex. L-H1-Staff-055, Ex. L-H1-Staff-246, Ex. L-H1-Staff-247, Ex. L-I1-Staff-258, Ex. L-I1-265
Undertakings	Ex. JT5.8

Issue 44

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

Settlement Status: Complete Settlement

The Parties agree that the effective date for the blended nuclear payment amounts and payments riders and the regulated hydroelectric payment amounts and payment riders arising from this proceeding shall be January 1, 2027.

Subject to the OEB's consideration and determination, if this Settlement Proposal is approved by the OEB, the Parties agree that they are amenable to the OEB bifurcating the consideration of the issues settled pursuant to this Settlement Proposal and the Outstanding Issue by:

- the OEB issuing a final decision and order on the draft Payment Amounts Order set out in Appendix B (subject to the update for the prevailing ROE rate specified by the OEB as discussed in Section 2, Part B, subpart (iii) and Section 3, Part B, subpart (ii)) to permit such payment amounts and payment riders to be effective and implemented for January 1, 2027, and

- the OEB hearing the Outstanding Issue by way of written hearing, to establish a separate order setting a corresponding payment rider, commencing no earlier than July 1, 2027, to the extent recorded amounts in respect of the Outstanding Issue, in whole or in part, are approved for disposition by the OEB.

Parties in Support:	Applicants, AMPCO, BOMA, CCMBC, CCC, Energy Probe, OAPPA, QMA, SEC, VECC
Parties Taking no Position:	PWU, Society, Minogi (as it relates to DNNP), IESO, Environmental Defence

Evidence

Exhibits	Ex. A1-2-2 (Approvals), Ex. I1-4-1 (IESO Settlement Process)
Interrogatories	Ex. L-I1-Staff-268
Undertakings	N/A

Issue 45

If there is a difference between the effective date and the implementation date for new payment amounts and riders, how should foregone revenue be recovered with due consideration to interim rates and customer impacts?

Settlement Status: Complete Settlement

As a result of the substantial settlement comprising this Settlement Proposal, the Parties believe that there should not be a difference between the agreed upon effective date of

January 1, 2027 and the implementation date for the payment amounts and payment riders arising from this proceeding that results in foregone revenues to be recovered by the Applicants[25].

In the event such a difference occurs, the Parties agree that the existing payment amounts would be treated as interim effective January 1, 2027, up until the implementation date of the OEB's payment amounts order in this proceeding, and any foregone revenue would be recovered pursuant to the IESO's Recalculated Settlement Statement ("**RCSS**") process without a need for separate interim period shortfall payment riders.

Parties in Support:	Applicants, AMPCO, BOMA, CCMBC, CCC, Energy Probe, OAPPA, QMA, SEC, VECC
Parties Taking no Position:	PWU, Society, Minogi (as it relates to DNNP), IESO, Environmental Defence

Evidence

Exhibits	Ex. I1-4-1 (IESO Settlement Process)
Interrogatories	Ex. L-I1-Staff-268
Undertakings	N/A

[25] Based on the current IESO settlement process and the daily settlement frequency of the nuclear and regulated hydroelectric payment amounts, for payment amounts and payment riders arising from this proceeding effective January 1, 2027 to be reflected in the IESO settlement and associated monthly invoice for all days of that month, without requiring the IESO's RCSS process, a final payment amounts order establishing the new payment amounts and payment riders should be issued by no later than January 20, 2027 (Ex. I1-4-1, Section 2.0).

APPENDIX A – REPORTING AND RECORD KEEPING REQUIREMENTS

1.0 List of OPG and DNNP LP reporting requirements to be filed with the OEB

OPG and DNNP LP reporting shall be posted on the OEB's website and OPG's website, for public access – redacted as necessary:

- Unaudited balances of deferral and variance accounts within 60 days of the quarter's end for the first three quarters and within 90 days for the December 31 year-end), separately showing the balance and any remaining approved amortization amounts for each account.
    - When reporting the year-end balances for the deferral and variance accounts established by O. Reg 53/05, OPG and DNNP LP will include a summary explanation of the major drivers of the additions recorded in each account during such year, where such aggregate annual additions for the account exceed $20M for OPG and $10M for DNNP LP.
    - When reporting the Q2 balances for the Pickering B Refurbishment Project Variance Account and the Darlington New Nuclear Project Variance Account re Capital Costs, OPG and DNNP LP will provide such annual forecast balances at that year's end.
- The OPG MD&A and financial statements within 60 days of the quarter's end for the first three quarters and within 120 days for the December 31 year-end.
- The DNNP LP year-end financial statements within 120 days of the December 31 year-end.
- Nuclear unit capability rate and hydroelectric availability for the regulated facilities within 60 days of the quarter's end for the first three quarters and within 120 days for the December year-end, as reported in OPG's quarterly and annual MD&A.
- FTE information by April 30 each year.
- Capital in-service additions and construction work in progress by April 30 each year.
- An analysis of the actual annual regulatory return, after tax on rate base, dollars for the OPG regulated business as a whole and separately for OPG's regulated nuclear and hydroelectric business segments, and a percentage for the regulated business based on OPG's approved capital structure, and a comparison with the regulatory return included in the payment amounts by July 31 each year.

Additionally and in consideration of the settlement, OPG agrees to provide, as part of this annual reporting, a calculation equivalent to dividing the actual dollar regulatory return for each of its regulated nuclear and hydroelectric business segments by 45% of the corresponding rate base for each of these segments, where 45% is the equity thickness in the agreed upon capital structure for OPG's regulated business.

- Report on any long-term debt issued by OPG in excess of $50M (whether directly or through an affiliate), by April 30 each year, for debt issued in the prior calendar year, including quantity, term, and interest rate.

- An analysis of the actual annual regulatory return, after tax on rate base, dollars for DNNP LP, and a percentage based on DNNP LP's actual capital structure, and a comparison with the regulatory return included in the payment amounts by July 31 of each year, beginning with the year that DNNP Unit 1 is placed in service.

- Report on any long-term debt issued by DNNP LP (whether directly or through an affiliate), by April 30 each year, for debt issued in the prior calendar year, including quantity, term, and interest rate.

- Annual report on OPG's expenses related to nuclear liability by June 30 each year.

- Annual regulated hydroelectric performance report by April 30 each year.

- Annual nuclear performance report by April 30 each year (Annual nuclear performance report to be re-filed with benchmark quartile results no later than November 30 each year).

- Annual PRP and DNNP reporting as defined in Section 2.0 Annual Public Reporting for DNNP Unit 1 and all PRP units. In addition, by August 31 each year, the following information for each of PRP and DNNP Unit 1, as of June 30th:

    - Cost Performance Index ("**CPI**");

    - Schedule Performance Index ("**SPI**"); and

    - A summary of key changes to the applicable performance measurement baseline over the period impacting the reported CPI or SPI.

Hydroelectric surplus baseload generation – Annual reporting by June 30:

- all SBG claimed amounts including total MW on an hourly basis by each regulated facility, and the calculation of these amounts booked in the SBGVA; and

- information in relation to usage of the Sir Adam Beck Pump Generating Station ("**PGS**") as provided in Ex. JT2.22 (EB-2020-0290), revised to an hourly resolution.

2.0 Annual Public Reporting for DNNP Unit 1 and all PRP units

Annual public reporting for DNNP Unit 1 and all PRP units, unless otherwise stated (filed with the OEB and posted publicly on OPG's website, by April 30th reflecting previous years information). First report to be filed by April 30, 2027, reflecting 2026 information.

Category	Measure
Introduction and Table Contents	N/A
Executive Summary	N/A
Overall Program Status	• High level overview of DNNP/PRP
Progress	• Key Achievements • % Complete
Safety	• Serious Injury Incident Rate • Summary of any material safety events
Significant Quality Events	• # of Significant Quality Events • Quality Metric (Score) [In the form of Ex. JT4.4] • Weld Failure Rate – only available for DPSC fabrication for DNNP and Feeder Welding for PRP
Cost	• Current cost performance (relative to OEB-approved) • Cost Performance Index – quarterly data provided annually • Life-to-date cost • Forecast to Complete • Estimate at Complete • Average Annual Forecast Accuracy Factor • Quarterly actual versus forecast cumulative capital costs • DNNP specific – Actual cumulative capital costs (all units) • Any Levelized Cost of Electricity (LCOE) figures for the PRP and/or the DNNP provided to the OPG Board of Directors' or the DNNP GP Board of Directors', as applicable, in relation to a request for approval of an initial or superseding Release Quality Estimate and/or funding release for either program. The most recent updated LCOE provided to the applicable Board of Directors on such basis, will be filed as part of the next payment amounts application, if available.

Category	Measure
Schedule	• Current schedule performance (relative to OEB-approved) • Schedule Performance Index – quarterly data provided annually • Status of Key Milestones • Critical Path Progress • Forecasted Completion Dates for each PRP unit and DNNP Unit 1 • High confidence scheduled in-service dates for DNNP Units 2-4 – once approved for construction.
Engineering	• Summary of engineering status and key issues
Procurement	• Summary of procurement status and key issues
Construction	• Summary of construction progress and analysis of any material variances from plan • Summary of any material labour issues • Summary of any material environmental issues
Testing, Start-Up and Commissioning	• Summary of systems tested, commissioned, started, and any material key results and issues
Program Risks and Risk Management	• Key risks and mitigation • Key issues and corrective actions
Staffing	• Actual staffing levels against OEB-approved plan • Summary of any material staffing issues

For clarity, the reporting identified in Appendix A, Section 2.0 is without prejudice to any person seeking additional information, such as DNNP Unit 1 LCOE figures, through other means, outside of this proceeding, such as freedom of information requests.

3.0 List of Independent Studies / Reports for next OPG / DNNP LP payment amounts proceeding

- General/Custom IR Framework
    - Customer Engagement Study (continue)
    - Total Factor Productivity Study and Total Cost Benchmarking for Hydroelectric (if proposing an Incentive Rate-Setting Mechanism (“IRM”) / Custom Incentive Rate-setting Mechanism (“CIR”))

- Total Factor Productivity Study and/or Total Cost Benchmarking for OPG Nuclear (if proposing a IRM / CIR)

- Benchmarking
  - OPG Nuclear Staffing Benchmarking (continue)
  - OPG Nuclear Benchmarking Approach Review (continue)
  - Corporate Costs Benchmarking (continue)
- Compensation and Staffing
  - Compensation Benchmarking Study on the current two-segment benchmarking approach only (continue)
  - Pension / OPEBs – most recent actuarial funding valuation, Report on Estimated Accounting Cost for Post-Employment Benefit Plans, Report on the Accounting Cost for Post-Employment Benefit Plans (continue)
- Other Matters
  - Cost Allocation methodology:
    - A full Cost Allocation methodology review that considers whether the methodology reasonably separates OPG's shared costs between regulated and unregulated businesses, including allocators used to allocate costs between the various business units (including the unregulated businesses), and assesses alternatives to various material aspects of the methodology, with recommendations. The study will include asset service fees and discuss any material changes to the methodology since EB-2025-0297. The study will also apply the methodology to the allocation of OPG's forecast shared costs in the next payment amounts application.
  - Depreciation Study (continue)
  - Summary of all internal audit reports completed in 2026 and the 2027-2031 period to date (continue)
  - US GAAP and IFRS analysis for OPG and DNNP LP:

- Should OPG or DNNP LP make entries in the respective Impact for IFRS Deferral Accounts, or should OPG otherwise cease to be able to use US GAAP for continuous disclosure purposes in Canada, OPG and the DNNP LP, as applicable, in their next cost-based payments application provide, on a best efforts basis, provide estimated financial impacts (including any proposed revenue requirement impacts) of an initial transition from US GAAP to IFRS for regulatory purposes, as well as estimated financial impacts (including any proposed revenue requirement impacts) for regulatory purposes for the remainder of the payment amounts term covered by such application, subsequent to the transition.

- Nuclear Business Interruption Insurance:

  - If OPG or DNNP LP proposes to include costs for purchasing nuclear business interruption insurance in their next payment amounts application, OPG or DNNP LP, as applicable, will provide a business justification analysis in support of such costs.

4.0 List of Commitments for next Application Seeking to Clear SBGVA and HIMVA balances

- As part of the next application seeking to clear the SBGVA or HIMVA balances, OPG shall ask that the issues list include a full review of the treatment of the SBGVA, the HIM, and the MWPs. If the OEB does not include said review within the scope of that proceeding, OPG shall file a stand-alone application on the treatment of the SBGVA, the HIM, and the MWPs as soon as reasonably possible thereafter, subject to any directions to the contrary from the OEB. The Parties agree that such a review should be evidence-based.

- Effective January 1, 2027, OPG will only record amounts relating to global spill,[26] and not amounts relating to local SBG spill, in the SBGVA until the effective date of the payment amounts orders in the next application seeking to clear the SBGVA balances, at which time a determination with respect to the treatment of local SBG spill in the SBGVA will be made on a then go-forward basis. Without prejudice to the position the Parties may take in this respect in that proceeding, should the outcome of that proceeding exclude local SBG spill from the scope of the SBGVA, at the time of OPG's next rebasing application for regulated hydroelectric facilities, OPG will be entitled to reflect a corresponding reduction for local SBG spill in the

[26] As described in Section 2.0, Part G of this Settlement Proposal.

regulated hydroelectric production forecast, which the Parties acknowledge will be subject to the OEB's determination in that payment amounts proceeding.

In support of future requested clearances of the SBGVA, OPG will file, as part of its pre-filed evidence: the same information as set out in Ex. H1-1-1, Attachments 3 and 4, together with the following additional information by facility (as applicable): i) the regulated hydroelectric payment amount, ii) Gross Revenue Charge (specific to the facility), iii) for the period pre-Market Renewal Program, the Hourly Ontario Energy Price, iv) for the period of the Market Renewal Program, the Locational Marginal Price(s) (specific to the facility), and v) the hourly average Energy Reference Price for the period when OPG will only record amounts relating to global spill as outlined in this Settlement Proposal[27].

- OPG shall report on its efforts and the outcomes of those efforts to seek an exemption from the GRC with respect to PGS cycling based on the impact on total customer cost, as outlined in Ex. E1-2-1, Attachment 1, at the next application seeking to clear the SBGVA balances.

- On a best efforts basis, OPG will report on available actual results for the PGS with respect to increased generation and reduced SBG spill associated with the exemption of the PGS from transmission charges, as approved in EB-2022-0325. The reporting will be prepared in such a manner that it can be compared to the results presented in Ex. E1-2-1, Attachment 1, Section 3.3.1.2. Where results cannot be normalized to provide a direct comparison, OPG will indicate the factors for why the results cannot be normalized.

5.0 Indigenous Procurement

In alignment with the Ministry of Energy's statement in the Integrated Energy Plan[28], OPG is exploring mechanisms for Indigenous participation and economic benefits in relation to new generating capacity from existing generating facilities; some examples are noted in Ex. JT1.1, including the redevelopment revenue payment agreement with local First Nations for the Kakabeka Falls GS redevelopment.

OPG's Indigenous Reconciliation Action Plan ("**RAP**") outlines OPG's commitments for Indigenous economic empowerment, including growing economic impact for Indigenous communities and businesses – with a target of $1B in economic impact through Indigenous procurement and ongoing equity partnership revenues by 2031.

[27] *Ibid*.
[28] Energy for Generations, June 2025, p.135.

For purposes of settlement, as part of the 2027 RAP refresh, OPG commits to:

- Evaluate the impact of the $1B procurement commitment and assess if this continues to be the appropriate metric and determine whether any changes may be required to external reporting of OPG's commitment. As part of this evaluation, OPG will continue to work with First Nations rightsholders[29], Indigenous communities, and Indigenous Businesses[30] on the impact of the $1B commitment and progress to date.

- Review OPG's procurement framework to ensure consistency with industry best practices for increasing economic reconciliation and procurement opportunities for Indigenous Businesses and First Nations rightsholders, including evaluating measures such as establishing an Indigenous procurement target and whether additional procurement-related reporting should be included in the RAP or OPG's other public reporting, such as reporting on the progress toward Indigenous procurement commitments and targets, internal OPG barriers to procurement for Indigenous Businesses, and increasing participation of First Nations rightsholders and other Indigenous communities in OPG procurement. OPG will report on the outcome of this review as part of the 2027 RAP refresh.

For purposes of settlement, OPG commits that where capabilities and qualifications align, it will continue to engage with First Nations rightsholders and seek to maximize First Nations rightsholders and Indigenous Business participation in the remaining PRP work, in accordance with OPG's procurement framework (Ex. F3-3-1).

[29] First Nations rightsholder means a First Nation in whose treaty lands or traditional territories OPG's facilities are located.

[30] OPG defines an Indigenous Business as a business that is at least 51% owned and controlled by Indigenous People. If the business is a partnership or joint venture, it must have at least 51% of the ownership rights (including any voting rights) directly held by one or more Indigenous Business, Indigenous People, or Indigenous Communities. Qualification is verified via certification by a recognized Equity, Diversity & Inclusion council such as the Canadian Council for Indigenous Business (Ex. JT1.2d).

APPENDIX B – DRAFT PAYMENT AMOUNTS ORDER

EB-2025-0297

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Ontario Power Generation Inc. and DNNP LP for an order or orders approving payment amounts for prescribed generating facilities commencing January 1, 2027.

BEFORE: **Allison Duff**
Presiding Commissioner

Damien Côté
Commissioner

Vinay Sharma
Commissioner

DRAFT PAYMENT AMOUNTS ORDER

October 5, 2026

Ontario Power Generation Inc. ("OPG") and DNNP LP (collectively, the "Applicants" and individually, an "Applicant") filed an application with the Ontario Energy Board ("OEB") in December 2025 (the "Application"). The Application was filed under section 78.1 of the *Ontario Energy Board Act, 1998* (the "Act") seeking approval of the following payment amounts and payment riders:

- a payment amount for hydroelectric generating facilities ("regulated hydroelectric facilities") prescribed under *Ontario Regulation 53/05* of the Act, as amended, ("O. Reg. 53/05"), for the period from January 1, 2027 through December 31, 2027, together with a regulated hydroelectric payment amount setting formula for the period from January 1, 2028 to December 31, 2031;

- a payment rider for the regulated hydroelectric facilities for the period from January 1, 2027 through December 31, 2029;
- payment amounts for nuclear generating facilities ("nuclear facilities") prescribed under O. Reg. 53/05, for the period from January 1, 2027 through December 31, 2031 ("IR Term"); and
- payment riders for the nuclear facilities for the period from January 1, 2027 through December 31, 2031.

A full listing of approvals sought by the Applicants was filed as Ex. A1-2-2.

The OEB issued and published a Notice of Hearing on January 12, 2026 and Procedural Order No. 1 on February 5, 2026. A Pre-Hearing Conference was held on February 18 and 19, 2026 where there was agreement on certain revisions to the draft Issues List that was attached to Procedural Order No. 1. The final approved issues list ("Issues List") is attached as Schedule A to Procedural Order No. 2. Pursuant to Procedural Order No. 2, the Interrogatories process took place between March and May 2026. Between May 27 and June 3, 2026 and on June 18, 2026, the parties engaged in a Technical Conference. On June 22, 2026, the OEB issued a decision and order indicating that it was satisfied that the conditions set out in section 8 of O. Reg. 53/05, relating to the regulation of DNNP LP as a prescribed generator, had been met. On June 29, 2026, the parties proceeded to a Settlement Conference.

On June 29, 2026, a Settlement Conference was held and a comprehensive settlement was achieved by intervenors and the Applicants with respect to all issues on the Issues List with the exception of a partial settlement related to the clearance of balances recorded in the Capacity Refurbishment Variance Account related to the Darlington Refurbishment Project ("DRP"). The Settlement Proposal was filed with the OEB on October 5, 2026 as Exhibit O ("Settlement Proposal").

In conjunction with the Settlement Proposal, the Applicants filed a draft payment amounts order ("Draft Order") on October 5, 2026 based on the Settlement Proposal and assuming OPG's proposed clearance of balances recorded in the Capacity Refurbishment Variance Account related to the DRP. With the exception of the clearance of the balances recorded in the Capacity Refurbishment Variance Account related to the DRP (the "Outstanding Issue"), the Draft Order had been reviewed and agreed to by the parties to the Settlement Proposal.

The OEB issued a Decision and Order approving the Settlement Proposal on ● (the "Decision"). A copy of the OEB-approved Settlement Proposal was attached as Schedule ● to the Decision.

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. Regulated Hydroelectric Revenue Requirement: The 2027 regulated hydroelectric revenue requirement is $1,543.6M, as set out in Appendix A, Table 1, line 22, col. (c).

2. Regulated Hydroelectric Production Forecast: The 2027 production forecast for the regulated hydroelectric facilities is 32.9TWh.

3. OPG Nuclear Facilities Revenue Requirement: The IR term revenue requirements for the OPG nuclear facilities, net of stretch factor adjustments, are $3,856.8M in 2027, $3,970.6M in 2028, $4,335.9M in 2029, $4,464.5M in 2030, and $5,189.4M in 2031. These amounts are set out in Appendix A, Tables 2 to 6, col. (c), line 30.

4. DNNP Facilities Revenue Requirement: The IR term revenue requirements for the DNNP LP facilities are $296.3M in 2027, $364.1M in 2028, $373.1M in 2029, $512.0M in 2030, and $962.8M in 2031. These amounts are set out in Appendix A, Tables 8 to 12, col. (c), line 22.

5. OPG Nuclear Facilities Production Forecast: The IR term production forecast for the OPG nuclear facilities is 19.3TWh in 2027, 27.6TWh in 2028, 25.8TWh in 2029, 27.7TWh in 2030 and 29.9TWh in 2031, as set out in Appendix B, Table 3, line 6.

6. DNNP Facilities Production Forecast: The IR term production forecast for the DNNP LP facilities is 0.0TWh in 2027, 0.0TWh in 2028, 0.0TWh in 2029, 0.5TWh in 2030 and 2.0TWh in 2031, as set out in Appendix B, Table 3, line 7.

7. Hydroelectric Payment Amounts:[1] Effective January 1, 2027, the payment amount for the regulated hydroelectric facilities is $46.90/MWh, for the average hourly net energy

[1] Subject to update for the prevailing ROE rate specified by the OEB as of the effective date of the final payment amounts order in this proceeding.

production (MWh) from the regulated hydroelectric facilities in any given day for each hour of that day. This regulated hydroelectric payment amount is set out in Appendix B, Table 1, line 12, col. (a).

Effective January 1 of each year in 2028 to 2031, the regulated hydroelectric payment amounts will be determined through an annual hydroelectric payment amount adjustment application. Each such regulated hydroelectric payment amount shall be determined using the Custom Price-cap Index proposed by OPG in Ex. A1-3-2 of this proceeding, under which the regulated hydroelectric payment amount for the prior year is adjusted by the generation industry-weighted inflation factor (using the most current Statistics Canada values for Canadian Gross Domestic Product Implicit Price Index – Final Domestic Demand ("GDPI-PI FDD") and Average Weekly Earnings for Ontario – Industrial Aggregate ("Ontario AWE")), less a productivity factor of 0% less a stretch factor of 0.3%, and adjusted by the following factors as set out in Appendix B, Table 1, lines 7-9:

Effective Date	Custom Capital Factor	GRC Factor	Production Growth Factor
January 1, 2028	2.51%	0.46%	0.80%
January 1, 2029	7.99%	0.52%	0.69%
January 1, 2030	1.58%	0.61%	0.09%
January 1, 2031	-0.13%	0.48%	-0.17%

The regulated hydroelectric payment amount will apply to 50% of the output of OPG's Chats Falls Generating Station.

8. OPG's revenues from the regulated hydroelectric payment amount shall be adjusted by the following hydroelectric incentive mechanism in any given day for each hour of that day:

   For the resource(s) at regulated hydroelectric facilities, for each hour where the IESO day-ahead market energy schedule (the "Day-Ahead Energy Schedule") differs from the average hourly energy schedule from the IESO's day-ahead market for that day (the "Average Day-Ahead Energy Schedule"), OPG's revenues will be adjusted by the difference between the Day-Ahead Energy Schedule and the Average Day-Ahead Energy Schedule, multiplied by the day-ahead locational marginal price for the resource for that hour. For the resource(s) at regulated hydroelectric facilities, for each hour where (i) the difference between the net

energy production supplied to the IESO's real-time market and the Day-Ahead Energy Schedule ("Real-Time Energy Difference") differs from (ii) the difference between the average hourly net energy production over that day and the Average Day-Ahead Energy Schedule for that day ("Average Real-Time Energy Difference"), OPG's revenues will be adjusted by the difference between the Real-Time Energy Difference and the Average Real-Time Energy Difference, multiplied by the real-time locational marginal price for the resource for that hour, calculated on a five-minute basis.

9. Blended Nuclear Payment Amounts:[2] Effective January 1 of each year of the IR term, the blended payment amounts for the OPG nuclear facilities and the DNNP LP facilities over the IR Term are as follows: $196.62/MWh in 2027, $169.94/MWh in 2028, $182.40/MWh in 2029, $176.64/MWh in 2030, and $192.42/MWh in 2031, as set out in Appendix B, Table 3, line 9. These payment amounts reflect the application of payment amount shaping as set out in paragraph 10 below.

10. Payment Amount Shaping: The portion of the approved 2027 revenue requirement for the OPG nuclear facilities that is to be recorded in the Payment Amount Shaping Deferral Account and recovered in 2028 is $350.0M, with resulting Payment Amount Shaping Deferral Account additions of $350.0M in 2027, ($350.0M) in 2028, $0.0 in 2029, $0.0 in 2030, and $0.0 in 2031. These payment amount shaping amounts are set out in Appendix B, Table 3, line 4.

11. Recovery of Balances in Deferral and Variance Accounts: The Applicants shall recover or repay the December 31, 2024 audited balances in the following deferral and variance accounts in accordance with Appendix C and Appendix D, effective January 1, 2027:
    - Hydroelectric Water Conditions Variance Account;
    - Ancillary Services Net Revenue Variance Account – Hydroelectric and Nuclear Sub-Accounts;
    - Hydroelectric Incentive Mechanism Variance Account;

[2] Subject to update for the prevailing ROE rate specified by the OEB as of the effective date of the final payment amounts order in this proceeding.

- Hydroelectric Surplus Baseload Generation Variance Account[3];
- Income and Other Taxes Variance Account (OPG);
- Capacity Refurbishment Variance Account[4];
- Niagara Tunnel Project pre-December 2008 Disallowance Variance Account;
- Pension and OPEB Cost Variance Account (OPG);
- Pension & OPEB Cash Payment Variance Account;
- Pension & OPEB Cash Versus Accrual Differential Deferral Account;
- Pension & OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance Account – Carrying Charges Sub-Account;
- Nuclear Liability Deferral Account;
- Nuclear Development Variance Account[5];
- Bruce Lease Net Revenues Variance Account;
- SR&ED ITC Variance Account (OPG);
- Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account;
- Fitness for Duty Deferral Account;
- Rate Smoothing Deferral Account;
- Pickering Closure Costs Deferral Account;
- Clarington Corporate Campus Deferral Account;
- Sale of Unprescribed Kipling Site Deferral Account;
- Hydroelectric Deferral and Variance Over/Under Recovery Variance Account; and
- Nuclear Deferral and Variance Over/Under Recovery Variance Account.

12. Continuing Deferral and Variance Accounts: OPG shall continue the following deferral and variance accounts in accordance with Appendix E, effective January 1, 2027:
    - Hydroelectric Water Conditions Variance Account;
    - Ancillary Services Net Revenue Variance Account – Hydroelectric and Nuclear Sub-Accounts;
    - Hydroelectric Incentive Mechanism Variance Account;

[3] Clearance of a total portion equal to $37.0M of the December 31, 2024 debit balance in the Hydroelectric Surplus Baseload Generation Variance Account is deferred to a subsequent proceeding.
[4] Clearance of the portion of the Capacity Refurbishment Variance Account related to the Outstanding Issue is subject to the OEB's decision on the Outstanding Issue. Clearance of the portion of the Capacity Refurbishment Variance Account related to the regulated hydroelectric facilities is deferred to a subsequent proceeding.
[5] Clearance of the portion of the December 31, 2024 Nuclear Development Variance Account balance not related to the Darlington New Nuclear Program is deferred to a subsequent proceeding.

- Hydroelectric Surplus Baseload Generation Variance Account;
- Income and Other Taxes Variance Account (OPG);
- Capacity Refurbishment Variance Account;
- Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account;
- Pension and OPEB Cost Variance Account (OPG);
- Pension & OPEB Cash Payment Variance Account;
- Pension & OPEB Cash Versus Accrual Differential Deferral Account;
- Pension & OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance Account;
- Gross Revenue Charge Variance Account;
- Nuclear Liability Deferral Account;
- Nuclear Development Variance Account;
- Bruce Lease Net Revenues Variance Account;
- SR&ED ITC Variance Account (OPG);
- Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account;
- Fitness for Duty Deferral Account;
- Rate Smoothing Deferral Account;
- Pickering Closure Costs Deferral Account;
- Earnings Sharing Deferral Account;
- Impact for IFRS Deferral Account (OPG);
- Pickering B Variance Account;
- Sale of Unprescribed Kipling Site Deferral Account;
- Hydroelectric Deferral and Variance Over/Under Recovery Variance Account; and
- Nuclear Deferral and Variance Over/Under Recovery Variance Account.

OPG shall also maintain the Pickering B Refurbishment Project Variance Account and the Darlington New Nuclear Project Variance Account, established pursuant to O. Reg. 53/05.

DNNP LP shall also maintain the Darlington New Nuclear Project Variance Account re Development, the Darlington New Nuclear Project Variance Account re Capital Cost

Amounts, and the DNNP Generator Capital Structure Variance Account, established pursuant to O. Reg. 53/05.[6]

13. New and Terminated Deferral and Variance Accounts: OPG shall establish the following deferral and variance accounts in accordance with Appendix F, effective January 1, 2027:
    - Global Hydroelectric Capital Variance Account;
    - Clean Electricity ITC Variance Account (OPG);
    - DNNP Nuclear Liability Deferral Account;
    - Payment Amount Shaping Deferral Account;
    - Nuclear Security Regulation and American Eel Impact Deferral Account (OPG);
    - Nuclear Fuel Cost Variance Account (OPG);
    - Darlington Planned Outage Days (2027-2031) Settlement Variance Account;
    - Change in CCA Rules or Rates Variance Account (OPG); and
    - Pickering Refurbishment 2027-2031 Early Return to Service Variance Account.

    DNNP LP shall establish the following deferral and variance accounts in accordance with Appendix F, effective January 1, 2027:
    - Income and Other Taxes Variance Account (DNNP);
    - Pension and OPEB Cost Variance Account (DNNP);
    - Nuclear Deferral and Variance Over/Under Recovery Variance Account (DNNP);
    - SR&ED ITC Variance Account (DNNP);
    - Impact for IFRS Deferral Account (DNNP);
    - Clean Electricity ITC and Other Benefits Variance Account (DNNP);
    - Impact of Change in Tax Status Variance Account (DNNP);
    - Change in CCA Rules or Rates Variance Account (DNNP) and
    - Nuclear Security Regulation Impact Deferral Account (DNNP).

    OPG shall terminate the Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2017) Deferral Account, Clarington Corporate Campus Deferral Account and the Incremental Cloud Computing Arrangement Implementation Costs Deferral Account, effective January 1, 2027.

[6] Pursuant to the OEB's June 22, 2026 Decision and Order under Section 8 of O. Reg. 53/05.

14. Hydroelectric Payment Rider: The regulated hydroelectric payment rider for the recovery or repayment of the approved deferral and variance account balances for the regulated hydroelectric facilities, together with the income tax impacts associated with the recovery or repayment of the Pension & OPEB Cash Versus Accrual Differential Deferral Account, shall be $(1.53)/MWh from January 1, 2027 to December 31, 2027, ($1.51)/MWh from January 1, 2028 to December 31, 2028, and ($1.50)/MWh from January 1, 2029 to December 31, 2029 (Appendix C, Table 1, line 19, cols. (h) to (j)). The approved disposition amount for this proceeding related to regulated hydroelectric deferral and variance accounts is a credit of $150.8M (Appendix C, Table 1, col. (m), line 17), reflecting disposition of audited December 31, 2024 balances in deferral and variance accounts, less amortization amounts approved in EB-2020-0290 and EB-2023-0336 for 2025 and 2026 and less amounts deferred to future applications. The regulated hydroelectric payment rider will apply to 50% of the output of OPG's Chats Falls Generating Station.

15. Blended Nuclear Payment Rider:[7] The blended nuclear payment rider for the recovery or repayment of the approved deferral and variance account balances for the OPG nuclear facilities and the DNNP LP facilities shall be $3.88/MWh from January 1, 2027 to December 31, 2027, $2.72/MWh from January 1, 2028 to December 31, 2028, $2.90/MWh from January 1, 2029 to December 31, 2029, $2.40/MWh from January 1, 2030 to December 31, 2030, and $2.12/MWh from January 1, 2031 to December 31, 2031 (Appendix D, Table 1, line 32). The approved disposition amount for this proceeding related to nuclear deferral and variance accounts is a debit of $360.4M (Appendix D, Table 1, col. (m), line 30), reflecting disposition of audited December 31, 2024 balances in deferral and variance accounts, less amortization amounts approved in EB-2020-0290 and EB-2023-0336 for 2025 and 2026 and less amounts deferred to future applications.

16. The IESO shall make payments to OPG in accordance with this order as of January 1, 2027.

17. The respective Applicant(s) shall file an accounting order application with the OEB and provide notice to intervenors of record in EB-2025-0297 if:

[7] Subject to the OEB's decision on the Outstanding Issue.

i. OPG proposes an accounting change impacting the calculation of OPG's nuclear liabilities, other than as a result of an Ontario Nuclear Funds Agreement Reference Plan update, which results in a material revenue requirement impact for OPG's prescribed facilities; or

ii. An Applicant proposes to change the end-of-life dates of a prescribed nuclear facility for depreciation and amortization purposes that results in a material non-asset retirement cost revenue requirement impact for an Applicant.

An accounting order application by an Applicant shall only be required if the respective revenue requirement impact is neither reflected in current or proposed payment amounts nor recorded in an authorized deferral or variance account and the annualized revenue requirement impact is $20M or greater for OPG's prescribed facilities or $10M or greater for the DNNP LP facilities, as applicable.

DATED at Toronto _____, 2026

ONTARIO ENERGY BOARD

_____
Ritchie Murray
Registrar

EB-2025-0297 PAYMENT AMOUNTS ORDER - APPENDICES

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Numbers may not add due to rounding.

Table 1

2027 Summary of Regulated Hydroelectric Revenue Requirement and Deferral and Variance Account Amortization Amounts ($M)

Line No.	Description	Note	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Rate Base				
1	**Net Fixed Assets**	2	9,115.6	(126.8)	8,988.8
2	**Working Capital**		0.3	0.0	0.3
3	**Cash Working Capital**		19.3	0.0	19.3
4	**Total Rate Base**		9,135.1	(126.8)	9,008.4
	Capitalization				
5	**Short-Term Debt**	3	152.7	0.3	153.0
6	**Long-Term Debt**	3	4,232.1	569.5	4,801.6
7	**Common Equity**	3	4,750.3	(696.5)	4,053.8
8	**Total Capital**		9,135.1	(126.8)	9,008.4
	Cost of Capital				
9	**Short-Term Debt**	3	7.7	0.0	7.7
10	**Long-Term Debt**	3	193.8	25.3	219.1
11	**Common Equity**	3	432.7	(63.5)	369.3
12	**Total Cost of Capital**		634.2	(38.1)	596.1
	Expenses:				
13	**OM&A**	4	499.3	(25.0)	474.3
14	**GRC**	5	352.2	6.5	358.7
15	**Depreciation & Amortization**	2	215.4	(2.2)	213.2
16	**Property Tax**		2.1	0.0	2.1
17	**Total Expenses**		1,069.0	(20.7)	1,048.3
	Less:				
	Other Revenues				
18	**Ancillary and Other Revenue**	6	62.2	29.4	91.6
19	**Total Other Revenues**		62.2	29.4	91.6
20	**Income Tax**	7	27.3	(30.6)	(3.3)
21	**General Revenue Requirement Adjustment**	8	0.0	(5.9)	(5.9)
22	**Revenue Requirement** (line 12 + line 17 - line 19 + line 20 + line 21)		1,668.3	(124.7)	1,543.6
23	**Amortization of Deferral & Variance Account Amounts**	9	(37.9)	(12.3)	(50.3)
24	**Revenue Requirement Plus Deferral & Variance Account Amounts** (line 22 + line 23)		1,630.4	(137.1)	1,493.4

For notes see Table 1a.

Table 1a
Notes to Table 1
2027 Summary of Regulated Hydroelectric Revenue Requirement and Deferral and Variance Account Amortization Amounts ($M)

1 Per Ex. I1-1-1, Table 1.

2 Adjusted to reflect the following reductions per the Settlement Proposal (Section 2, Part B, ii): (i) application of forecast CEITCs to the Net Fixed Assets rate base and depreciation and amortization per Ex. L-F4-CCC-084; (ii) reduction of 13% to annual forecast Regulated Hydroelectric in-service capital additions net of CEITCs and reduction of 11% to annual forecast Corporate Support Services in-service capital additions; (iii) permanent 2027 opening rate base reduction of $40.0M; (iv) a reduction to rate base to reflect lower than forecast actual Regulated Hydroelectric in-service capital additions for 2025 of $19.5M. Supporting continuity schedules for resulting Net Fixed Assets rate base amounts are provided in App. A, Tables 15 and 16.

3 Adjusted to reflect (i) the settlement adjusted rate base; (ii) the capital structure per the Settlement Proposal of 45% equity and 55% debt (Section 2, Part B, iii); and (iii) reduction of cost of debt rates due to lower forecast new long-term debt issues as a result of the application of forecast CEITCs per Ex. L-F4-CCC-084 (Settlement Proposal, Section 2, Part B, iii). Supporting details are provided in Appendix A, Table 19.

4 Adjusted to reflect the Settlement Proposal (Section 2, Part D, iii) reduction to recovery of forecast OM&A costs of $25.0M.

5 Adjusted to reflect increased GRC expense associated with the Settlement Proposal (Section 2, Part C, ii) increase to the regulated hydroelectric production forecast.

6 Adjusted to reflect the Settlement Proposal (Section 2, Part E) increases to ancillary services revenues of $8.0M, non-ancillary services other revenues of $3.0M, and hydroelectric incentive mechanism revenues of 50% of $36.7M.

7 Col. (c) per App. A, Table 29, line 23.

8 Adjusted to reflect the Settlement Proposal (Section 2, Part F) reduction to overall regulated hydroelectric revenue requirement for purposes of settlement.

9 Col. (c) per App. C, Table 1, line 17.

Numbers may not add due to rounding.

Table 2

2027 Summary of OPG Nuclear Revenue Requirement and Deferral and Variance Account Amortization Amounts ($M)

Line No.	Description	Note	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Rate Base				
1	**Net Fixed Assets**	2	14,920.0	(260.2)	14,659.9
2	**Working Capital**		851.8	0.0	851.8
3	**Cash Working Capital**		(22.5)	0.0	(22.5)
4	**Total Rate Base**		15,749.4	(260.2)	15,489.2
	Capitalization				
5	**Short-term Debt**	3	261.6	(0.3)	261.3
6	**Long-Term Debt**	3	7,250.0	952.6	8,202.7
7	**Common Equity**	3	8,063.7	(1,202.6)	6,861.1
8	**EB-2020-0290 Settlement Adjustment for Equity at Long-Term Debt Rate**	3	73.9	(10.0)	64.0
9	**Adjustment for Lesser of UNL or ARC**		100.1	0.0	100.1
10	**Total Capital**		15,749.4	(260.2)	15,489.2
	Cost of Capital				
11	**Short-term Debt**	3	13.2	(0.0)	13.2
12	**Long-Term Debt**	3	331.9	42.3	374.2
13	**Common Equity**	3	734.6	(109.6)	625.0
14	**EB-2020-0290 Settlement Adjustment for Equity at Long-Term Debt Rate**	3	3.4	(0.5)	2.9
15	**Adjustment for Lesser of UNL or ARC**		4.7	0.0	4.7
16	**Total Cost of Capital**		1,087.9	(67.8)	1,020.1
	Expenses:				
17	**OM&A**	4	1,863.7	(90.0)	1,773.7
18	**Fuel**	5	150.9	3.7	154.6
19	**Depreciation & Amortization**	2	663.3	(10.8)	652.5
20	**Property Tax**		14.0	0.0	14.0
21	**Total Expenses**		2,691.9	(97.1)	2,594.8
	Less:				
	Other Revenues				
22	**Bruce Lease Revenues Net of Direct Costs**		(5.2)	0.0	(5.2)
23	**Ancillary and Other Revenue**		6.3	0.0	6.3
24	**Total Other Revenues**		1.1	0.0	1.1
25	**Concurrent Cost Recovery - Pickering Refurbishment Program**	6	297.6	(2.6)	295.0
26	**Income Tax**	7	(16.6)	0.0	(16.6)
27	**General Revenue Requirement Adjustment**	8	0.0	(35.4)	(35.4)
28	**Revenue Requirement Before Stretch Factor**		4,059.7	(202.9)	3,856.8
	(line 16 + line 21 - line 24 + line 25 + line 26 + line 27)				
29	**Cumulative Nuclear Stretch Dollars**		0.0	0.0	0.0
30	**Revenue Requirement Net of Stretch Factor**		4,059.7	(202.9)	3,856.8
	(line 28 - line 29)				
31	**Amortization of Deferral & Variance Account Amounts**	9	134.5	(59.5)	75.0
32	**Revenue Requirement Net of Stretch Factor Plus Deferral & Variance Account Amounts** (line 30 + line 31)		4,194.1	(262.3)	3,931.8

For notes see Table 2a.

Numbers may not add due to rounding.

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1 Per Ex. I1-1-1, Table 2, with the following exceptions, per Settlement Proposal, p. 6:
Lines 2, 5-7, and 11-13 revised to reflect minor corrections identified by the Applicants in Ex. L-B1-CCC-019 and Ex. JT4.11.
Line 17 revised to reflect minor corrections identified by the Applicants in Ex. L-A2-SEC-025 and Ex. L-F3-SEC-174.

2 Adjusted to reflect the following reductions per the Settlement Proposal (Section 2, Part B, i): (i) application of forecast CEITCs to the Net Fixed Assets rate base and depreciation and amortization per Ex. L-F4-CCC-084; (ii) adjustment to the Darlington Refurbishment Program net fixed asset rate base to reflect OPG's updated, lower total project cost forecast since the filing of the Application; (iii) reduction of 10% to annual forecast Nuclear Operations in-service capital additions net of CEITCs and reduction of 11% to annual forecast Corporate Support Services in-service capital additions; (iv) permanent 2027 opening rate base reduction of $40.0M; and (v) change in forecast timing of rate base inclusion of certain Nuclear Operations in-service capital amounts tied to Pickering to 2031, with corresponding reductions over 2027-2030. Supporting continuity schedules for resulting Net Fixed Assets rate base amounts are provided in App. A, Tables 17 and 18.

3 Adjusted to reflect (i) the settlement adjusted rate base; (ii) the capital structure per the Settlement Proposal (Section 2, Part B, iii) of 45% equity and 55% debt; and (iii) reduction of cost of debt rates due to lower forecast new long-term debt issues as a result of the application of forecast CEITCs per Ex. L-F4-CCC-084 (Settlement Proposal, Section 2, Part B, iii). Supporting details are provided in App. A, Table 19.

4 Adjusted to reflect the Settlement Proposal (Section 2, Part D, i) reduction to recovery of forecast OM&A costs (excluding Pickering Refurbishment Program OM&A costs) of $90.0M in 2027.

5 Adjusted to reflect (i) the Settlement Proposal (Section 2, Part D, ii) replacement of high-mid price uranium forecast with mid-price uranium forecast, and (ii) increased fuel expense associated with the Settlement Proposal (Section 2, Part C, i) increase to OPG's nuclear production forecast. Supporting details are provided in App. A, Table 7.

6 Adjusted to reflect (i) application of forecast CEITCs per Ex. L-F4-CCC-084 to reduce PRP capital costs for purposes of forecast CCR interest amounts (Settlement Proposal, Section 2, Part B, i), and (ii) reduction of OPG's cost of debt rates due to lower forecast new long-term debt issues as a result of the application of forecast CEITCs per Ex. L-F4-CCC-084 (Settlement Proposal, Section 2, Part B, iii). Supporting details are provided in App. A, Table 61.

7 Col. (c) per App. A, Table 34, line 30.

8 Adjusted to reflect the Settlement Proposal (Section 2, Part F) reduction to overall nuclear revenue requirement for purposes of settlement.

9 Col. (c) per App. D, Table 1, line 30.

Numbers may not add due to rounding.

Table 3

2028 Summary of OPG Nuclear Revenue Requirement and Deferral and Variance Account Amortization Amounts ($M)

Line No.	Description	Note	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Rate Base				
1	**Net Fixed Assets**	2	15,375.4	(487.0)	14,888.4
2	**Working Capital**		925.7	0.0	925.7
3	**Cash Working Capital**		(22.4)	0.0	(22.4)
4	**Total Rate Base**		16,278.6	(487.0)	15,791.6
	Capitalization				
5	**Short-term Debt**	3	259.6	(0.2)	259.4
6	**Long-Term Debt**	3	7,543.1	870.3	8,413.3
7	**Common Equity**	3	8,386.8	(1,348.2)	7,038.7
8	**EB-2020-0290 Settlement Adjustment for Equity at Long-Term Debt Rate**	3	66.1	(8.9)	57.2
9	**Adjustment for Lesser of UNL or ARC**		23.0	0.0	23.0
10	**Total Capital**		16,278.6	(487.0)	15,791.6
	Cost of Capital				
11	**Short-term Debt**	3	12.2	(0.0)	12.2
12	**Long-Term Debt**	3	360.9	39.1	400.0
13	**Common Equity**	3	764.0	(122.8)	641.2
14	**EB-2020-0290 Settlement Adjustment for Equity at Long-Term Debt Rate**	3	3.2	(0.4)	2.7
15	**Adjustment for Lesser of UNL or ARC**		1.1	0.0	1.1
16	**Total Cost of Capital**		1,141.4	(84.2)	1,057.2
	Expenses:				
17	**OM&A**	4	1,756.0	(125.0)	1,631.0
18	**Fuel**	5	221.7	3.5	225.2
19	**Depreciation & Amortization**	2	708.5	(21.0)	687.5
20	**Property Tax**		14.2	0.0	14.2
21	**Total Expenses**		2,700.5	(142.5)	2,558.0
	Less:				
	Other Revenues				
22	**Bruce Lease Revenues Net of Direct Costs**		11.5	0.0	11.5
23	**Ancillary and Other Revenue**		32.7	0.0	32.7
24	**Total Other Revenues**		44.2	0.0	44.2
25	**Concurrent Cost Recovery - Pickering Refurbishment Program**	6	479.9	(14.3)	465.5
26	**Income Tax**	7	(16.6)	0.0	(16.6)
27	**General Revenue Requirement Adjustment**	8	0.0	(35.4)	(35.4)
28	**Revenue Requirement Before Stretch Factor**		4,260.9	(276.4)	3,984.5
	(line 16 + line 21 - line 24 + line 25 + line 26 + line 27)				
29	**Cumulative Nuclear Stretch Dollars**	9	7.0	7.0	13.9
30	**Revenue Requirement Net of Stretch Factor**		4,253.9	(283.4)	3,970.6
	(line 28 - line 29)				
31	**Amortization of Deferral & Variance Account Amounts**	10	134.5	(59.5)	75.0
32	**Revenue Requirement Net of Stretch Factor Plus Deferral & Variance Account Amounts** (line 30 + line 31)		4,388.4	(342.8)	4,045.6

For notes see Table 3a.

Numbers may not add due to rounding.

Table 3a
Notes to Table 3
2028 Summary of OPG Nuclear Revenue Requirement and Deferral and Variance Account Amortization Amounts ($M)

1 Per Ex. I1-1-1, Table 2, with the following exceptions, per Settlement Proposal, p. 6:
Lines 2, 5-7, and 11-13 revised to reflect minor corrections identified by the Applicants in Ex. L-B1-CCC-019 and Ex. JT4.11.
Line 17 revised to reflect minor corrections identified by the Applicants in Ex. L-A2-SEC-025 and Ex. L-F3-SEC-174.

2 Adjusted to reflect the following reductions per the Settlement Proposal (Section 2, Part B, i): (i) application of forecast CEITCs to the Net Fixed Assets rate base and depreciation and amortization per Ex. L-F4-CCC-084; (ii) adjustment to the Darlington Refurbishment Program net fixed asset rate base to reflect OPG's updated, lower total project cost forecast since the filing of the Application; (iii) reduction of 10% to annual forecast Nuclear Operations in-service capital additions net of CEITCs and reduction of 11% to annual forecast Corporate Support Services in-service capital additions; (iv) permanent 2027 opening rate base reduction of $40.0M; and (v) change in forecast timing of rate base inclusion of certain Nuclear Operations in-service capital amounts tied to Pickering to 2031, with corresponding reductions over 2027-2030. Supporting continuity schedules for resulting Net Fixed Assets rate base amounts are provided in App. A, Tables 17 and 18.

3 Adjusted to reflect (i) the settlement adjusted rate base; (ii) the capital structure per the Settlement Proposal (Section 2, Part B, iii) of 45% equity and 55% debt; and (iii) reduction of cost of debt rates due to lower forecast new long-term debt issues as a result of the application of forecast CEITCs per Ex. L-F4-CCC-084 (Settlement Proposal, Section 2, Part B, iii). Supporting details are provided in App. A, Table 20.

4 Adjusted to reflect the Settlement Proposal (Section 2, Part D, i) reduction to recovery of forecast OM&A costs (excluding Pickering Refurbishment Program OM&A costs) of $125.0M in 2028.

5 Adjusted to reflect (i) the Settlement Proposal (Section 2, Part D, ii) replacement of high-mid price uranium forecast with mid-price uranium forecast, and (ii) increased fuel expense associated with the Settlement Proposal (Section 2, Part C, i) increase to OPG's nuclear production forecast. Supporting details are provided in App. A, Table 7.

6 Adjusted to reflect (i) application of forecast CEITCs per Ex. L-F4-CCC-084 to reduce Pickering Refurbishment Program capital costs for purposes of forecast CCR interest amounts (Settlement Proposal, Section 2, Part B, i), and (ii) reduction of OPG's cost of debt rates due to lower forecast new long-term debt issues as a result of the application of forecast CEITCs per Ex. L-F4-CCC-084 (Settlement Proposal, Section 2, Part B, iii). Supporting details are provided in App. A, Table 61.

7 Col. (c) per App. A, Table 35, line 30.

8 Adjusted to reflect the Settlement Proposal (Section 2, Part F) reduction to overall nuclear revenue requirement for purposes of settlement.

9 Per the Settlement Proposal, adjusted to increase the nuclear stretch factor to 0.6% and expand the scope of the stretch factor (Settlement Proposal, Section 2, Part A). Supporting calculation is provided in App. A, Table 13.

10 Col. (c) per App. D, Table 1, line 30.

Numbers may not add due to rounding.

Table 4

2029 Summary of OPG Nuclear Revenue Requirement and Deferral and Variance Account Amortization Amounts ($M)

Line No.	Description	Note	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Rate Base				
1	**Net Fixed Assets**	2	15,247.3	(583.3)	14,664.0
2	**Working Capital**		992.7	0.0	992.7
3	**Cash Working Capital**		(22.5)	0.0	(22.5)
4	**Total Rate Base**		16,217.5	(583.3)	15,634.3
	Capitalization				
5	**Short-term Debt**	3	248.6	0.7	249.3
6	**Long-Term Debt**	3	7,535.8	813.7	8,349.5
7	**Common Equity**	3	8,373.5	(1,389.7)	6,983.8
8	**EB-2020-0290 Settlement Adjustment for Equity at Long-Term Debt Rate**	3	59.6	(8.0)	51.6
9	**Adjustment for Lesser of UNL or ARC**		0.0	0.0	0.0
10	**Total Capital**		16,217.5	(583.3)	15,634.3
	Cost of Capital				
11	**Short-term Debt**	3	12.0	0.0	12.1
12	**Long-Term Debt**	3	369.3	36.6	405.9
13	**Common Equity**	3	762.8	(126.6)	636.2
14	**EB-2020-0290 Settlement Adjustment for Equity at Long-Term Debt Rate**	3	2.9	(0.4)	2.5
15	**Adjustment for Lesser of UNL or ARC**		0.0	0.0	0.0
16	**Total Cost of Capital**		1,147.1	(90.4)	1,056.7
	Expenses:				
17	**OM&A**	4	1,917.4	(130.0)	1,787.4
18	**Fuel**	5	223.6	0.5	224.0
19	**Depreciation & Amortization**	2	730.3	(26.3)	704.0
20	**Property Tax**		14.5	0.0	14.5
21	**Total Expenses**		2,885.7	(155.9)	2,729.9
	Less:				
	Other Revenues				
22	**Bruce Lease Revenues Net of Direct Costs**		(18.1)	0.0	(18.1)
23	**Ancillary and Other Revenue**		13.8	0.0	13.8
24	**Total Other Revenues**		(4.3)	0.0	(4.3)
25	**Concurrent Cost Recovery - Pickering Refurbishment Program**	6	667.7	(41.3)	626.4
26	**Income Tax**	7	(16.6)	0.0	(16.6)
27	**General Revenue Requirement Adjustment**	8	0.0	(35.4)	(35.4)
28	**Revenue Requirement Before Stretch Factor**		4,688.2	(323.0)	4,365.2
	(line 16 + line 21 - line 24 + line 25 + line 26 + line 27)				
29	**Cumulative Nuclear Stretch Dollars**	9	14.6	14.7	29.3
30	**Revenue Requirement Net of Stretch Factor**		4,673.6	(337.7)	4,335.9
	(line 28 - line 29)				
31	**Amortization of Deferral & Variance Account Amounts**	10	134.5	(59.5)	75.0
32	**Revenue Requirement Net of Stretch Factor Plus Deferral & Variance Account Amounts** (line 30 + line 31)		4,808.1	(397.2)	4,410.9

For notes see Table 4a.

Numbers may not add due to rounding.

Table 4a
Notes to Table 4
2029 Summary of OPG Nuclear Revenue Requirement and Deferral and Variance Account Amortization Amounts ($M)

1 Per Ex. I1-1-1, Table 2, with the following exceptions, per Settlement Proposal, p. 6:
Lines 2, 5-7, and 11-13 revised to reflect minor corrections identified by the Applicants in Ex. L-B1-CCC-019 and Ex. JT4.11.
Line 17 revised to reflect minor corrections identified by the Applicants in Ex. L-A2-SEC-025 and Ex. L-F3-SEC-174.

2 Adjusted to reflect the following reductions per the Settlement Proposal (Section 2, Part B, i): (i) application of forecast CEITCs to the Net Fixed Assets rate base and depreciation and amortization per Ex. L-F4-CCC-084; (ii) adjustment to the Darlington Refurbishment Program net fixed asset rate base to reflect OPG's updated, lower total project cost forecast since the filing of the Application; (iii) reduction of 10% to annual forecast Nuclear Operations in-service capital additions net of CEITCs and reduction of 11% to annual forecast Corporate Support Services in-service capital additions; (iv) permanent 2027 opening rate base reduction of $40.0M; and (v) change in forecast timing of rate base inclusion of certain Nuclear Operations in-service capital amounts tied to Pickering to 2031, with corresponding reductions over 2027-2030. Supporting continuity schedules for resulting Net Fixed Assets rate base amounts are provided in App. A, Tables 17 and 18.

3 Adjusted to reflect (i) the settlement adjusted rate base; (ii) the capital structure per the Settlement Proposal (Section 2, Part B, iii) of 45% equity and 55% debt; and (iii) reduction of cost of debt rates due to lower forecast new long-term debt issues as a result of the application of forecast CEITCs per Ex. L-F4-CCC-084 (Settlement Proposal, Section 2, Part B, iii). Supporting details are provided in App. A, Table 21.

4 Adjusted to reflect the Settlement Proposal (Section 2, Part D, i) reduction to recovery of forecast OM&A costs (excluding Pickering Refurbishment Program OM&A costs) of $130.0M in 2029.

5 Adjusted to reflect (i) the Settlement Proposal (Section 2, Part D, ii) replacement of high-mid price uranium forecast with mid-price uranium forecast, and (ii) increased fuel expense associated with the Settlement Proposal (Section 2, Part C, i) increase to OPG's nuclear production forecast. Supporting details are provided in App. A, Table 7.

6 Adjusted to reflect (i) application of forecast CEITCs per Ex. L-F4-CCC-084 to reduce Pickering Refurbishment Program capital costs for purposes of forecast CCR interest amounts (Settlement Proposal, Section 2, Part B, i), and (ii) reduction of OPG's cost of debt rates due to lower forecast new long-term debt issues as a result of the application of forecast CEITCs per Ex. L-F4-CCC-084 (Settlement Proposal, Section 2, Part B, iii). Supporting details are provided in App. A, Table 21.

7 Col. (c) per App. A, Table 36, line 30.

8 Adjusted to reflect the Settlement Proposal (Section 2, Part F) reduction to overall nuclear revenue requirement for purposes of settlement.

9 Per the Settlement Proposal, adjusted to increase the nuclear stretch factor to 0.6% and expand the scope of the stretch factor (Settlement Proposal, Section 2, Part A). Supporting calculation is provided in App. A, Table 13.

10 Col. (c) per App. D, Table 1, line 30.

Numbers may not add due to rounding.

Table 5

2030 Summary of OPG Nuclear Revenue Requirement and Deferral and Variance Account Amortization Amounts ($M)

Line No.	Description	Note	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Rate Base				
1	**Net Fixed Assets**	2	15,769.2	(812.7)	14,956.4
2	**Working Capital**		1,060.6	0.0	1,060.6
3	**Cash Working Capital**		(22.5)	0.0	(22.5)
4	**Total Rate Base**		16,807.3	(812.7)	15,994.5
	Capitalization				
5	**Short-term Debt**	3	246.3	0.6	246.8
6	**Long-Term Debt**	3	7,821.2	728.9	8,550.2
7	**Common Equity**	3	8,685.8	(1,535.0)	7,150.9
8	**EB-2020-0290 Settlement Adjustment for Equity at Long-Term Debt Rate**	3	53.9	(7.3)	46.7
9	**Adjustment for Lesser of UNL or ARC**		0.0	0.0	0.0
10	**Total Capital**		16,807.3	(812.7)	15,994.5
	Cost of Capital				
11	**Short-term Debt**	3	11.4	0.0	11.5
12	**Long-Term Debt**	3	388.4	31.4	419.9
13	**Common Equity**	3	791.3	(139.8)	651.4
14	**EB-2020-0290 Settlement Adjustment for Equity at Long-Term Debt Rate**	3	2.7	(0.4)	2.3
15	**Adjustment for Lesser of UNL or ARC**		0.0	0.0	0.0
16	**Total Cost of Capital**		1,193.8	(108.7)	1,085.1
	Expenses:				
17	**OM&A**	4	1,854.9	(130.0)	1,724.9
18	**Fuel**	5	261.2	(1.9)	259.3
19	**Depreciation & Amortization**	2	779.8	(36.2)	743.7
20	**Property Tax**		14.8	0.0	14.8
21	**Total Expenses**		2,910.7	(168.0)	2,742.7
	Less:				
	Other Revenues				
22	**Bruce Lease Revenues Net of Direct Costs**		7.3	0.0	7.3
23	**Ancillary and Other Revenue**		13.5	0.0	13.5
24	**Total Other Revenues**		20.8	0.0	20.8
25	**Concurrent Cost Recovery - Pickering Refurbishment Program**	6	832.0	(77.1)	755.0
26	**Income Tax**	7	(16.6)	0.0	(16.6)
27	**General Revenue Requirement Adjustment**	8	0.0	(35.4)	(35.4)
28	**Revenue Requirement Before Stretch Factor**		4,899.1	(389.3)	4,509.9
	(line 16 + line 21 - line 24 + line 25 + line 26 + line 27)				
29	**Cumulative Nuclear Stretch Dollars**	9	22.5	22.9	45.4
30	**Revenue Requirement Net of Stretch Factor**		4,876.7	(412.2)	4,464.5
	(line 28 - line 29)				
31	**Amortization of Deferral & Variance Account Amounts**	10	67.7	0.0	67.7
32	**Revenue Requirement Net of Stretch Factor Plus Deferral & Variance Account Amounts** (line 30 + line 31)		4,944.4	(412.2)	4,532.2

For notes see Table 5a.

Numbers may not add due to rounding.

Table 5a
Notes to Table 5
2030 Summary of OPG Nuclear Revenue Requirement and Deferral and Variance Account Amortization Amounts ($M)

1 Per Ex. I1-1-1, Table 2, with the following exceptions, per Settlement Proposal, p. 6:
Lines 2, 5-7, and 11-13 revised to reflect minor corrections identified by the Applicants in Ex. L-B1-CCC-019 and Ex. JT4.11.
Line 17 revised to reflect minor corrections identified by the Applicants in Ex. L-A2-SEC-025 and Ex. L-F3-SEC-174.

2 Adjusted to reflect the following reductions per the Settlement Proposal (Section 2, Part B, i): (i) application of forecast CEITCs to the Net Fixed Assets rate base and depreciation and amortization per Ex. L-F4-CCC-084; (ii) adjustment to the Darlington Refurbishment Program net fixed asset rate base to reflect OPG's updated, lower total project cost forecast since the filing of the Application; (iii) reduction of 10% to annual forecast Nuclear Operations in-service capital additions net of CEITCs and reduction of 11% to annual forecast Corporate Support Services in-service capital additions; (iv) permanent 2027 opening rate base reduction of $40.0M; and (v) change in forecast timing of rate base inclusion of certain Nuclear Operations in-service capital amounts tied to Pickering to 2031, with corresponding reductions over 2027-2030. Supporting continuity schedules for resulting Net Fixed Assets rate base amounts are provided in App. A, Tables 17 and 18.

3 Adjusted to reflect (i) the settlement adjusted rate base; (ii) the capital structure per the Settlement Proposal (Section 2, Part B, iii) of 45% equity and 55% debt; and (iii) reduction of cost of debt rates due to lower forecast new long-term debt issues as a result of the application of forecast CEITCs per Ex. L-F4-CCC-084 (Settlement Proposal, Section 2, Part B, iii). Supporting details are provided in App. A, Table 22.

4 Adjusted to reflect the Settlement Proposal (Section 2, Part D, i) reduction to recovery of forecast OM&A costs (excluding Pickering Refurbishment Program OM&A costs) of $130.0M in 2030.

5 Adjusted to reflect (i) the Settlement Proposal (Section 2, Part D, ii) replacement of high-mid price uranium forecast with mid-price uranium forecast, and (ii) increased fuel expense associated with the Settlement Proposal (Section 2, Part C, i) increase to OPG's nuclear production forecast. Supporting details are provided in App. A, Table 7.

6 Adjusted to reflect (i) application of forecast CEITCs per Ex. L-F4-CCC-084 to reduce Pickering Refurbishment Program capital costs for purposes of forecast CCR interest amounts (Settlement Proposal, Section 2, Part B, i), and (ii) reduction of OPG's cost of debt rates due to lower forecast new long-term debt issues as a result of the application of forecast CEITCs per Ex. L-F4-CCC-084 (Settlement Proposal, Section 2, Part B, iii). Supporting details are provided in App. A, Table 61.

7 Col. (c) per App. A, Table 37, line 30.

8 Adjusted to reflect the Settlement Proposal (Section 2, Part F) reduction to overall nuclear revenue requirement for purposes of settlement.

9 Per the Settlement Proposal, adjusted to increase the nuclear stretch factor to 0.6% and expand the scope of the stretch factor (Settlement Proposal, Section 2, Part A). Supporting calculation is provided in App. A, Table 13.

10 Col. (c) per App. D, Table 1, line 30.

Numbers may not add due to rounding.

Table 6

2031 Summary of OPG Nuclear Revenue Requirement and Deferral and Variance Account Amortization Amounts ($M)

Line No.	Description	Note	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Rate Base				
1	**Net Fixed Assets**	2	22,435.9	(1,575.4)	20,860.5
2	**Working Capital**		1,105.9	0.0	1,105.9
3	**Cash Working Capital**		(22.5)	0.0	(22.5)
4	**Total Rate Base**		23,519.3	(1,575.4)	21,943.9
	Capitalization				
5	**Short-term Debt**	3	274.3	(0.7)	273.6
6	**Long-Term Debt**	3	11,015.0	780.5	11,795.5
7	**Common Equity**	3	12,180.4	(2,348.6)	9,831.8
8	**EB-2020-0290 Settlement Adjustment for Equity at Long-Term Debt Rate**	3	49.6	(6.7)	43.0
9	**Adjustment for Lesser of UNL or ARC**		0.0	0.0	0.0
10	**Total Capital**		23,519.3	(1,575.4)	21,943.9
	Cost of Capital				
11	**Short-term Debt**	3	13.2	(0.0)	13.2
12	**Long-Term Debt**	3	548.8	31.2	580.0
13	**Common Equity**	3	1,109.6	(214.0)	895.7
14	**EB-2020-0290 Settlement Adjustment for Equity at Long-Term Debt Rate**	3	2.5	(0.4)	2.1
15	**Adjustment for Lesser of UNL or ARC**		0.0	0.0	0.0
16	**Total Cost of Capital**		1,674.2	(183.2)	1,491.0
	Expenses:				
17	**OM&A**	4	2,150.6	(140.0)	2,010.6
18	**Fuel**	5	306.1	(3.6)	302.6
19	**Depreciation & Amortization**	2	992.6	(60.6)	932.0
20	**Property Tax**		15.0	0.0	15.0
21	**Total Expenses**		3,464.3	(204.1)	3,260.2
	Less:				
	Other Revenues				
22	**Bruce Lease Revenues Net of Direct Costs**		(17.1)	0.0	(17.1)
23	**Ancillary and Other Revenue**		23.6	0.0	23.6
24	**Total Other Revenues**		6.5	0.0	6.5
25	**Concurrent Cost Recovery - Pickering Refurbishment Program**	6	646.2	(70.2)	576.0
26	**Income Tax**	7	(16.6)	0.0	(16.6)
27	**General Revenue Requirement Adjustment**	8	0.0	(50.4)	(50.4)
28	**Revenue Requirement Before Stretch Factor**		5,761.5	(507.9)	5,253.6
	(line 16 + line 21 - line 24 + line 25 + line 26 + line 27)				
29	**Cumulative Nuclear Stretch Dollars**	9	31.7	32.5	64.2
30	**Revenue Requirement Net of Stretch Factor**		5,729.8	(540.4)	5,189.4
	(line 28 - line 29)				
31	**Amortization of Deferral & Variance Account Amounts**	10	67.7	0.0	67.7
32	**Revenue Requirement Net of Stretch Factor Plus Deferral & Variance Account Amounts** (line 30 + line 31)		5,797.5	(540.4)	5,257.2

For notes see Table 6a.

Numbers may not add due to rounding.

Table 6a
Notes to Table 6
2031 Summary of OPG Nuclear Revenue Requirement and Deferral and Variance Account Amortization Amounts ($M)

1 Per Ex. I1-1-1, Table 2, with the following exceptions, per Settlement Proposal, p. 6:
Lines 2, 5-7, and 11-13 revised to reflect minor corrections identified by the Applicants in Ex. L-B1-CCC-019 and Ex. JT4.11.
Line 17 revised to reflect minor corrections identified by the Applicants in Ex. L-A2-SEC-025 and Ex. L-F3-SEC-174.

2 Adjusted to reflect the following reductions per the Settlement Proposal (Section 2, Part B, i): (i) application of forecast CEITCs to the Net Fixed Assets rate base and depreciation and amortization per Ex. L-F4-CCC-084; (ii) adjustment to the Darlington Refurbishment Program net fixed asset rate base to reflect OPG's updated, lower total project cost forecast since the filing of the Application; (iii) reduction of 10% to annual forecast Nuclear Operations in-service capital additions net of CEITCs and reduction of 11% to annual forecast Corporate Support Services in-service capital additions; (iv) permanent 2027 opening rate base reduction of $40.0M; and (v) change in forecast timing of rate base inclusion of certain Nuclear Operations in-service capital amounts tied to Pickering totaling to 2031, with corresponding reductions over 2027-2030. Supporting continuity schedules for resulting Net Fixed Assets rate base amounts are provided in App. A, Tables 17 and 18.

3 Adjusted to reflect (i) the settlement adjusted rate base; (ii) the capital structure per the Settlement Proposal (Section 2, Part B, iii) of 45% equity and 55% debt; and (iii) reduction of cost of debt rates due to lower forecast new long-term debt issues as a result of the application of forecast CEITCs per Ex. L-F4-CCC-084 (Section 2, Part B, iii). Supporting details are provided in App. A, Table 23.

4 Adjusted to reflect the Settlement Proposal (Section 2, Part D, i) reduction to recovery of forecast OM&A costs (excluding Pickering Refurbishment Program OM&A costs) of $140.0M in 2031.

5 Adjusted to reflect (i) the Settlement Proposal (Section 2, Part D, ii) replacement of high-mid price uranium forecast with mid-price uranium forecast, and (ii) increased fuel expense associated with the Settlement Proposal (Section 2, Part C, i) increase to OPG's nuclear production forecast. Supporting details are provided in App. A, Table 7.

6 Adjusted to reflect (i) application of forecast CEITCs per Ex. L-F4-CCC-084 to reduce Pickering Refurbishment Program capital costs for purposes of forecast CCR interest amounts (Settlement Proposal, Section 2, Part B, i), and (ii) reduction of OPG's cost of debt rates due to lower forecast new long-term debt issues as a result of the application of forecast CEITCs per Ex. L-F4-CCC-084 (Settlement Proposal, Section 2, Part B, iii). Supporting details are provided in App. A, Table 61.

7 Col. (c) per App. A, Table 38, line 30.

8 Adjusted to reflect the Settlement Proposal (Section 2, Part F) reduction to overall nuclear revenue requirement for purposes of settlement.

9 Per the Settlement Proposal, adjusted to increase the nuclear stretch factor to 0.6% and expand the scope of the stretch factor (Settlement Proposal, Section 2, Part A). Supporting calculation is provided in App. A, Table 13.

10 Col. (c) per App. D, Table 1, line 30.

Numbers may not add due to rounding.

Table 7
2027 to 2031 Summary of OPG Nuclear Facilities Fuel Costs

Line No.	Description	Reference	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
1	OPG Proposed CANDU Fuel Bundle Cost ($M)	Ex. F2-5-1, Table 1a, line 3	121.2	181.6	183.9	209.3	250.2
2	Settlement Adjustment for Mid-Price Uranium Forecast ($M)	Note 1	(1.4)	(3.6)	(6.0)	(9.8)	(13.6)
3	CANDU Fuel Bundle Cost Adjusted for Mid-Price Uranium Forecast ($M)	line 1 + line 2	119.8	178.0	177.9	199.5	236.6
4	OPG Proposed CANDU Used Fuel Storage & Disposal Cost ($M)	Ex. F2-5-1, Table 1a, line 5	26.8	38.5	38.0	50.2	54.2
5	OPG Proposed Nuclear Production (TWh)	Ex. E2-1-1, Table 1, line 3	18.7	26.7	25.1	26.8	28.9
6	Settlement Adjusted CANDU Fuel Bundle Cost Rate ($/MWh)	line 3 / line 5	6.4	6.7	7.1	7.4	8.2
7	CANDU Used Fuel Storage & Disposal Cost Rate ($/MWh)	line 4 / line 5	1.4	1.4	1.5	1.9	1.9
8	Settlement Adjusted OPG Nuclear Fuel Cost Rate (excl. Fuel Oil) ($/MWh)	line 6 + line 7	7.8	8.1	8.6	9.3	10.0
9	Settlement Adjusted OPG Nuclear Production (TWh)	Note 2	19.3	27.6	25.8	27.7	29.9
10	Settlement Adjusted CANDU Fuel Bundle Cost ($M)	line 6 x line 9	124.0	183.8	183.2	205.8	244.7
11	Settlement Adjusted CANDU Used Fuel Storage & Disposal Cost ($M)	line 7 x line 9	27.7	39.8	39.1	51.8	56.1
12	Settlement Adjusted OPG Nuclear Fuel Cost (excl. Fuel Oil) ($M)	line 10 + line 11	151.7	223.5	222.3	257.6	300.8
13	Fuel Oil ($M)	Ex. F2-5-1, Table 1a, line 6	2.9	1.7	1.7	1.7	1.8
14	Settlement Adjusted Total OPG Nuclear Fuel Cost ($M)	line 12 + line 13	154.6	225.2	224.0	259.3	302.6

Notes:
1 Settlement adjustment to replace the high-price midpoint uranium forecast reflected in the Application with the mid-price midpoint uranium forecast as set out in Ex. L-F2-SEC-171 (Settlement Proposal, Section 2, Part D, ii).
2 Per App. B, Table 3, line 6, cols. (a) through (e).

Numbers may not add due to rounding.

Table 8

2027 Summary of DNNP LP Revenue Requirement and Deferral and Variance Account Amortization Amounts ($M)

Line No.	Description	Note	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Rate Base				
1	**Net Fixed Assets**		0.0	0.0	0.0
2	**Working Capital**		0.0	0.0	0.0
3	**Cash Working Capital**		0.0	0.0	0.0
4	**Total Rate Base**		0.0	0.0	0.0
	Capitalization				
5	**Short-term Debt**		0.0	0.0	0.0
6	**Long-Term Debt**		0.0	0.0	0.0
7	**Common Equity**		0.0	0.0	0.0
8	**Total Capital**		0.0	0.0	0.0
	Cost of Capital				
9	**Short-term Debt**		0.0	0.0	0.0
10	**Long-Term Debt**		0.0	0.0	0.0
11	**Return on Equity**		0.0	0.0	0.0
12	**Total Cost of Capital**		0.0	0.0	0.0
	Expenses:				
13	**OM&A**	2	77.0	(4.0)	73.0
14	**Fuel**		9.1	0.0	9.1
15	**Depreciation & Amortization**		0.0	0.0	0.0
16	**Property Tax**		0.0	0.0	0.0
17	**Total Expenses**		86.1	(4.0)	82.1
	Less:				
	Other Revenues				
18	**Ancillary and Other Revenue**		0.0	0.0	0.0
19	**Total Other Revenues**		0.0	0.0	0.0
20	**Concurrent Cost Recovery - Darlington New Nuclear Program**	3	214.9	(0.8)	214.2
21	**Income Tax**		0.0	0.0	0.0
22	**Revenue Requirement**		301.0	(4.8)	296.3
	(line 12 + line 17 - line 19 + line 20 + line 21)				
23	**Amortization of Deferral & Variance Account Amounts**		0.0	0.0	0.0
24	**Revenue Requirement Plus Deferral & Variance Account Amounts** (line 22 + line 23)		301.0	(4.8)	296.3

For notes see Table 8a.

Numbers may not add due to rounding.

Table 8a
Notes to Table 8
2027 Summary of DNNP LP Revenue Requirement and Deferral and Variance Account Amortization Amounts ($M)

1 Per Ex. I1-1-1, Table 2a, with the exception of line 13 that reflects minor corrections identified by the Applicants in Ex. L-A2-SEC-025 and Ex. L-F3-SEC-174 (Settlement Proposal, p. 6).

2 Col. (c) reflects Settlement Proposal (Section 3, Part D, i) reduction to recovery of forecast OM&A costs (excluding DNNP Operational Readiness OM&A costs) of $4.0M in 2027.

3 Adjusted to reflect (i) application of forecast CEITCs per Ex. L-F4-CCC-084 to reduce Darlington New Nuclear Program capital costs for purposes of forecast CCR interest amounts (Settlement Proposal, Section 3, Part B, i), and (ii) reduction of OPG's cost of debt rates due to lower forecast new long-term debt issues as a result of the application of forecast CEITCs per Ex. L-F4-CCC-084 (Settlement Proposal, Section 3, Part B, ii). Supporting details are provided in App. A, Table 62.

Numbers may not add due to rounding.

Table 9

2028 Summary of DNNP LP Revenue Requirement and Deferral and Variance Account Amortization Amounts ($M)

Line No.	Description	Note	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Rate Base				
1	**Net Fixed Assets**		0.0	0.0	0.0
2	**Working Capital**		0.0	0.0	0.0
3	**Cash Working Capital**		0.0	0.0	0.0
4	**Total Rate Base**		0.0	0.0	0.0
	Capitalization				
5	**Short-term Debt**		0.0	0.0	0.0
6	**Long-Term Debt**		0.0	0.0	0.0
7	**Common Equity**		0.0	0.0	0.0
8	**Total Capital**		0.0	0.0	0.0
	Cost of Capital				
9	**Short-term Debt**		0.0	0.0	0.0
10	**Long-Term Debt**		0.0	0.0	0.0
11	**Return on Equity**		0.0	0.0	0.0
12	**Total Cost of Capital**		0.0	0.0	0.0
	Expenses:				
13	**OM&A**	2	80.1	(4.0)	76.1
14	**Fuel**		13.8	0.0	13.8
15	**Depreciation & Amortization**		0.0	0.0	0.0
16	**Property Tax**		0.0	0.0	0.0
17	**Total Expenses**		93.9	(4.0)	89.9
	Less:				
	Other Revenues				
18	**Ancillary and Other Revenue**		0.0	0.0	0.0
19	**Total Other Revenues**		0.0	0.0	0.0
20	**Concurrent Cost Recovery - Darlington New Nuclear Program**	3	284.8	(10.7)	274.2
21	**Income Tax**		0.0	0.0	0.0
22	**Revenue Requirement**		378.8	(14.7)	364.1
	(line 12 + line 17 - line 19 + line 20 + line 21)				
23	**Amortization of Deferral & Variance Account Amounts**		0.0	0.0	0.0
24	**Revenue Requirement Plus Deferral & Variance Account Amounts** (line 22 + line 23)		378.8	(14.7)	364.1

For notes see Table 9a.

Numbers may not add due to rounding.

Table 9a
Notes to Table 9
2028 Summary of DNNP LP Revenue Requirement and Deferral and Variance Account Amortization Amounts ($M)

1 Per Ex. I1-1-1, Table 2a, with the exception of line 13 that reflects minor corrections identified by the Applicants in Ex. L-A2-SEC-025 and Ex. L-F3-SEC-174 (Settlement Proposal, p. 6).

2 Col. (c) reflects Settlement Proposal (Section 3, Part D, i) reduction to recovery of forecast OM&A costs (excluding DNNP Operational Readiness OM&A costs) of $4.0M in 2028.

3 Adjusted to reflect (i) application of forecast CEITCs per Ex. L-F4-CCC-084 to reduce Darlington New Nuclear Program capital costs for purposes of forecast CCR interest amounts (Settlement Proposal, Section 3, Part B, i), and (ii) reduction of OPG's cost of debt rates due to lower forecast new long-term debt issues as a result of the application of forecast CEITCs per Ex. L-F4-CCC-084 (Settlement Proposal, Section 3, Part B, ii). Supporting details are provided in App. A, Table 62.

Numbers may not add due to rounding.

Table 10

2029 Summary of DNNP LP Revenue Requirement and Deferral and Variance Account Amortization Amounts ($M)

Line No.	Description	Note	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Rate Base				
1	**Net Fixed Assets**		0.0	0.0	0.0
2	**Working Capital**		2.1	0.0	2.1
3	**Cash Working Capital**		0.0	0.0	0.0
4	**Total Rate Base**		2.1	0.0	2.1
	Capitalization				
5	**Short-term Debt**		0.0	0.0	0.0
6	**Long-Term Debt**		0.0	0.0	0.0
7	**Common Equity**		2.1	0.0	2.1
8	**Total Capital**		2.1	0.0	2.1
	Cost of Capital				
9	**Short-term Debt**		0.0	0.0	0.0
10	**Long-Term Debt**		0.0	0.0	0.0
11	**Return on Equity**		0.2	0.0	0.2
12	**Total Cost of Capital**		0.2	0.0	0.2
	Expenses:				
13	**OM&A**	2	70.8	(4.0)	66.8
14	**Fuel**		12.7	0.0	12.7
15	**Depreciation & Amortization**		0.0	0.0	0.0
16	**Property Tax**		0.0	0.0	0.0
17	**Total Expenses**		83.5	(4.0)	79.5
	Less:				
	Other Revenues				
18	**Ancillary and Other Revenue**		0.0	0.0	0.0
19	**Total Other Revenues**		0.0	0.0	0.0
20	**Concurrent Cost Recovery - Darlington New Nuclear Program**	3	321.2	(27.8)	293.4
21	**Income Tax**		0.0	0.0	0.0
22	**Revenue Requirement**		404.9	(31.8)	373.1
	(line 12 + line 17 - line 19 + line 20 + line 21)				
23	**Amortization of Deferral & Variance Account Amounts**		0.0	0.0	0.0
24	**Revenue Requirement Plus Deferral & Variance Account Amounts** (line 22 + line 23)		404.9	(31.8)	373.1

For notes see Table 10a.

Numbers may not add due to rounding.

Table 10a
Notes to Table 10
2029 Summary of DNNP LP Revenue Requirement and Deferral and Variance Account Amortization Amounts ($M)

1 Per Ex. I1-1-1, Table 2a, with the exception of line 13 that reflects minor corrections identified by the Applicants in Ex. L-A2-SEC-025 and Ex. L-F3-SEC-174 (Settlement Proposal, p. 6).

2 Col. (c) reflects Settlement Proposal (Section 3, Part D, i) reduction to recovery of forecast OM&A costs (excluding DNNP Operational Readiness OM&A costs) of $4.0M in 2029.

3 Adjusted to reflect (i) application of forecast CEITCs per Ex. L-F4-CCC-084 to reduce Darlington New Nuclear Program capital costs for purposes of forecast CCR interest amounts (Settlement Proposal, Section 3, Part B, i), and (ii) reduction of OPG's cost of debt rates due to lower forecast new long-term debt issues as a result of the application of forecast CEITCs per Ex. L-F4-CCC-084 (Settlement Proposal, Section 3, Part B, ii). Supporting details are provided in App. A, Table 62.

Numbers may not add due to rounding.

Table 11

2030 Summary of DNNP LP Revenue Requirement and Deferral and Variance Account Amortization Amounts ($M)

Line No.	Description	Note	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Rate Base				
1	**Net Fixed Assets**	2	1,360.5	(134.2)	1,226.3
2	**Working Capital**		11.1	0.0	11.1
3	**Cash Working Capital**		(0.6)	0.0	(0.6)
4	**Total Rate Base**		1,371.1	(134.2)	1,236.9
	Capitalization				
5	**Short-term Debt**		0.0	0.0	0.0
6	**Long-Term Debt**		0.0	0.0	0.0
7	**Common Equity**	3	1,371.1	(134.2)	1,236.9
8	**Total Capital**		1,371.1	(134.2)	1,236.9
	Cost of Capital				
9	**Short-term Debt**		0.0	0.0	0.0
10	**Long-Term Debt**		0.0	0.0	0.0
11	**Return on Equity**	3	124.9	(12.2)	112.7
12	**Total Cost of Capital**		124.9	(12.2)	112.7
	Expenses:				
13	**OM&A**	4	119.6	(4.0)	115.6
14	**Fuel**		18.1	0.0	18.1
15	**Depreciation & Amortization**	2	22.6	(2.2)	20.4
16	**Property Tax**		0.8	0.0	0.8
17	**Total Expenses**		161.1	(6.2)	154.9
	Less:				
	Other Revenues				
18	**Ancillary and Other Revenue**		0.0	0.0	0.0
19	**Total Other Revenues**		0.0	0.0	0.0
20	**Concurrent Cost Recovery - Darlington New Nuclear Program**	5	274.2	(29.8)	244.4
21	**Income Tax**		0.0	0.0	0.0
22	**Revenue Requirement**		560.2	(48.3)	512.0
	(line 12 + line 17 - line 19 + line 20 + line 21)				
23	**Amortization of Deferral & Variance Account Amounts**		0.0	0.0	0.0
24	**Revenue Requirement Plus Deferral & Variance Account Amounts** (line 22 + line 23)		560.2	(48.3)	512.0

For notes see Table 11a.

Numbers may not add due to rounding.

Table 11a
Notes to Table 11
2030 Summary of DNNP LP Revenue Requirement and Deferral and Variance Account Amortization Amounts ($M)

1 Per Ex. I1-1-1, Table 2a, with the exception of line 13 that reflects minor corrections identified by the Applicants in Ex. L-A2-SEC-025 and Ex. L-F3-SEC-174 (Settlement Proposal, p. 6).

2 Adjusted to reflect application of forecast CEITCs to the Net Fixed Assets rate base and depreciation and amortization per Ex. L-F4-CCC-084 (Settlement Proposal, Section 3, Part B, i). Supporting continuity schedules for resulting Net Fixed Assets rate base amounts are provided in App. A, Tables 17 and 18.

3 Adjusted to reflect the settlement adjusted rate base. Supporting details are provided in App. A, Tables 17 and 18.

4 Col. (c) reflects Settlement Proposal (Section 3, Part D, i) reduction to recovery of forecast OM&A costs (excluding DNNP Operational Readiness OM&A costs) of $4.0M in 2030.

5 Adjusted to reflect (i) application of forecast CEITCs per Ex. L-F4-CCC-084 to reduce Darlington New Nuclear Program capital costs for purposes of forecast CCR interest amounts (Settlement Proposal, Section 3, Part B, i), and (ii) reduction of OPG's cost of debt rates due to lower forecast new long-term debt issues as a result of the application of forecast CEITCs per Ex. L-F4-CCC-084 (Settlement Proposal, Section 3, Part B, ii). Supporting details are provided in App. A, Table 62.

Numbers may not add due to rounding.

Table 12

2031 Summary of DNNP LP Revenue Requirement and Deferral and Variance Account Amortization Amounts ($M)

Line No.	Description	Note	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Rate Base				
1	**Net Fixed Assets**	2	6,507.4	(641.9)	5,865.5
2	**Working Capital**		25.0	0.0	25.0
3	**Cash Working Capital**		(2.4)	0.0	(2.4)
4	**Total Rate Base**		6,530.0	(641.9)	5,888.1
	Capitalization				
5	**Short-term Debt**		0.0	0.0	0.0
6	**Long-Term Debt**		0.0	0.0	0.0
7	**Common Equity**	2	6,530.0	(641.9)	5,888.1
8	**Total Capital**		6,530.0	(641.9)	5,888.1
	Cost of Capital				
9	**Short-term Debt**		0.0	0.0	0.0
10	**Long-Term Debt**		0.0	0.0	0.0
11	**Return on Equity**	2	594.9	(58.5)	536.4
12	**Total Cost of Capital**		594.9	(58.5)	536.4
	Expenses:				
13	**OM&A**	3	259.7	(8.0)	251.6
14	**Fuel**	5	49.8	1.4	51.2
15	**Depreciation & Amortization**	2	109.7	(10.8)	98.9
16	**Property Tax**		3.7	0.0	3.7
17	**Total Expenses**		422.9	(17.4)	405.5
	Less:				
	Other Revenues				
18	**Ancillary and Other Revenue**		0.0	0.0	0.0
19	**Total Other Revenues**		0.0	0.0	0.0
20	**Concurrent Cost Recovery - Darlington New Nuclear Program**	2, 4	24.6	(3.7)	20.9
21	**Income Tax**		0.0	0.0	0.0
22	**Revenue Requirement**		1,042.4	(79.6)	962.8
	(line 12 + line 17 - line 19 + line 20 + line 21)				
23	**Amortization of Deferral & Variance Account Amounts**		0.0	0.0	0.0
24	**Revenue Requirement Plus Deferral & Variance Account Amounts** (line 22 + line 23)		1,042.4	(79.6)	962.8

For notes see Table 12a.

Numbers may not add due to rounding.

Table 12a
Notes to Table 12
2031 Summary of DNNP LP Revenue Requirement and Deferral and Variance Account Amortization Amounts ($M)

1 Per Ex. I1-1-1, Table 2a, with the exception of line 13 that reflects minor corrections identified by the Applicants in Ex. L-A2-SEC-025 and Ex. L-F3-SEC-174 (Settlement Proposal, p. 6).

2 Adjusted to reflect application of forecast CEITCs to the Net Fixed Assets rate base and depreciation and amortization per Ex. L-F4-CCC-084 (Settlement Proposal, Section 3, Part B, i). Supporting continuity schedules for resulting Net Fixed Assets rate base amounts are provided in App. A, Tables 17 and 18.

3 Col. (c) reflects Settlement Proposal (Section 3, Part D, i) reduction to recovery of forecast OM&A costs (excluding DNNP Operational Readiness OM&A costs) of $8.0M in 2031.

4 Adjusted to reflect (i) application of forecast CEITCs per Ex. L-F4-CCC-084 to reduce Darlington New Nuclear Program capital costs for purposes of forecast CCR interest amounts (Settlement Proposal, Section 3, Part B, i), and (ii) reduction of OPG's cost of debt rates due to lower forecast new long-term debt issues as a result of the application of forecast CEITCs per Ex. L-F4-CCC-084 (Settlement Proposal, Section 3, Part B, ii). Supporting details are provided in App. A, Table 62.

5 Adjusted to reflect the increased fuel expense associated with the Settlement Proposal (Section 3, Part D, ii) increase to DNNP LP's production forecast, as follows:

Line No.	Description	2031
5a	DNNP LP Proposed Nuclear Fuel Service Fee ($M) (Ex. F2-1-1, Table 1b, line 10)	49.8
5b	Total SMR Fuel Assembly Cost ($/MWh) (Ex. F2-5-1, Table 1b, line 2)	14.4
5c	Settlement Adjusted DNNP LP Production (TWh) (App. B, Table 3, line 7, col. (e))	2.0
5d	Settlement Adjusted Nuclear Fuel Expense Portion of Nuclear Fuel Service Fee ($M) (line 5b x line 5c)	29.3
5e	Remaining Portion of Nuclear Fuel Service Fee (Ex. F3-2-1, Table 3: line 1 + line 8)	21.9
5f	Settlement Adjusted DNNP LP Nuclear Fuel Service Fee (line 5d + line 5e)	51.2

Numbers may not add due to rounding.

Table 13
Calculation of OPG Nuclear Stretch Factor ($M)
January 1, 2027 to December 31, 2031

Line No.	Description	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
	Stretch Factor Applicable Nuclear OM&A Expenses and Other Non-Capital Related Nuclear Revenue Requirement Components						
	Darlington Nuclear OM&A Expenses						
1	**Base OM&A**	1		709.8	745.1	750.8	765.8
2	**Project OM&A**	2		54.2	53.9	51.6	54.3
3	**Outage OM&A**	3		112.7	219.1	121.6	115.8
4	**Allocation of Corporate Costs**	4		205.8	214.9	213.7	222.0
5	**Darlington Total OM&A Expenses Subject to Stretch Factor** (sum of lines 1 to 4)			1,082.5	1,232.9	1,137.8	1,157.8
	Pickering Total Nuclear OM&A Expenses						
6	**Base OM&A**	5		140.9	153.4	166.0	459.7
7	**Project OM&A**	6		16.5	19.6	23.0	22.5
8	**Outage OM&A**	7		0.0	0.0	0.0	26.5
9	**Pickering Cyclical Maintenance OM&A**	8		160.9	168.9	169.9	106.6
10	**Allocation of Corporate Costs**	9		206.4	217.8	230.1	249.1
11	**Pickering Total OM&A Expenses Subject to Stretch Factor** (sum of lines 6 to 10)			524.7	559.7	589.0	864.4
12	**Asset Service Fees**	23		73.9	89.5	99.0	99.4
13	**Project OM&A (Operations and Project Support)**	10		11.7	10.5	10.2	6.4
14	**Allocation of Centrally Held Costs**	11		(30.8)	(60.1)	(33.8)	(24.1)
15	**Fuel Costs**	12		225.2	224.0	259.3	302.6
16	**Working Capital and Cash Working Capital**	13		73.0	79.0	84.7	88.5
17	**Property Tax**	14		14.2	14.5	14.8	15.0
18	**Other Revenue**	15		(32.7)	(13.8)	(13.5)	(23.6)
19	**Total Other Revenue Requirement Components Subject to Stretch Factor** (sum of lines 12 to 18)			334.5	343.6	420.7	464.3
20	**Settlement Adjustment to OM&A Expenses Subject to Stretch Factor**	16		(125.0)	(130.0)	(130.0)	(140.0)
	Stretch Factor Applicable Nuclear Capital Related Revenue Requirement						
	Darlington (excl. Darlington Refurbishment Program) and Operations & Project Support						
21	**Cost of Capital**	17		303.2	321.1	370.1	427.7
22	**Depreciation and Amortization Expense**	17		255.1	276.4	317.5	366.9
23	**Income Tax Expense on Cost of Capital and Depreciation and Amortization Expense**	17		146.4	156.6	180.0	208.0
24	**Total Darlington and Operations & Project Support Capital Related Revenue Requirement Subject to Stretch Factor** (line 21 + line 22 + line 23)			704.8	754.1	867.6	1,002.6
	Pickering (excl. Pickering Refurbishment Program)						
25	**Cost of Capital**	18		23.0	28.0	42.9	56.5
26	**Depreciation and Amortization Expense**	18		26.6	26.8	34.4	41.6
27	**Income Tax Expense on Cost of Capital and Depreciation and Amortization Expense**	18		13.6	14.6	20.1	25.2
28	**Total Pickering Capital Related Revenue Requirement Subject to Stretch Factor** (line 25 + line 26 + line 27)			63.2	69.4	97.4	123.3
28a	**Settlement Adjustment to Capital Related Revenue Requirement Subject to Stretch Factor**	19		(25.9)	(40.7)	(69.6)	(82.9)
29	**Income Tax Expense - Capital Cost Allowance (excl. Darlington Refurbishment Program and Pickering Refurbishment Program)**	20		(200.8)	(194.0)	(193.1)	(209.5)
30	**General Revenue Requirement Adjustment**	21		(35.4)	(35.4)	(35.4)	(50.4)
31	**Total Revenue Requirement Amount Subject to Stretch Factor** (line 5 + line 11 + line 19 + line 20 + line 24 + line 28 + line 28a + line 29 + line 30)			2,322.5	2,559.5	2,684.5	3,129.5
32	**OPG Nuclear Stretch Factor**	22		0.60%	0.60%	0.60%	0.60%
33	**OPG Nuclear Stretch Factor Revenue Requirement Adjustment**			13.9	29.3	45.4	64.2

For notes see Table 13a.

Numbers may not add due to rounding.

Table 13a
Notes to Table 13
Calculation of OPG Nuclear Stretch Factor ($M)
January 1, 2027 to December 31, 2031

1 Per Ex. F2-2-1, Tables 11-14: line 13, col. (a).
2 Per Ex. F2-3-1, Table 1, line 1, cols. (i) to (l), plus Ex. F2-3-1, Table 1, Note 3, lines 3a and 3d.
3 Per Ex. F2-4-1, Table 1, line 3, cols. (i) to (l).
4 Per Ex. F3-1-1, Table 3a, line 10, cols. (i) to (l), revised to reflect minor corrections identified in Ex. L-F3-SEC-174.
5 Per Ex. F2-2-1, Tables 11-14: line 13, col. (b).
6 Per Ex. F2-3-1, Table 1, line 2, cols. (i) to (l), plus Ex. F2-3-1, Table 1, Note 3, lines 3b and 3e.
7 Per Ex. F2-4-1, Table 1, line 6, cols. (i) to (l).
8 Per Ex. F2-4-1, Table 1, line 14, cols. (i) to (l).
9 Per Ex. F3-1-1, Table 3b, line 10, cols. (i) to (l).
10 Per Ex. F2-3-1, Table 1, line 3, cols. (i) to (l), plus Ex. F2-3-1, Table 1, Note 3, lines 3c and 3f.
11 Per Ex. F4-4-1, Table 3, line 7, cols. (i) to (l), revised to reflect minor corrections identified in Ex. L-A2-SEC-025.
12 Per App. A, Table 7, line 14, cols. (b) to (e).
13 Capital related revenue requirement for Working Capital and Cash Working for 2028-2031 is calculated as follows:

		2028	2029	2030	2031
13a	Working Capital and Cash Working Capital (App. A, Tables 3-6, col. (c): sum of lines 2 and 3)	903.2	970.3	1,038.1	1,083.5
13b	Cost of Capital: Common Equity (line 13a x 45% x 9.11%)	37.0	39.8	42.6	44.4
13c	Cost of Capital: Short-term Debt and Long-term Debt (line 13a x 55% x App. A, Tables 20-23, col. (c), line 4)	23.6	25.9	28.0	29.3
13d	Total Cost of Capital (lines 13b + 13c)	60.6	65.7	70.6	73.7
13e	Net Regulatory Taxable Income Increase / (Decrease) (line 13b)	37.0	39.8	42.6	44.4
13f	Income Tax Expense (line 13e x 25% / (1 - 25%))	12.3	13.3	14.2	14.8
13g	Total Working Capital and Cash Working Capital Revenue Requirement (line 13d + line 13f)	73.0	79.0	84.7	88.5

14 Per App. A, Tables 3-6: line 20, col. (c).
15 Per App. A, Tables 3-6: line 23, col. (c).
16 Per App. A, Tables 3-6, line 17, col. (b).
17 Capital related revenue requirement for Darlington and Operations & Project Support net of CEITCs and before other settlement adjustments for 2028-2031 is calculated as follows:

		2028	2029	2030	2031
17a	Darlington GS and Operations & Project Support Net Fixed Asset Rate Base excluding Net Fixed Asset Rate Base for which common equity is subject to return at the long-term debt rate: 2028: App. A, Table 17, col. (g): lines 14 & 19, less Table 18, col. (f): lines 14 & 19, less line 17b below; 2029: App. A, Table 17, col. (g): lines 27 & 32, less Table 18, col. (f): lines 27 & 32, less line 17b below; 2030: App. A, Table 17, col. (g): lines 40 & 45, less Table 18, col. (f): lines 40 & 45, less line 17b below; 2031: App. A, Table 17, col. (g): lines 53 & 58, less Table 18, col. (f): lines 53 & 58, less line 17b below.	4,426.5	4,658.4	5,370.6	6,218.2
17b	Darlington GS and Operations & Project Support Net Fixed Asset Rate Base for which equity is subject to return at long-term debt rate (EB-2020-0290 Settlement Adjustment)	127.1	114.6	103.7	95.5
17c	Return on Equity at ROE Rate (line 17a x 45% x 9.11%)	181.5	191.0	220.2	254.9
17d	EB-2020-0290 Settlement Adjustment for Equity at Long-Term Debt Rate (line 17b x 45% x App. A., Tables 20-23, line 5, col. (c))	2.7	2.5	2.3	2.1
17e	Cost of Debt ((line 17a + line 17b) x 55% x App. A, Tables 20-23, line 4, col. (c))	119.0	127.6	147.6	170.7
17f	Total Cost of Capital (lines 17c + 17d + 17e)	303.2	321.1	370.1	427.7
17g	Depreciation and Amortization Expense 2028: App. A, Table 18, lines 14 & 19, cols. (b) & (c); 2029: App. A, Table 18, lines 27 & 32, cols. (b) & (c); 2030: App. A, Table 18, lines 40 & 45, cols. (b) & (c); 2031: App. A, Table 18, lines 53 & 58, cols. (b) & (c).	255.1	276.4	317.5	366.9
17h	Net Regulatory Taxable Income Increase / (Decrease) (line 17c + line 17d + line 17g)	439.3	469.8	540.0	623.9
17i	Income Tax Expense (line 17h x 25% / (1 - 25%))	146.4	156.6	180.0	208.0

18 Capital related revenue reqiurement for Pickering net of CEITCs and before other settlement adjustments for 2028-2031 is calculated as follows:

		2028	2029	2030	2031
18a	Pickering GS Net Fixed Asset Rate Base excluding Net Fixed Asset Rate Base for which equity is subject to return at the long-term debt rate: 2028: App. A, Table 17, line 17, col. (g), less Table 18, line 17, col. (b), less line 18b below; 2029: App. A, Table 17, line 30, col. (g), less Table 18, line 30, col. (b), less line 18b below; 2030: App. A, Table 17, line 43, col. (g), less Table 18, line 43, col. (b), less line 18b below; 2031: App. A, Table 17, line 56, col. (g), less Table 18, line 56, col. (b), less line 18b below.	343.2	412.9	631.5	830.6
18b	Pickering GS Net Fixed Asset Rate Base for which equity is subject to return at long- term debt rate (EB-2020-0290 Settlement Adjustment)	0.0	0.0	0.0	0.0
18c	Return on Equity at ROE Rate (line 18a x 45% x 9.11%)	14.1	16.9	25.9	34.0
18d	EB-2020-0290 Settlement Adjustment for Equity at Long-Term Debt Rate (line 18b x 45% x App. A, Tables 20-23, line 5, col. (c))	0.0	0.0	0.0	0.0
18e	Cost of Debt ((line 18a + line 18b) x 55% x App. A, Tables 20-23, line 4, col. (c))	9.0	11.0	17.0	22.5
18f	Total Cost of Capital (lines 18c + 18d + 18e)	23.0	28.0	42.9	56.5
18g	Depreciation and Amortization Expense (per App. A, Table 18, cols. (b) & (c): lines 17,30, 43 and 56)	26.6	26.8	34.4	41.6
18h	Net Regulatory Taxable Income Increase / (Decrease) (line 18c + line 18d + line 18g)	40.7	43.8	60.3	75.6
18i	Income Tax Expense (line 18h x 25% / (1 - 25%))	13.6	14.6	20.1	25.2

19 Capital related revenue requirement for settlement adjustments to rate base other than CEITCs (Settlement Proposal, Section 2, Part B, i) for 2028-2031 is calculated as follows:

		2028	2029	2030	2031
19a	Settlement Adjustments other than CEITCs to OPG Nuclear Net Fixed Asset Rate Base 2028: App. A, Table 17, col. (g): lines 19 & 20, less Table 18, col. (f): lines 21 & 22; 2029: App. A, Table 17, col. (g): lines 31 & 32, less Table 18, col. (f): lines 34 & 35; 2030: App. A, Table 17, col. (g): lines 43 & 44, less Table 18, col. (f): lines 47 & 48; 2031: App. A, Table 17, col. (g): lines 55 & 56, less Table 18, col. (f): lines 60 & 61.	(180.5)	(279.7)	(493.1)	(572.0)
19b	Return on Equity at ROE Rate (line 19a x 45% x 9.11%)	(7.4)	(11.5)	(20.2)	(23.4)
19c	Cost of Debt (line 19a x 55% x App. A, Tables 20-23, line 4, col. (c))	(4.7)	(7.5)	(13.3)	(15.5)
19d	Total Cost of Capital (lines 19b + 19c)	(12.1)	(18.9)	(33.5)	(38.9)
19e	Depreciation and Amortization Expense 2028: App. A, Table 18, cols. (b) and (c): lines 21 & 22; 2029: App. A, Table 18, cols. (b) and (c): lines 34 & 35; 2030: App. A, Table 18, cols. (b) and (c): lines 47 & 48; 2031: App. A, Table 18, cols. (b) and (c): lines 60 & 61.	(8.5)	(13.5)	(22.0)	(27.1)
19f	Net Regulatory Taxable Income Increase / (Decrease) (line 19b + 19e)	(15.9)	(24.9)	(42.2)	(50.6)
19g	Income Tax Expense (line 19f x 25% / (1 - 25%))	(5.3)	(8.3)	(14.1)	(16.9)
19h	Total Capital Related Revenue Requirement Settlement Adjustments (line 19d + line 19e + line 19g)	(25.9)	(40.7)	(69.6)	(82.9)

20 Settlement adjusted capital cost allowance income tax component of the OPG nuclear capital related revenue requirement subject to stretch factor for 2028-2031 is calculated as follows:

		2028	2029	2030	2031
20a	Capital Cost Allowance (App. A, Tables 35-38, col. (c), line 15 less Darlington Refurbishment Program and Pickering Refurbishment Program CCA per App. A, Tables 35a-38a, Note 8)	(602.4)	(582.1)	(579.4)	(628.4)
20b	Income Tax Expense (line 20a x 25% / (1 - 25%))	(200.8)	(194.0)	(193.1)	(209.5)

21 Per App. A, Tables 3-6: line 27, col. (c).
22 Per Settlement Proposal, Section 2, Part A.
23 Ex. F3-2-1, Table 2, line 5, cols. (i) to (l).

Numbers may not add due to rounding.

Table 14a
Summary of Revenue Deficiency - Regulated Hydroelectric
January 1, 2027 to December 31, 2027

Line No.	Description	Note	2027
			(a)
1	**Forecast Production (TWh)**	1	32.9
2	**2026 Payment Amount per EB-2020-0290 ($/MWh)**	2	43.88
3	**Indicated Production Revenue ($M)** (line 1 x line 2)		1,444.2
4	**Revenue Requirement ($M)**	3	1,543.6
5	**Revenue Requirement Deficiency ($M)** (line 4 - line 3)		99.4

Notes:
1 Per App. B, Table 5, line 3, col. (b).
2 EB-2020-0290 Payment Amounts Order, App. B, Table 3, line 1, col. (f).
3 Per App. A, Table 1, line 22, col. (c).

Numbers may not add due to rounding.

Table 14b
Summary of Revenue Deficiency - OPG Nuclear
January 1, 2027 to December 31, 2031

Line No.	Description	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
1	**Forecast Production (TWh)**	1	19.3	27.6	25.8	27.7	29.9
2	**2026 Payment Amount per EB-2020-0290 ($/MWh)**	2	111.33	111.33	111.33	111.33	111.33
3	**Indicated Production Revenue ($M)** (line 1 x line 2)		2,153.4	3,069.0	2,874.1	3,080.9	3,333.6
4	**Revenue Requirement Net of Stretch Factor ($M)**	3	3,856.8	3,970.6	4,335.9	4,464.5	5,189.4
5	**Revenue Requirement Deficiency ($M)** (line 4 - line 3)		1,703.4	901.5	1,461.8	1,383.6	1,855.9

Notes:
1 Per App. B, Table 3, line 6, cols. (a) through (e).
2 EB-2020-0290 Payment Amounts Order, App. B, Table 3, line 4, col. (f).
3 Per App. A, Tables 2-6, line 30, col. (c).

Numbers may not add due to rounding.

Table 15
Continuity of Gross Property, Plant and Equipment - Regulated Hydroelectric ($M)
Years Ending December 31, 2027 to 2031

Line No.	Prescribed Facility Category	Note	Gross Opening Balance	In-Service Additions	Settlement Adjustment: CEITC Adjustments	Retirements, Transfers & Adjustments	(b)+(c)+(d) Net Change	(a)+(e) Closing Balance	(a+f)/2 Gross Plant Rate Base Amount
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
			Note 1	Note 1	Note 1	Note 1			Note 4
	2027:								
1	**Niagara Region**		5,090.1	167.1	(0.5)	(10.6)	156.0	5,246.1	5,176.1
2	**Eastern Region**		5,578.9	265.3	(19.7)	(3.3)	242.4	5,821.3	5,700.1
3	**Western Region**		1,616.1	410.7	(5.3)	(5.2)	400.2	2,016.3	1,849.2
4	**Other Settlement Adjustments**	2, 3	(59.5)	(106.3)	0.0	0.0	(106.3)	(165.8)	(112.6)
5	**Total**		12,225.6	736.8	(25.4)	(19.1)	692.3	12,917.9	12,612.9
	2028:	5							
6	**Niagara Region**		5,246.1	342.9	(1.7)	(12.6)	328.7	5,574.8	5,338.4
7	**Eastern Region**		5,821.3	465.5	(16.1)	(4.8)	444.6	6,265.9	6,029.7
8	**Western Region**		2,016.3	297.9	(29.3)	(2.4)	266.2	2,282.5	2,089.4
9	**Other Settlement Adjustments**	2, 3	(165.8)	(137.7)	0.0	0.0	(137.7)	(303.4)	(234.6)
10	**Total**		12,917.9	968.6	(47.0)	(19.8)	901.8	13,819.7	13,222.9
	2029:	5							
11	**Niagara Region**		5,574.8	567.7	(12.2)	(15.0)	540.5	6,115.3	5,937.0
12	**Eastern Region**		6,265.9	331.1	(11.0)	(2.4)	317.7	6,583.6	6,424.7
13	**Western Region**		2,282.5	218.3	(24.7)	(2.3)	191.4	2,473.9	2,378.2
14	**Other Settlement Adjustments**	2, 3	(303.4)	(139.0)	0.0	0.0	(139.0)	(442.4)	(372.9)
15	**Total**		13,819.7	978.1	(47.9)	(19.7)	910.6	14,730.3	14,367.0
	2030:	5							
16	**Niagara Region**		6,115.3	535.6	(17.2)	(14.0)	504.4	6,619.7	6,346.3
17	**Eastern Region**		6,583.6	219.4	(5.7)	(2.5)	211.2	6,794.8	6,689.2
18	**Western Region**		2,473.9	185.1	(2.4)	(3.7)	178.9	2,652.8	2,563.3
19	**Other Settlement Adjustments**	2, 3	(442.4)	(118.9)	0.0	0.0	(118.9)	(561.3)	(501.9)
20	**Total**		14,730.3	821.1	(25.2)	(20.3)	775.6	15,505.9	15,096.9
	2031:	5							
21	**Niagara Region**		6,619.7	48.5	(8.1)	(13.1)	27.3	6,647.0	6,633.4
22	**Eastern Region**		6,794.8	281.1	(5.2)	(2.3)	273.6	7,068.4	6,931.6
23	**Western Region**		2,652.8	298.9	(3.0)	(3.3)	292.6	2,945.4	2,799.1
24	**Other Settlement Adjustments**	2, 3	(561.3)	(79.6)	0.0	0.0	(79.6)	(640.9)	(601.1)
25	**Total**		15,505.9	549.0	(16.3)	(18.7)	514.1	16,020.0	15,763.0

For notes see Table 15a.

Numbers may not add due to rounding.

Table 15a
Notes to Table 15
Continuity of Gross Property, Plant and Equipment - Regulated Hydroelectric ($M)
Years Ending December 31, 2027 to 2031

1 Cols. (a) to (d) - except lines 4, 9, 14, 19, 24 - per Ex. L-F4-CCC-084, Att. 1, Table 2, cols. (a) to (d), respectively.

2 Settlement adjustment in col. (a), line 4 represents the following, as per the Settlement Proposal (Section 2, Part B, ii): a permanent 2027 opening rate base reduction of $40.0M and a reduction to rate base of $19.5M (as of 2025) to reflect lower than forecast actual regulated hydroelectric capital in-service additions for 2025. Settlement adjustments in col. (a), lines 9, 14, 19, and 24 comprise the cumulative impact of the above adjustments and the preceding years' settlement adjustments to forecast capital in-service additions per Note 3 below.

3 Settlement adjustments in col. (b) represent the following, as per the Settlement Proposal (Section 2, Part B, ii): a reduction of 13% to annual forecast Regulated Hydroelectric capital in-service additions net of CEITCs and a reduction of 11% to annual forecast Corporate Support Services capital in-service additions. The amounts are calculated as follows:

Line No.	Description	2027	2028	2029	2030	2031
3a	Regulated Hydroelectric (Ex. D1-1-2, Table 4, line 37, cols. (a) to (e))	(841.5)	(1,104.7)	(1,115.5)	(938.5)	(627.1)
3b	Regulated Hydroelectric - CEITC Adjustments (Ex. L-F4-CCC-084, Att. 1, Table 2, col. (c): lines 4, 8, 12, 16, 20)	25.4	47.0	47.9	25.2	16.3
3c	Regulated Hydroelectric net of CEITC Adjustments (line 3a + line 3b) x 13%	(106.1)	(137.5)	(138.8)	(118.7)	(79.4)
3d	Corporate Support Services (Ex. D3-1-2, Table 5a, line 23, cols. (j) and (l); Table 5b, line 2, cols. (c), (e), and (g)) x 11%	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
3e	Total Settlement Adjustment to Forecasted Regulated Hydrolectric Capital In-Service Additions (line 3c + line 3d)	(106.3)	(137.7)	(139.0)	(118.9)	(79.6)

4 Except lines 4, 9, 14, 19, and 24, in-service addition amounts included in col. (b) that are individually equal to or higher than $50M and any associated CEITC adjustment amounts in that year in col. (c) are applied to the gross plant rate base calculation at at the forecast in-service month, per Ex. L-F4-CCC-084, Att. 1, Table 3, Note 1. The settlement adjustments in lines 4, 9, 14, 19, and 24, col. (b) are applied to the gross plant rate base calculation at the mid-year average.

5 Rate base amounts for 2028-2031 are reflected in the capital related revenue requirement used in the determination of the Custom Capital Factor in App. B, Table 2 (Settlement Proposal, Section 2, Part A).

Numbers may not add due to rounding.

Table 16
Continuity of Accumulated Depreciation and Amortization - Regulated Hydroelectric ($M)
Years Ending December 31, 2027 to 2031

Line No.	Prescribed Facility Category	Note	Opening Balance	Depreciation and Amortization	Settlement Adjustment: CEITC Adjustment on Depreciation and Amortization	Retirements, Transfers & Adjustments	(a)+(b)+(c)+(d) Closing Balance	(a+e)/2 Accumulated Depreciation and Amortization Rate Base Amount
			(a)	(b)	(c)	(d)	(e)	(f)
			Note 1	Note 1	Note 1	Note 1		
	2027:							
1	**Niagara Region**		1,409.8	70.2	(0.0)	0.0	1,479.9	1,444.8
2	**Eastern Region**		1,674.8	96.6	(0.2)	0.0	1,771.2	1,723.0
3	**Western Region**		442.9	29.5	(0.1)	0.0	472.3	457.6
4	**Other Settlement Adjustments**	2, 3	(0.5)	(1.9)	0.0	0.0	(2.4)	(1.4)
5	**Total**		3,527.0	194.4	(0.3)	0.0	3,721.1	3,624.0
	2028:	4						
6	**Niagara Region**		1,479.9	72.9	(0.0)	0.0	1,552.8	1,516.4
7	**Eastern Region**		1,771.2	102.2	(0.5)	0.0	1,872.9	1,822.0
8	**Western Region**		472.3	33.5	(0.1)	0.0	505.7	489.0
9	**Other Settlement Adjustments**	2, 3	(2.4)	(4.0)	0.0	0.0	(6.3)	(4.4)
10	**Total**		3,721.1	204.6	(0.6)	0.0	3,925.1	3,823.1
	2029:	4						
11	**Niagara Region**		1,552.8	82.7	(0.2)	0.0	1,635.3	1,594.1
12	**Eastern Region**		1,872.9	108.4	(0.7)	0.0	1,980.6	1,926.7
13	**Western Region**		505.7	38.9	(0.8)	0.0	543.8	524.7
14	**Other Settlement Adjustments**	2, 3	(6.3)	(6.3)	0.0	0.0	(12.6)	(9.5)
15	**Total**		3,925.1	223.7	(1.7)	0.0	4,147.1	4,036.1
	2030:	4						
16	**Niagara Region**		1,635.3	89.3	(0.4)	0.0	1,724.2	1,679.7
17	**Eastern Region**		1,980.6	112.2	(0.9)	0.0	2,091.9	2,036.3
18	**Western Region**		543.8	41.9	(1.0)	0.0	584.7	564.2
19	**Other Settlement Adjustments**	2, 3	(12.6)	(8.5)	0.0	0.0	(21.1)	(16.9)
20	**Total**		4,147.1	234.8	(2.3)	0.0	4,379.6	4,263.3
	2031:	4						
21	**Niagara Region**		1,724.2	93.6	(0.6)	0.0	1,817.2	1,770.7
22	**Eastern Region**		2,091.9	114.9	(0.9)	0.0	2,205.8	2,148.9
23	**Western Region**		584.7	44.5	(1.1)	0.0	628.1	606.4
24	**Other Settlement Adjustments**	2, 3	(21.1)	(10.2)	0.0	0.0	(31.3)	(26.2)
25	**Total**		4,379.6	242.9	(2.6)	0.0	4,619.9	4,499.8

For notes see Table 16a.

Table 16a
Notes to Table 16
Continuity of Accumulated Depreciation and Amortization - Regulated Hydroelectric ($M)
Years Ending December 31, 2027 to 2031

1 Cols. (a) to (d) - except lines 4, 9, 14, 19, 24 - per Ex. L-F4-CCC-084, Att. 1, Table 4, cols. (a) to (e), respectively. Col (b) is the sum of Ex. L-F4-CCC-084, Att. 1, Table 4, cols. (b) and (c).

2 Settlement adjustment in col. (a), line 4 represents the 2025 and forecast 2026 depreciation and amortization impact of the $19.5M reduction to gross plant (as of 2025) to reflect lower than forecast actual regulated hydroelectric capital in-service additions for 2025 (Settlement Proposal, Section 2, Part B, ii). Settlement adjustments in col. (a), lines 9, 14, 19, and 24 comprise the above adjustment and the preceding years' cumulative settlement adjustments to depreciation and amortization per Note 3 below.

3 Settlement adjustments in col. (b) represent the forecast annual depreciation and amortization impacts resulting from the applicable Settlement Proposal adjustments to the 2027-2031 rate base per App. A, Table 15, lines 4, 9, 14, 19, and 24.

4 Rate base amounts for 2028-2031 are reflected in the capital related revenue requirement used in the determination of the Custom Capital Factor in App. B, Table 2 (Settlement Proposal, Section 2, Part A).

Numbers may not add due to rounding.

Table 17
Continuity of Gross Property, Plant and Equipment - OPG Nuclear and DNNP LP ($M)
Years Ending December 31, 2027 to 2031

Line No.	Prescribed Facility Category	Note	Gross Plant Opening Balance	In-Service Additions	Settlement Adjustment: CEITC Adjustments	Retirements, Transfers & Adjustments	(b)+(c)+(d) Net Change	(a)+(e) Closing Balance	(a+f)/2 Gross Plant Rate Base Amount
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
			Note 1	Note 1	Note 1	Note 1			Note 6
	2027:								
1	**Darlington NGS (excluding DRP)**		4,648.5	826.9	(10.0)	0.0	816.9	5,465.4	4,966.5
2	**Darlington Refurbishment Program (DRP) (excluding D2O Storage)**		11,906.5	0.0	(249.1)	0.0	(249.1)	11,657.4	11,781.9
3	**Heavy Water Storage Facility (D2O Storage)**		395.6	0.0	0.0	0.0	0.0	395.6	395.6
4	**Pickering NGS (excluding PRP)**		2,882.5	119.1	0.0	0.0	119.1	3,001.6	2,942.0
5	**Pickering Refurbishment Program (PRP)**		159.3	20.6	(0.4)	0.0	20.2	179.5	169.4
6	**Operations and Project Support**		812.8	36.0	0.0	0.0	36.0	848.7	830.8
7	**Settlement Adjustment: DRP Updated Estimate**	4	(50.0)	0.0	0.0	0.0	0.0	(50.0)	(50.0)
8	**Settlement Adjustment: Rate Base Inclusion Timing of Specified Pickering NGS Capital**	5	0.0	(0.5)	0.0	0.0	(0.5)	(0.5)	(0.3)
9	**Other Settlement Adjustments**	2, 3	(40.0)	(98.5)	0.0	0.0	(98.5)	(138.5)	(89.2)
10	**OPG Nuclear Facilities - Excluding Asset Retirement Costs**		20,715.2	903.5	(259.5)	0.0	644.0	21,359.2	20,946.8
11	**Asset Retirement Costs**		3,104.7	0.0	0.0	0.0	0.0	3,104.7	3,104.7
12	**Total OPG Nuclear Facilities**		23,819.9	903.5	(259.5)	0.0	644.0	24,463.9	24,051.5
13	**DNNP LP - Darlington New Nuclear Program**		0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2028:								
14	**Darlington NGS (excluding DRP)**		5,465.4	741.5	(16.2)	0.0	725.3	6,190.7	5,940.9
15	**Darlington Refurbishment Program (DRP) (excluding D2O Storage)**		11,657.4	0.0	0.0	0.0	0.0	11,657.4	11,657.4
16	**Heavy Water Storage Facility (D2O Storage)**		395.6	0.0	0.0	0.0	0.0	395.6	395.6
17	**Pickering NGS (excluding PRP)**		3,001.6	90.6	0.0	0.0	90.6	3,092.2	3,046.9
18	**Pickering Refurbishment Program (PRP)**		179.5	0.0	0.0	0.0	0.0	179.5	179.5
19	**Operations and Project Support**		848.7	29.7	0.0	0.0	29.7	878.5	863.6
20	**Settlement Adjustment: DRP Updated Estimate**	4	(50.0)	0.0	0.0	0.0	0.0	(50.0)	(50.0)
21	**Settlement Adjustment: Rate Base Inclusion Timing of Specified Pickering NGS Capital**	5	(0.5)	(15.7)	0.0	0.0	(15.7)	(16.2)	(8.4)
22	**Other Settlement Adjustments**	2, 3	(138.5)	(83.6)	0.0	0.0	(83.6)	(222.1)	(180.3)
23	**OPG Nuclear Facilities - Excluding Asset Retirement Costs**		21,359.2	762.6	(16.2)	0.0	746.4	22,105.5	21,845.3
24	**Asset Retirement Costs**		3,104.7	0.0	0.0	0.0	0.0	3,104.7	3,104.7
25	**Total OPG Nuclear Facilities**		24,463.9	762.6	(16.2)	0.0	746.4	25,210.3	24,950.0
26	**DNNP LP - Darlington New Nuclear Program**		0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2029:								
27	**Darlington NGS (excluding DRP)**		6,190.7	936.6	(26.9)	0.0	909.7	7,100.4	6,394.8
28	**Darlington Refurbishment Program (DRP) (excluding D2O Storage)**		11,657.4	0.0	0.0	0.0	0.0	11,657.4	11,657.4
29	**Heavy Water Storage Facility (D2O Storage)**		395.6	0.0	0.0	0.0	0.0	395.6	395.6
30	**Pickering NGS (excluding PRP)**		3,092.2	102.2	(0.1)	0.0	102.1	3,194.3	3,143.3
31	**Pickering Refurbishment Program (PRP)**		179.5	0.0	0.0	0.0	0.0	179.5	179.5
32	**Operations and Project Support**		878.5	32.9	0.0	0.0	32.9	911.4	894.9
33	**Settlement Adjustment: DRP Updated Estimate**	4	(50.0)	0.0	0.0	0.0	0.0	(50.0)	(50.0)
34	**Settlement Adjustment: Rate Base Inclusion Timing of Specified Pickering NGS Capital**	5	(16.2)	(17.6)	0.0	0.0	(17.6)	(33.8)	(25.0)
35	**Other Settlement Adjustments**	2, 3	(222.1)	(103.4)	0.0	0.0	(103.4)	(325.5)	(273.8)
36	**OPG Nuclear Facilities - Excluding Asset Retirement Costs**		22,105.5	950.8	(27.0)	0.0	923.7	23,029.3	22,316.7
37	**Asset Retirement Costs**		3,104.7	0.0	0.0	0.0	0.0	3,104.7	3,104.7
38	**Total OPG Nuclear Facilities**		25,210.3	950.8	(27.0)	0.0	923.7	26,134.0	25,421.4
39	**DNNP LP - Darlington New Nuclear Program**		0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2030:								
40	**Darlington NGS (excluding DRP)**		7,100.4	1,059.2	(53.4)	0.0	1,005.8	8,106.2	7,340.9
41	**Darlington Refurbishment Program (DRP) (excluding D2O Storage)**		11,657.4	0.0	0.0	0.0	0.0	11,657.4	11,657.4
42	**Heavy Water Storage Facility (D2O Storage)**		395.6	0.0	0.0	0.0	0.0	395.6	395.6
43	**Pickering NGS (excluding PRP)**		3,194.3	348.9	(1.6)	0.0	347.3	3,541.5	3,392.5
44	**Pickering Refurbishment Program (PRP)**		179.5	0.0	0.0	0.0	0.0	179.5	179.5
45	**Operations and Project Support**		911.4	71.4	0.0	0.0	71.4	982.7	947.1
46	**Settlement Adjustment: DRP Updated Estimate**	4	(50.0)	0.0	0.0	0.0	0.0	(50.0)	(50.0)
47	**Settlement Adjustment: Rate Base Inclusion Timing of Specified Pickering NGS Capital**	5	(33.8)	(220.2)	0.0	0.0	(220.2)	(254.0)	(143.9)
48	**Other Settlement Adjustments**	2, 3	(325.5)	(121.1)	0.0	0.0	(121.1)	(446.6)	(386.1)
49	**OPG Nuclear Facilities - Excluding Asset Retirement Costs**		23,029.3	1,138.1	(55.0)	0.0	1,083.1	24,112.3	23,332.9
50	**Asset Retirement Costs**		3,104.7	0.0	0.0	0.0	0.0	3,104.7	3,104.7
51	**Total OPG Nuclear Facilities**		26,134.0	1,138.1	(55.0)	0.0	1,083.1	27,217.1	26,437.7
52	**DNNP LP - Darlington New Nuclear Program**		0.0	6,584.9	(649.5)	0.0	5,935.4	5,935.4	1,236.5
	2031:								
53	**Darlington NGS (excluding DRP)**		8,106.2	768.2	(58.6)	0.0	709.6	8,815.8	8,461.0
54	**Darlington Refurbishment Program (DRP) (excluding D2O Storage)**		11,657.4	0.0	0.0	0.0	0.0	11,657.4	11,657.4
55	**Heavy Water Storage Facility (D2O Storage)**		395.6	0.0	0.0	0.0	0.0	395.6	395.6
56	**Pickering NGS (excluding PRP)**		3,541.5	178.6	(2.6)	0.0	176.0	3,717.5	3,629.5
57	**Pickering Refurbishment Program (PRP)**		179.5	9,688.0	(1,005.3)	0.0	8,682.7	8,862.2	5,606.2
58	**Operations and Project Support**		982.7	51.5	0.0	0.0	51.5	1,034.3	1,008.5
59	**Settlement Adjustment: DRP Updated Estimate**	4	(50.0)	0.0	0.0	0.0	0.0	(50.0)	(50.0)
60	**Settlement Adjustment: Rate Base Inclusion Timing of Specified Pickering NGS Capital**	5	(254.0)	254.0	0.0	0.0	254.0	0.0	(127.0)
61	**Other Settlement Adjustments**	2, 3	(446.6)	(119.5)	0.0	0.0	(119.5)	(566.1)	(506.4)
62	**OPG Nuclear Facilities - Excluding Asset Retirement Costs**		24,112.3	10,820.9	(1,066.5)	0.0	9,754.3	33,866.7	30,074.8
63	**Asset Retirement Costs**		3,104.7	0.0	0.0	0.0	0.0	3,104.7	3,104.7
64	**Total OPG Nuclear Facilities**		27,217.1	10,820.9	(1,066.5)	0.0	9,754.3	36,971.4	33,179.6
65	**DNNP LP - Darlington New Nuclear Program**		5,935.4	0.0	0.0	0.0	0.0	5,935.4	5,935.4

For notes see Table 17a.

Numbers may not add due to rounding.

Table 17a
Notes to Table 17
Continuity of Gross Property, Plant and Equipment - OPG Nuclear and DNNP LP ($M)
Years Ending December 31, 2027 to December 31, 2031

1 Cols. (a) to (d) - except lines 7-9, 20-22, 33-35, 46-48, and 59-61 - per Ex. L-F4-CCC-084, Att. 1, Table 7, cols. (a) to (d), respectively.

2 Settlement adjustment in line 9, col. (a) represents a permanent 2027 opening rate base reduction of $40.0M (Settlement Proposal, Section 2, Part B, (i)). Settlement adjustments in col. (a), lines 22, 35, 48, and 61 comprise the cumulative impact of the above adjustments and the preceding years' settlement adjustments to forecast capital in-service additions per Note 3 below.

3 Settlement adjustments in col. (b), lines 9, 22, 35, 48, and 61 represent the following, as per the Settlement Proposal (Section 2, Part B, i): a reduction of 10% to annual forecast Nuclear Operations capital in-service additions net of CEITCs, and a reduction of 11% to annual forecast Corporate Support Services capital in-service additions. The amounts are calculated as follows:

Line No.	Description	2027	2028	2029	2030	2031
3a	Darlington NGS, excluding DRP (Ex. D2-1-3, Table 4a, cols. (j) and (l), lines 26, 30, 35-38, 41-43, 45; Table 4b, cols. (c), (e), (g): lines 52, 56, 61-64, 67-69, 71)	(729.5)	(698.4)	(897.9)	(1,039.8)	(750.0)
3b	Darlington NGS, excluding DRP - CEITC Adjustments (Ex. L-F4-CCC-084, Att. 1, Table 7, col. (c), lines 1, 13, 25, 37, 49)	10.0	16.2	26.9	53.4	58.6
3c	Darlington NGS, excluding DRP, net of CEITC Adjustments (3a + 3b) x 10%	(72.0)	(68.2)	(87.1)	(98.6)	(69.1)
3d	Pickering NGS, excluding PRP (Ex. D2-1-3, Table 4a, cols. (j) and (l), lines 27, 31, 39, 44, 46; Table 4b, cols. (c), (e), (g): lines 53, 57, 65, 70, 72 minus Table 17, col. (b), lines 8, 21, 34, 47, 60)	(82.1)	(55.9)	(56.2)	(76.6)	(411.1)
3e	Pickering NGS, excluding PRP - CEITC Adjustments (Ex. L-F4-CCC-084, Att. 1, Table 7, col. (c): lines 5, 17, 29, 41, 53)	0.0	0.0	0.1	1.6	2.6
3f	Pickering NGS, excluding PRP, net of CEITC Adjustments (3d + 3e) x 10%	(8.2)	(5.6)	(5.6)	(7.5)	(40.8)
3g	Operations and Project Support (Ex. D2-1-3, Table 4a, cols. (j) and (l), lines 28, 32, and 47; Table 4b, cols. (c), (e), (g): lines 54, 58, 73) x 10%	(3.6)	(3.0)	(3.3)	(7.1)	(5.2)
3h	Nuclear Operations In-Service Capital 10% Reduction (line 3c + line 3f + line 3g)	(83.8)	(76.8)	(96.0)	(113.3)	(115.1)
3i	Corporate Support Services (Ex. D3-1-2, Table 5a, cols. (j) and (l), lines 22 and 27; Table 5b, cols. (c), (e), and (g): lines 1 and 6) x 11%	(14.7)	(6.8)	(7.4)	(7.9)	(4.4)
3j	Total Settlement Adjustment to Forecasted OPG Nuclear Capital In-Service Additions (line 3h + line 3i +line 3j)	(98.5)	(83.6)	(103.4)	(121.1)	(119.5)

4 Settlement adjustment represents a $50.0M reduction to gross plant (as of 2026) to reflect OPG's updated, lower total cost forecast of $12.65B for the Darlington Refurbishment Program since the filing of the Application (Settlement Proposal, Section 2, Part B, (i)).

5 Settlement adjustment represents changes to forecast timing of rate base inclusion of certain Nuclear Operations in-service capital amounts tied to Pickering from 2027-2030 to 2031 (Settlement Proposal, Section 2, Part B, (i)).

6 Except lines 7-9, 20-22, 33-35, 46-48, and 59-61, in-service addition amounts included in col. (b) that are individually equal or higher than $50M and any associated CEITC adjustment amounts in that year in col. (c) are applied to the gross plant rate base calculation at the forecast in-service month, per Ex. L-F4-CCC-084, Att. 1, Table 8, Note 1. The settlement adjustments in lines 8, 9, 21, 22, 34, 35, 47, 48, 60, and 61, col. (b) are applied to the gross plant rate base calculation at the mid-year average.

Numbers may not add due to rounding.

Table 18
Continuity of Accumulated Depreciation and Amortization - OPG Nuclear and DNNP LP ($M)
Years Ending December 31, 2027 to 2031

Line No.	Prescribed Facility Category	Note	Opening Balance	Depreciation and Amortization	Settlement Adjustment: CEITC Adjustment on Depreciation and Amortization	Retirements, Transfers & Adjustments	(a)+(b)+(c)+(d) Closing Balance	(a+e)/2 Accumulated Depreciation and Amortization Rate Base Amount
			(a)	(b)	(c)	(d)	(e)	(f)
			Note 1	Note 1	Note 1	Note 1		
	2027:							
1	**Darlington NGS (excluding DRP)**		1,364.8	178.6	(0.1)	0.0	1,543.3	1,454.0
2	**Darlington Refurbishment Program (DRP) (excluding D2O Storage)**		1,800.6	398.5	(4.9)	0.0	2,194.2	1,997.4
3	**Heavy Water Storage Facility (D2O Storage)**		83.3	12.0	0.0	0.0	95.3	89.3
4	**Pickering NGS (excluding PRP)**		2,668.8	21.5	0.0	0.0	2,690.3	2,679.6
5	**Pickering Refurbishment Program (PRP)**		1.2	3.8	(0.0)	0.0	5.0	3.1
6	**Operations and Project Support**		542.6	37.5	0.0	0.0	580.1	561.3
7	**Settlement Adjustment: DRP Updated Estimate**	2	(1.3)	(1.9)	0.0	0.0	(3.2)	(2.3)
8	**Settlement Adjustment: Rate Base Inclusion Timing of Specified Pickering NGS Capital**	3	0.0	(0.0)	0.0	0.0	(0.0)	(0.0)
9	**Other Settlement Adjustments**	4	0.0	(3.9)	0.0	0.0	(3.9)	(2.0)
10	**OPG Nuclear Facilities - Excluding Asset Retirement Costs**		6,460.0	646.1	(5.0)	0.0	7,101.1	6,780.6
11	**Asset Retirement Costs**		2,605.4	11.3	0.0	0.0	2,616.8	2,611.1
12	**Total OPG Nuclear Facilities**		9,065.4	657.5	(5.0)	0.0	9,717.9	9,391.6
13	**DNNP LP - Darlington New Nuclear Program**		0.0	0.0	0.0	0.0	0.0	0.0
	2028:							
14	**Darlington NGS (excluding DRP)**		1,543.3	219.6	(0.9)	0.0	1,762.0	1,652.6
15	**Darlington Refurbishment Program (DRP) (excluding D2O Storage)**		2,194.2	398.5	(9.7)	0.0	2,583.0	2,388.6
16	**Heavy Water Storage Facility (D2O Storage)**		95.3	12.0	0.0	0.0	107.3	101.3
17	**Pickering NGS (excluding PRP)**		2,690.3	26.6	0.0	0.0	2,716.9	2,703.6
18	**Pickering Refurbishment Program (PRP)**		5.0	4.1	(0.0)	0.0	9.1	7.1
19	**Operations and Project Support**		580.1	36.4	0.0	0.0	616.5	598.3
20	**Settlement Adjustment: DRP Updated Estimate**	2	(3.2)	(1.9)	0.0	0.0	(5.1)	(4.1)
21	**Settlement Adjustment: Rate Base Inclusion Timing of Specified Pickering NGS Capital**	3	(0.0)	(0.2)	0.0	0.0	(0.2)	(0.1)
22	**Other Settlement Adjustments**	4	(3.9)	(8.3)	0.0	0.0	(12.2)	(8.1)
23	**OPG Nuclear Facilities - Excluding Asset Retirement Costs**		7,101.1	686.8	(10.6)	0.0	7,777.3	7,439.2
24	**Asset Retirement Costs**		2,616.8	11.3	0.0	0.0	2,628.1	2,622.4
25	**Total OPG Nuclear Facilities**		9,717.9	698.1	(10.6)	0.0	10,405.4	10,061.7
26	**DNNP LP - Darlington New Nuclear Program**		0.0	0.0	0.0	0.0	0.0	0.0
	2029:							
27	**Darlington NGS (excluding DRP)**		1,762.0	242.6	(1.3)	0.0	2,003.3	1,882.6
28	**Darlington Refurbishment Program (DRP) (excluding D2O Storage)**		2,583.0	398.4	(9.7)	0.0	2,971.6	2,777.3
29	**Heavy Water Storage Facility (D2O Storage)**		107.3	12.0	0.0	0.0	119.3	113.3
30	**Pickering NGS (excluding PRP)**		2,716.9	26.8	(0.0)	0.0	2,743.8	2,730.4
31	**Pickering Refurbishment Program (PRP)**		9.1	4.1	(0.0)	0.0	13.1	11.1
32	**Operations and Project Support**		616.5	35.1	0.0	0.0	651.6	634.1
33	**Settlement Adjustment: DRP Updated Estimate**	2	(5.1)	(1.9)	0.0	0.0	(6.9)	(6.0)
34	**Settlement Adjustment: Rate Base Inclusion Timing of Specified Pickering NGS Capital**	3	(0.2)	(0.6)	0.0	0.0	(0.8)	(0.5)
35	**Other Settlement Adjustments**	4	(12.2)	(12.9)	0.0	0.0	(25.1)	(18.6)
36	**OPG Nuclear Facilities - Excluding Asset Retirement Costs**		7,777.3	703.6	(11.0)	0.0	8,469.9	8,123.6
37	**Asset Retirement Costs**		2,628.1	11.3	0.0	0.0	2,639.5	2,633.8
38	**Total OPG Nuclear Facilities**		10,405.4	715.0	(11.0)	0.0	11,109.4	10,757.4
39	**DNNP LP - Darlington New Nuclear Program**		0.0	0.0	0.0	0.0	0.0	0.0
	2030:							
40	**Darlington NGS (excluding DRP)**		2,003.3	283.8	(2.5)	0.0	2,284.5	2,143.9
41	**Darlington Refurbishment Program (DRP) (excluding D2O Storage)**		2,971.6	398.0	(9.7)	0.0	3,359.8	3,165.7
42	**Heavy Water Storage Facility (D2O Storage)**		119.3	12.0	0.0	0.0	131.3	125.3
43	**Pickering NGS (excluding PRP)**		2,743.8	34.4	(0.0)	0.0	2,778.2	2,761.0
44	**Pickering Refurbishment Program (PRP)**		13.1	4.1	(0.0)	0.0	17.2	15.2
45	**Operations and Project Support**		651.6	36.3	0.0	0.0	687.9	669.7
46	**Settlement Adjustment: DRP Updated Estimate**	2	(6.9)	(1.9)	0.0	0.0	(8.8)	(7.9)
47	**Settlement Adjustment: Rate Base Inclusion Timing of Specified Pickering NGS Capital**	3	(0.8)	(3.6)	0.0	0.0	(4.4)	(2.6)
48	**Other Settlement Adjustments**	4	(25.1)	(18.4)	0.0	0.0	(43.5)	(34.3)
49	**OPG Nuclear Facilities - Excluding Asset Retirement Costs**		8,469.9	744.6	(12.3)	0.0	9,202.3	8,836.1
50	**Asset Retirement Costs**		2,639.5	11.3	0.0	0.0	2,650.8	2,645.1
51	**Total OPG Nuclear Facilities**		11,109.4	756.0	(12.3)	0.0	11,853.1	11,481.2
52	**DNNP LP - Darlington New Nuclear Program**		0.0	22.6	(2.2)	0.0	20.4	10.2
	2031:							

53	**Darlington NGS (excluding DRP)**		2,284.5	336.0	(6.0)	0.0	2,614.5	2,449.5
54	**Darlington Refurbishment Program (DRP) (excluding D2O Storage)**		3,359.8	398.0	(9.7)	0.0	3,748.0	3,553.9
55	**Heavy Water Storage Facility (D2O Storage Project)**		131.3	12.0	0.0	0.0	143.4	137.4
56	**Pickering NGS (excluding PRP)**		2,778.2	41.6	(0.1)	0.0	2,819.8	2,799.0
57	**Pickering Refurbishment Program (PRP)**		17.2	156.7	(15.7)	0.0	158.2	87.7
58	**Operations and Project Support**		687.9	36.9	0.0	0.0	724.8	706.3
59	**Settlement Adjustment: DRP Updated Estimate**	2	(8.8)	(1.9)	0.0	0.0	(10.7)	(9.8)
60	**Settlement Adjustment: Rate Base Inclusion Timing of Specified Pickering NGS Capital**	3	(4.4)	(3.1)	0.0	0.0	(7.4)	(5.9)
61	**Other Settlement Adjustments**	4	(43.5)	(24.1)	0.0	0.0	(67.6)	(55.5)
62	**OPG Nuclear Facilities - Excluding Asset Retirement Costs**		9,202.3	952.2	(31.6)	0.0	10,122.9	9,662.6
63	**Asset Retirement Costs**		2,650.8	11.3	0.0	0.0	2,662.2	2,656.5
64	**Total OPG Nuclear Facilities**		11,853.1	963.6	(31.6)	0.0	12,785.1	12,319.1
65	**DNNP LP - Darlington New Nuclear Program**		20.4	109.7	(10.8)	0.0	119.3	69.9

For notes see Table 18a.

Table 18a
Notes to Table 18
Continuity of Accumulated Depreciation and Amortization - OPG Nuclear and DNNP LP ($M)
Years Ending December 31, 2027 to December 31, 2031

1 Cols. (a) to (d) - except lines 7-9, 20-22, 33-35, 46-48, and 59-61 - per Ex. L-F4-CCC-084, Att. 1, Table 9, cols. (a) to (e), respectively. Col (b) is the sum of Ex. L-F4-CCC-084, Att. 1, Table 9, cols. (b) and (c).

2 Settlement adjustment represents the forecast depreciation and amortization impact of the $50.0M reduction to gross plant (as of 2026) to reflect OPG's updated, lower total costs forecast of $12.65B for the Darlington Refurbishment Program since the filing of the Application (Settlement Proposal, Section 2, Part B, (i)).

3 Settlement adjustment represents the forecast depreciation and amortization impact of thr changes to forecast timing of rate base inclusion of certain Nuclear Operations in-service capital amounts tied to Pickering from 2027-2030 to 2031 (Settlement Proposal, Section 2, Part B, (i)).

4 Settlement adjustments represent the forecast depreciation and amortization impacts resulting from the applicable Settlement Proposal adjustments to 2027-2031 rate base per App. A, Table 17, lines 9, 22, 35, 48, and 61.

Numbers may not add due to rounding.

Table 19
Summary of Capitalization and Cost of Capital - OPG
Year Ending December 31, 2027

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1, 3, 6	414.3	1.70%	2.79%	21.0
2	**Existing/Planned Long-Term Debt**	2, 4, 6	6,292.1	25.79%	4.56%	287.1
3	**Other Long-Term Debt Provision**	2, 6, 10	6,712.2	27.51%	4.56%	306.2
4	**Total Debt**	5	13,418.6	55.0%	4.58%	614.3
5	**EB-2020-0290 Settlement Adjustment for Equity at Long-Term Debt Rate**	2, 3, 9	64.0	0.26%	4.56%	2.9
5a	**Common Equity**	1, 6, 8	10,914.9	44.74%	9.11%	994.3
5b	**Total Equity**	5	10,978.9	45.0%	9.08%	997.3
6	**Rate Base Financed by Capital Structure**		24,397.5	99.6%	6.61%	1,611.5
7	**Adjustment for Lesser of UNL or ARC**	1, 3	100.1	0.4%	4.72%	4.7
8	**Rate Base**	7	24,497.5	100%	6.60%	1,616.3

Notes:

1 Col. (c) as proposed by OPG in Ex. C1-1-1, Tables 1-5 (Settlement Proposal, Section 2, Part B, iii).

2 Col. (c) per Ex. L-F4-CCC-084, Att. 1, Table 15, line 31, col. (e) (Settlement Proposal, Section 2, Part B, iii).

3 Col. (a) per Ex. C1-1-1, Tables 1-5.

4 Col. (a) per Ex. L-F4-CCC-084, Att. 1, Table 15, line 31, col. (a) (Settlement Proposal, Section 2, Part B, iii).

5 The Debt / Equity ratio of 55% debt, 45% equity as per Settlement Proposal, Section 2, Part B, iii.

6 Capitalization and cost of capital is allocated to regulated hydroelectric facilities and OPG's nuclear facilities using rate base financed by capital structure (Regulated hydroelectric per App. B, Table 2, Note 3, line 3c; OPG nuclear per App. A, Tables 2-6: line 4 less line 9).

7 Col. (a) is the sum of App. A, Table 1, line 4, col. (c) and App. A, Table 2, line 4, col. (c).

8 The return on equity rate of 9.11% in col. (c) is per the OEB 2026 Cost of Capital Parameter Update Letter, October 31, 2025, and is subject to update for the prevailing ROE rate specified by the OEB as of the effective date of the final payment amounts order in this proceeding (Settlement Proposal, Section 2, Part B, iii).

9 Represents the portion of rate base financed by equity that is subject to return at the long-term debt rate until the end of 2036 per the EB-2020-0290 settlement proposal approved by the OEB (EB-2020-0290 Decision and Order, Schedule A, p. 23).

10 Debt required to balance capital structure with rate base.

Numbers may not add due to rounding.

Table 20
Summary of Capitalization and Cost of Capital - OPG
Year Ending December 31, 2028

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1, 3, 6	414.3	1.6%	2.93%	19.5
2	**Existing/Planned Long-Term Debt**	2, 4, 6	7,783.0	30.9%	4.75%	370.0
3	**Other Long-Term Debt Provision**	2, 6, 10	5,656.0	22.5%	4.75%	268.9
4	**Total Debt**	5	13,853.3	55.0%	4.75%	658.4
5	**EB-2020-0290 Settlement Adjustment for Equity at Long-Term Debt Rate**	2, 3, 9	57.2	0.2%	4.75%	2.7
5a	**Common Equity**	1, 6, 8	11,277.3	44.8%	9.11%	1,027.4
5b	**Total Equity**	5	11,334.5	45.0%	9.09%	1,030.1
6	**Rate Base Financed by Capital Structure**		25,187.8	99.9%	6.70%	1,688.5
7	**Adjustment for Lesser of UNL or ARC**	1, 3	23.0	0.1%	4.72%	1.1
8	**Rate Base**	7	25,210.9	100%	6.70%	1,689.6

Notes:

1 Col. (c) as proposed by OPG in Ex. C1-1-1, Tables 1-5 (Settlement Proposal, Section 2, Part B, iii).

2 Col. (c) per Ex. L-F4-CCC-084, Att. 1, Table 17, line 33, col. (e) (Settlement Proposal, Section 2, Part B, iii).

3 Col. (a) per Ex. C1-1-1, Tables 1-5.

4 Col. (a) per Ex. L-F4-CCC-084, Att. 1, Table 17, line 33, col. (a) (Settlement Proposal, Section 2, Part B, iii).

5 The Debt / Equity ratio of 55% debt, 45% equity as per Settlement Proposal, Section 2, Part B, iii.

6 Capitalization and cost of capital is allocated to regulated hydroelectric facilities and OPG's nuclear facilities using rate base financed by capital structure (Regulated hydroelectric per App. B, Table 2, Note 3, line 3c; OPG nuclear per App. A, Tables 2-6: line 4 less line 9).

7 Col. (a) is the sum of App. A, Table 3, line 4, col. (c) and App. B, Table 2, Note 3, line 3c.

8 The return on equity rate of 9.11% in col. (c) is per the OEB 2026 Cost of Capital Parameter Update Letter, October 31, 2025, and is subject to update for the prevailing ROE rate specified by the OEB as of the effective date of the final payment amounts order in this proceeding (Settlement Proposal, Section 2, Part B, iii).

9 Represents the portion of rate base financed by equity that is subject to return at the long-term debt rate until the end of 2036 per the EB-2020-0290 settlement proposal approved by the OEB (EB-2020-0290 Decision and Order, Schedule A, p. 23).

10 Debt required to balance capital structure with rate base.

Numbers may not add due to rounding.

Table 21
Summary of Capitalization and Cost of Capital - OPG
Year Ending December 31, 2029

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1, 3, 6	414.3	1.6%	3.07%	20.1
2	**Existing/Planned Long-Term Debt**	2, 4, 6	9,834.2	37.8%	4.86%	478.1
3	**Other Long-Term Debt Provision**	2, 6, 10	4,043.1	15.6%	4.86%	196.6
4	**Total Debt**	5	14,291.6	55.0%	4.86%	694.7
5	**EB-2020-0290 Settlement Adjustment for Equity at Long-Term Debt Rate**	2, 3, 9	51.6	0.2%	4.86%	2.5
5a	**Common Equity**	1, 6, 8	11,641.6	44.8%	9.11%	1,060.5
5b	**Total Equity**	5	11,693.1	45.0%	9.09%	1,063.1
6	**Rate Base Financed by Capital Structure**		25,984.8	100.0%	6.76%	1,757.7
7	**Adjustment for Lesser of UNL or ARC**	1, 3	0.0	0.0%	4.72%	0.0
8	**Rate Base**	7	25,984.8	100%	6.76%	1,757.7

Notes:

1 Col. (c) as proposed by OPG in Ex. C1-1-1, Tables 1-5 (Settlement Proposal, Section 2, Part B, iii).

2 Col. (c) per Ex. L-F4-CCC-084, Att. 1, Table 19, line 37, col. (e) (Settlement Proposal, Section 2, Part B, iii).

3 Col. (a) per Ex. C1-1-1, Tables 1-5.

4 Col. (a) per Ex. L-F4-CCC-084, Att. 1, Table 19, line 37, col. (a) (Settlement Proposal, Section 2, Part B, iii).

5 The Debt / Equity ratio of 55% debt, 45% equity as per Settlement Proposal, Section 2, Part B, iii.

6 Capitalization and cost of capital is allocated to regulated hydroelectric facilities and OPG's nuclear facilities using rate base financed by capital structure (Regulated hydroelectric per App. B, Table 2, Note 3, line 3c; OPG nuclear per App. A, Tables 2-6: line 4 less line 9).

7 Col. (a) is the sum of App. A, Table 4, line 4, col. (c) and App. B, Table 2, Note 3, line 3c.

8 The return on equity rate of 9.11% in col. (c) is per the OEB 2026 Cost of Capital Parameter Update Letter, October 31, 2025, and is subject to update for the prevailing ROE rate specified by the OEB as of the effective date of the final payment amounts order in this proceeding (Settlement Proposal, Section 2, Part B, iii).

9 Represents the portion of rate base financed by equity that is subject to return at the long-term debt rate until the end of 2036 per the EB-2020-0290 settlement proposal approved by the OEB (EB-2020-0290 Decision and Order, Schedule A, P. 23).

10 Debt required to balance capital structure with rate base.

Numbers may not add due to rounding.

Table 22
Summary of Capitalization and Cost of Capital - OPG
Year Ending December 31, 2030

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1, 3, 6	414.3	1.5%	3.22%	19.2
2	**Existing/Planned Long-Term Debt**	2, 4, 6	11,141.5	41.5%	4.91%	547.2
3	**Other Long-Term Debt Provision**	2, 6, 10	3,210.4	12.0%	4.91%	157.7
4	**Total Debt**	5	14,766.2	55.0%	4.90%	724.0
5	**EB-2020-0290 Settlement Adjustment for Equity at Long-Term Debt Rate**	2, 3, 9	46.7	0.2%	4.91%	2.3
5a	**Common Equity**	1, 6, 8	12,034.8	44.8%	9.11%	1,096.4
5b	**Total Equity**	5	12,081.4	45.0%	9.09%	1,098.7
6	**Rate Base Financed by Capital Structure**		26,847.6	100.0%	6.79%	1,822.7
7	**Adjustment for Lesser of UNL or ARC**	1, 3	0.0	0.0%	4.72%	0.0
8	**Rate Base**	7	26,847.6	100%	6.79%	1,822.7

Notes:

1 Col. (c) as proposed by OPG in Ex. C1-1-1, Tables 1-5 (Settlement Proposal, Section 2, Part B, iii).

2 Col. (c) per Ex. L-F4-CCC-084, Att. 1, Table 21, line 38, col. (e) (Settlement Proposal, Section 2, Part B, iii).

3 Col. (a) per Ex. C1-1-1, Tables 1-5.

4 Col. (a) per Ex. L-F4-CCC-084, Att. 1, Table 21, line 38, col. (a) (Settlement Proposal, Section 2, Part B, iii).

5 The Debt / Equity ratio of 55% debt, 45% equity as per Settlement Proposal, Section 2, Part B, iii.

6 Capitalization and cost of capital is allocated to regulated hydroelectric facilities and OPG's nuclear facilities using rate base financed by capital structure (Regulated hydroelectric per App. B, Table 2, Note 3, line 3c; OPG nuclear per App. A, Tables 2-6: line 4 less line 9).

7 Col. (a) is the sum of App. A, Table 5, line 4, col. (c) and App. B, Table 2, Note 3, line 3c.

8 The return on equity rate of 9.11% in col. (c) is per the OEB 2026 Cost of Capital Parameter Update Letter, October 31, 2025, and is subject to update for the prevailing ROE rate specified by the OEB as of the effective date of the final payment amounts order in this proceeding (Settlement Proposal, Section 2, Part B, iii).

9 Represents the portion of rate base financed by equity that is subject to return at the long-term debt rate until the end of 2036 per the EB-2020-0290 settlement proposal approved by the OEB (EB-2020-0290 Decision and Order, Schedule A, p. 23).

10 Debt required to balance capital structure with rate base.

Numbers may not add due to rounding.

Table 23
Summary of Capitalization and Cost of Capital - OPG
Year Ending December 31, 2031

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1, 3, 6	414.3	1.2%	3.39%	19.9
2	**Existing/Planned Long-Term Debt**	2, 4, 6	11,400.2	34.3%	4.92%	560.6
3	**Other Long-Term Debt Provision**	2, 6, 10	6,460.1	19.4%	4.92%	317.7
4	**Total Debt**	5	18,274.7	55.0%	4.91%	898.2
5	**EB-2020-0290 Settlement Adjustment for Equity at Long-Term Debt Rate**	2, 3, 9	43.0	0.1%	4.92%	2.1
5a	**Common Equity**	1, 6, 8	14,909.0	44.9%	9.11%	1,358.2
5b	**Total Equity**	5	14,952.0	45.0%	9.10%	1,360.3
6	**Rate Base Financed by Capital Structure**		33,226.6	100.0%	6.80%	2,258.5
7	**Adjustment for Lesser of UNL or ARC**	1, 3	0.0	0.0%	4.72%	0.0
8	**Rate Base**	7	33,226.6	100%	6.80%	2,258.5

Notes:

1 Col. (c) as proposed by OPG in Ex. C1-1-1, Tables 1-5 (Settlement Proposal, Section 2, Part B, iii).

2 Col. (c) per Ex. L-F4-CCC-084, Att. 1, Table 23, line 38, col. (e) (Settlement Proposal, Section 2, Part B, iii).

3 Col. (a) per Ex. C1-1-1, Tables 1-5.

4 Col. (a) per Ex. L-F4-CCC-084, Att. 1, Table 23, line 38, col. (a) (Settlement Proposal, Section 2, Part B, iii).

5 The Debt / Equity ratio of 55% debt, 45% equity as per Settlement Proposal, Section 2, Part B, iii.

6 Capitalization and cost of capital is allocated to regulated hydroelectric facilities and OPG's nuclear facilities using rate base financed by capital structure (Regulated hydroelectric per App. B, Table 2, Note 3, line 3c; OPG nuclear per App. A, Tables 2-6: line 4 less line 9).

7 Col. (a) is the sum of App. A, Table 6, line 4, col. (c) and App. B, Table 2, Note 3, line 3c.

8 The return on equity rate of 9.11% in col. (c) is per the OEB 2026 Cost of Capital Parameter Update Letter, October 31, 2025, and is subject to update for the prevailing ROE rate specified by the OEB as of the effective date of the final payment amounts order in this proceeding (Settlement Proposal, Section 2, Part B, iii).

9 Represents the portion of rate base financed by equity that is subject to return at the long-term debt rate until the end of 2036 per the EB-2020-0290 settlement proposal approved by the OEB (EB-2020-0290 Decision and Order, Schedule A, p. 23).

10 Debt required to balance capital structure with rate base.

Numbers may not add due to rounding.

Table 24
Summary of Capitalization and Cost of Capital - DNNP LP
Year Ending December 31, 2027

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**		0.0	0.0%	0.00%	0.0
2	**Existing/Planned Long-Term Debt**		0.0	0.0%	0.00%	0.0
3	**Total Debt**	1	0.0	0.0%	0.00%	0.0
4	**Common Equity**	1, 3	0.0	100.0%	9.11%	0.0
5	**Rate Base Financed by Capital Structure**		0.0	0.0%	0.00%	0.0
6	**Rate Base**	2	0.0	100%	0.00%	0.0

Notes:

1 Capital Structure of Debt / Equity ratio of 0% debt, 100% equity as per Settlement Proposal, Section 3, Part B, ii.

2 Col. (a) per App. A, Table 8, line 4, col. (c).

3 The return on equity rate of 9.11% in col. (c) is per the OEB 2026 Cost of Capital Parameter Update Letter, October 31, 2025, and is subject to update for the prevailing ROE rate specified by the OEB as of the effective date of the final payment amounts order in this proceeding (Settlement Proposal, Section 2, Part B, iii).

Numbers may not add due to rounding.

Table 25
Summary of Capitalization and Cost of Capital - DNNP LP
Year Ending December 31, 2028

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**		0.0	0.0%	0.00%	0.0
2	**Existing/Planned Long-Term Debt**		0.0	0.0%	0.00%	0.0
3	**Total Debt**	1	0.0	0.0%	0.00%	0.0
4	**Common Equity**	1, 3	0.0	100.0%	9.11%	0.0
5	**Rate Base Financed by Capital Structure**		0.0	0.0%	0.00%	0.0
6	**Rate Base**	2	0.0	100%	0.00%	0.0

Notes:

1 Capital Structure of Debt / Equity ratio of 0% debt, 100% equity as per Settlement Proposal, Section 3, Part B, ii.

2 Col. (a) per App. A, Table 9, line 4, col. (c).

3 The return on equity rate of 9.11% in col. (c) is per the OEB 2026 Cost of Capital Parameter Update Letter, October 31, 2025, and is subject to update for the prevailing ROE rate specified by the OEB as of the effective date of the final payment amounts order in this proceeding (Settlement Proposal, Section 2, Part B, iii).

Numbers may not add due to rounding.

Table 26
Summary of Capitalization and Cost of Capital - DNNP LP
Year Ending December 31, 2029

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**		0.0	0.0%	0.00%	0.0
2	**Existing/Planned Long-Term Debt**		0.0	0.0%	0.00%	0.0
3	**Total Debt**	1	0.0	0.0%	0.00%	0.0
4	**Common Equity**	1, 3	2.1	100.0%	9.11%	0.2
5	**Rate Base Financed by Capital Structure**		2.1	100.0%	9.11%	0.2
6	**Rate Base**	2	2.1	100%	9.11%	0.2

Notes:

1 Capital Structure of Debt / Equity ratio of 0% debt, 100% equity as per Settlement Proposal, Section 3, Part B, ii.

2 Col. (a) per App. A, Table 10, line 4, col. (c).

3 The return on equity rate of 9.11% in col. (c) is per the OEB 2026 Cost of Capital Parameter Update Letter, October 31, 2025, and is subject to update for the prevailing ROE rate specified by the OEB as of the effective date of the final payment amounts order in this proceeding (Settlement Proposal, Section 2, Part B, iii).

Numbers may not add due to rounding.

Table 27
Summary of Capitalization and Cost of Capital - DNNP LP
Year Ending December 31, 2030

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**		0.0	0.0%	0.00%	0.0
2	**Existing/Planned Long-Term Debt**		0.0	0.0%	0.00%	0.0
3	**Total Debt**	1	0.0	0.0%	0.00%	0.0
4	**Common Equity**	1, 3	1,236.9	100.0%	9.11%	112.7
5	**Rate Base Financed by Capital Structure**		1,236.9	100.0%	9.11%	112.7
6	**Rate Base**	2	1,236.9	100.0%	9.11%	112.7

Notes:

1 Capital Structure of Debt / Equity ratio of 0% debt, 100% equity as per Settlement Proposal, Section 3, Part B, ii.

2 Col. (a) per App. A, Table 11, line 4, col. (c).

3 The return on equity rate of 9.11% in col. (c) is per the OEB 2026 Cost of Capital Parameter Update Letter, October 31, 2025, and is subject to update for the prevailing ROE rate specified by the OEB as of the effective date of the final payment amounts order in this proceeding (Settlement Proposal, Section 2, Part B, iii).

Numbers may not add due to rounding.

Table 28
Summary of Capitalization and Cost of Capital - DNNP LP
Year Ending December 31, 2031

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**		0.0	0.0%	0.00%	0.0
2	**Existing/Planned Long-Term Debt**		0.0	0.0%	0.00%	0.0
3	**Total Debt**	1	0.0	0.0%	0.00%	0.0
4	**Common Equity**	1, 3	5,888.1	100.0%	9.11%	536.4
5	**Rate Base Financed by Capital Structure**		5,888.1	100.0%	9.11%	536.4
6	**Rate Base**	2	5,888.1	100.0%	9.11%	536.4

Notes:

1 Capital Structure of Debt / Equity ratio of 0% debt, 100% equity as per Settlement Proposal, Section 3, Part B, ii.

2 Col. (a) per App. A, Table 12, line 4, col. (c).

3 The return on equity rate of 9.11% in col. (c) is per the OEB 2026 Cost of Capital Parameter Update Letter, October 31, 2025, and is subject to update for the prevailing ROE rate specified by the OEB as of the effective date of the final payment amounts order in this proceeding (Settlement Proposal, Section 2, Part B, iii).

Numbers may not add due to rounding.

Table 29

2027 Summary of Changes in Regulatory Income Taxes for Regulated Hydroelectric Facilities ($M)

Line No.	Particulars	Note	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Determination of Regulatory Taxable Income				
1	**Regulatory Earnings Before Tax**	2	470.2	(94.1)	376.2
	Additions for Regulatory Tax Purposes:				
2	**Depreciation and Amortization**	3	215.4	(2.2)	213.2
3	**Pension and OPEB Accrual**		44.2	0.0	44.2
4	**Regulatory Liability Amortization - Pension & OPEB Cash Versus Accrual Differential Deferral Account**		(10.2)	0.0	(10.2)
5	**Regulatory Liability Amortization - Income and Other Taxes Variance Account**		(2.7)	0.0	(2.7)
6	**Restricted Net Interest and Financing Expenses**		0.0	0.0	0.0
7	**Taxable SR&ED Investment Tax Credits of Prior Periods & Current Provincial Portion**		3.3	0.0	3.3
8	**Other**		7.4	0.0	7.4
9	**Total Additions**		257.4	(2.2)	255.2
	Deductions for Regulatory Tax Purposes:				
10	**CCA**	4, 5	537.7	62.2	599.9
11	**Pension Plan Contributions**		19.5	0.0	19.5
12	**OPEB Payments**		22.9	0.0	22.9
13	**Reversal of Return on Rate Base Recorded in Deferral and Variance Accounts**		0.0	0.0	0.0
14	**Deductible SR&ED Qualifying Expenditures**		25.0	0.0	25.0
15	**Other**		0.0	0.0	0.0
16	**Total Deductions**		605.1	62.2	667.3
17	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 9 - line 16)		122.5	(158.4)	(35.9)
18	**Tax Loss Carry-Over / (Applied)**	6	0.0	35.9	35.9
19	**Regulatory Taxable Income After Tax Loss Carry-Over** (line 17 + line 18)		122.5	(122.5)	0.0
20	**Regulatory Income Taxes - Federal** (line 19 x line 24)		18.4	(18.4)	0.0
21	**Regulatory Income Taxes - Provincial** (line 19 x line 25)		12.2	(12.2)	0.0
22	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		(3.3)	0.0	(3.3)
23	**Total Regulatory Income Taxes** (line 20 + line 21 + line 22)		27.3	(30.6)	(3.3)
	Income Tax Rate:				
24	**Federal Tax**		15.00%	0.00%	15.00%
25	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	0.00%	10.00%
26	**Total Income Tax Rate**		25.00%	0.00%	25.00%

For notes see Table 29a.

Table 29a
Notes to Table 29
2027 Summary of Changes in Regulatory Income Taxes for Regulated Hydroelectric Facilities ($M)

1 Per Ex. F4-2-1, Table 3b.
2 Regulatory Earnings Before Tax are calculated as follows:

Line No.	Item	Reference for Settled Amount	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
1a	After Tax Return on Equity - Regulated Hydroelectric Facilities	App. A, Table 1, line 11	432.7	(63.5)	369.3
2a	Additions for Regulatory Tax Purposes	line 9	257.4	(2.2)	255.2
3a	Less: Regulatory Liability Amort - Pension & OPEB Cash Vs Accrual Diff Def Act	App. C Table 1, lines 8-10	(10.2)	0.0	(10.2)
4a	Deductions for Regulatory Tax Purposes	line 16	605.1	62.2	667.3
5a		line 1a + line 2a - line 3a - line 4a	95.2	(127.8)	(32.6)
6a	Regulatory Income Taxes - Federal	(lines 5a + 12a + line 22) x line 24/ (1 - line 26)	18.4	(23.8)	(5.4)
7a	Regulatory Income Taxes - Provincial	(lines 5a + 12a + line 22) x line 25/ (1 - line 26)	12.2	(15.8)	(3.6)
8a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 22	(3.3)	0.0	(3.3)
9a	Total Regulatory Income Taxes Before Loss Carry-Over	line 6a + line 7a + line 8a	27.3	(39.6)	(12.3)
10a	Effect on Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	line 18 x line 24	0.0	5.4	5.4
11a	Effect on Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	line 18 x line 25	0.0	3.6	3.6
12a	Reduction in Total Regulatory Income Taxes Due to Loss Carry-Over	line 10a + line 11a	0.0	9.0	9.0
13a	Regulatory Income Taxes After Tax Loss Carry-Over - Federal	line 6a + line 10a	18.4	(18.4)	(0.0)
14a	Regulatory Income Taxes After Tax Loss Carry-Over - Provincial	line 7a + line 11a	12.2	(12.3)	(0.0)
15a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 22	(3.3)	0.0	(3.3)
16a	Total Regulatory Income Taxes After Tax Loss Carry-Over	line 13a + line 14a + line 15a	27.3	(30.6)	(3.3)
17a	After Tax Return on Equity	line 1a	432.7	(63.5)	369.3
18a	Less: Regulatory Liability Amort - Pension & OPEB Cash Vs Accrual Diff Def Act	line 3a	(10.2)	0.0	(10.2)
19a	Add: Total Regulatory Income Taxes After Tax Loss Carry-Over	line 16a	27.3	(30.6)	(3.3)
20a	Regulatory Earnings Before Tax	lines 17a - 18a + 19a	470.2	(94.1)	376.2

3 Col. (c) per App. A, Table 1, line 15, col. (c).

4 Col. (c) per App. A, Table 46, line 23, col. (j) - col. (i), which reflects the forecast Capital Cost Allowance impacts of the forecast CEITCs and the reinstated accelerated investment property rules per Ex. L-F4-CCC-084 (Settlement Proposal, Section 2, Part D, vi) and the applicable Settlement Proposal adjustments to rate base per App. A, Table 1a, Note 2.

5 Col. (c) includes annual CCA for regulated hydroelectric project expenditures treated as eligible for the Capacity Refurbishment Variance Account of $395.6M.

Col. (c) also includes the CEITC impact on annual CCA for regulated hydroelectric project expenditures excluding the Capacity Refurbishment Variance Account eligible expenditures of ($2.5M).

6 As discussed in Ex. F4-2-1, Section 3.1, in a situation where a tax loss is forecast in a given year, the loss is applied (carried back or carried forward) to reduce such business' taxable income in other years of this period, with any remaining tax losses carried forward to future rate-setting periods.

Numbers may not add due to rounding.

Table 30

2028 Summary of Changes in Regulatory Income Taxes for Regulated Hydroelectric Facilities ($M)

Line No.	Particulars	Note	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Determination of Regulatory Taxable Income	2			
1	**Regulatory Earnings Before Tax**	3	539.4	(128.1)	411.3
	Additions for Regulatory Tax Purposes:				
2	**Depreciation and Amortization**	4	228.4	(4.6)	223.8
3	**Pension and OPEB Accrual**		45.6	0.0	45.6
4	**Regulatory Liability Amortization - Pension & OPEB Cash Versus Accrual Differential Deferral Account**		(10.2)	0.0	(10.2)
5	**Regulatory Liability Amortization - Income and Other Taxes Variance Account**		(2.7)	0.0	(2.7)
6	**Restricted Net Interest and Financing Expenses**		0.0	0.0	0.0
7	**Taxable SR&ED Investment Tax Credits of Prior Periods & Current Provincial Portion**		3.3	0.0	3.3
8	**Other**		8.1	0.0	8.1
9	**Total Additions**		272.4	(4.6)	267.8
	Deductions for Regulatory Tax Purposes:				
10	**CCA**	5, 6	448.3	52.7	501.0
11	**Pension Plan Contributions**		20.2	0.0	20.2
12	**OPEB Payments**		23.8	0.0	23.8
13	**Reversal of Return on Rate Base Recorded in Deferral and Variance Accounts**		0.0	0.0	0.0
14	**Deductible SR&ED Qualifying Expenditures**		25.0	0.0	25.0
15	**Other**		0.0	0.0	0.0
16	**Total Deductions**		517.3	52.7	570.0
17	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 9 - line 16)		294.5	(185.4)	109.1
18	**Tax Loss Carry-Over / (Applied)**	7	0.0	(35.9)	(35.9)
19	**Regulatory Taxable Income After Tax Loss Carry-Over** (line 17 + line 18)		294.5	(221.3)	73.2
20	**Regulatory Income Taxes - Federal** (line 19 x line 24)		44.2	(33.2)	11.0
21	**Regulatory Income Taxes - Provincial** (line 19 x line 25)		29.4	(22.1)	7.3
22	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		(3.3)	0.0	(3.3)
23	**Total Regulatory Income Taxes** (line 20 + line 21 + line 22)		70.3	(55.3)	15.0
	Income Tax Rate:				
24	**Federal Tax**		15.00%	0.00%	15.00%
25	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	0.00%	10.00%
26	**Total Income Tax Rate**		25.00%	0.00%	25.00%

For notes see Table 30a.

Table 30a
Notes to Table 30
2028 Summary of Changes in Regulatory Income Taxes for Regulated Hydroelectric Facilities ($M)

1 Per Ex. F4-2-1, Table 3b.

2 Income tax amounts for 2028-2031 are reflected in the capital related revenue requirement used in the determination of the Custom Capital Factor in App. B, Table 2 (Settlement Proposal, Section 2, Part A).

3 Regulatory Earnings Before Tax are calculated as follows:

Line No.	Item	Reference for Settled Amount	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
1a	After Tax Return on Equity - Regulated Hydroelectric Facilities	App. B, Table 2, line 3	458.9	(72.8)	386.1
2a	Additions for Regulatory Tax Purposes	line 9	272.4	(4.6)	267.8
3a	Less: Regulatory Liability Amort - Pension & OPEB Cash Vs Accrual Diff Def Act	App. C Table 1, lines 8-10	(10.2)	0.0	(10.2)
4a	Deductions for Regulatory Tax Purposes	line 16	517.3	52.7	570.0
5a		line 1a + line 2a - line 3a - line 4a	224.2	(130.1)	94.1
6a	Regulatory Income Taxes - Federal	(lines 5a + 12a + line 22) x line 24/ (1 - line 26)	44.2	(27.8)	16.4
7a	Regulatory Income Taxes - Provincial	(lines 5a + 12a + line 22) x line 25/ (1 - line 26)	29.4	(18.5)	10.9
8a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 22	(3.3)	0.0	(3.3)
9a	Total Regulatory Income Taxes Before Loss Carry-Over	line 6a + line 7a + line 8a	70.3	(46.3)	24.0
10a	Effect on Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	line 18 x line 24	0.0	(5.4)	(5.4)
11a	Effect on Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	line 18 x line 25	0.0	(3.6)	(3.6)
12a	Reduction in Total Regulatory Income Taxes Due to Loss Carry-Over	line 10a + line 11a	0.0	(9.0)	(9.0)
13a	Regulatory Income Taxes After Tax Loss Carry-Over - Federal	line 6a + line 10a	44.2	(33.2)	11.0
14a	Regulatory Income Taxes After Tax Loss Carry-Over - Provincial	line 7a + line 11a	29.4	(22.1)	7.3
15a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 22	(3.3)	0.0	(3.3)
16a	Total Regulatory Income Taxes After Tax Loss Carry-Over	line 13a + line 14a + line 15a	70.3	(55.3)	15.0
17a	After Tax Return on Equity	line 1a	458.9	(72.8)	386.1
18a	Less: Regulatory Liability Amort - Pension & OPEB Cash Vs Accrual Diff Def Act	line 3a	(10.2)	0.0	(10.2)
19a	Add: Total Regulatory Income Taxes After Tax Loss Carry-Over	line 16a	70.3	(55.3)	15.0
20a	Regulatory Earnings Before Tax	lines 17a - 18a + 19a	539.4	(128.1)	411.3

4 Col. (c) per App. B, Table 2, line 1. Adjustments per App. A, Table 1a, Note 2.

5 Col. (c) per App. A, Table 47, line 23, col. (j) - col. (i), which reflects the forecast Capital Cost Allowance impacts of the forecast CEITCs and the reinstated accelerated investment property rules per Ex. L-F4-CCC-084 (Settlement Proposal, Section 2, Part D, vi) and the applicable Settlement Proposal adjustments to rate base per App. A, Table 1a, Note 2.

6 Col. (c) includes annual CCA for regulated hydroelectric project expenditures treated as eligible for the Capacity Refurbishment Variance Account of $292.2M.

Col. (c) also includes the CEITC impact on annual CCA for regulated hydroelectric project expenditures excluding the Capacity Refurbishment Variance Account eligible expenditures of ($0.3M).

7 As discussed in Ex. F4-2-1, Section 3.1, in a situation where a tax loss is forecast in a given year, the loss is applied (carried back or carried forward) to reduce such business' taxable income in other years of this period, with any remaining tax losses carried forward to future rate-setting periods.

Numbers may not add due to rounding.

Table 31
2029 Summary of Changes in Regulatory Income Taxes for Regulated Hydroelectric Facilities ($M)

Line No.	Particulars	Note	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Determination of Regulatory Taxable Income	2			
1	**Regulatory Earnings Before Tax**	3	610.0	(89.1)	520.9
	Additions for Regulatory Tax Purposes:				
2	**Depreciation and Amortization**	4	249.6	(8.0)	241.6
3	**Pension and OPEB Accrual**		45.6	0.0	45.6
4	**Regulatory Liability Amortization - Pension & OPEB Cash Versus Accrual Differential Deferral Account**		(10.2)	0.0	(10.2)
5	**Regulatory Liability Amortization - Income and Other Taxes Variance Account**		(2.7)	0.0	(2.7)
6	**Restricted Net Interest and Financing Expenses**		0.0	0.0	0.0
7	**Taxable SR&ED Investment Tax Credits of Prior Periods & Current Provincial Portion**		3.3	0.0	3.3
8	**Other**		8.5	0.0	8.5
9	**Total Additions**		294.2	(8.0)	286.2
	Deductions for Regulatory Tax Purposes:				
10	**CCA**	5, 6	468.7	(92.5)	376.1
11	**Pension Plan Contributions**		21.4	0.0	21.4
12	**OPEB Payments**		25.4	0.0	25.4
13	**Reversal of Return on Rate Base Recorded in Deferral and Variance Accounts**		0.0	0.0	0.0
14	**Deductible SR&ED Qualifying Expenditures**		25.0	0.0	25.0
15	**Other**		0.2	0.0	0.2
16	**Total Deductions**		540.6	(92.5)	448.1
17	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 9 - line 16)		363.6	(4.6)	359.0
18	**Tax Loss Carry-Over / (Applied)**	7	0.0	0.0	0.0
19	**Regulatory Taxable Income After Tax Loss Carry-Over** (line 17 + line 18)		363.6	(4.6)	359.0
20	**Regulatory Income Taxes - Federal** (line 19 x line 24)		54.5	(0.7)	53.9
21	**Regulatory Income Taxes - Provincial** (line 19 x line 25)		36.4	(0.5)	35.9
22	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		(3.3)	0.0	(3.3)
23	**Total Regulatory Income Taxes** (line 20 + line 21 + line 22)		87.6	(1.1)	86.5
	Income Tax Rate:				
24	**Federal Tax**		15.00%	0.00%	15.00%
25	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	0.00%	10.00%
26	**Total Income Tax Rate**		25.00%	0.00%	25.00%

For notes see Table 31a.

Table 31a
Notes to Table 31
2029 Summary of Changes in Regulatory Income Taxes for Regulated Hydroelectric Facilities ($M)

1 Per Ex. F4-2-1, Table 3b.

2 Income tax amounts for 2028-2031 are reflected in the capital related revenue requirement used in the determination of the Custom Capital Factor in App. B, Table 2 (Settlement Proposal, Section 2, Part A).

3 Regulatory Earnings Before Tax are calculated as follows:

Line No.	Item	Reference for Settled Amount	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
1a	After Tax Return on Equity - Regulated Hydroelectric Facilities	App. B, Table 2, line 3	512.3	(88.0)	424.3
2a	Additions for Regulatory Tax Purposes	line 9	294.2	(8.0)	286.2
3a	Less: Regulatory Liability Amort - Pension & OPEB Cash Vs Accrual Diff Def Act	App. C Table 1, lines 8-10	(10.2)	0.0	(10.2)
4a	Deductions for Regulatory Tax Purposes	line 16	540.6	(92.5)	448.1
5a		line 1a + line 2a - line 3a - line 4a	276.0	(3.4)	272.6
6a	Regulatory Income Taxes - Federal	(lines 5a + 12a + line 22) x line 24/ (1 - line 26)	54.5	(0.7)	53.9
7a	Regulatory Income Taxes - Provincial	(lines 5a + 12a + line 22) x line 25/ (1 - line 26)	36.4	(0.5)	35.9
8a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 22	(3.3)	0.0	(3.3)
9a	Total Regulatory Income Taxes Before Loss Carry-Over	line 6a + line 7a + line 8a	87.6	(1.1)	86.5
10a	Effect on Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	line 18 x line 24	0.0	0.0	0.0
11a	Effect on Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	line 18 x line 25	0.0	0.0	0.0
12a	Reduction in Total Regulatory Income Taxes Due to Loss Carry-Over	line 10a + line 11a	0.0	0.0	0.0
13a	Regulatory Income Taxes After Tax Loss Carry-Over - Federal	line 6a + line 10a	54.5	(0.7)	53.9
14a	Regulatory Income Taxes After Tax Loss Carry-Over - Provincial	line 7a + line 11a	36.4	(0.5)	35.9
15a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 22	(3.3)	0.0	(3.3)
16a	Total Regulatory Income Taxes After Tax Loss Carry-Over	line 13a + line 14a + line 15a	87.6	(1.1)	86.5
17a	After Tax Return on Equity	line 1a	512.3	(88.0)	424.3
18a	Less: Regulatory Liability Amort - Pension & OPEB Cash Vs Accrual Diff Def Act	line 3a	(10.2)	0.0	(10.2)
19a	Add: Total Regulatory Income Taxes After Tax Loss Carry-Over	line 16a	87.6	(1.1)	86.5
20a	Regulatory Earnings Before Tax	lines 17a - 18a + 19a	610.0	(89.1)	520.9

4 Col. (c) per App. B, Table 2, line 1. Adjustments per App. A, Table 1a, Note 2.

5 Col. (c) per App. A, Table 48, line 23, col. (j) - col. (i), which reflects the forecast Capital Cost Allowance impacts of the forecast CEITCs and the reinstated accelerated investment property rules per Ex. L-F4-CCC-084 (Settlement Proposal,Section 2, Part D, vi) and the applicable Settlement Proposal adjustments to rate base per App. A, Table 1a, Note 2.

6 Col. (c) includes CCA for regulated hydroelectric project expenditures treated as eligible for the Capacity Refurbishment Variance Account of $137.7M.

Col. (c) also includes the CEITC impact on CCA for regulated hydroelectric project expenditures excluding the Capacity Refurbishment Variance Account eligible expenditures of ($0.4M).

7 As discussed in Ex. F4-2-1, Section 3.1, in a situation where a tax loss is forecast in a given year, the loss is applied (carried back or carried forward) to reduce such business' taxable income in other years of this period, with any remaining tax losses carried forward to future rate-setting periods.

Numbers may not add due to rounding.

Table 32

2030 Summary of Changes in Regulatory Income Taxes for Regulated Hydroelectric Facilities ($M)

Line No.	Particulars	Note	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Determination of Regulatory Taxable Income	2			
1	**Regulatory Earnings Before Tax**	3	645.0	(99.9)	545.0
	Additions for Regulatory Tax Purposes:				
2	**Depreciation and Amortization**	4	263.6	(10.7)	252.8
3	**Pension and OPEB Accrual**		45.6	0.0	45.6
4	**Regulatory Liability Amortization - Pension & OPEB Cash Versus Accrual Differential Deferral Account**		0.0	0.0	0.0
5	**Regulatory Liability Amortization - Income and Other Taxes Variance Account**		0.0	0.0	0.0
6	**Restricted Net Interest and Financing Expenses**		0.0	0.0	0.0
7	**Taxable SR&ED Investment Tax Credits of Prior Periods & Current Provincial Portion**		3.3	0.0	3.3
8	**Other**		9.3	0.0	9.3
9	**Total Additions**		321.8	(10.7)	311.1
	Deductions for Regulatory Tax Purposes:				
10	**CCA**	5, 6	473.6	(104.8)	368.7
11	**Pension Plan Contributions**		22.1	0.0	22.1
12	**OPEB Payments**		26.6	0.0	26.6
13	**Reversal of Return on Rate Base Recorded in Deferral and Variance Accounts**		0.0	0.0	0.0
14	**Deductible SR&ED Qualifying Expenditures**		25.0	0.0	25.0
15	**Other**		0.1	0.0	0.1
16	**Total Deductions**		547.4	(104.8)	442.5
17	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 9 - line 16)		419.5	(5.9)	413.6
18	**Tax Loss Carry-Over / (Applied)**	7	0.0	0.0	0.0
19	**Regulatory Taxable Income After Tax Loss Carry-Over** (line 17 + line 18)		419.5	(5.9)	413.6
20	**Regulatory Income Taxes - Federal** (line 19 x line 24)		62.9	(0.9)	62.0
21	**Regulatory Income Taxes - Provincial** (line 19 x line 25)		41.9	(0.6)	41.4
22	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		(3.3)	0.0	(3.3)
23	**Total Regulatory Income Taxes** (line 20 + line 21 + line 22)		101.6	(1.5)	100.1
	Income Tax Rate:				
24	**Federal Tax**		15.00%	0.00%	15.00%
25	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	0.00%	10.00%
26	**Total Income Tax Rate**		25.00%	0.00%	25.00%

For notes see Table 32a.

Numbers may not add due to rounding.

Table 32a
Notes to Table 32
2030 Summary of Changes in Regulatory Income Taxes for Regulated Hydroelectric Facilities ($M)

Notes:

1 Per Ex. F4-2-1, Table 3b.

2 Income tax amounts for 2028-2031 are reflected in the capital related revenue requirement used in the determination of the Custom Capital Factor in App. B, Table 2 (Settlement Proposal, Section 2, Part A).

3 Regulatory Earnings Before Tax are calculated as follows:

Line No.	Item	Reference for Settled Amount	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
1a	After Tax Return on Equity - Regulated Hydroelectric Facilities	App. B, Table 2, line 3	543.4	(98.5)	444.9
2a	Additions for Regulatory Tax Purposes	line 9	321.8	(10.7)	311.1
3a	Less: Regulatory Liability Amort - Pension & OPEB Cash Vs Accrual Diff Def Act	App. C Table 1, lines 8-10	0.0	0.0	0.0
4a	Deductions for Regulatory Tax Purposes	line 16	547.4	(104.8)	442.5
5a		line 1a + line 2a - line 3a - line 4a	317.9	(4.4)	313.5
6a	Regulatory Income Taxes - Federal	(lines 5a + 12a + line 22) x line 24/ (1 - line 26)	62.9	(0.9)	62.0
7a	Regulatory Income Taxes - Provincial	(lines 5a + 12a + line 22) x line 25/ (1 - line 26)	41.9	(0.6)	41.4
8a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 22	(3.3)	0.0	(3.3)
9a	Total Regulatory Income Taxes Before Loss Carry-Over	line 6a + line 7a + line 8a	101.6	(1.5)	100.1
10a	Effect on Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	line 18 x line 24	0.0	0.0	0.0
11a	Effect on Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	line 18 x line 25	0.0	0.0	0.0
12a	Reduction in Total Regulatory Income Taxes Due to Loss Carry-Over	line 10a + line 11a	0.0	0.0	0.0
13a	Regulatory Income Taxes After Tax Loss Carry-Over - Federal	line 6a + line 10a	62.9	(0.9)	62.0
14a	Regulatory Income Taxes After Tax Loss Carry-Over - Provincial	line 7a + line 11a	41.9	(0.6)	41.4
15a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 22	(3.3)	0.0	(3.3)
16a	Total Regulatory Income Taxes After Tax Loss Carry-Over	line 13a + line 14a + line 15a	101.6	(1.5)	100.1
17a	After Tax Return on Equity	line 1a	543.4	(98.5)	444.9
18a	Less: Regulatory Liability Amort - Pension & OPEB Cash Vs Accrual Diff Def Act	line 3a	0.0	0.0	0.0
19a	Add: Total Regulatory Income Taxes After Tax Loss Carry-Over	line 16a	101.6	(1.5)	100.1
20a	Regulatory Earnings Before Tax	lines 17a - 18a + 19a	645.0	(99.9)	545.0

4 Col. (c) per App. B, Table 2, line 1. Adjustments per App. A, Table 1a, Note 2.

5 Col. (c) per App. A, Table 49, line 23, col. (j) - col. (i), which reflects the forecast Capital Cost Allowance impacts of the forecast CEITCs and the reinstated accelerated investment property rules per Ex. L-F4-CCC-084 (Settlement Proposal, Section 2, Part D, vi) and the applicable Settlement Proposal adjustments to rate base per App. A, Table 1a, Note 2.

6 Col. (c) includes annual CCA for regulated hydroelectric project expenditures treated as eligible for the Capacity Refurbishment Variance Account of $164.9M.

Col. (c) also includes the CEITC impact on annual CCA for regulated hydroelectric project expenditures excluding the Capacity Refurbishment Variance Account eligible expenditures of ($0.2M).

7 As discussed in Ex. F4-2-1, Section 3.1, in a situation where a tax loss is forecast in a given year, the loss is applied (carried back or carried forward) to reduce such business' taxable income in other years of this period, with any remaining tax losses carried forward to future rate-setting periods.

Table 33
2031 Summary of Changes in Regulatory Income Taxes for Regulated Hydroelectric Facilities ($M)

Line No.	Particulars	Note	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Determination of Regulatory Taxable Income	2			
1	**Regulatory Earnings Before Tax**	3	679.5	(120.4)	559.0
	Additions for Regulatory Tax Purposes:				
2	**Depreciation and Amortization**	4	271.7	(12.8)	259.0
3	**Pension and OPEB Accrual**		45.7	0.0	45.7
4	**Regulatory Liability Amortization - Pension & OPEB Cash Versus Accrual Differential Deferral Account**		0.0	0.0	0.0
5	**Regulatory Liability Amortization - Income and Other Taxes Variance Account**		0.0	0.0	0.0
6	**Restricted Net Interest and Financing Expenses**		0.0	0.0	0.0
7	**Taxable SR&ED Investment Tax Credits of Prior Periods & Current Provincial Portion**		3.3	0.0	3.3
8	**Other**		9.9	0.0	9.9
9	**Total Additions**		330.7	(12.8)	317.9
	Deductions for Regulatory Tax Purposes:				
10	**CCA**	5, 6	477.8	(76.6)	401.3
11	**Pension Plan Contributions**		22.9	0.0	22.9
12	**OPEB Payments**		27.7	0.0	27.7
13	**Reversal of Return on Rate Base Recorded in Deferral and Variance Accounts**		0.0	0.0	0.0
14	**Deductible SR&ED Qualifying Expenditures**		25.0	0.0	25.0
15	**Other**		0.9	0.0	0.9
16	**Total Deductions**		554.3	(76.6)	477.7
17	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 9 - line 16)		455.8	(56.6)	399.2
18	**Tax Loss Carry-Over / (Applied)**	7	0.0	0.0	0.0
19	**Regulatory Taxable Income After Tax Loss Carry-Over** (line 17 + line 18)		455.8	(56.6)	399.2
20	**Regulatory Income Taxes - Federal** (line 19 x line 24)		68.4	(8.5)	59.9
21	**Regulatory Income Taxes - Provincial** (line 19 x line 25)		45.6	(5.7)	39.9
22	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		(3.3)	0.0	(3.3)
23	**Total Regulatory Income Taxes** (line 20 + line 21 + line 22)		110.7	(14.1)	96.5
	Income Tax Rate:				
24	**Federal Tax**		15.00%	0.00%	15.00%
25	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	0.00%	10.00%
26	**Total Income Tax Rate**		25.00%	0.00%	25.00%

For notes see Table 33a.

Numbers may not add due to rounding.

Table 33a
Notes to Table 33
2031 Summary of Changes in Regulatory Income Taxes for Regulated Hydroelectric Facilities ($M)

1 Per Ex. F4-2-1, Table 3b.

2 Income tax amounts for 2028-2031 are reflected in the capital related revenue requirement used in the determination of the Custom Capital Factor in App. B, Table 2 (Settlement Proposal, Section 2, Part A).

3 Regulatory Earnings Before Tax are calculated as follows:

Line No.	Item	Reference for Settled Amount	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
1a	After Tax Return on Equity - Regulated Hydroelectric Facilities	App. B, Table 2, line 3	568.8	(106.3)	462.5
2a	Additions for Regulatory Tax Purposes	line 9	330.7	(12.8)	317.9
3a	Less: Regulatory Liability Amort - Pension & OPEB Cash Vs Accrual Diff Def Act	App. C, Table 1, lines 8-10	0.0	0.0	0.0
4a	Deductions for Regulatory Tax Purposes	line 16	554.3	(76.6)	477.7
5a		line 1a + line 2a - line 3a - line 4a	345.2	(42.4)	302.7
6a	Regulatory Income Taxes - Federal	(lines 5a + 12a + line 22) x line 24/ (1 - line 26)	68.4	(8.5)	59.9
7a	Regulatory Income Taxes - Provincial	(lines 5a + 12a + line 22) x line 25/ (1 - line 26)	45.6	(5.7)	39.9
8a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 22	(3.3)	0.0	(3.3)
9a	Total Regulatory Income Taxes Before Loss Carry-Over	line 6a + line 7a + line 8a	110.7	(14.1)	96.5
10a	Effect on Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	line 18 x line 24	0.0	0.0	0.0
11a	Effect on Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	line 18 x line 25	0.0	0.0	0.0
12a	Reduction in Total Regulatory Income Taxes Due to Loss Carry-Over	line 10a + line 11a	0.0	0.0	0.0
13a	Regulatory Income Taxes After Tax Loss Carry-Over - Federal	line 6a + line 10a	68.4	(8.5)	59.9
14a	Regulatory Income Taxes After Tax Loss Carry-Over - Provincial	line 7a + line 11a	45.6	(5.7)	39.9
15a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 22	(3.3)	0.0	(3.3)
16a	Total Regulatory Income Taxes After Tax Loss Carry-Over	line 13a + line 14a + line 15a	110.7	(14.1)	96.5
17a	After Tax Return on Equity	line 1a	568.8	(106.3)	462.5
18a	Less: Regulatory Liability Amort - Pension & OPEB Cash Vs Accrual Diff Def Act	line 3a	0.0	0.0	0.0
19a	Add: Total Regulatory Income Taxes After Tax Loss Carry-Over	line 16a	110.7	(14.1)	96.5
20a	Regulatory Earnings Before Tax	lines 17a - 18a + 19a	679.5	(120.4)	559.0

4 Col. (c) per App. B, Table 2, line 1. Adjustments per App. A, Table 1a, Note 2.

5 Col. (c) per App. A, Table 50, line 23, col. (j) - col. (i), which reflects the forecast Capital Cost Allowance impacts of the forecast CEITCs and the reinstated accelerated investment property rules per Ex. L-F4-CCC-084 (Settlement Proposal, Section 2, Part D, vi) and the applicable Settlement Proposal adjustments to rate base per App. A, Table 1a, Note 2.

6 Col. (c) includes annual CCA for regulated hydroelectric project expenditures treated as eligible for the Capacity Refurbishment Variance Account of $199.5M.

Col. (c) also includes the CEITC impact on annual CCA for regulated hydroelectric project expenditures excluding the Capacity Refurbishment Variance Account eligible expenditures of ($0.1M).

7 As discussed in Ex. F4-2-1, Section 3.1, in a situation where a tax loss is forecast in a given year, the loss is applied (carried back or carried forward) to reduce such business' taxable income in other years of this period, with any remaining tax losses carried forward to future rate-setting periods.

Numbers may not add due to rounding.

Table 34
2027 Summary of Changes in Regulatory Income Taxes for OPG Nuclear Facilities ($M)

Line No.	Particulars	Note	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Determination of Regulatory Taxable Income				
1	**Regulatory Earnings Before Tax**	2	728.7	(112.2)	616.6
	Additions for Regulatory Tax Purposes:				
2	**Depreciation and Amortization**	3	663.3	(10.8)	652.5
3	**Nuclear Waste Management Expenses**	4	30.4	0.9	31.3
4	**Receipts from Nuclear Segregated Funds**		498.2	0.0	498.2
5	**Pension and OPEB Accrual**		226.6	0.0	226.6
6	**Regulatory Liability Amortization - Bruce Lease Net Revenues Variance Account**		(34.5)	0.0	(34.5)
7	**Regulatory Asset Amortization - Pension & OPEB Cash Versus Accrual Differential Deferral Account**		0.0	0.0	0.0
8	**Regulatory Liability Amortization - Income and Other Taxes Variance Account**		(0.7)	0.0	(0.7)
9	**Adjustment Related to Financing Cost for Nuclear Liabilities**		4.7	0.0	4.7
10	**Restricted Net Interest and Financing Expenses**		0.0	0.0	0.0
11	**Taxable SR&ED Investment Tax Credits of Prior Periods & Current Provincial Portion**		16.6	0.0	16.6
12	**Nuclear Fuel Expense Half Charge Adjustment**	5	(35.9)	1.383	(34.5)
13	**Other**		95.1	0.0	95.1
14	**Total Additions**		1,463.9	(8.5)	1,455.4
	Deductions for Regulatory Tax Purposes:				
15	**CCA**	6, 8	1,266.2	97.3	1,363.5
16	**Cash Expenditures for Nuclear Waste & Decommissioning**		637.4	0.0	637.4
17	**Contributions to Nuclear Segregated Funds and Earnings**		0.0	0.0	0.0
18	**Pension Plan Contributions**		100.6	0.0	100.6
19	**OPEB Payments**		118.0	0.0	118.0
20	**Reversal of Return on Rate Base Recorded in Deferral and Variance Accounts**		0.0	0.0	0.0
21	**Deductible SR&ED Qualifying Expenditures**		81.4	0.0	81.4
22	**Other**		9.7	0.0	9.7
23	**Total Deductions**		2,213.3	97.3	2,310.6
24	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 14 - line 23)		(20.6)	(217.9)	(238.6)
25	**Tax Loss Carry-Over / (Applied)**	7	20.6	217.9	238.6
26	**Regulatory Taxable Income After Tax Loss Carry-Over** (line 24 + line 25)		0.0	0.0	0.0
27	**Regulatory Income Taxes - Federal** (line 26 x line 31)		0.0	0.0	0.0
28	**Regulatory Income Taxes - Provincial** (line 26 x line 32)		0.0	0.0	0.0
29	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		(16.6)	0.0	(16.6)
30	**Total Regulatory Income Taxes** (line 27 + line 28 + line 29)		(16.6)	0.0	(16.6)
	Income Tax Rate:				
31	**Federal Tax**		15.00%	0.00%	15.00%
32	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	0.00%	10.00%
33	**Total Income Tax Rate**		25.00%	0.00%	25.00%

For notes see Table 34a.

Numbers may not add due to rounding.

Table 34a
Notes to Table 34
2027 Summary of Changes in Regulatory Income Taxes for OPG Nuclear Facilities ($M)

1 As per Ex. F4-2-1, Table 3d, cols. (a) - (e), as revised for adjustments set out in App. A, Table 2a, Note 1.
2 Regulatory Earnings Before Tax are calculated as follows:

Line No.	Item	Reference for OEB Approved Amount	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
1a	After Tax Return on Equity - OPG Nuclear Facilities	App. A, Table 2, line 13 and line 14	740.1	(112.2)	628.0
2a	Less: Bruce Lease Net Revenues	App. A, Table 2, line 22	(5.2)	0.0	(5.2)
3a		line 1a - line 2a	745.4	(112.2)	633.2
4a	Additions for Regulatory Tax Purposes	line 14	1,463.9	(8.5)	1,455.4
5a	Less: Regulatory Asset Amort - Pension & OPEB Cash Vs Accrual Diff Def Act	App. D, Table 1, lines 13-15	0.0	0.0	0.0
6a	Deductions for Regulatory Tax Purposes	line 23	2,213.3	97.3	2,310.6
7a		line 3a + line 4a - line 5a - line 6a	(4.0)	(217.9)	(221.9)
8a	Regulatory Income Taxes - Federal	(lines 7a + 14a + 29) x line 31/ (1 - line 33)	(3.1)	(32.7)	(35.8)
9a	Regulatory Income Taxes - Provincial	(lines 7a + 14a + 29) x line 32 / (1 - line 33)	(2.1)	(21.8)	(23.9)
10a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 29	(16.6)	0.0	(16.6)
11a	Total Regulatory Income Taxes Before Loss Carry-Over	line 8a + line 9a + line 10a	(21.8)	(54.5)	(76.3)
12a	Effect on Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	line 25 x line 31	3.1	32.7	35.8
13a	Effect on Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	line 25 x line 32	2.1	21.8	23.9
14a	Effect on Total Regulatory Income Taxes Due to Loss Carry-Over	line 12a + line 13a	5.2	54.5	59.6
15a	Regulatory Income Taxes After Tax Loss Carry-Over - Federal	line 8a + line 12a	0.0	(0.0)	0.0
16a	Regulatory Income Taxes After Tax Loss Carry-Over - Provincial	line 9a + line 13a	0.0	0.0	0.0
17a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 29	(16.6)	0.0	(16.6)
18a	Total Regulatory Income Taxes After Tax Loss Carry-Over	line 15a + line 16a + line 17a	(16.6)	(0.0)	(16.6)
19a	After Tax Return on Equity	line 1a	740.1	(112.2)	628.0
20a	Less: Bruce Lease Net Revenues	line 2a	(5.2)	0.0	(5.2)
21a	Less: Regulatory Asset Amort - Pension & OPEB Cash Vs Accrual Diff Def Act	line 5a	0.0	0.0	0.0
22a	Add: Total Regulatory Income Taxes After Tax Loss Carry-Over	line 18a	(16.6)	(0.0)	(16.6)
23a	Regulatory Earnings Before Tax	lines 19a - 20a - 21a + 22a	728.7	(112.2)	616.6

3 Col. (c) per App. A, Table 2, line 19, col. (c).
4 Reflects the impact of the settlement adjusted used fuel storage & disposal expense per App. A, Table 7, col. (a), line 11 less line 4.
5 Reflects the impact of the settlement adjusted nuclear fuel bundle cost expense on fifty per cent of such expense that is not deductible for tax purposes until the following year.
6 Col. (c) per App. A, Table 51, line 24, col. (j) - col. (i), which reflects the forecast Capital Cost Allowance impacts of the forecast CEITCs and the reinstated accelerated investment property rules per Ex. L-F4-CCC-084 (Settlement Proposal, Section 2, Part D, vi) and the applicable Settlement Proposal adjustments to rate base per App. A, Table 2a, Note 2.
7 As discussed in Ex. F4-2-1, Section 3.1, in a situation where a tax loss is forecast in a given year(s) of the 2027-2031 period, the loss is applied (carried back or carried forward) to reduce such business' taxable income in other years of this period, with any remaining tax losses carried forward to future rate-setting periods. Refer to App. A, Table 39 for the regulatory tax loss continuity schedule.
8 Col. (c) includes CCA for the Pickering Refurbishment Program expenditures of $383.0M; CCA for the Darlington Refurbishment Program expenditures of $457.5M; and CCA for the OPG nuclear project expenditures, excluding the Pickering Refurbishment Program and the Darlington Refurbishment Program, treated as eligible for the Capacity Refurbishment Variance Account of $82.1M.

Col. (c) includes the CEITC impact on the CCA for OPG nuclear project expenditures excluding the Pickering Refurbishment Program, Darlington Refurbishment Program and other Capacity Refurbishment Variance Account eligible expenditures of ($0.7M).

Numbers may not add due to rounding.

Table 35
2028 Summary of Changes in Regulatory Income Taxes for OPG Nuclear Facilities ($M)

Line No.	Particulars	Note	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Determination of Regulatory Taxable Income				
1	**Regulatory Earnings Before Tax**	2	742.1	(126.3)	615.8
	Additions for Regulatory Tax Purposes:				
2	**Depreciation and Amortization**	3	708.5	(21.0)	687.5
3	**Nuclear Waste Management Expenses**	4	47.2	1.262	48.5
4	**Receipts from Nuclear Segregated Funds**		420.1	0.0	420.1
5	**Pension and OPEB Accrual**		224.8	0.0	224.8
6	**Regulatory Liability Amortization - Bruce Lease Net Revenues Variance Account**		(34.5)	0.0	(34.5)
7	**Regulatory Asset Amortization - Pension & OPEB Cash Versus Accrual Differential Deferral Account**		0.0	0.0	0.0
8	**Regulatory Liability Amortization - Income and Other Taxes Variance Account**		(0.7)	0.0	(0.7)
9	**Adjustment Related to Financing Cost for Nuclear Liabilities**		1.1	0.0	1.1
10	**Restricted Net Interest and Financing Expenses**		0.0	0.0	0.0
11	**Taxable SR&ED Investment Tax Credits of Prior Periods & Current Provincial Portion**		16.6	0.0	16.6
12	**Nuclear Fuel Expense Half Charge Adjustment**	5	30.2	(0.267)	29.9
13	**Other**		85.9	0.0	85.9
14	**Total Additions**		1,499.2	(20.0)	1,479.3
	Deductions for Regulatory Tax Purposes:				
15	**CCA**	6, 8	1,496.1	389.4	1,885.6
16	**Cash Expenditures for Nuclear Waste & Decommissioning**		539.1	0.0	539.1
17	**Contributions to Nuclear Segregated Funds and Earnings**		0.0	0.0	0.0
18	**Pension Plan Contributions**		103.4	0.0	103.4
19	**OPEB Payments**		122.4	0.0	122.4
20	**Reversal of Return on Rate Base Recorded in Deferral and Variance Accounts**		0.0	0.0	0.0
21	**Deductible SR&ED Qualifying Expenditures**		81.4	0.0	81.4
22	**Other**		9.8	0.0	9.8
23	**Total Deductions**		2,352.2	389.4	2,741.6
24	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 14 - line 23)		(110.8)	(535.7)	(646.5)
25	**Tax Loss Carry-Over / (Applied)**	7	110.8	535.7	646.5
26	**Regulatory Taxable Income After Tax Loss Carry-Over** (line 24 + line 25)		0.0	0.0	0.0
27	**Regulatory Income Taxes - Federal** (line 26 x line 31)		0.0	0.0	0.0
28	**Regulatory Income Taxes - Provincial** (line 26 x line 32)		0.0	0.0	0.0
29	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		(16.6)	0.0	(16.6)
30	**Total Regulatory Income Taxes** (line 27 + line 28 + line 29)		(16.6)	0.0	(16.6)
	Income Tax Rate:				
31	**Federal Tax**		15.00%	0.00%	15.00%
32	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	0.00%	10.00%
33	**Total Income Tax Rate**		25.00%	0.00%	25.00%

For notes see Table 35a.

Table 35a
Notes to Table 35
2028 Summary of Changes in Regulatory Income Taxes for OPG Nuclear Facilities ($M)

1 As per Ex. F4-2-1, Table 3d, cols. (a) - (e), as revised for adjustments set out in App. A, Table 3a, Note 1.
2 Regulatory Earnings Before Tax are calculated as follows:

Line No.	Item	Reference for OEB Approved	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
1a	After Tax Return on Equity - OPG Nuclear Facilities	App. A, Table 3, line 13 and line 14	770.2	(126.3)	643.9
2a	Less: Bruce Lease Net Revenues	App. A, Table 3, line 22	11.5	0.0	11.5
3a		line 1a - line 2a	758.7	(126.3)	632.4
4a	Additions for Regulatory Tax Purposes	line 14	1,499.2	(20.0)	1,479.3
5a	Less: Regulatory Asset Amort - Pension & OPEB Cash Vs Accrual Diff Def Act	App. D, Table 1, lines 13-15	0.0	0.0	0.0
6a	Deductions for Regulatory Tax Purposes	line 23	2,352.2	389.4	2,741.6
7a		line 3a + line 4a - line 5a - line 6a	(94.2)	(535.7)	(629.9)
8a	Regulatory Income Taxes - Federal	(lines 7a + 14a + 29) x line 31/ (1 - line 33)	(16.6)	(80.4)	(97.0)
9a	Regulatory Income Taxes - Provincial	(lines 7a + 14a + 29) x line 32 / (1 - line 33)	(11.1)	(53.6)	(64.7)
10a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 29	(16.6)	0.0	(16.6)
11a	Total Regulatory Income Taxes Before Loss Carry-Over	line 8a + line 9a + line 10a	(44.3)	(133.9)	(178.3)
12a	Effect on Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	line 25 x line 31	16.6	80.4	97.0
13a	Effect on Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	line 25 x line 32	11.1	53.6	64.7
14a	Effect on Total Regulatory Income Taxes Due to Loss Carry-Over	line 12a + line 13a	27.7	133.9	161.6
15a	Regulatory Income Taxes After Tax Loss Carry-Over - Federal	line 8a + line 12a	(0.0)	0.0	0.0
16a	Regulatory Income Taxes After Tax Loss Carry-Over - Provincial	line 9a + line 13a	(0.0)	0.0	0.0
17a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 29	(16.6)	0.0	(16.6)
18a	Total Regulatory Income Taxes After Tax Loss Carry-Over	line 15a + line 16a + line 17a	(16.6)	0.0	(16.6)
19a	After Tax Return on Equity	line 1a	770.2	(126.3)	643.9
20a	Less: Bruce Lease Net Revenues	line 2a	11.5	0.0	11.5
21a	Less: Regulatory Asset Amort - Pension & OPEB Cash Vs Accrual Diff Def Act	line 5a	0.0	0.0	0.0
22a	Add: Total Regulatory Income Taxes After Tax Loss Carry-Over	line 18a	(16.6)	0.0	(16.6)
23a	Regulatory Earnings Before Tax	lines 19a - 20a - 21a + 22a	742.1	(126.3)	615.8

3 Col. (c) per App. A, Table 3, line 19, col. (c).
4 Reflects the impact of the settlement adjusted used fuel storage & disposal expense per App. A, Table 7, col. (b), line 11 less line 4.
5 Reflects the impact of the settlement adjusted nuclear fuel bundle cost expense on fifty per cent of such expense that is not deductible for tax purposes until the following year.
6 Col. (c) per App. A, Table 52, line 24, col. (j) - col. (i), which reflects the forecast Capital Cost Allowance impacts of the forecast CEITCs and the reinstated accelerated investment property rules per Ex. L-F4-CCC-084 (Settlement Proposal, Section 2, Part D, vi) and the applicable Settlement Proposal adjustments to rate base per App. A, Table 3a, Note 2.
7 As discussed in Ex. F4-2-1, Section 3.1, in a situation where a tax loss is forecast in a given year(s) of the 2027-2031 period, the loss is applied (carried back or carried forward) to reduce such business' taxable income in other years of this period, with any remaining tax losses carried forward to future rate-setting periods. Refer to App. A, Table 39 for the regulatory tax loss continuity schedule.
8 Col. (c) includes CCA for the Pickering Refurbishment Program expenditures of $862.1M; CCA for the Darlington Refurbishment Program expenditures of $421.1M; and CCA for OPG nuclear project expenditures, excluding the Pickering Refurbishment Program and the Darlington Refurbishment Program, treated as eligible for the Capacity Refurbishment Variance Account, of $176.9M.

Col. (c) includes the CEITC impact on CCA for nuclear project expenditures excluding the Pickering Refurbishment Program, Darlington Refurbishment Program and other Capacity Refurbishment Variance Account eligible expenditures, of ($1.4M).

Table 36
2029 Summary of Changes in Regulatory Income Taxes for OPG Nuclear Facilities ($M)

Line No.	Particulars	Note	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Determination of Regulatory Taxable Income				
1	**Regulatory Earnings Before Tax**	2	770.2	(130.0)	640.2
	Additions for Regulatory Tax Purposes:				
2	**Depreciation and Amortization**	3	730.3	(26.3)	704.0
3	**Nuclear Waste Management Expenses**	4	58.9	1.1	60.0
4	**Receipts from Nuclear Segregated Funds**		347.2	0.0	347.2
5	**Pension and OPEB Accrual**		233.2	0.0	233.2
6	**Regulatory Liability Amortization - Bruce Lease Net Revenues Variance Account**		(34.5)	0.0	(34.5)
7	**Regulatory Asset Amortization - Pension & OPEB Cash Versus Accrual Differential Deferral Account**		0.0	0.0	0.0
8	**Regulatory Liability Amortization - Income and Other Taxes Variance Account**		(0.7)	0.0	(0.7)
9	**Adjustment Related to Financing Cost for Nuclear Liabilities**		0.0	0.0	0.0
10	**Restricted Net Interest and Financing Expenses**		0.0	0.0	0.0
11	**Taxable SR&ED Investment Tax Credits of Prior Periods & Current Provincial Portion**		16.6	0.0	16.6
12	**Nuclear Fuel Expense Half Charge Adjustment**	5	1.2	(1.456)	(0.3)
13	**Other**		87.4	0.0	87.4
14	**Total Additions**		1,439.6	(26.7)	1,412.9
	Deductions for Regulatory Tax Purposes:				
15	**CCA**	6, 8	1,945.0	232.6	2,177.6
16	**Cash Expenditures for Nuclear Waste & Decommissioning**		437.9	0.0	437.9
17	**Contributions to Nuclear Segregated Funds and Earnings**		0.0	0.0	0.0
18	**Pension Plan Contributions**		109.0	0.0	109.0
19	**OPEB Payments**		129.6	0.0	129.6
20	**Reversal of Return on Rate Base Recorded in Deferral and Variance Accounts**		0.0	0.0	0.0
21	**Deductible SR&ED Qualifying Expenditures**		81.4	0.0	81.4
22	**Other**		10.6	0.0	10.6
23	**Total Deductions**		2,713.5	232.6	2,946.1
24	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 14 - line 23)		(503.8)	(389.2)	(893.0)
25	**Tax Loss Carry-Over / (Applied)**	7	503.8	389.2	893.0
26	**Regulatory Taxable Income After Tax Loss Carry-Over** (line 24 + line 25)		0.0	0.0	0.0
27	**Regulatory Income Taxes - Federal** (line 26 x line 31)		0.0	0.0	0.0
28	**Regulatory Income Taxes - Provincial** (line 26 x line 32)		0.0	0.0	0.0
29	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		(16.6)	0.0	(16.6)
30	**Total Regulatory Income Taxes** (line 27 + line 28 + line 29)		(16.6)	0.0	(16.6)
	Income Tax Rate:				
31	**Federal Tax**		15.00%	0.00%	15.00%
32	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	0.00%	10.00%
33	**Total Income Tax Rate**		25.00%	0.00%	25.00%

For notes see Table 36a.

Table 36a
Notes to Table 36
2029 Summary of Changes in Regulatory Income Taxes for OPG Nuclear Facilities ($M)

1 As per Ex. F4-2-1, Table 3d, cols. (a) - (e), as revised for adjustments set out in App. A, Table 4a, Note 1.
2 Regulatory Earnings Before Tax are calculated as follows:

Line No.	Item	Reference for OEB Approved	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
1a	After Tax Return on Equity - OPG Nuclear Facilities	App. A, Table 4, line 13 and line 14	768.7	(130.0)	638.7
2a	Less: Bruce Lease Net Revenues	App. A, Table 4, line 22	(18.1)	0.0	(18.1)
3a		line 1a - line 2a	786.8	(130.0)	656.9
4a	Additions for Regulatory Tax Purposes	line 14	1,439.6	(26.7)	1,412.9
5a	Less: Regulatory Asset Amort - Pension & OPEB Cash Vs Accrual Diff Def Act	App. D, Table 1, lines 13-15	0.0	0.0	0.0
6a	Deductions for Regulatory Tax Purposes	line 23	2,713.5	232.6	2,946.1
7a		line 3a + line 4a - line 5a - line 6a	(487.1)	(389.2)	(876.3)
8a	Regulatory Income Taxes - Federal	(lines 7a + 14a + 29) x line 31/ (1 - line 33)	(75.6)	(58.4)	(133.9)
9a	Regulatory Income Taxes - Provincial	(lines 7a + 14a + 29) x line 32 / (1 - line 33)	(50.4)	(38.9)	(89.3)
10a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 29	(16.6)	0.0	(16.6)
11a	Total Regulatory Income Taxes Before Loss Carry-Over	line 8a + line 9a + line 10a	(142.6)	(97.3)	(239.9)
12a	Effect on Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	line 25 x line 31	75.6	58.4	133.9
13a	Effect on Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	line 25 x line 32	50.4	38.9	89.3
14a	Effect on Total Regulatory Income Taxes Due to Loss Carry-Over	line 12a + line 13a	125.9	97.3	223.2
15a	Regulatory Income Taxes After Tax Loss Carry-Over - Federal	line 8a + line 12a	0.0	0.0	0.0
16a	Regulatory Income Taxes After Tax Loss Carry-Over - Provincial	line 9a + line 13a	0.0	0.0	0.0
17a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 29	(16.6)	0.0	(16.6)
18a	Total Regulatory Income Taxes After Tax Loss Carry-Over	line 15a + line 16a + line 17a	(16.6)	0.0	(16.6)
19a	After Tax Return on Equity	line 1a	768.7	(130.0)	638.7
20a	Less: Bruce Lease Net Revenues	line 2a	(18.1)	0.0	(18.1)
21a	Less: Regulatory Asset Amort - Pension & OPEB Cash Vs Accrual Diff Def Act	line 5a	0.0	0.0	0.0
22a	Add: Total Regulatory Income Taxes After Tax Loss Carry-Over	line 18a	(16.6)	0.0	(16.6)
23a	Regulatory Earnings Before Tax	lines 19a - 20a - 21a + 22a	770.2	(130.0)	640.2

3 Col. (c) per App. A, Table 4, line 19, col. (c).
4 Reflects the impact of the settlement adjusted used fuel storage & disposal expense per App. A, Table 7, col. (c), line 11 less line 4.
5 Reflects the impact of the settlement adjusted nuclear fuel bundle cost expense on fifty per cent of such expense that is not deductible for tax purposes until the following year.
6 Col. (c) per App. A, Table 53, line 24, col. (j) - col. (i), which reflects the forecast Capital Cost Allowance impacts of the forecast CEITCs and the reinstated accelerated investment property rules per Ex. L-F4-CCC-084 (Settlement Proposal, Section 2, Part D, vi) and the applicable Settlement Proposal adjustments to rate base per App. A, Table 4a, Note 2.
7 As discussed in Ex. F4-2-1, section 3.1, in a situation where a tax loss is forecast in a given year(s) of the 2027-2031 period, the loss is applied (carried back or carried forward) to reduce such business' taxable income in other years of this period, with any remaining tax losses carried forward to future rate-setting periods. Refer to App. A, Table 39 for the regulatory tax loss continuity schedule.
8 Col. (c) includes CCA for the Pickering Refurbishment Program expenditures of $1,207.9M; CCA for the Darlington Refurbishment Program expenditures of $387.6M; and CCA for OPG nuclear project expenditures, excluding the Pickering Refurbishment Program and the Darlington Refurbishment Program, treated as eligible for the Capacity Refurbishment Variance Account, of $179.5M.

Col. (c) includes the CEITC impact on CCA for nuclear project expenditures excluding the Pickering Refurbishment Program, Darlington Refurbishment Program and other Capacity Refurbishment Variance Account eligible expenditures, of ($2.1M).

Numbers may not add due to rounding.

Table 37

2030 Summary of Changes in Regulatory Income Taxes for OPG Nuclear Facilities ($M)

Line No.	Particulars	Note	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Determination of Regulatory Taxable Income				
1	**Regulatory Earnings Before Tax**	2	772.9	(143.1)	629.8
	Additions for Regulatory Tax Purposes:				
2	**Depreciation and Amortization**	3	779.8	(36.2)	743.7
3	**Nuclear Waste Management Expenses**	4	72.9	1.6	74.5
4	**Receipts from Nuclear Segregated Funds**		326.7	0.0	326.7
5	**Pension and OPEB Accrual**		239.0	0.0	239.0
6	**Regulatory Liability Amortization - Bruce Lease Net Revenues Variance Account**		0.0	0.0	0.0
7	**Regulatory Asset Amortization - Pension & OPEB Cash Versus Accrual Differential Deferral Account**		0.0	0.0	0.0
8	**Regulatory Liability Amortization - Income and Other Taxes Variance Account**		0.0	0.0	0.0
9	**Adjustment Related to Financing Cost for Nuclear Liabilities**		0.0	0.0	0.0
10	**Restricted Net Interest and Financing Expenses**		0.0	0.0	0.0
11	**Taxable SR&ED Investment Tax Credits of Prior Periods & Current Provincial Portion**		16.6	0.0	16.6
12	**Nuclear Fuel Expense Half Charge Adjustment**	5	12.7	(1.400)	11.3
13	**Other**		95.3	0.0	95.3
14	**Total Additions**		1,543.1	(36.0)	1,507.1
	Deductions for Regulatory Tax Purposes:				
15	**CCA**	6, 8	2,169.5	(154.1)	2,015.4
16	**Cash Expenditures for Nuclear Waste & Decommissioning**		443.3	0.0	443.3
17	**Contributions to Nuclear Segregated Funds and Earnings**		0.0	0.0	0.0
18	**Pension Plan Contributions**		111.6	0.0	111.6
19	**OPEB Payments**		134.3	0.0	134.3
20	**Reversal of Return on Rate Base Recorded in Deferral and Variance Accounts**		0.0	0.0	0.0
21	**Deductible SR&ED Qualifying Expenditures**		81.4	0.0	81.4
22	**Other**		10.0	0.0	10.0
23	**Total Deductions**		2,950.1	(154.1)	2,796.0
24	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 14 - line 23)		(634.2)	(24.9)	(659.1)
25	**Tax Loss Carry-Over / (Applied)**	7	634.2	24.9	659.1
26	**Regulatory Taxable Income After Tax Loss Carry-Over** (line 24 + line 25)		0.0	0.0	0.0
27	**Regulatory Income Taxes - Federal** (line 26 x line 31)		0.0	0.0	0.0
28	**Regulatory Income Taxes - Provincial** (line 26 x line 32)		0.0	0.0	0.0
29	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		(16.6)	0.0	(16.6)
30	**Total Regulatory Income Taxes** (line 27 + line 28 + line 29)		(16.6)	0.0	(16.6)
	Income Tax Rate:				
31	**Federal Tax**		15.00%	0.00%	15.00%
32	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	0.00%	10.00%
33	**Total Income Tax Rate**		25.00%	0.00%	25.00%

For notes see Table 37a.

Table 37a
Notes to Table 37
2030 Summary of Changes in Regulatory Income Taxes for OPG Nuclear Facilities ($M)

1 As per Ex. F4-2-1, Table 3d, cols. (a) - (e), as revised for adjustments set out in App. A, Table 5a, Note 1.
2 Regulatory Earnings Before Tax are calculated as follows:

Line No.	Item	Reference for OEB Approved	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
1a	After Tax Return on Equity - OPG Nuclear Facilities	App. A, Table 5, line 13 and line 14	796.8	(143.1)	653.7
2a	Less: Bruce Lease Net Revenues	App. A, Table 5, line 22	7.3	0.0	7.3
3a		line 1a - line 2a	789.5	(143.1)	646.4
4a	Additions for Regulatory Tax Purposes	line 14	1,543.1	(36.0)	1,507.1
5a	Less: Regulatory Asset Amort - Pension & OPEB Cash Vs Accrual Diff Def Act	App. D, Table 1, lines 13-15	0.0	0.0	0.0
6a	Deductions for Regulatory Tax Purposes	line 23	2,950.1	(154.1)	2,796.0
7a		line 3a + line 4a - line 5a - line 6a	(617.6)	(24.9)	(642.5)
8a	Regulatory Income Taxes - Federal	(lines 7a + 14a + 29) x line 31/ (1 - line 33)	(95.1)	(3.7)	(98.9)
9a	Regulatory Income Taxes - Provincial	(lines 7a + 14a + 29) x line 32 / (1 - line 33)	(63.4)	(2.5)	(65.9)
10a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 29	(16.6)	0.0	(16.6)
11a	Total Regulatory Income Taxes Before Loss Carry-Over	line 8a + line 9a + line 10a	(175.2)	(6.2)	(181.4)
12a	Effect on Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	line 25 x line 31	95.1	3.7	98.9
13a	Effect on Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	line 25 x line 32	63.4	2.5	65.9
14a	Effect on Total Regulatory Income Taxes Due to Loss Carry-Over	line 12a + line 13a	158.5	6.2	164.8
15a	Regulatory Income Taxes After Tax Loss Carry-Over - Federal	line 8a + line 12a	0.0	0.0	0.0
16a	Regulatory Income Taxes After Tax Loss Carry-Over - Provincial	line 9a + line 13a	0.0	0.0	0.0
17a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 29	(16.6)	0.0	(16.6)
18a	Total Regulatory Income Taxes After Tax Loss Carry-Over	line 15a + line 16a + line 17a	(16.6)	0.0	(16.6)
19a	After Tax Return on Equity	line 1a	796.8	(143.1)	653.7
20a	Less: Bruce Lease Net Revenues	line 2a	7.3	0.0	7.3
21a	Less: Regulatory Asset Amort - Pension & OPEB Cash Vs Accrual Diff Def Act	line 5a	0.0	0.0	0.0
22a	Add: Total Regulatory Income Taxes After Tax Loss Carry-Over	line 18a	(16.6)	0.0	(16.6)
23a	Regulatory Earnings Before Tax	lines 19a - 20a - 21a + 22a	772.9	(143.1)	629.8

3 Col. (c) per App. A, Table 5, line 19, col. (c).
4 Reflects the impact of the settlement adjusted used fuel storage & disposal expense per App. A, Table 7, col. (d), line 11 less line 4.
5 Reflects the impact of the settlement adjusted nuclear fuel bundle cost expense on fifty per cent of such expense that is not deductible for tax purposes until the following year.
6 Col. (c) per App. A, Table 54, line 24, col. (j) - col. (i), which reflects the forecast Capital Cost Allowance impacts of the forecast CEITCs and the reinstated accelerated investment property rules per Ex. L-F4-CCC-084 (Settlement Proposal, Section 2, Part D, vi) and the applicable Settlement Proposal adjustments to rate base per App. A, Table 5a, Note 2.
7 As discussed in Ex. F4-2-1, section 3.1, in a situation where a tax loss is forecast in a given year(s) of the 2027-2031 period, the loss is applied (carried back or carried forward) to reduce such business' taxable income in other years of this period, with any remaining tax losses carried forward to future rate-setting periods. Refer to App. A, Table 39 for the regulatory tax loss continuity schedule.
8 Col. (c) includes CCA for the Pickering Refurbishment Program expenditures of $1,079.1M; CCA for the Darlington Refurbishment Program expenditures of $356.9M; and CCA for OPG nuclear project expenditures, excluding the Pickering Refurbishment Program and the Darlington Refurbishment Program, treated as eligible for the Capacity Refurbishment Variance Account, of $138.0M.

Col. (c) includes the CEITC impact on CCA for nuclear project expenditures excluding the Pickering Refurbishment Program, Darlington Refurbishment Program and other Capacity Refurbishment Variance Account eligible expenditures, of ($2.4M).

Numbers may not add due to rounding.

Table 38

2031 Summary of Changes in Regulatory Income Taxes for OPG Nuclear Facilities ($M)

Line No.	Particulars	Note	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Determination of Regulatory Taxable Income				
1	**Regulatory Earnings Before Tax**	2	1,115.8	(217.6)	898.3
	Additions for Regulatory Tax Purposes:				
2	**Depreciation and Amortization**	3	992.6	(60.6)	932.0
3	**Nuclear Waste Management Expenses**	4	79.1	1.9	81.0
4	**Receipts from Nuclear Segregated Funds**		342.0	0.0	342.0
5	**Pension and OPEB Accrual**		251.0	0.0	251.0
6	**Regulatory Liability Amortization - Bruce Lease Net Revenues Variance Account**		0.0	0.0	0.0
7	**Regulatory Asset Amortization - Pension & OPEB Cash Versus Accrual Differential Deferral Account**		0.0	0.0	0.0
8	**Regulatory Liability Amortization - Income and Other Taxes Variance Account**		0.0	0.0	0.0
9	**Adjustment Related to Financing Cost for Nuclear Liabilities**		0.0	0.0	0.0
10	**Restricted Net Interest and Financing Expenses**		0.0	0.0	0.0
11	**Taxable SR&ED Investment Tax Credits of Prior Periods & Current Provincial Portion**		16.6	0.0	16.6
12	**Nuclear Fuel Expense Half Charge Adjustment**	5	20.4	(1.0)	19.5
13	**Other**		109.0	0.0	109.0
14	**Total Additions**		1,810.7	(59.7)	1,751.0
	Deductions for Regulatory Tax Purposes:				
15	**CCA**	6, 8	2,268.4	(204.3)	2,064.0
16	**Cash Expenditures for Nuclear Waste & Decommissioning**		472.1	0.0	472.1
17	**Contributions to Nuclear Segregated Funds and Earnings**		0.0	0.0	0.0
18	**Pension Plan Contributions**		115.3	0.0	115.3
19	**OPEB Payments**		139.4	0.0	139.4
20	**Reversal of Return on Rate Base Recorded in Deferral and Variance Accounts**		0.0	0.0	0.0
21	**Deductible SR&ED Qualifying Expenditures**		81.4	0.0	81.4
22	**Other**		14.6	0.0	14.6
23	**Total Deductions**		3,091.2	(204.3)	2,886.8
24	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 14 - line 23)		(164.6)	(72.9)	(237.5)
25	**Tax Loss Carry-Over / (Applied)**	7	164.6	72.9	237.5
26	**Regulatory Taxable Income After Tax Loss Carry-Over** (line 24 + line 25)		0.0	0.0	0.0
27	**Regulatory Income Taxes - Federal** (line 26 x line 31)		0.0	0.0	0.0
28	**Regulatory Income Taxes - Provincial** (line 26 x line 32)		0.0	0.0	0.0
29	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		(16.6)	0.0	(16.6)
30	**Total Regulatory Income Taxes** (line 27 + line 28 + line 29)		(16.6)	0.0	(16.6)
	Income Tax Rate:				
31	**Federal Tax**		15.00%	0.00%	15.00%
32	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	0.00%	10.00%
33	**Total Income Tax Rate**		25.00%	0.00%	25.00%

For notes see Table 38a.

Numbers may not add due to rounding.

Table 38a
Notes to Table 38
2031 Summary of Changes in Regulatory Income Taxes for OPG Nuclear Facilities ($M)

1 As per Ex. F4-2-1, Table 3d, cols. (a) - (e), as revised for adjustments set out in App. A, Table 6a, Note 1.
2 Regulatory Earnings Before Tax are calculated as follows:

Line No.	Item	Reference for OEB Approved	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
1a	After Tax Return on Equity - OPG Nuclear Facilities	App. A, Table 6, line 13 and line 14	1,115.4	(217.6)	897.8
2a	Less: Bruce Lease Net Revenues	App. A, Table 6, line 22	(17.1)	0.0	(17.1)
3a		line 1a - line 2a	1,132.5	(217.6)	914.9
4a	Additions for Regulatory Tax Purposes	line 14	1,810.7	(59.7)	1,751.0
5a	Less: Regulatory Asset Amort - Pension & OPEB Cash Vs Accrual Diff Def Act	App. D, Table 1, lines 13-15	0.0	0.0	0.0
6a	Deductions for Regulatory Tax Purposes	line 23	3,091.2	(204.3)	2,886.8
7a		line 3a + line 4a - line 5a - line 6a	(148.0)	(72.9)	(220.9)
8a	Regulatory Income Taxes - Federal	(lines 7a + 14a + 29) x line 31/ (1 - line 33)	(24.7)	(10.9)	(35.6)
9a	Regulatory Income Taxes - Provincial	(lines 7a + 14a + 29) x line 32 / (1 - line 33)	(16.5)	(7.3)	(23.8)
10a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 29	(16.6)	0.0	(16.6)
11a	Total Regulatory Income Taxes Before Loss Carry-Over	line 8a + line 9a + line 10a	(57.8)	(18.2)	(76.0)
12a	Effect on Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	line 25 x line 31	24.7	10.9	35.6
13a	Effect on Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	line 25 x line 32	16.5	7.3	23.8
14a	Effect on Total Regulatory Income Taxes Due to Loss Carry-Over	line 12a + line 13a	41.2	18.2	59.4
15a	Regulatory Income Taxes After Tax Loss Carry-Over - Federal	line 8a + line 12a	0.0	(0.0)	0.0
16a	Regulatory Income Taxes After Tax Loss Carry-Over - Provincial	line 9a + line 13a	0.0	(0.0)	0.0
17a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 29	(16.6)	0.0	(16.6)
18a	Total Regulatory Income Taxes After Tax Loss Carry-Over	line 15a + line 16a + line 17a	(16.6)	(0.0)	(16.6)
19a	After Tax Return on Equity	line 1a	1,115.4	(217.6)	897.8
20a	Less: Bruce Lease Net Revenues	line 2a	(17.1)	0.0	(17.1)
21a	Less: Regulatory Asset Amort - Pension & OPEB Cash Vs Accrual Diff Def Act	line 5a	0.0	0.0	0.0
22a	Add: Total Regulatory Income Taxes After Tax Loss Carry-Over	line 18a	(16.6)	(0.0)	(16.6)
23a	Regulatory Earnings Before Tax	lines 19a - 20a - 21a + 22a	1,115.8	(217.6)	898.3

3 Col. (c) per App. A, Table 6, line 19, col. (c).
4 Reflects the impact of the settlement adjusted used fuel storage & disposal expense per App. A, Table 7, col. (e), line 11 less line 4.
5 Reflects the impact of the settlement adjusted nuclear fuel bundle cost expense on fifty per cent of such expense that is not deductible for tax purposes until the following year.
6 Col. (c) per App. A, Table 55, line 24, col. (j) - col. (i), which reflects the forecast Capital Cost Allowance impacts of the forecast CEITCs and the reinstated accelerated investment property rules per Ex. L-F4-CCC-084 (Settlement Proposal, Section 2, Part D, vi) and the applicable Settlement Proposal adjustments to rate base per App. A, Table 6a, Note 2.
7 As discussed in Ex. F4-2-1, section 3.1, in a situation where a tax loss is forecast in a given year(s) of the 2027-2031 period, the loss is applied (carried back or carried forward) to reduce such business' taxable income in other years of this period, with any remaining tax losses carried forward to future rate-setting periods. Refer to App. A, Table 39 for the regulatory tax loss continuity schedule.
8 Col. (c) includes annual CCA for the Pickering Refurbishment Program expenditures, of $1,106.9M; CCA for the Darlington Refurbishment Program expenditures of $328.7M; and CCA for OPG nuclear project expenditures, excluding the Pickering Refurbishment Program and the Darlington Refurbishment Program, treated as eligible for the Capacity Refurbishment Variance Account, of $171.0M.

Col. (c) includes the CEITC impact on annual CCA for nuclear project expenditures excluding the Pickering Refurbishment Program, Darlington Refurbishment Program and other Capacity Refurbishment Variance Account eligible expenditures, of ($2.9M).

Table 39
2027 - 2031 Summary of OPG Nuclear Regulatory Tax Losses ($M)

Line No.	Particulars	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
1	**Loss Brought Forward**	1	(373.4)	(612.0)	(1,258.5)	(2,151.5)	(2,810.6)
2	**Income/(Loss) for the Year**	2	(238.6)	(646.5)	(893.0)	(659.1)	(237.5)
3	**Tax Loss Applied**	2	0.0	0.0	0.0	0.0	0.0
4	**Loss Carried Forward** (line 1 + line 2 + line 3)		(612.0)	(1,258.5)	(2,151.5)	(2,810.6)	(3,048.1)

Notes:
1 Col. (a) per EB-2020-0290 Payment Amounts Order, App. A, Table 22, line 4, col. (e).
2 App. A, Tables 34-38, line 24, col. (c)

Numbers may not add due to rounding.

Table 40
2027 Summary of Changes in Regulatory Income Taxes for DNNP LP ($M)

Line No.	Particulars	Note	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Determination of Regulatory Taxable Income				
1	**Regulatory Earnings Before Tax**	2	0.0	0.0	0.0
	Additions for Regulatory Tax Purposes:				
2	**Depreciation and Amortization**	3	0.0	0.0	0.0
3	**Pension and OPEB Accrual**		14.1	0.0	14.1
4	**Restricted Net Interest and Financing Expenses**		0.0	0.0	0.0
5	**Taxable SR&ED Investment Tax Credits of Prior Periods & Current Provincial Portion**		0.0	0.0	0.0
6	**Other**		0.0	0.0	0.0
7	**Total Additions**		14.1	0.0	14.1
	Deductions for Regulatory Tax Purposes:				
8	**CCA**	4	195.5	72.7	268.2
9	**Pension Plan Contributions**		1.4	0.0	1.4
10	**OPEB Payments**		12.7	0.0	12.7
11	**Reversal of Return on Rate Base Recorded in Deferral and Variance Accounts**		0.0	0.0	0.0
12	**Deductible SR&ED Qualifying Expenditures**		0.0	0.0	0.0
13	**Other**		0.0	0.0	0.0
14	**Total Deductions**		209.6	72.7	282.3
15	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 7 - line 14)		(195.5)	(72.7)	(268.2)
16	**Tax Loss (Income) Attributable to Non-taxable Partners** (line 15 x 22.5%)	5, 6	44.0	16.4	60.3
17	**Tax Loss (Income) Attributable to Taxable Partners** (line 15 x 77.5%)	5, 6	151.5	56.3	207.8
18	**Regulatory Taxable Income After Tax Loss Carry-Over Subject to Tax** ([line 15 x 77.5%] + line 17)	6	0.0	0.0	0.0
19	**Regulatory Income Taxes - Federal** (line 18 x line 24)		0.0	0.0	0.0
20	**Regulatory Income Taxes - Provincial** (line 18 x line 25)		0.0	0.0	0.0
21	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		0.0	0.0	0.0
22	**Less: SR&ED Investment Tax Credits - Non-taxable Partners** (line 21 x 22.5%)		0.0	0.0	0.0
23	**Total Regulatory Income Taxes** (line 19 + line 20 + line 21 - line 22)		0.0	0.0	0.0
	Income Tax Rate:				
24	**Federal Tax**		15.00%	0.00%	15.00%
25	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	0.00%	10.00%
26	**Total Income Tax Rate**		25.00%	0.00%	25.00%

For notes see Table 40a.

Table 40a
Notes to Table 40
2027 Summary of Changes in Regulatory Income Taxes for DNNP LP ($M)

1 Per Ex. F4-2-1, Table 3g, col. (b).
2 Regulatory Earnings Before Tax are calculated as follows (before adjustment for non-taxable partners):

Line No.	Item	Reference for OEB Approved	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
1a	After Tax Return on Equity - DNNP LP	App. A, Table 8, line 11	0.0	0.0	0.0
2a	Additions for Regulatory Tax Purposes	line 7	14.1	0.0	14.1
3a	Deductions for Regulatory Tax Purposes	line 14	209.6	72.7	282.3
4a		line 1a + line 2a - line 3a	(195.5)	(72.7)	(268.2)
5a	Regulatory Income Taxes - Federal	(lines 4a + 11a + line 21) x line 24/ (1 - line 26)	(29.3)	(10.9)	(40.2)
6a	Regulatory Income Taxes - Provincial	(lines 4a + 11a + line 21) x line 25/ (1 - line 26)	(19.5)	(7.3)	(26.8)
7a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 21	0.0	0.0	0.0
8a	Total Regulatory Income Taxes Before Loss Carry-Over	line 5a + line 6a + line 7a	(48.9)	(18.2)	(67.0)
9a	Effect on Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	(line 16 + line 17) x line 24	29.3	10.9	40.2
10a	Effect on Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	(line 16 + line 17) x line 25	19.5	7.3	26.8
11a	Effect on Total Regulatory Income Taxes Due to Loss Carry-Over	line 9a + line 10a	48.9	18.2	67.0
12a	Regulatory Income Taxes After Tax Loss Carry-Over - Federal	line 5a + line 9a	0.0	0.0	0.0
13a	Regulatory Income Taxes After Tax Loss Carry-Over - Provincial	line 6a + line 10a	0.0	0.0	0.0
14a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 7a	0.0	0.0	0.0
15a	Total Regulatory Income Taxes After Tax Loss Carry-Over	line 12a + line 13a + line 14a	0.0	0.0	0.0
16a	After Tax Return on Equity	line 1a	0.0	0.0	0.0
17a	Add: Total Regulatory Income Taxes After Tax Loss Carry-Over	line 15a	0.0	0.0	0.0
18a	Regulatory Earnings Before Tax	line 16a + line 17a	0.0	0.0	0.0

3 Col. (c) per App. A, Table 8, line 15, col. (c).
4 Col. (c) per App. A, Table 56, line 23, col. (j) - col. (i), which reflects the Capital Cost Allowances impacts of the forecast CEITCs and the reinstated accelerated investment property program per Ex. L-F4-CCC-084 (Settlement Proposal, Section 3, Part D, iv).
5 As discussed in Ex. F4-2-1, Section 3.1, in a situation where a tax loss is forecast in a given year(s) of the 2027-2031 period, the loss is applied (carried back or carried forward) to reduce such business' taxable income in other years of this period, with any remaining tax losses carried forward to future rate-setting periods. Refer to App. A, Table 45 for the regulatory tax loss continuity schedule.
6 DNNP LP is a limited partnership in which non-taxable investors hold a stake of 22.5% and as a result, are not subject to DNNP LP's taxable income or entitled to utilize the corresponding proportion of the entity's tax loss carry-over each year. Therefore, DNNP LP's revenue requirement reflects the impact of the remaining 77.5% interest in determining regulatory income taxes and the tax loss carry-over each year.

Numbers may not add due to rounding.

Table 41
2028 Summary of Changes in Regulatory Income Taxes for DNNP LP ($M)

Line No.	Particulars	Note	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Determination of Regulatory Taxable Income				
1	**Regulatory Earnings Before Tax**	2	0.0	0.0	0.0
	Additions for Regulatory Tax Purposes:				
2	**Depreciation and Amortization**	3	0.0	0.0	0.0
3	**Pension and OPEB Accrual**		13.3	0.0	13.3
4	**Restricted Net Interest and Financing Expenses**		0.0	0.0	0.0
5	**Taxable SR&ED Investment Tax Credits of Prior Periods & Current Provincial Portion**		0.0	0.0	0.0
6	**Other**		0.0	0.0	0.0
7	**Total Additions**		13.3	0.0	13.3
	Deductions for Regulatory Tax Purposes:				
8	**CCA**	4	311.1	74.5	385.6
9	**Pension Plan Contributions**		0.3	0.0	0.3
10	**OPEB Payments**		13.0	0.0	13.0
11	**Reversal of Return on Rate Base Recorded in Deferral and Variance Accounts**		0.0	0.0	0.0
12	**Deductible SR&ED Qualifying Expenditures**		0.0	0.0	0.0
13	**Other**		0.0	0.0	0.0
14	**Total Deductions**		324.4	74.5	398.9
15	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 7 - line 14)		(311.1)	(74.5)	(385.6)
16	**Tax Loss (Income) Attributable to Non-taxable Partners** (line 15 x 22.5%)	5, 6	70.0	16.8	86.8
17	**Tax Loss (Income) Attributable to Taxable Partners** (line 15 x 77.5%)	5, 6	241.1	57.7	298.8
18	**Regulatory Taxable Income After Tax Loss Carry-Over Subject to Tax** ([line 15 x 77.5%] + line 17)	6	0.0	0.0	0.0
19	**Regulatory Income Taxes - Federal** (line 19 x line 24)		0.0	0.0	0.0
20	**Regulatory Income Taxes - Provincial** (line 19 x line 25)		0.0	0.0	0.0
21	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		0.0	0.0	0.0
22	**Less: SR&ED Investment Tax Credits - Non-taxable Partners** (line 21 x 22.5%)		0.0	0.0	0.0
23	**Total Regulatory Income Taxes** (line 19 + line 20 + line 21 - line 22)		0.0	0.0	0.0
	Income Tax Rate:				
24	**Federal Tax**		15.00%	0.00%	15.00%
25	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	0.00%	10.00%
26	**Total Income Tax Rate**		25.00%	0.00%	25.00%

For notes see Table 41a.

Table 41a
Notes to Table 41
2028 Summary of Changes in Regulatory Income Taxes for DNNP LP ($M)

1 Per Ex. F4-2-1, Table 3g, col. (c).
2 Regulatory Earnings Before Tax are calculated as follows (before adjustment for non-taxable partners):

Line No.	Item	Reference for OEB Approved	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
1a	After Tax Return on Equity - DNNP LP	App. A, Table 9, line 11	0.0	0.0	0.0
2a	Additions for Regulatory Tax Purposes	line 7	13.3	0.0	13.3
3a	Deductions for Regulatory Tax Purposes	line 14	324.4	74.5	398.9
4a		line 1a + line 2a - line 3a	(311.1)	(74.5)	(385.6)
5a	Regulatory Income Taxes - Federal	(lines 4a + 11a + line 21) x line 24/ (1 - line 26)	(46.7)	(11.2)	(57.8)
6a	Regulatory Income Taxes - Provincial	(lines 4a + 11a + line 21) x line 25/ (1 - line 26)	(31.1)	(7.4)	(38.6)
7a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 21	0.0	0.0	0.0
8a	Total Regulatory Income Taxes Before Loss Carry-Over	line 5a + line 6a + line 7a	(77.8)	(18.6)	(96.4)
9a	Effect on Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	(line 16 + line 17) x line 24	46.7	11.2	57.8
10a	Effect on Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	(line 16 + line 17) x line 25	31.1	7.4	38.6
11a	Effect on Total Regulatory Income Taxes Due to Loss Carry-Over	line 9a + line 10a	77.8	18.6	96.4
12a	Regulatory Income Taxes After Tax Loss Carry-Over - Federal	line 5a + line 9a	0.0	0.0	0.0
13a	Regulatory Income Taxes After Tax Loss Carry-Over - Provincial	line 6a + line 10a	0.0	0.0	0.0
14a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 7a	0.0	0.0	0.0
15a	Total Regulatory Income Taxes After Tax Loss Carry-Over	line 12a + line 13a + line 14a	0.0	0.0	0.0
16a	After Tax Return on Equity	line 1a	0.0	0.0	0.0
17a	Add: Total Regulatory Income Taxes After Tax Loss Carry-Over	line 15a	0.0	0.0	0.0
18a	Regulatory Earnings Before Tax	line 16a + line 17a	0.0	0.0	0.0

3 Col. (c) per App. A, Table 9, line 15, col. (c).
4 Col. (c) per App. A, Table 57, line 23, col. (j) - col. (i), which reflects the Capital Cost Allowances impacts of the forecast CEITCs and the reinstated accelerated investment property program per Ex. L-F4-CCC-084 (Settlement Proposal, Section 3, Part D, iv).
5 As discussed in Ex. F4-2-1, Section 3.1, in a situation where a tax loss is forecast in a given year(s) of the 2027-2031 period, the loss is applied (carried back or carried forward) to reduce such business' taxable income in other years of this period, with any remaining tax losses carried forward to future rate-setting periods. Refer to App. A, Table 45 for the regulatory tax loss continuity schedule.
6 DNNP LP is a limited partnership in which non-taxable investors hold a stake of 22.5% and as a result, are not subject to DNNP LP's taxable income or entitled to utilize the corresponding proportion of the entity's tax loss carry-over each year. Therefore, DNNP LP's revenue requirement reflects the impact of the remaining 77.5% interest in determining regulatory income taxes and the tax loss carry-over each year.

Numbers may not add due to rounding.

Table 42
2029 Summary of Changes in Regulatory Income Taxes for DNNP LP ($M)

Line No.	Particulars	Note	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Determination of Regulatory Taxable Income				
1	**Regulatory Earnings Before Tax**	2	0.2	0.0	0.2
	Additions for Regulatory Tax Purposes:				
2	**Depreciation and Amortization**	3	0.0	0.0	0.0
3	**Pension and OPEB Accrual**		11.9	0.0	11.9
4	**Restricted Net Interest and Financing Expenses**		0.0	0.0	0.0
5	**Taxable SR&ED Investment Tax Credits of Prior Periods & Current Provincial Portion**		0.0	0.0	0.0
6	**Other**		0.0	0.0	0.0
7	**Total Additions**		11.9	0.0	11.9
	Deductions for Regulatory Tax Purposes:				
8	**CCA**	4	345.0	(19.8)	325.2
9	**Pension Plan Contributions**		0.4	0.0	0.4
10	**OPEB Payments**		11.5	0.0	11.5
11	**Reversal of Return on Rate Base Recorded in Deferral and Variance Accounts**		0.0	0.0	0.0
12	**Deductible SR&ED Qualifying Expenditures**		0.0	0.0	0.0
13	**Other**		0.0	0.0	0.0
14	**Total Deductions**		356.9	(19.8)	337.1
15	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 7 - line 14)		(344.8)	19.8	(325.0)
16	**Tax Loss (Income) Attributable to Non-taxable Partners** (line 15 x 22.5%)	5, 6	77.6	(4.5)	73.1
17	**Tax Loss (Income) Attributable to Taxable Partners** (line 15 x 77.5%)	5, 6	267.2	(15.4)	251.9
18	**Regulatory Taxable Income After Tax Loss Carry-Over Subject to Tax** ([line 15 x 77.5%] + line 17)	6	0.0	0.0	0.0
19	**Regulatory Income Taxes - Federal** (line 19 x line 24)		0.0	0.0	0.0
20	**Regulatory Income Taxes - Provincial** (line 19 x line 25)		0.0	0.0	0.0
21	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		0.0	0.0	0.0
22	**Less: SR&ED Investment Tax Credits - Non-taxable Partners** (line 21 x 22.5%)		0.0	0.0	0.0
23	**Total Regulatory Income Taxes** (line 19 + line 20 + line 21 - line 22)		0.0	0.0	0.0
	Income Tax Rate:				
24	**Federal Tax**		15.00%	0.00%	15.00%
25	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	0.00%	10.00%
26	**Total Income Tax Rate**		25.00%	0.00%	25.00%

For notes see Table 42a.

Table 42a
Notes to Table 42
2029 Summary of Changes in Regulatory Income Taxes for DNNP LP ($M)

1 Per Ex. F4-2-1, Table 3g, col. (d).
2 Regulatory Earnings Before Tax are calculated as follows (before adjustment for non-taxable partners):

Line No.	Item	Reference for OEB Approved	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
1a	After Tax Return on Equity - DNNP LP	App. A, Table 10, line 11	0.2	0.0	0.2
2a	Additions for Regulatory Tax Purposes	line 7	11.9	0.0	11.9
3a	Deductions for Regulatory Tax Purposes	line 14	356.9	(19.8)	337.1
4a		line 1a + line 2a - line 3a	(344.8)	19.8	(325.0)
5a	Regulatory Income Taxes - Federal	(lines 4a + 11a + line 21) x line 24/ (1 - line 26)	(51.7)	3.0	(48.7)
6a	Regulatory Income Taxes - Provincial	(lines 4a + 11a + line 21) x line 25/ (1 - line 26)	(34.5)	2.0	(32.5)
7a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 21	0.0	0.0	0.0
8a	Total Regulatory Income Taxes Before Loss Carry-Over	line 5a + line 6a + line 7a	(86.2)	5.0	(81.2)
9a	Effect on Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	(line 16 + line 17) x line 24	51.7	(3.0)	48.7
10a	Effect on Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	(line 16 + line 17) x line 25	34.5	(2.0)	32.5
11a	Effect on Total Regulatory Income Taxes Due to Loss Carry-Over	line 9a + line 10a	86.2	(5.0)	81.2
12a	Regulatory Income Taxes After Tax Loss Carry-Over - Federal	line 5a + line 9a	0.0	0.0	0.0
13a	Regulatory Income Taxes After Tax Loss Carry-Over - Provincial	line 6a + line 10a	0.0	0.0	0.0
14a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 7a	0.0	0.0	0.0
15a	Total Regulatory Income Taxes After Tax Loss Carry-Over	line 12a + line 13a + line 14a	0.0	0.0	0.0
16a	After Tax Return on Equity	line 1a	0.2	0.0	0.2
17a	Add: Total Regulatory Income Taxes After Tax Loss Carry-Over	line 15a	0.0	0.0	0.0
18a	Regulatory Earnings Before Tax	line 16a + line 17a	0.2	0.0	0.2

3 Col. (c) per App. A, Table 10, line 15, col. (c).
4 Col. (c) per App. A, Table 58, line 23, col. (j) - col. (i), which reflects the Capital Cost Allowances impacts of the forecast CEITCs and the reinstated accelerated investment property program per Ex. L-F4-CCC-084 (Settlement Proposal, Section 3, Part D, iv).
5 As discussed in Ex. F4-2-1, Section 3.1, in a situation where a tax loss is forecast in a given year(s) of the 2027-2031 period, the loss is applied (carried back or carried forward) to reduce such business' taxable income in other years of this period, with any remaining tax losses carried forward to future rate-setting periods. Refer to App. A, Table 45 for the regulatory tax loss continuity schedule.
6 DNNP LP is a limited partnership in which non-taxable investors hold a stake of 22.5% and as a result, are not subject to DNNP LP's taxable income or entitled to utilize the corresponding proportion of the entity's tax loss carry-over each year. Therefore, DNNP LP's revenue requirement reflects the impact of the remaining 77.5% interest in determining regulatory income taxes and the tax loss carry-over each year.

Numbers may not add due to rounding.

Table 43
2030 Summary of Changes in Regulatory Income Taxes for DNNP LP ($M)

Line No.	Particulars	Note	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Determination of Regulatory Taxable Income				
1	**Regulatory Earnings Before Tax**	2	124.9	(12.2)	112.7
	Additions for Regulatory Tax Purposes:				
2	**Depreciation and Amortization**	3	22.6	(2.2)	20.4
3	**Pension and OPEB Accrual**		10.1	0.0	10.1
4	**Restricted Net Interest and Financing Expenses**		0.0	0.0	0.0
5	**Taxable SR&ED Investment Tax Credits of Prior Periods & Current Provincial Portion**		0.0	0.0	0.0
6	**Other**		0.0	0.0	0.0
7	**Total Additions**		32.7	(2.2)	30.5
	Deductions for Regulatory Tax Purposes:				
8	**CCA**	4	365.6	(28.3)	337.4
9	**Pension Plan Contributions**		0.2	0.0	0.2
10	**OPEB Payments**		9.9	0.0	9.9
11	**Reversal of Return on Rate Base Recorded in Deferral and Variance Accounts**		0.0	0.0	0.0
12	**Deductible SR&ED Qualifying Expenditures**		0.0	0.0	0.0
13	**Other**		0.0	0.0	0.0
14	**Total Deductions**		375.7	(28.3)	347.5
15	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 7 - line 14)		(218.1)	13.8	(204.3)
16	**Tax Loss (Income) Attributable to Non-taxable Partners** (line 15 x 22.5%)	5, 6	49.1	(3.1)	46.0
17	**Tax Loss (Income) Attributable to Taxable Partners** (line 15 x 77.5%)	5, 6	169.0	(10.7)	158.3
18	**Regulatory Taxable Income After Tax Loss Carry-Over Subject to Tax** ([line 15 x 77.5%] + line 17)	6	0.0	0.0	0.0
19	**Regulatory Income Taxes - Federal** (line 19 x line 24)		0.0	0.0	0.0
20	**Regulatory Income Taxes - Provincial** (line 19 x line 25)		0.0	0.0	0.0
21	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		0.0	0.0	0.0
22	**Less: SR&ED Investment Tax Credits - Non-taxable Partners** (line 21 x 22.5%)		0.0	0.0	0.0
23	**Total Regulatory Income Taxes** (line 19 + line 20 + line 21 - line 22)		0.0	0.0	0.0
	Income Tax Rate:				
24	**Federal Tax**		15.00%	0.00%	15.00%
25	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	0.00%	10.00%
26	**Total Income Tax Rate**		25.00%	0.00%	25.00%

For notes see Table 43a.

Numbers may not add due to rounding.

Table 43a
Notes to Table 43
2030 Summary of Changes in Regulatory Income Taxes for DNNP LP ($M)

1 Per Ex. F4-2-1, Table 3g, col. (e).
2 Regulatory Earnings Before Tax are calculated as follows (before adjustment for non-taxable partners):

Line No.	Item	Reference for OEB Approved	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
1a	After Tax Return on Equity - DNNP LP	App. A, Table 11, line 11	124.9	(12.2)	112.7
2a	Additions for Regulatory Tax Purposes	line 7	32.7	(2.2)	30.5
3a	Deductions for Regulatory Tax Purposes	line 14	375.7	(28.3)	347.5
4a		line 1a + line 2a - line 3a	(218.1)	13.8	(204.3)
5a	Regulatory Income Taxes - Federal	(lines 4a + 11a + line 21) x line 24/ (1 - line 26)	(32.7)	2.1	(30.6)
6a	Regulatory Income Taxes - Provincial	(lines 4a + 11a + line 21) x line 25/ (1 - line 26)	(21.8)	1.4	(20.4)
7a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 21	0.0	0.0	0.0
8a	Total Regulatory Income Taxes Before Loss Carry-Over	line 5a + line 6a + line 7a	(54.5)	3.5	(51.1)
9a	Effect on Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	(line 16 + line 17) x line 24	32.7	(2.1)	30.6
10a	Effect on Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	(line 16 + line 17) x line 25	21.8	(1.4)	20.4
11a	Effect on Total Regulatory Income Taxes Due to Loss Carry-Over	line 9a + line 10a	54.5	(3.5)	51.1
12a	Regulatory Income Taxes After Tax Loss Carry-Over - Federal	line 5a + line 9a	0.0	0.0	0.0
13a	Regulatory Income Taxes After Tax Loss Carry-Over - Provincial	line 6a + line 10a	0.0	0.0	0.0
14a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 7a	0.0	0.0	0.0
15a	Total Regulatory Income Taxes After Tax Loss Carry-Over	line 12a + line 13a + line 14a	0.0	0.0	0.0
16a	After Tax Return on Equity	line 1a	124.9	(12.2)	112.7
17a	Add: Total Regulatory Income Taxes After Tax Loss Carry-Over	line 15a	0.0	0.0	0.0
18a	Regulatory Earnings Before Tax	line 16a + line 17a	124.9	(12.2)	112.7

3 Col. (c) per App. A, Table 11, line 15, col. (c).
4 Col. (c) per App. A, Table 59, line 23, col. (j) - col. (i), which reflects the Capital Cost Allowances impacts of the forecast CEITCs and the reinstated accelerated investment property program per Ex. L-F4-CCC-084 (Settlement Proposal, Section 3, Part D, iv).
5 As discussed in Ex. F4-2-1, Section 3.1, in a situation where a tax loss is forecast in a given year(s) of the 2027-2031 period, the loss is applied (carried back or carried forward) to reduce such business' taxable income in other years of this period, with any remaining tax losses carried forward to future rate-setting periods. Refer to App. A, Table 45 for the regulatory tax loss continuity schedule.
6 DNNP LP is a limited partnership in which non-taxable investors hold a stake of 22.5% and as a result, are not subject to DNNP LP's taxable income or entitled to utilize the corresponding proportion of the entity's tax loss carry-over each year. Therefore, DNNP LP's revenue requirement reflects the impact of the remaining 77.5% interest in determining regulatory income taxes and the tax loss carry-over each year.

Numbers may not add due to rounding.

Table 44
2031 Summary of Changes in Regulatory Income Taxes for DNNP LP ($M)

Line No.	Particulars	Note	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Determination of Regulatory Taxable Income				
1	**Regulatory Earnings Before Tax**	2	594.9	(58.5)	536.4
	Additions for Regulatory Tax Purposes:				
2	**Depreciation and Amortization**	3	109.7	(10.8)	98.9
3	**Pension and OPEB Accrual**		9.5	0.0	9.5
4	**Restricted Net Interest and Financing Expenses**		0.0	0.0	0.0
5	**Taxable SR&ED Investment Tax Credits of Prior Periods & Current Provincial Portion**		0.0	0.0	0.0
6	**Other**		0.0	0.0	0.0
7	**Total Additions**		119.2	(10.8)	108.4
	Deductions for Regulatory Tax Purposes:				
8	**CCA**	4	377.3	(42.8)	334.5
9	**Pension Plan Contributions**		0.3	0.0	0.3
10	**OPEB Payments**		9.2	0.0	9.2
11	**Reversal of Return on Rate Base Recorded in Deferral and Variance Accounts**		0.0	0.0	0.0
12	**Deductible SR&ED Qualifying Expenditures**		0.0	0.0	0.0
13	**Other**		0.0	0.0	0.0
14	**Total Deductions**		386.8	(42.8)	344.0
15	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 7 - line 14)		327.3	(26.5)	300.8
16	**Tax Loss (Income) Attributable to Non-taxable Partners** (line 15 x 22.5%)	5, 6	(73.7)	6.0	(67.7)
17	**Tax Loss (Income) Attributable to Taxable Partners** (line 15 x 77.5%)	5, 6	(253.7)	20.6	(233.1)
18	**Regulatory Taxable Income After Tax Loss Carry-Over Subject to Tax** ([line 15 x 77.5%] + line 17)	6	0.0	0.0	0.0
19	**Regulatory Income Taxes - Federal** (line 19 x line 24)		0.0	0.0	0.0
20	**Regulatory Income Taxes - Provincial** (line 19 x line 25)		0.0	0.0	0.0
21	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		0.0	0.0	0.0
22	**Less: SR&ED Investment Tax Credits - Non-taxable Partners** (line 21 x 22.5%)		0.0	0.0	0.0
23	**Total Regulatory Income Taxes** (line 19 + line 20 + line 21 - line 22)		0.0	0.0	0.0
	Income Tax Rate:				
24	**Federal Tax**		15.00%	0.00%	15.00%
25	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	0.00%	10.00%
26	**Total Income Tax Rate**		25.00%	0.00%	25.00%

For notes see Table 44a.

Numbers may not add due to rounding.

Table 44a
Notes to Table 44
2031 Summary of Changes in Regulatory Income Taxes for DNNP LP ($M)

1 Per Ex. F4-2-1, Table 3g, col. (f).
2 Regulatory Earnings Before Tax are calculated as follows (before adjustment for non-taxable partners):

Line No.	Item	Reference for OEB Approved	Application Proposed	Settlement Adjustment	OEB Approved
			(a)	(b)	(c)
1a	After Tax Return on Equity - DNNP LP	App. A, Table 12, line 11	594.9	(58.5)	536.4
2a	Additions for Regulatory Tax Purposes	line 7	119.2	(10.8)	108.4
3a	Deductions for Regulatory Tax Purposes	line 14	386.8	(42.8)	344.0
4a		line 1a + line 2a - line 3a	327.3	(26.5)	300.8
5a	Regulatory Income Taxes - Federal	(lines 4a + 11a + line 21) x line 24/ (1 - line 26)	49.1	(4.0)	45.1
6a	Regulatory Income Taxes - Provincial	(lines 4a + 11a + line 21) x line 25/ (1 - line 26)	32.7	(2.7)	30.1
7a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 21	0.0	0.0	0.0
8a	Total Regulatory Income Taxes Before Loss Carry-Over	line 5a + line 6a + line 7a	81.8	(6.6)	75.2
9a	Effect on Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	(line 16 + line 17) x line 24	(49.1)	4.0	(45.1)
10a	Effect on Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	(line 16 + line 17) x line 25	(32.7)	2.7	(30.1)
11a	Effect on Total Regulatory Income Taxes Due to Loss Carry-Over	line 9a + line 10a	(81.8)	6.6	(75.2)
12a	Regulatory Income Taxes After Tax Loss Carry-Over - Federal	line 5a + line 9a	0.0	0.0	0.0
13a	Regulatory Income Taxes After Tax Loss Carry-Over - Provincial	line 6a + line 10a	0.0	0.0	0.0
14a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 7a	0.0	0.0	0.0
15a	Total Regulatory Income Taxes After Tax Loss Carry-Over	line 12a + line 13a + line 14a	0.0	0.0	0.0
16a	After Tax Return on Equity	line 1a	594.9	(58.5)	536.4
17a	Add: Total Regulatory Income Taxes After Tax Loss Carry-Over	line 15a	0.0	0.0	0.0
18a	Regulatory Earnings Before Tax	line 16a + line 17a	594.9	(58.5)	536.4

3 Col. (c) per App. A, Table 12, line 15, col. (c).
4 Col. (c) per App. A, Table 60, line 23, col. (j) - col. (i), which reflects the Capital Cost Allowances impacts of the forecast CEITCs and the reinstated accelerated investment property program per Ex. L-F4-CCC-084 (Settlement Proposal, Section 3, Part D, iv).
5 As discussed in Ex. F4-2-1, Section 3.1, in a situation where a tax loss is forecast in a given year(s) of the 2027-2031 period, the loss is applied (carried back or carried forward) to reduce such business' taxable income in other years of this period, with any remaining tax losses carried forward to future rate-setting periods. Refer to App. A, Table 45 for the regulatory tax loss continuity schedule.
6 DNNP LP is a limited partnership in which non-taxable investors hold a stake of 22.5% and as a result, are not subject to DNNP LP's taxable income or entitled to utilize the corresponding proportion of the entity's tax loss carry-over each year. Therefore, DNNP LP's revenue requirement reflects the impact of the remaining 77.5% interest in determining regulatory income taxes and the tax loss carry-over each year.

Numbers may not add due to rounding.

Table 45
2027 - 2031 Summary of DNNP LP Regulatory Tax Losses ($M)

Line No.	Particulars	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
1	**Loss Brought Forward**		0.0	(207.8)	(506.7)	(758.5)	(916.9)
2	**Income/(Loss) for the Year**	1	(207.8)	(298.8)	(251.9)	(158.3)	0.0
3	**Tax Loss Applied**	2	0.0	0.0	0.0	0.0	233.1
4	**Loss Carried Forward** (line 1 + line 2 + line 3)		(207.8)	(506.7)	(758.5)	(916.9)	(683.7)

Notes:

1 Cols. (a) to (d) per App. A, Tables 40-43: line 17, col. (c).

2 Col. (e) per App. A, Table 44, line 17, col. (c).

Table 46
Undepreciated Capital Cost and Capital Cost Allowance Schedule for Regulated Hydroelectric Facilities ($M)
Year Ending December 31, 2027

Line No.	Class	Undepreciated Capital Cost at Beginning of Year	Settlement Adjustment to Undepreciated Capital Cost at Beginning of Year (2027)	(a)+(a1) Total Undepreciated Capital Cost at Beginning of Year	Cost of Acquisitions	Settlement Adjustments to Cost of Acquisitions	(b)+(b1) Total Cost of Acquisitions	Cost of Acquisitions that are RIIP	Settlement Adjustments: CEITCs	Net Adjustments	Proceeds of Dispositions	(a2)+(b2)+(c)+(c1)-(d) UCC1	50% Rule or UCC adj for RIIP	(e)-(f) Reduced or Increased Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a) Note 1	(a1) Note 2	(a2)	(b) Note 1	(b1) Note 3	(b2)	(b3) Note 4	(c) Note 1	(c1)	(d)	(e)	(f) Note 4	(g)	(h)	(i)	(j)	(k)
1	**1**	2,057.0	(15.2)	2,041.8	266.5	(24.8)	241.7	241.7	(3.0)	0.0	0.0	2,280.5	(120.8)	2,401.3	4%	0.0	96.1	2,184.5
2	**1-rolling start**	265.9	(6.6)	259.3	162.4	(15.1)	147.3	147.3	0.0	0.0	0.0	406.6	(73.6)	480.2	4%	0.0	19.2	387.4
3	**1.1**	100.8	(1.6)	99.2	28.4	(2.7)	25.8	25.8	(0.3)	0.0	0.0	124.6	(12.9)	137.5	6%	0.0	8.3	116.4
4	**1.1-rolling start**	6.6	(0.7)	5.9	16.6	(1.5)	15.0	15.0	0.0	0.0	0.0	21.0	(7.5)	28.5	6%	0.0	1.7	19.3
5	**2**	794.8	0.0	794.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	794.8	0.0	794.8	6%	0.0	47.7	747.1
6	**3**	0.2	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.2	5%	0.0	0.0	0.2
7	**6**	5.1	0.0	5.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.1	0.0	5.1	10%	0.0	0.5	4.6
8	**8**	121.8	(3.3)	118.5	63.5	(5.9)	57.6	57.6	(0.7)	0.0	0.0	175.3	(28.8)	204.1	20%	0.0	40.8	134.5
9	**8-rolling start**	11.5	(1.6)	9.9	39.6	(3.7)	35.9	35.9	0.0	0.0	0.0	45.8	(18.0)	63.7	20%	0.0	12.7	33.0
10	**10**	0.3	(0.0)	0.3	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.3	(0.0)	0.3	30%	0.0	0.1	0.2
11	**12**	0.0	(0.9)	(0.9)	26.2	(2.4)	23.8	23.8	0.0	0.0	0.0	22.9	0.0	22.9	100%	0.0	22.9	0.0
12	**12-rolling start**	0.0	(0.6)	(0.6)	18.5	(1.7)	16.8	16.8	0.0	0.0	0.0	16.1	0.0	16.1	100%	0.0	16.1	0.0
13	**13**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	n/a	0.0	0.0	0.0
14	**14.1**	(0.1)	0.0	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.1)	0.0	(0.1)	5%	0.0	(0.0)	(0.1)
15	**17**	476.8	(5.5)	471.3	100.0	(9.3)	90.7	90.7	(1.3)	0.0	0.0	560.6	(45.4)	606.0	8%	0.0	48.5	512.2
16	**17-rolling start**	28.1	(3.0)	25.1	73.5	(6.8)	66.6	66.6	0.0	0.0	0.0	91.7	(33.3)	125.1	8%	0.0	10.0	81.7
17	**42**	2.3	0.0	2.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.3	0.0	2.3	12%	0.0	0.3	2.1
18	**43.1**	0.0	(4.1)	(4.1)	116.7	(10.9)	105.8	105.8	(26.6)	0.0	0.0	75.1	(246.8)	322.0	30%	0.0	75.1	0.0
19	**43.1-rolling start**	0.0	(8.0)	(8.0)	227.9	(21.2)	206.7	206.7	0.0	0.0	0.0	198.7	(482.3)	681.0	30%	0.0	198.7	0.0
20	**43.2**	1.7	0.0	1.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.7	0.0	1.7	50%	0.0	0.9	0.9
21	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
22	**50**	0.1	(0.0)	0.1	0.4	(0.0)	0.3	0.3	0.0	0.0	0.0	0.4	(0.2)	0.6	55%	0.0	0.3	0.1
23	**Total**	3,872.7	(51.1)	3,821.6	1,140.3	(106.3)	1,034.0	1,034.0	(31.9)	0.0	0.0	4,823.7	(1,069.6)	5,893.3		0.0	599.9	4,223.8

Notes:

1 Per Ex. L-F4-CCC-084, Att. 1, Table 37.

2 Line 23 per App. A, Table 15, line 4, col. (a), as reduced by: (i) the forecast CCA impact resulting from the settlement adjustment reduction to rate base of $19.5M (as of 2025) to reflect lower than forecast actual regulated hydroelectric capital in-service additions for 2025; and (ii) and by a permanent 2027 opening rate base reduction of $40.0M (Settlement Proposal (Section 2, Part B, (ii)).

3 Line 23 per App. A, Table 15, line 4, col. (b)

4 RIIP represents the reinstated accelerated investment incentive ("RIIP") for qualifying property acquired on or after January 1, 2025 and available for use before 2034 that was made effective through legislation which received Royal Assent on March 26, 2026. Under these rules, the half-year rule is suspended until it is phased out.

Table 47
Undepreciated Capital Cost and Capital Cost Allowance Schedule for Regulated Hydroelectric Facilities ($M)
Year Ending December 31, 2028

Line No.	Class	Undepreciated Capital Cost at Beginning of Year (incl. Prior Year(s)' Settlement Adjustments)	Settlement Adjustment to Undepreciated Capital Cost at Beginning of Year	(a)+(a1) Total Undepreciated Capital Cost at Beginning of Year	Cost of Acquisitions	Settlement Adjustments to Cost of Acquisitions	(b)+(b1) Total Cost of Acquisitions	Cost of Acquisitions that are RIIP	Settlement Adjustments: CEITCs	Net Adjustments	Proceeds of Dispositions	(a2)+(b2)+(c)+(c1)-(d) UCC1	50% Rule or UCC adj for RIIP	(e)-(f) Reduced or Increased Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a) Note 1	(a1)	(a2)	(b) Note 5	(b1) Note 2	(b2)	(b3) Note 3	(c) Note 4	(c1)	(d)	(e)	(f) Note 3	(g)	(h)	(i)	(j)	(k)
1	**1**	2,184.5	0.0	2,184.5	336.9	(43.4)	293.5	293.5	(6.0)	0.0	0.0	2,472.0	(146.8)	2,618.8	4%	0.0	104.8	2,367.3
2	**1-rolling start**	387.4	0.0	387.4	122.7	(15.8)	106.9	106.9	0.0	0.0	0.0	494.2	(53.4)	547.7	4%	0.0	21.9	472.3
3	**1.1**	116.4	0.0	116.4	37.0	(4.8)	32.3	32.3	(0.6)	0.0	0.0	148.0	(16.1)	164.2	6%	0.0	9.9	138.2
4	**1.1-rolling start**	19.3	0.0	19.3	12.5	(1.6)	10.9	10.9	0.0	0.0	0.0	30.2	(5.5)	35.7	6%	0.0	2.1	28.1
5	**2**	747.1	0.0	747.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	747.1	0.0	747.1	6%	0.0	44.8	702.3
6	**3**	0.2	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.2	5%	0.0	0.0	0.2
7	**6**	4.6	0.0	4.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.6	0.0	4.6	10%	0.0	0.5	4.1
8	**8**	134.5	0.0	134.5	84.0	(10.8)	73.2	73.2	(1.5)	0.0	0.0	206.2	(36.6)	242.8	20%	0.0	48.6	157.7
9	**8-rolling start**	33.0	0.0	33.0	29.9	(3.9)	26.1	26.1	0.0	0.0	0.0	59.1	(13.0)	72.1	20%	0.0	14.4	44.7
10	**10**	0.2	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.2	30%	0.0	0.1	0.1
11	**12**	0.0	0.0	0.0	28.7	(3.7)	25.0	25.0	0.0	0.0	0.0	25.0	0.0	25.0	100%	0.0	25.0	0.0
12	**12-rolling start**	0.0	0.0	0.0	15.1	(1.9)	13.1	13.1	0.0	0.0	0.0	13.1	0.0	13.1	100%	0.0	13.1	0.0
13	**13**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	n/a	0.0	0.0	0.0
14	**14.1**	(0.1)	0.0	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.1)	0.0	(0.1)	5%	0.0	(0.0)	(0.1)
15	**17**	512.2	0.0	512.2	126.6	(16.3)	110.3	110.3	(2.7)	0.0	0.0	619.8	(55.2)	675.0	8%	0.0	54.0	565.8
16	**17-rolling start**	81.7	0.0	81.7	55.5	(7.1)	48.4	48.4	0.0	0.0	0.0	130.1	(24.2)	154.3	8%	0.0	12.3	117.7
17	**42**	2.1	0.0	2.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.1	0.0	2.1	12%	0.0	0.2	1.8
18	**43.1**	0.0	0.0	0.0	17.2	(2.2)	15.0	15.0	(42.8)	0.0	0.0	(27.8)	(35.0)	7.2	30%	27.8	0.0	0.0
19	**43.1-rolling start**	0.0	0.0	0.0	202.4	(26.1)	176.3	176.3	0.0	0.0	0.0	176.3	(411.4)	587.7	30%	0.0	176.3	0.0
20	**43.2**	0.9	0.0	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.9	0.0	0.9	50%	0.0	0.4	0.4
21	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
22	**50**	0.1	0.0	0.1	0.5	(0.1)	0.4	0.4	0.0	0.0	0.0	0.5	(0.2)	0.7	55%	0.0	0.4	0.1
23	**Total**	4,223.8	0.0	4,223.8	1,069.1	(137.7)	931.4	931.4	(53.6)	0.0	0.0	5,101.6	(797.3)	5,899.0		27.8	528.8	4,600.7

Notes:

1 Per App. A, Table 46, col. (k).
2 Line 23 per App. A, Table 15, line 9, col. (b)
3 RIIP represents the reinstated accelerated investment incentive ("RIIP") for qualifying property acquired on or after January 1, 2025 and available for use before 2034 that was made effective through legislation which received Royal Assent on March 26, 2026. Under these rules, the half-year rule is suspended until it is phased out.
4 Per Ex. L-F4-CCC-084, Att. 1, Table 38, col. (c).
5 Per Ex. L-F4-CCC-084, Att. 1, Table 38, col. (b).

Table 48
Undepreciated Capital Cost and Capital Cost Allowance Schedule for Regulated Hydroelectric Facilities ($M)
Year Ending December 31, 2029

Line No.	Class	Undepreciated Capital Cost at Beginning of Year (incl. Prior Year(s)' Settlement Adjustments)	Settlement Adjustment to Undepreciated Capital Cost at Beginning of Year	(a)+(a1) Total Undepreciated Capital Cost at Beginning of Year	Cost of Acquisitions	Settlement Adjustments to Cost of Acquisitions	(b)+(b1) Total Cost of Acquisitions	Cost of Acquisitions that are RIIP	Settlement Adjustments: CEITCs	Net Adjustments	Proceeds of Dispositions	(a2)+(b2)+(c)+(c1)-(d) UCC1	50% Rule or UCC adj for RIIP	(e)-(f) Reduced or Increased Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a) Note 1	(a1)	(a2)	(b) Note 5	(b1) Note 2	(b2)	(b3) Note 3	(c) Note 4	(c1)	(d)	(e)	(f) Note 3	(g)	(h)	(i)	(j)	(k)
1	**1**	2,367.3	0.0	2,367.3	473.9	(59.2)	414.6	414.6	(11.4)	0.0	0.0	2,770.4	(207.3)	2,977.7	4%	0.0	119.1	2,651.3
2	**1-rolling start**	472.3	0.0	472.3	129.7	(16.2)	113.5	113.5	0.0	0.0	0.0	585.8	(56.8)	642.6	4%	0.0	25.7	560.1
3	**1.1**	138.2	0.0	138.2	51.2	(6.4)	44.8	44.8	(1.2)	0.0	0.0	181.8	(22.4)	204.2	6%	0.0	12.3	169.6
4	**1.1-rolling start**	28.1	0.0	28.1	13.3	(1.7)	11.6	11.6	0.0	0.0	0.0	39.6	(5.8)	45.4	6%	0.0	2.7	36.9
5	**2**	702.3	0.0	702.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	702.3	0.0	702.3	6%	0.0	42.1	660.1
6	**3**	0.2	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.2	5%	0.0	0.0	0.1
7	**6**	4.1	0.0	4.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.1	0.0	4.1	10%	0.0	0.4	3.7
8	**8**	157.7	0.0	157.7	117.9	(14.7)	103.1	103.1	(2.8)	0.0	0.0	258.0	(51.6)	309.6	20%	0.0	61.9	196.1
9	**8-rolling start**	44.7	0.0	44.7	31.6	(4.0)	27.7	27.7	0.0	0.0	0.0	72.3	(13.8)	86.2	20%	0.0	17.2	55.1
10	**10**	0.1	0.0	0.1	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.2	(0.0)	0.2	30%	0.0	0.1	0.1
11	**12**	0.0	0.0	0.0	37.4	(4.7)	32.7	32.7	0.0	0.0	0.0	32.7	0.0	32.7	100%	0.0	32.7	0.0
12	**12-rolling start**	0.0	0.0	0.0	8.3	(1.0)	7.3	7.3	0.0	0.0	0.0	7.3	0.0	7.3	100%	0.0	7.3	0.0
13	**13**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	n/a	0.0	0.0	0.0
14	**14.1**	(0.1)	0.0	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.1)	0.0	(0.1)	5%	0.0	(0.0)	(0.1)
15	**17**	565.8	0.0	565.8	188.0	(23.5)	164.5	164.5	(5.2)	0.0	0.0	725.1	(82.2)	807.3	8%	0.0	64.6	660.5
16	**17-rolling start**	117.7	0.0	117.7	58.7	(7.3)	51.4	51.4	0.0	0.0	0.0	169.1	(25.7)	194.8	8%	0.0	15.6	153.5
17	**42**	1.8	0.0	1.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.8	0.0	1.8	12%	0.0	0.2	1.6
18	**43.1**	0.0	0.0	0.0	0.2	(0.0)	0.2	0.2	(27.3)	0.0	0.0	(27.1)	(0.5)	(26.6)	30%	27.1	0.0	0.0
19	**43.1-rolling start**	0.0	0.0	0.0	0.7	(0.1)	0.6	0.6	0.0	0.0	0.0	0.6	(1.5)	2.2	30%	0.0	0.6	0.0
20	**43.2**	0.4	0.0	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.4	50%	0.0	0.2	0.2
21	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
22	**50**	0.1	0.0	0.1	0.5	(0.1)	0.5	0.5	0.0	0.0	0.0	0.6	(0.2)	0.8	55%	0.0	0.4	0.1
23	**Total**	4,600.7	0.0	4,600.7	1,111.4	(139.0)	972.4	972.4	(47.8)	0.0	0.0	5,525.2	(467.8)	5,993.0		27.1	403.2	5,149.1

Notes:
1 Per App. A, Table 47, col. (k).
2 Line 23 per App. A, Table 15, line 14, col. (b)
3 RIIP represents the reinstated accelerated investment incentive ("RIIP") for qualifying property acquired on or after January 1, 2025 and available for use before 2034 that was made effective through legislation which received Royal Assent on March 26, 2026. Under these rules, the half-year rule is suspended until it is phased out.
4 Per Ex. L-F4-CCC-084, Att. 1, Table 39, col. (c).
5 Per Ex. L-F4-CCC-084, Att. 1, Table 39, col. (b).

Numbers may not add due to rounding.

Table 49
Undepreciated Capital Cost and Capital Cost Allowance Schedule for Regulated Hydroelectric Facilities ($M)
Year Ending December 31, 2030

Line No.	Class	Undepreciated Capital Cost at Beginning of Year (incl. Prior Year(s)' Settlement Adjustments)	Settlement Adjustment to Undepreciated Capital Cost at Beginning of Year	(a)+(a1) Total Undepreciated Capital Cost at Beginning of Year	Cost of Acquisitions	Settlement Adjustments to Cost of Acquisitions	(b)+(b1) Total Cost of Acquisitions	Cost of Acquisitions that are RIIP	Settlement Adjustments: CEITCs	Net Adjustments	Proceeds of Dispositions	(a2)+(b2)+(c)+(c1)-(d) UCC1	50% Rule or UCC adj for RIIP	(e)-(f) Reduced or Increased Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a) Note 1	(a1)	(a2)	(b) Note 5	(b1) Note 2	(b2)	(b3) Note 3	(c) Note 4	(c1)	(d)	(e)	(f) Note 3	(g)	(h)	(i)	(j)	(k)
1	**1**	2,651.3	0.0	2,651.3	306.6	(48.0)	258.6	258.6	(12.1)	0.0	0.0	2,897.8	0.0	2,897.8	4%	0.0	115.9	2,781.9
2	**1-rolling start**	560.1	0.0	560.1	108.3	(16.9)	91.3	91.3	0.0	0.0	0.0	651.5	0.0	651.5	4%	0.0	26.1	625.4
3	**1.1**	169.6	0.0	169.6	34.0	(5.3)	28.7	28.7	(1.2)	0.0	0.0	197.0	0.0	197.0	6%	0.0	11.8	185.2
4	**1.1-rolling start**	36.9	0.0	36.9	11.1	(1.7)	9.3	9.3	0.0	0.0	0.0	46.3	0.0	46.3	6%	0.0	2.8	43.5
5	**2**	660.1	0.0	660.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	660.1	0.0	660.1	6%	0.0	39.6	620.5
6	**3**	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.1	5%	0.0	0.0	0.1
7	**6**	3.7	0.0	3.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.7	0.0	3.7	10%	0.0	0.4	3.3
8	**8**	196.1	0.0	196.1	76.9	(12.0)	64.9	64.9	(3.0)	0.0	0.0	258.0	0.0	258.0	20%	0.0	51.6	206.4
9	**8-rolling start**	55.1	0.0	55.1	26.4	(4.1)	22.3	22.3	0.0	0.0	0.0	77.4	0.0	77.4	20%	0.0	15.5	61.9
10	**10**	0.1	0.0	0.1	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.1	30%	0.0	0.0	0.1
11	**12**	0.0	0.0	0.0	27.4	(4.3)	23.1	23.1	0.0	0.0	0.0	23.1	0.0	23.1	100%	0.0	23.1	0.0
12	**12-rolling start**	0.0	0.0	0.0	6.9	(1.1)	5.8	5.8	0.0	0.0	0.0	5.8	0.0	5.8	100%	0.0	5.8	0.0
13	**13**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	n/a	0.0	0.0	0.0
14	**14.1**	(0.1)	0.0	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.1)	0.0	(0.1)	5%	0.0	(0.0)	(0.1)
15	**17**	660.5	0.0	660.5	112.6	(17.6)	94.9	94.9	(5.5)	0.0	0.0	749.9	0.0	749.9	8%	0.0	60.0	689.9
16	**17-rolling start**	153.5	0.0	153.5	49.0	(7.7)	41.3	41.3	0.0	0.0	0.0	194.8	0.0	194.8	8%	0.0	15.6	179.3
17	**42**	1.6	0.0	1.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.6	0.0	1.6	12%	0.0	0.2	1.4
18	**43.1**	0.0	0.0	0.0	0.2	(0.0)	0.2	0.2	(0.1)	0.0	0.0	0.1	(0.4)	0.5	30%	0.0	0.2	(0.1)
19	**43.1-rolling start**	0.0	0.0	0.0	(0.2)	0.0	(0.2)	(0.2)	0.0	0.0	0.0	(0.2)	0.5	(0.7)	30%	0.2	0.0	0.0
20	**43.2**	0.2	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.2	50%	0.0	0.1	0.1
21	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
22	**50**	0.1	0.0	0.1	0.5	(0.1)	0.5	0.5	0.0	0.0	0.0	0.6	0.0	0.6	55%	0.0	0.3	0.3
23	**Total**	5,149.1	0.0	5,149.1	759.7	(118.9)	640.8	640.8	(21.9)	0.0	0.0	5,767.9	0.0	5,767.9		0.2	369.0	5,399.2

Notes:
1 Per App. A, Table 48, col. (k).
2 Line 23 per App. A, Table 15, line 19, col. (b)
3 RIIP represents the reinstated accelerated investment incentive ("RIIP") for qualifying property acquired on or after January 1, 2025 and available for use before 2034 that was made effective through legislation which received Royal Assent on March 26, 2026. Under these rules, the half-year rule is suspended until it is phased out.
4 Per Ex. L-F4-CCC-084, Att. 1, Table 40, col. (c).
5 Per Ex. L-F4-CCC-084, Att. 1, Table 40, col. (b).

Numbers may not add due to rounding.

Table 50
Undepreciated Capital Cost and Capital Cost Allowance Schedule for Regulated Hydroelectric Facilities ($M)
Year Ending December 31, 2031

Line No.	Class	Undepreciated Capital Cost at Beginning of Year (incl. Prior Year(s)' Settlement Adjustments)	Settlement Adjustment to Undepreciated Capital Cost at Beginning of Year	(a)+(a1) Total Undepreciated Capital Cost at Beginning of Year	Cost of Acquisitions	Settlement Adjustments to Cost of Acquisitions	(b)+(b1) Total Cost of Acquisitions	Cost of Acquisitions that are RIIP	Settlement Adjustments: CEITCs	Net Adjustments	Proceeds of Dispositions	(a2)+(b2)+(c)+(c1)-(d) UCC1	50% Rule or UCC adj for RIIP	(e)-(f) Reduced or Increased Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a) Note 1	(a1)	(a2)	(b) Note 5	(b1) Note 2	(b2)	(b3) Note 3	(c) Note 4	(c1)	(d)	(e)	(f) Note 3	(g)	(h)	(i)	(j)	(k)
1	**1**	2,781.9	0.0	2,781.9	353.8	(32.0)	321.8	321.8	(10.3)	0.0	0.0	3,093.3	0.0	3,093.3	4%	0.0	123.7	2,969.6
2	**1-rolling start**	625.4	0.0	625.4	125.4	(11.3)	114.1	114.1	0.0	0.0	0.0	739.5	0.0	739.5	4%	0.0	29.6	709.9
3	**1.1**	185.2	0.0	185.2	38.7	(3.5)	35.2	35.2	(1.1)	0.0	0.0	219.4	0.0	219.4	6%	0.0	13.2	206.2
4	**1.1-rolling start**	43.5	0.0	43.5	12.8	(1.2)	11.7	11.7	0.0	0.0	0.0	55.1	0.0	55.1	6%	0.0	3.3	51.8
5	**2**	620.5	0.0	620.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	620.5	0.0	620.5	6%	0.0	37.2	583.3
6	**3**	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.1	5%	0.0	0.0	0.1
7	**6**	3.3	0.0	3.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.3	0.0	3.3	10%	0.0	0.3	3.0
8	**8**	206.4	0.0	206.4	88.2	(8.0)	80.2	80.2	(2.5)	0.0	0.0	284.1	0.0	284.1	20%	0.0	56.8	227.3
9	**8-rolling start**	61.9	0.0	61.9	30.6	(2.8)	27.8	27.8	0.0	0.0	0.0	89.7	0.0	89.7	20%	0.0	17.9	71.8
10	**10**	0.1	0.0	0.1	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.1	30%	0.0	0.0	0.1
11	**12**	0.0	0.0	0.0	30.9	(2.8)	28.1	28.1	0.0	0.0	0.0	28.1	0.0	28.1	100%	0.0	28.1	0.0
12	**12-rolling start**	0.0	0.0	0.0	8.0	(0.7)	7.3	7.3	0.0	0.0	0.0	7.3	0.0	7.3	100%	0.0	7.3	0.0
13	**13**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	n/a	0.0	0.0	0.0
14	**14.1**	(0.1)	0.0	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.1)	0.0	(0.1)	5%	0.0	(0.0)	(0.1)
15	**17**	689.9	0.0	689.9	134.4	(12.1)	122.2	122.2	(4.7)	0.0	0.0	807.5	0.0	807.5	8%	0.0	64.6	742.9
16	**17-rolling start**	179.3	0.0	179.3	56.8	(5.1)	51.6	51.6	0.0	0.0	0.0	230.9	0.0	230.9	8%	0.0	18.5	212.4
17	**42**	1.4	0.0	1.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	0.0	1.4	12%	0.0	0.2	1.2
18	**43.1**	(0.1)	0.0	(0.1)	(0.0)	0.0	(0.0)	(0.0)	0.0	0.0	0.0	(0.1)	0.0	(0.1)	30%	0.0	0.0	(0.1)
19	**43.1-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
20	**43.2**	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.1	50%	0.0	0.1	0.1
21	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
22	**50**	0.3	0.0	0.3	0.5	(0.0)	0.5	0.5	0.0	0.0	0.0	0.8	0.0	0.8	55%	0.0	0.4	0.3
23	**Total**	5,399.2	0.0	5,399.2	880.1	(79.6)	800.6	800.6	(18.6)	0.0	0.0	6,181.2	0.0	6,181.1		0.0	401.3	5,779.9

Notes:

1 Per App. A, Table 49, col. (k).
2 Line 23 per App. A, Table 15, line 24, col. (b)
3 RIIP represents the reinstated accelerated investment incentive ("RIIP") for qualifying property acquired on or after January 1, 2025 and available for use before 2034 that was made effective through legislation which received Royal Assent on March 26, 2026. Under these rules, the half-year rule is suspended until it is phased out.
4 Per Ex. L-F4-CCC-084, Att. 1, Table 41, col. (c).
5 Per Ex. L-F4-CCC-084, Att. 1, Table 41, col. (b).

Numbers may not add due to rounding.

Table 51
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG Nuclear Facilities ($M)
Year Ending December 31, 2027

Line No.	Class	Undepreciated Capital Cost at Beginning of Year	Settlement Adjustment to Undepreciated Capital Cost at Beginning of Year (2027)	(a)+(a1) Total Undepreciated Capital Cost at Beginning of Year	Cost of Acquisitions	Settlement Adjustments to Cost of Acquisitions	(b)+(b1) Total Cost of Acquisitions	Cost of Acquisitions that are RIIP	Settlement Adjustments: CEITCs	Net Adjustments	Proceeds of Dispositions	(a2)+(b2)+(c)+(c1)-(d) UCC1	50% Rule or UCC adj for RIIP	(e)-(f) Reduced or Increased Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a) Note 1	(a1) Note 2	(a2)	(b) Note 1	(b1) Note 3	(b2)	(b3) Note 4	(c) Note 1	(c1)	(d)	(e)	(f) Note 4	(g)	(h)	(i)	(j)	(k)
1	**1**	1,173.8	(2.4)	1,171.4	232.6	(5.9)	226.8	226.8	(7.9)	0.0	0.0	1,390.3	(113.4)	1,503.6	4%	0.0	60.1	1,330.1
2	**1-rolling start**	171.0	(1.6)	169.4	152.5	(3.8)	148.7	148.7	0.0	0.0	0.0	318.1	(74.3)	392.4	4%	0.0	15.7	302.4
3	**1.1**	560.8	(0.9)	559.9	89.1	(2.2)	86.8	86.8	(1.8)	0.0	0.0	645.0	(43.4)	688.4	6%	0.0	41.3	603.7
4	**1.1-rolling start**	210.5	(0.2)	210.3	21.0	(0.5)	20.4	20.4	0.0	0.0	0.0	230.8	(10.2)	241.0	6%	0.0	14.5	216.3
5	**2**	(0.0)	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	6%	0.0	(0.0)	(0.0)
6	**3**	(0.0)	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	5%	0.0	(0.0)	(0.0)
7	**6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	0.0	0.0
8	**8**	356.2	(1.9)	354.3	189.5	(4.8)	184.7	184.7	(4.3)	0.0	0.0	534.7	(92.4)	627.0	20%	0.0	125.4	409.3
9	**8-rolling start**	69.6	(0.6)	69.1	56.8	(1.4)	55.4	55.4	0.0	0.0	0.0	124.5	(27.7)	152.2	20%	0.0	30.4	94.0
10	**10**	4.6	0.0	4.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.6	0.0	4.6	30%	0.0	1.4	3.2
11	**12**	0.0	(1.5)	(1.5)	147.7	(3.7)	144.0	144.0	0.0	0.0	0.0	142.5	0.0	142.5	100%	0.0	142.5	0.0
12	**12-rolling start**	0.0	(0.2)	(0.2)	21.0	(0.5)	20.4	20.4	0.0	0.0	0.0	20.2	0.0	20.2	100%	0.0	20.2	0.0
13	**13**	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.1	n/a	0.0	0.0	0.0
14	**14.1**	3.6	0.0	3.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	0.0	3.6	7%	0.0	0.3	3.4
15	**14.1**	10.4	0.0	10.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.4	0.0	10.4	5%	0.0	0.5	9.9
16	**17**	6,174.9	(60.3)	6,114.6	1,600.0	(40.3)	1,559.7	1,559.7	(315.6)	0.0	0.0	7,358.8	(779.8)	8,138.6	8%	0.0	651.1	6,707.7
17	**17-rolling start**	1,149.9	(14.4)	1,135.5	1,414.7	(35.7)	1,379.1	1,379.1	0.0	0.0	0.0	2,514.6	(689.5)	3,204.1	8%	0.0	256.3	2,258.3
18	**26**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
19	**42**	18.6	0.0	18.6	(0.1)	0.0	(0.1)	(0.1)	0.0	0.0	0.0	18.5	0.0	18.5	12%	0.0	2.2	16.3
20	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
21	**43.2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50%	0.0	0.0	0.0
22	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
23	**50**	0.5	(0.0)	0.5	1.6	(0.0)	1.5	1.5	0.0	0.0	0.0	2.0	(0.8)	2.8	55%	0.0	1.5	0.5
24	**Total**	9,904.6	(84.0)	9,820.6	3,926.4	(99.0)	3,827.4	3,827.4	(329.6)	0.0	0.0	13,318.5	(1,831.5)	15,150.0		0.0	1,363.5	11,954.9

Notes:

1 Per Ex. L-F4-CCC-084, Att. 1, Table 44.

2 Line 24 per App. A, Table 17, lines 7 and 9, col. (a), adjusted for: (i) the forecast CCA impact resulting from the Settlement Proposal reduction of $50.0M to gross plant (as of 2026) to reflect OPG's updated, lower total cost forecast of $12.65B for the Darlington Refurbishment Program since the filing of the Application; and (ii) the permanent 2027 opening rate base reduction of $40.0M (Settlement Proposal, Section 2, Part B, (i)).

3 Line 24 per App. A, Table 17, col. (b) the sum of lines 7, 8, and 9.

4 RIIP represents the reinstated accelerated investment incentive ("RIIP") for qualifying property acquired on or after January 1, 2025 and available for use before 2034 that was made effective through legislation which received Royal Assent on March 26, 2026. Under these rules, the half-year rule is suspended until it is phased out.

Numbers may not add due to rounding.

Table 52
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG Nuclear Facilities ($M)
Year Ending December 31, 2028

Line No.	Class	Undepreciated Capital Cost at Beginning of Year (incl. Prior Year(s)' Settlement Adjustments)	Settlement Adjustment to Undepreciated Capital Cost at Beginning of Year	(a)+(a1) Total Undepreciated Capital Cost at Beginning of Year	Cost of Acquisitions	Settlement Adjustments to Cost of Acquisitions	(b)+(b1) Total Cost of Acquisitions	Cost of Acquisitions that are RIIP	Settlement Adjustments: CEITCs	Net Adjustments	Proceeds of Dispositions	(a2)+(b2)+(c)+(c1)-(d) UCC1	50% Rule or UCC adj for RIIP	(e)-(f) Reduced or Increased Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a) Note 1	(a1)	(a2)	(b) Note 5	(b1) Note 2	(b2)	(b3) Note 3	(c) Note 4	(c1)	(d)	(e)	(f) Note 3	(g)	(h)	(i)	(j)	(k)
1	**1**	1,330.1	0.0	1,330.1	345.6	(5.0)	340.6	340.6	(34.1)	0.0	0.0	1,636.6	(170.3)	1,806.9	4%	0.0	72.3	1,564.3
2	**1-rolling start**	302.4	0.0	302.4	273.0	(4.0)	269.0	269.0	0.0	0.0	0.0	571.4	(134.5)	705.9	4%	0.0	28.2	543.2
3	**1.1**	603.7	0.0	603.7	80.9	(1.2)	79.7	79.7	(3.2)	0.0	0.0	680.1	(39.8)	719.9	6%	0.0	43.2	636.9
4	**1.1-rolling start**	216.3	0.0	216.3	35.2	(0.5)	34.7	34.7	0.0	0.0	0.0	251.0	(17.4)	268.4	6%	0.0	16.1	234.9
5	**2**	(0.0)	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	6%	0.0	(0.0)	(0.0)
6	**3**	(0.0)	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	5%	0.0	(0.0)	(0.0)
7	**6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	0.0	0.0
8	**8**	409.3	0.0	409.3	185.0	(2.7)	182.3	182.3	(10.0)	0.0	0.0	581.6	(91.2)	672.7	20%	0.0	134.5	447.0
9	**8-rolling start**	94.0	0.0	94.0	97.4	(1.4)	95.9	95.9	0.0	0.0	0.0	190.0	(48.0)	238.0	20%	0.0	47.6	142.4
10	**10**	3.2	0.0	3.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.2	0.0	3.2	30%	0.0	1.0	2.2
11	**12**	0.0	0.0	0.0	144.3	(2.1)	142.2	142.2	0.0	0.0	0.0	142.2	0.0	142.2	100%	0.0	142.2	0.0
12	**12-rolling start**	0.0	0.0	0.0	35.2	(0.5)	34.7	34.7	0.0	0.0	0.0	34.7	0.0	34.7	100%	0.0	34.7	0.0
13	**13**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	n/a	0.0	0.0	0.0
14	**14.1**	3.4	0.0	3.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.4	0.0	3.4	7%	0.0	0.2	3.1
15	**14.1**	9.9	0.0	9.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.9	0.0	9.9	5%	0.0	0.5	9.4
16	**17**	6,707.7	0.0	6,707.7	3,032.1	(43.9)	2,988.2	2,988.2	(327.6)	0.0	0.0	9,368.2	(1,494.1)	10,862.3	8%	0.0	869.0	8,499.3
17	**17-rolling start**	2,258.3	0.0	2,258.3	2,632.9	(38.1)	2,594.8	2,594.8	0.0	0.0	0.0	4,853.1	(1,297.4)	6,150.5	8%	0.0	492.0	4,361.0
18	**26**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
19	**42**	16.3	0.0	16.3	(0.1)	0.0	(0.1)	(0.1)	0.0	0.0	0.0	16.2	0.0	16.2	12%	0.0	1.9	14.3
20	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
21	**43.2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50%	0.0	0.0	0.0
22	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
23	**50**	0.5	0.0	0.5	2.1	(0.0)	2.1	2.1	0.0	0.0	0.0	2.6	(1.0)	3.6	55%	0.0	2.0	0.6
24	**Total**	11,954.9	0.0	11,954.9	6,863.6	(99.3)	6,764.3	6,764.3	(374.9)	0.0	0.0	18,344.3	(3,293.7)	21,637.9		0.0	1,885.6	16,458.7

Notes:

1 Per App. A, Table 51, col (k).
2 Line 24 per App. A, Table 17, col. (b) the sum of lines 20, 21, and 22.
3 RIIP represents the reinstated accelerated investment incentive ("RIIP") for qualifying property acquired on or after January 1, 2025 and available for use before 2034 that was made effective through legislation which received Royal Assent on March 26, 2026. Under these rules, the half-year rule is suspended until it is phased out.
4 Per Ex. L-F4-CCC-084, Att. 1, Table 45, col. (c).
5 Per Ex. L-F4-CCC-084, Att. 1, Table 45, col. (b).

Numbers may not add due to rounding.

Table 53
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG Nuclear Facilities ($M)
Year Ending December 31, 2029

Line No.	Class	Undepreciated Capital Cost at Beginning of Year (incl. Prior Year(s)' Settlement Adjustments)	Settlement Adjustment to Undepreciated Capital Cost at Beginning of Year	(a)+(a1) Total Undepreciated Capital Cost at Beginning of Year	Cost of Acquisitions	Settlement Adjustments to Cost of Acquisitions	(b)+(b1) Total Cost of Acquisitions	Cost of Acquisitions that are RIIP	Settlement Adjustments: CEITCs	Net Adjustments	Proceeds of Dispositions	(a2)+(b2)+(c)+(c1)-(d) UCC1	50% Rule or UCC adj for RIIP	(e)-(f) Reduced or Increased Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a) Note 1	(a1)	(a2)	(b) Note 5	(b1) Note 2	(b2)	(b3) Note 3	(c) Note 4	(c1)	(d)	(e)	(f) Note 3	(g)	(h)	(i)	(j)	(k)
1	**1**	1,564.3	0.0	1,564.3	383.3	(6.7)	376.6	376.6	(63.3)	0.0	0.0	1,877.7	(188.3)	2,066.0	4%	0.0	82.6	1,795.0
2	**1-rolling start**	543.2	0.0	543.2	222.6	(3.9)	218.7	218.7	0.0	0.0	0.0	761.9	(109.4)	871.2	4%	0.0	34.8	727.0
3	**1.1**	636.9	0.0	636.9	57.0	(1.0)	56.0	56.0	(3.8)	0.0	0.0	689.1	(28.0)	717.1	6%	0.0	43.0	646.1
4	**1.1-rolling start**	234.9	0.0	234.9	23.5	(0.4)	23.1	23.1	0.0	0.0	0.0	258.1	(11.6)	269.6	6%	0.0	16.2	241.9
5	**2**	(0.0)	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	6%	0.0	(0.0)	(0.0)
6	**3**	(0.0)	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	5%	0.0	(0.0)	(0.0)
7	**6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	0.0	0.0
8	**8**	447.0	0.0	447.0	137.5	(2.4)	135.1	135.1	(14.3)	0.0	0.0	567.9	(67.6)	635.4	20%	0.0	127.1	440.8
9	**8-rolling start**	142.4	0.0	142.4	69.5	(1.2)	68.3	68.3	0.0	0.0	0.0	210.7	(34.1)	244.8	20%	0.0	49.0	161.7
10	**10**	2.2	0.0	2.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.2	0.0	2.2	30%	0.0	0.7	1.6
11	**12**	0.0	0.0	0.0	125.8	(2.2)	123.6	123.6	0.0	0.0	0.0	123.6	0.0	123.6	100%	0.0	123.6	0.0
12	**12-rolling start**	0.0	0.0	0.0	23.5	(0.4)	23.1	23.1	0.0	0.0	0.0	23.1	0.0	23.1	100%	0.0	23.1	0.0
13	**13**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	n/a	0.0	0.0	0.0
14	**14.1**	3.1	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.1	0.0	3.1	7%	0.0	0.2	2.9
15	**14.1**	9.4	0.0	9.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.4	0.0	9.4	5%	0.0	0.5	8.9
16	**17**	8,499.3	0.0	8,499.3	3,659.4	(63.8)	3,595.6	3,595.6	(642.8)	0.0	0.0	11,452.1	(1,797.8)	13,249.9	8%	0.0	1,060.0	10,392.1
17	**17-rolling start**	4,361.0	0.0	4,361.0	2,234.9	(39.0)	2,195.9	2,195.9	0.0	0.0	0.0	6,556.9	(1,097.9)	7,654.9	8%	0.0	612.4	5,944.6
18	**26**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
19	**42**	14.3	0.0	14.3	(0.1)	0.0	(0.1)	(0.1)	0.0	0.0	0.0	14.2	0.0	14.2	12%	0.0	1.7	12.5
20	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
21	**43.2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50%	0.0	0.0	0.0
22	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
23	**50**	0.6	0.0	0.6	2.9	(0.1)	2.9	2.9	0.0	0.0	0.0	3.5	(1.4)	4.9	55%	0.0	2.7	0.8
24	**Total**	16,458.7	0.0	16,458.7	6,939.9	(121.0)	6,818.9	6,818.9	(724.1)	0.0	0.0	22,553.5	(3,336.1)	25,889.6		0.0	2,177.6	20,375.9

Notes:
1 Per App. A, Table 52, col (k).
2 Line 24 per App. A, Table 17, col. (b) the sum of lines 33, 34, and 35.
3 RIIP represents the reinstated accelerated investment incentive ("RIIP") for qualifying property acquired on or after January 1, 2025 and available for use before 2034 that was made effective through legislation which received Royal Assent on March 26, 2026. Under these rules, the half-year rule is suspended until it is phased out.
4 Per Ex. L-F4-CCC-084, Att. 1, Table 46, col. (c).
5 Per Ex. L-F4-CCC-084, Att. 1, Table 46, col. (b).

Numbers may not add due to rounding.

Table 54
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG Nuclear Facilities ($M)
Year Ending December 31, 2030

Line No.	Class	Undepreciated Capital Cost at Beginning of Year (incl. Prior Year(s)' Settlement Adjustments)	Settlement Adjustment to Undepreciated Capital Cost at Beginning of Year	(a)+(a1) Total Undepreciated Capital Cost at Beginning of Year	Cost of Acquisitions	Settlement Adjustments to Cost of Acquisitions	(b)+(b1) Total Cost of Acquisitions	Cost of Acquisitions that are RIIP	Settlement Adjustments: CEITCs	Net Adjustments	Proceeds of Dispositions	(a2)+(b2)+(c)+(c1)-(d) UCC1	50% Rule or UCC adj for RIIP	(e)-(f) Reduced or Increased Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a) Note 1	(a1)	(a2)	(b) Note 5	(b1) Note 2	(b2)	(b3) Note 3	(c) Note 4	(c1)	(d)	(e)	(f) Note 3	(g)	(h)	(i)	(j)	(k)
1	**1**	1,795.0	0.0	1,795.0	306.2	(24.2)	282.0	282.0	(57.5)	0.0	0.0	2,019.6	0.0	2,019.6	4%	0.0	80.8	1,938.8
2	**1-rolling start**	727.0	0.0	727.0	79.4	(6.3)	73.1	73.1	0.0	0.0	0.0	800.2	0.0	800.2	4%	0.0	32.0	768.2
3	**1.1**	646.1	0.0	646.1	91.5	(7.2)	84.3	84.3	(1.4)	0.0	0.0	729.0	0.0	729.0	6%	0.0	43.7	685.3
4	**1.1-rolling start**	241.9	0.0	241.9	14.2	(1.1)	13.1	13.1	0.0	0.0	0.0	254.9	0.0	254.9	6%	0.0	15.3	239.6
5	**2**	(0.0)	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	6%	0.0	(0.0)	(0.0)
6	**3**	(0.0)	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	5%	0.0	(0.0)	(0.0)
7	**6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	0.0	0.0
8	**8**	440.8	0.0	440.8	200.9	(15.9)	185.0	185.0	(9.0)	0.0	0.0	616.9	0.0	616.9	20%	0.0	123.4	493.5
9	**8-rolling start**	161.7	0.0	161.7	35.8	(2.8)	33.0	33.0	0.0	0.0	0.0	194.7	0.0	194.7	20%	0.0	38.9	155.7
10	**10**	1.6	0.0	1.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.6	0.0	1.6	30%	0.0	0.5	1.1
11	**12**	0.0	0.0	0.0	167.4	(13.2)	154.2	154.2	0.0	0.0	0.0	154.2	0.0	154.2	100%	0.0	154.2	0.0
12	**12-rolling start**	0.0	0.0	0.0	14.2	(1.1)	13.1	13.1	0.0	0.0	0.0	13.1	0.0	13.1	100%	0.0	13.1	0.0
13	**13**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	n/a	0.0	0.0	0.0
14	**14.1**	2.9	0.0	2.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.9	0.0	2.9	7%	0.0	0.2	2.7
15	**14.1**	8.9	0.0	8.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.9	0.0	8.9	5%	0.0	0.4	8.5
16	**17**	10,392.1	0.0	10,392.1	2,589.9	(204.4)	2,385.5	2,385.5	(613.2)	0.0	0.0	12,164.4	0.0	12,164.4	8%	0.0	973.2	11,191.3
17	**17-rolling start**	5,944.6	0.0	5,944.6	822.8	(64.9)	757.9	757.9	0.0	0.0	0.0	6,702.4	0.0	6,702.4	8%	0.0	536.2	6,166.2
18	**26**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
19	**42**	12.5	0.0	12.5	(0.1)	0.0	(0.1)	(0.1)	0.0	0.0	0.0	12.5	0.0	12.5	12%	0.0	1.5	11.0
20	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
21	**43.2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50%	0.0	0.0	0.0
22	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
23	**50**	0.8	0.0	0.8	3.2	(0.3)	2.9	2.9	0.0	0.0	0.0	3.7	0.0	3.7	55%	0.0	2.0	1.7
24	**Total**	20,375.9	0.0	20,375.9	4,325.4	(341.4)	3,984.0	3,984.0	(681.0)	0.0	0.0	23,679.0	0.0	23,679.0		0.0	2,015.4	21,663.6

Notes:
1 Per App. A, Table 53, col (k).
2 Line 24 per App. A, Table 17, col. (b) the sum of lines 46, 47, and 48.
3 RIIP represents the reinstated accelerated investment incentive ("RIIP") for qualifying property acquired on or after January 1, 2025 and available for use before 2034 that was made effective through legislation which received Royal Assent on March 26, 2026. Under these rules, the half-year rule is suspended until it is phased out.
4 Per Ex. L-F4-CCC-084, Att. 1, Table 47, col. (c).
5 Per Ex. L-F4-CCC-084, Att. 1, Table 47, col. (b).

Numbers may not add due to rounding.

Table 55
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG Nuclear Facilities ($M)
Year Ending December 31, 2031

Line No.	Class	Undepreciated Capital Cost at Beginning of Year (incl. Prior Year(s)' Settlement Adjustments)	Settlement Adjustment to Undepreciated Capital Cost at Beginning of Year	(a)+(a1) Total Undepreciated Capital Cost at Beginning of Year	Cost of Acquisitions	Settlement Adjustments to Cost of Acquisitions	(b)+(b1) Total Cost of Acquisitions	Cost of Acquisitions that are RIIP	Settlement Adjustments: CEITCs	Net Adjustments	Proceeds of Dispositions	(a2)+(b2)+(c)+(c1)-(d) UCC1	50% Rule or UCC adj for RIIP	(e)-(f) Reduced or Increased Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a) Note 1	(a1)	(a2)	(b) Note 5	(b1) Note 2	(b2)	(b3) Note 3	(c) Note 4	(c1)	(d)	(e)	(f) Note 3	(g)	(h)	(i)	(j)	(k)
1	**1**	1,938.8	0.0	1,938.8	215.3	9.4	224.7	224.7	(37.9)	0.0	0.0	2,125.6	0.0	2,125.6	4%	0.0	85.0	2,040.6
2	**1-rolling start**	768.2	0.0	768.2	13.3	0.6	13.9	13.9	0.0	0.0	0.0	782.0	0.0	782.0	4%	0.0	31.3	750.7
3	**1.1**	685.3	0.0	685.3	54.5	2.4	56.9	56.9	(3.3)	0.0	0.0	738.9	0.0	738.9	6%	0.0	44.3	694.6
4	**1.1-rolling start**	239.6	0.0	239.6	12.8	0.6	13.3	13.3	0.0	0.0	0.0	253.0	0.0	253.0	6%	0.0	15.2	237.8
5	**2**	(0.0)	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	6%	0.0	(0.0)	(0.0)
6	**3**	(0.0)	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	5%	0.0	(0.0)	(0.0)
7	**6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	0.0	0.0
8	**8**	493.5	0.0	493.5	117.4	5.1	122.5	122.5	(10.5)	0.0	0.0	605.5	0.0	605.5	20%	0.0	121.1	484.4
9	**8-rolling start**	155.7	0.0	155.7	25.8	1.1	26.9	26.9	0.0	0.0	0.0	182.7	0.0	182.7	20%	0.0	36.5	146.1
10	**10**	1.1	0.0	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.1	0.0	1.1	30%	0.0	0.3	0.8
11	**12**	0.0	0.0	0.0	141.4	6.2	147.6	147.6	0.0	0.0	0.0	147.6	0.0	147.6	100%	0.0	147.6	0.0
12	**12-rolling start**	0.0	0.0	0.0	12.8	0.6	13.3	13.3	0.0	0.0	0.0	13.3	0.0	13.3	100%	0.0	13.3	0.0
13	**13**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	n/a	0.0	0.0	0.0
14	**14.1**	2.7	0.0	2.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.7	0.0	2.7	7%	0.0	0.2	2.5
15	**14.1**	8.5	0.0	8.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.5	0.0	8.5	5%	0.0	0.4	8.0
16	**17**	11,191.3	0.0	11,191.3	2,181.0	95.6	2,276.6	2,276.6	(389.1)	0.0	0.0	13,078.7	0.0	13,078.7	8%	0.0	1,046.3	12,032.4
17	**17-rolling start**	6,166.2	0.0	6,166.2	291.3	12.8	304.0	304.0	0.0	0.0	0.0	6,470.3	0.0	6,470.3	8%	0.0	517.6	5,952.6
18	**26**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
19	**42**	11.0	0.0	11.0	(0.1)	(0.0)	(0.1)	(0.1)	0.0	0.0	0.0	10.9	0.0	10.9	12%	0.0	1.3	9.6
20	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
21	**43.2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50%	0.0	0.0	0.0
22	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
23	**50**	1.7	0.0	1.7	4.4	0.2	4.6	4.6	0.0	0.0	0.0	6.2	0.0	6.2	55%	0.0	3.4	2.8
24	**Total**	21,663.6	0.0	21,663.6	3,069.8	134.5	3,204.4	3,204.4	(440.8)	0.0	0.0	24,427.1	0.0	24,427.1		0.0	2,064.0	22,363.1

Notes:
1 Per App. A, Table 54, col (k).
2 Line 24 per App. A, Table 17, col. (b) the sum of lines 59, 60, and 61.
3 RIIP represents the reinstated accelerated investment incentive ("RIIP") for qualifying property acquired on or after January 1, 2025 and available for use before 2034 that was made effective through legislation which received Royal Assent on March 26, 2026. Under these rules, the half-year rule is suspended until it is phased out.
4 Per Ex. L-F4-CCC-084, Att. 1, Table 48, col. (c).
5 Per Ex. L-F4-CCC-084, Att. 1, Table 48, col. (b).

Numbers may not add due to rounding.

Table 56
Undepreciated Capital Cost and Capital Cost Allowance Schedule for DNNP LP ($M)
Year Ending December 31, 2027

Line No.	Class	Settlement Adjustment to Undepreciated Capital Cost at Beginning of Year (2027)	Cost of Acquisitions	Cost of Acquisitions that are RIIP	Settlement Adjustments: CEITCs	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)+(c1)-(d) UCC1	50% Rule or UCC adj for RIIP	(e)-(f) Reduced or Increased Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a) Note 1	(b)	(b1) Note 2	(c) Note 1	(c1)	(d)	(e)	(f) Note 2	(g)	(h)	(i)	(j)	(k)
1	**1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4%	0.0	0.0	0.0
2	**1-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4%	0.0	0.0	0.0
3	**1.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6%	0.0	0.0	0.0
4	**1.1-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6%	0.0	0.0	0.0
5	**2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6%	0.0	0.0	0.0
6	**3**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
7	**6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	0.0	0.0
8	**8**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20%	0.0	0.0	0.0
9	**8-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20%	0.0	0.0	0.0
10	**10**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
11	**12**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100%	0.0	0.0	0.0
12	**13**	0.0	1,620.7	669.4	0.0	0.0	0.0	1,620.7	0.0	1,620.7	n/a	0.0	102.9	1,517.8
13	**13-rolling start**	0.0	2,093.2	2,093.2	0.0	0.0	0.0	2,093.2	0.0	2,093.2	n/a	0.0	165.2	1,927.9
14	**14.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7%	0.0	0.0	0.0
15	**14.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
16	**17**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
17	**17-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
18	**42**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12%	0.0	0.0	0.0
19	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
20	**43.2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50%	0.0	0.0	0.0
21	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
22	**50**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	55%	0.0	0.0	0.0
23	**Total**	0.0	3,713.8	2,762.5	0.0	0.0	0.0	3,713.8	0.0	3,713.8		0.0	268.2	3,445.7

Notes:

1 Per Ex. L-F4-CCC-084, Att. 1, Table 49.

2 RIIP represents the reinstated accelerated investment incentive ("RIIP") for qualifying property acquired on or after January 1, 2025 and available for use before 2034 that was made effective through legislation which received Royal Assent on March 26, 2026. Under these rules, the half-year rule is suspended until it is phased out.

Numbers may not add due to rounding.

Table 57
Undepreciated Capital Cost and Capital Cost Allowance Schedule for DNNP LP ($M)
Year Ending December 31, 2028

Line No.	Class	Undepreciated Capital Cost at Beginning of Year (incl. Prior Year(s)' Settlement Adjustments)	Cost of Acquisitions	Cost of Acquisitions that are RIIP	Settlement Adjustments: CEITCs	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)+(c1)-(d) UCC1	50% Rule or UCC adj for RIIP	(e)-(f) Reduced or Increased Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a) Note 1	(b)	(b1) Note 2	(c) Note 3	(c1)	(d)	(e)	(f) Note 2	(g)	(h)	(i)	(j)	(k)
1	**1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4%	0.0	0.0	0.0
2	**1-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4%	0.0	0.0	0.0
3	**1.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6%	0.0	0.0	0.0
4	**1.1-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6%	0.0	0.0	0.0
5	**2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6%	0.0	0.0	0.0
6	**3**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
7	**6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	0.0	0.0
8	**8**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20%	0.0	0.0	0.0
9	**8-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20%	0.0	0.0	0.0
10	**10**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
11	**12**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100%	0.0	0.0	0.0
12	**13**	1,517.8	896.7	896.7	(372.7)	0.0	0.0	2,041.8	0.0	2,041.8	n/a	0.0	139.3	1,902.4
13	**13-rolling start**	1,927.9	1,633.4	1,633.4	0.0	0.0	0.0	3,561.4	0.0	3,561.4	n/a	0.0	246.3	3,315.1
14	**14.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7%	0.0	0.0	0.0
15	**14.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
16	**17**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
17	**17-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
18	**42**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12%	0.0	0.0	0.0
19	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
20	**43.2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50%	0.0	0.0	0.0
21	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
22	**50**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	55%	0.0	0.0	0.0
23	**Total**	3,445.7	2,530.1	2,530.1	(372.7)	0.0	0.0	5,603.1	0.0	5,603.1		0.0	385.6	5,217.5

Notes:

1 Per App A, Table 56, col. (k).

2 RIIP represents the reinstated accelerated investment incentive ("RIIP") for qualifying property acquired on or after January 1, 2025 and available for use before 2034 that was made effective through legislation which received Royal Assent on March 26, 2026. Under these rules, the half-year rule is suspended until it is phased out.

3 Per Ex. L-F4-CCC-084, Att. 1, Table 50, col. (c).

Numbers may not add due to rounding.

Table 58
Undepreciated Capital Cost and Capital Cost Allowance Schedule for DNNP LP ($M)
Year Ending December 31, 2029

Line No.	Class	Undepreciated Capital Cost at Beginning of Year (incl. Prior Year(s)' Settlement Adjustments)	Cost of Acquisitions	Cost of Acquisitions that are RIIP	Settlement Adjustments: CEITCs	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)+(c1)-(d) UCC1	50% Rule or UCC adj for RIIP	(e)-(f) Reduced or Increased Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a) Note 1	(b)	(b1) Note 2	(c) Note 3	(c1)	(d)	(e)	(f) Note 2	(g)	(h)	(i)	(j)	(k)
1	**1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4%	0.0	0.0	0.0
2	**1-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4%	0.0	0.0	0.0
3	**1.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6%	0.0	0.0	0.0
4	**1.1-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6%	0.0	0.0	0.0
5	**2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6%	0.0	0.0	0.0
6	**3**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
7	**6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	0.0	0.0
8	**8**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20%	0.0	0.0	0.0
9	**8-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20%	0.0	0.0	0.0
10	**10**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
11	**12**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100%	0.0	0.0	0.0
12	**13**	1,902.4	304.7	304.7	(289.6)	0.0	0.0	1,917.6	0.0	1,917.6	n/a	0.0	124.3	1,793.3
13	**13-rolling start**	3,315.1	0.0	0.0	0.0	0.0	0.0	3,315.1	0.0	3,315.1	n/a	0.0	200.9	3,114.2
14	**14.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7%	0.0	0.0	0.0
15	**14.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
16	**17**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
17	**17-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
18	**42**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12%	0.0	0.0	0.0
19	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
20	**43.2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50%	0.0	0.0	0.0
21	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
22	**50**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	55%	0.0	0.0	0.0
23	**Total**	5,217.5	304.7	304.7	(289.6)	0.0	0.0	5,232.7	0.0	5,232.7		0.0	325.2	4,907.5

Notes:
1 Per App A, Table 57, col. (k).
2 RIIP represents the reinstated accelerated investment incentive ("RIIP") for qualifying property acquired on or after January 1, 2025 and available for use before 2034 that was made effective through legislation which received Royal Assent on March 26, 2026. Under these rules, the half-year rule is suspended until it is phased out.
3 Per Ex. L-F4-CCC-084, Att. 1, Table 51, col. (c).

Numbers may not add due to rounding.

Table 59
Undepreciated Capital Cost and Capital Cost Allowance Schedule for DNNP LP ($M)
Year Ending December 31, 2030

Line No.	Class	Undepreciated Capital Cost at Beginning of Year (incl. Prior Year(s)' Settlement Adjustments)	Cost of Acquisitions	Cost of Acquisitions that are RIIP	Settlement Adjustments: CEITCs	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)+(c1)-(d) UCC1	50% Rule or UCC adj for RIIP	(e)-(f) Reduced or Increased Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a) Note 1	(b)	(b1) Note 2	(c) Note 3	(c1)	(d)	(e)	(f) Note 2	(g)	(h)	(i)	(j)	(k)
1	**1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4%	0.0	0.0	0.0
2	**1-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4%	0.0	0.0	0.0
3	**1.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6%	0.0	0.0	0.0
4	**1.1-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6%	0.0	0.0	0.0
5	**2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6%	0.0	0.0	0.0
6	**3**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
7	**6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	0.0	0.0
8	**8**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20%	0.0	0.0	0.0
9	**8-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20%	0.0	0.0	0.0
10	**10**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
11	**12**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100%	0.0	0.0	0.0
12	**13**	1,793.3	373.2	373.2	(34.9)	0.0	0.0	2,131.7	0.0	2,131.7	n/a	0.0	136.4	1,995.2
13	**13-rolling start**	3,114.2	0.0	0.0	0.0	0.0	0.0	3,114.2	0.0	3,114.2	n/a	0.0	200.9	2,913.2
14	**14.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7%	0.0	0.0	0.0
15	**14.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
16	**17**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
17	**17-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
18	**42**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12%	0.0	0.0	0.0
19	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
20	**43.2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50%	0.0	0.0	0.0
21	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
22	**50**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	55%	0.0	0.0	0.0
23	**Total**	4,907.5	373.2	373.2	(34.9)	0.0	0.0	5,245.9	0.0	5,245.9		0.0	337.4	4,908.5

Notes:

1 Per App A, Table 58, col. (k).

2 RIIP represents the reinstated accelerated investment incentive ("RIIP") for qualifying property acquired on or after January 1, 2025 and available for use before 2034 that was made effective through legislation which received Royal Assent on March 26, 2026. Under these rules, the half-year rule is suspended until it is phased out.

3 Per Ex. L-F4-CCC-084, Att. 1, Table 52, col. (c).

Numbers may not add due to rounding.

Table 60
Undepreciated Capital Cost and Capital Cost Allowance Schedule for DNNP LP ($M)
Year Ending December 31, 2031

Line No.	Class	Undepreciated Capital Cost at Beginning of Year (incl. Prior Year(s)' Settlement Adjustments)	Cost of Acquisitions	Cost of Acquisitions that are RIIP	Settlement Adjustments: CEITCs	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)+(c1)-(d) UCC1	50% Rule or UCC adj for RIIP	(e)-(f) Reduced or increased Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a) Note 1	(b)	(b1) Note 2	(c) Note 3	(c1)	(d)	(e)	(f) Note 2	(g)	(h)	(i)	(j)	(k)
1	**1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4%	0.0	0.0	0.0
2	**1-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4%	0.0	0.0	0.0
3	**1.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6%	0.0	0.0	0.0
4	**1.1-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6%	0.0	0.0	0.0
5	**2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6%	0.0	0.0	0.0
6	**3**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
7	**6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	0.0	0.0
8	**8**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20%	0.0	0.0	0.0
9	**8-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20%	0.0	0.0	0.0
10	**10**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
11	**12**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100%	0.0	0.0	0.0
12	**13**	1,995.2	0.0	0.0	(42.7)	0.0	0.0	1,952.5	0.0	1,952.5	n/a	0.0	133.6	1,818.9
13	**13-rolling start**	2,913.2	0.0	0.0	0.0	0.0	0.0	2,913.2	0.0	2,913.2	n/a	0.0	200.9	2,712.3
14	**14.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7%	0.0	0.0	0.0
15	**14.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
16	**17**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
17	**17-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
18	**42**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12%	0.0	0.0	0.0
19	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
20	**43.2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50%	0.0	0.0	0.0
21	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
22	**50**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	55%	0.0	0.0	0.0
23	**Total**	4,908.5	0.0	0.0	(42.7)	0.0	0.0	4,865.8	0.0	4,865.8		0.0	334.5	4,531.3

Notes:
1 Per App A, Table 59, col. (k).
2 RIIP represents the reinstated accelerated investment incentive ("RIIP") for qualifying property acquired on or after January 1, 2025 and available for use before 2034 that was made effective through legislation which received Royal Assent on March 26, 2026. Under these rules, the half-year rule is suspended until it is phased out.
3 Per Ex. L-F4-CCC-084, Att. 1, Table 53, col. (c).

Numbers may not add due to rounding.

Table 61
Calculation of Forecast Concurrent Cost Recovery Interest Amounts - Pickering Refurbishment Program
January 1, 2027 to December 31, 2031 ($M)

Line No.	Description	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
1	**Opening Balance**	1	4,773.3	8,158.8	11,424.8	14,344.3	16,402.4
2	**Capital Expenditures**	2	3,473.2	3,607.6	3,578.3	2,681.4	1,860.5
2a	**Settlement Adjustment: CEITC Capital Expenditure Adjustment**	3	(67.5)	(341.6)	(658.7)	(623.3)	(383.2)
3	**In-Service**	4	20.2	0.0	0.0	0.0	8,682.7
4	**Closing Balance** (line 1 + line 2 + line 2a - line 3)		8,158.8	11,424.8	14,344.3	16,402.4	9,197.0
5	**Capital Costs for Purposes of Calculating CCR** ((line 1 + line 4) / 2	4	6,466.0	9,791.8	12,884.6	15,373.4	11,714.4
6	**OPG Cost of Long-Term Borrowing**	5	4.56%	4.75%	4.86%	4.91%	4.92%
7	**Concurrent Cost Recovery**		295.0	465.5	626.4	755.0	576.0

Notes:

1 Col. (a) per Ex. D2-3-8, Table 1, sum of line 4, cols. (a) through (f).

2 Per Ex. D2-3-8, Table 1, line 4.

3 Per Ex. L-F4-CCC-084, Att.1, Table 58, line 2a.

4 The 2031 in-service is weighted 7.5/12 months based on the forecast in-service date of May 15, 2031 for Pickering Refurbishment Program Unit 5 and Deep Water Intake, per Ex. L-F4-CCC-084, Att. 1, Table 8, Note 1.

5 Per App. A, Tables 19-23, line 2, col. (c).

Numbers may not add due to rounding.

Table 62
Calculation of Forecast Concurrent Cost Recovery Interest Amounts - Darlington New Nuclear Program
January 1, 2027 to December 31, 2031 ($M)

Line No.	Description	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
1	**Opening Balance**	1	3,884.0	5,504.7	6,028.7	6,043.8	446.7
2	**Capital Expenditures**	2	1,620.7	896.7	304.7	373.2	0.0
2a	**Settlement Adjustment: CEITC Capital Expenditure Adjustment**	3	0.0	(372.7)	(289.6)	(34.9)	(42.7)
3	**In-Service**	4	0.0	0.0	0.0	5,935.4	0.0
4	**Closing Balance** (line 1 + line 2 + line 2a - line 3)		5,504.7	6,028.7	6,043.8	446.7	404.0
5	**Capital Costs for Purposes of Calculating CCR** ((line 1 + line 4) / 2	4	4,694.3	5,766.7	6,036.2	4,976.4	425.4
6	**OPG Cost of Long-Term Borrowing**	5	4.56%	4.75%	4.86%	4.91%	4.92%
7	**Concurrent Cost Recovery** (line 5 x line 6)		214.2	274.2	293.4	244.4	20.9

Notes:

1 Col. (a) per Ex. D2-4-8, Table 1, sum of line 3, cols. (a) through (g).
2 Per Ex. D2-4-8, Table 1, line 3.
3 Per Ex. L-F4-CCC-084, Att. 1, Table 57, line 2a.
4 The 2030 in-service is weighted 2.5/12 months based on the forecast in-service date of October 17, 2030 for Darlington New Nuclear Program Unit 1, per Ex. L-F4-CCC-084, Att. 1, Table 8, Note 1.
5 Per App. A, Tables 19-23, line 2, col. (c).

Numbers may not add due to rounding.

Table 1
Payment Amounts – Regulated Hydroelectric
January 1, 2027 to December 31, 2031

Line No.	Description	Note	2027	Illustrative Payment Amounts 2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
				Note 1			
1	**Price Escalator (I-Factor)**	2	2.93%	2.93%	2.93%	2.93%	2.93%
2	**Labour: Average Weekly Earnings - Ontario**	2	3.58%	3.58%	3.58%	3.58%	3.58%
3	**Non-Labour: Canadian Gross Domestic Product Implicit Price Index - Final Domestic Demand**	2	2.81%	2.81%	2.81%	2.81%	2.81%
4	**Productivity Factor**	3	0.00%	0.00%	0.00%	0.00%	0.00%
5	**Stretch Factor**	4	0.30%	0.30%	0.30%	0.30%	0.30%
6	**"I-X"** (line 1 - line 4 - line 5)		2.63%	2.63%	2.63%	2.63%	2.63%
7	**Custom Capital Factor** (App. B, Table 2, line 11)			2.51%	7.99%	1.58%	-0.13%
8	**GRC Factor** (App. B, Table 2, Note 4, line 4c)			0.46%	0.52%	0.61%	0.48%
9	**Production Growth Factor**	6		0.80%	0.69%	0.09%	-0.17%
10	**Price Cap Index** (line 6 + line 7 - line 8 - line 9)			3.88%	9.40%	3.51%	2.18%
11	**Prior Year Hydroelectric Payment Amount ($/MWh)**			46.90	48.72	53.30	55.17
12	**Prior Year Price Cap Adjusted Hydroelectric Payment Amount ($/MWh)**	5	46.90	48.72	53.30	55.17	56.37

Notes:

1 Payment amounts for 2028-2031 are illustrative only - final payment amounts to be determined annually using corresponding I-factor values.

2 2027 inflation factor per 2027 inflation parameters published by the OEB in June 2026, and weightings per Ex. A1-3-2 Chart 3: 15.3% labour cost, 9.3% non-labour cost and 75.4% capital cost (Settlement Proposal, Section 2, Part A).

3 Per Ex. A1-3-2, Section 2.3.2.1 (Settlement Proposal, Section 2, Part A).

4 Per Settlement Proposal, Section 2, Part A.

5 2027 is a cost of service payment amount, determined as: 2027 revenue requirement (App. A, Table 1, line 22, col. (c)) divided by 2027 production forecast (Note 6a). Subsequent years are illustrative payment amounts determined by escalating the immediately preceding year's payment amount by the Price Cap Index (line 10).

6 The Production Growth Factor is calculated as follows, pursuant to the Settlement Proposal (Section 2, Part C, ii):

Line No.	Description		2027	2028	2029	2030	2031
6a	Hydroelectric Production Forecast (Settlement Proposal, Section 2, Part A)		32.9	33.2	33.4	33.4	33.4
6b	Production Growth Factor (year-over-year change in line 6a)			0.80%	0.69%	0.09%	-0.17%

Numbers may not add due to rounding.

Table 2
Calculation of Custom Capital Factor and GRC Factor - Regulated Hydroelectric Facilities
January 1, 2027 to December 31, 2031 ($M)

Line No.	Description	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
			Note 1				
1	**Depreciation & Amortization**	2028-2031: Note 2	213.2	223.8	241.6	252.8	259.0
2	**Cost of Capital: Short-Term Debt and Long-Term Debt**	2028-2031: Note 3	226.8	246.2	276.7	292.7	305.0
3	**Cost of Capital: Common Equity**	2028-2031: Note 3	369.3	386.1	424.3	444.9	462.5
4	**Income Taxes**	2028-2031: App. A, Tables 30-33, line 23, col. (c)	(3.3)	15.0	86.5	100.1	96.5
5	**Capital Related Revenue Requirement**	Sum lines 1 to 4	806.0	871.1	1,029.1	1,090.6	1,123.0
6	**Stretch Factor Capital Related Revenue Requirement Adjustment**	0.3% * line 5 (cumulative) Note 5		2.6	5.7	9.0	12.3
7	**Supplemental Capital Stretch Factor Capital Related Revenue Requirement Adjustment**	0.3% * line 5 (cumulative) Note 5		2.6	5.7	9.0	12.3
8	**Capital Related Revenue Requirement after Stretch Factor**	line 5 - line 6 - line 7	806.0	865.9	1,017.7	1,072.6	1,098.3
9	**Capital Afforded through (I-X) Adjustment** (assuming Custom Capital Factor in preceding years)	2027: line 8 2028-2031: (line 9_{t-1} + line 10_{t-1}) escalated by (I-X)	806.0	827.2	888.6	1,044.5	1,100.8
10	**Capital Related Revenue Requirement Shortfall/(Excess)**	line 8 - line 9	0.0	38.7	129.1	28.2	(2.4)
11	**Custom Capital Factor (C-Factor)**	line 10_t / line 16_{t-1}		2.5%	8.0%	1.6%	-0.1%
12	**OM&A**	2028-2031: line 12_{t-1} escalated by (I - X)	476.4	488.9	501.8	514.9	528.5
13	**GRC**	2028-2031: Note 4	358.7	361.0	362.0	360.7	361.3
14	**Other Revenues**	2028-2031: line 14_{t-1} escalated by (I - X)	(91.6)	(94.0)	(96.5)	(99.0)	(101.6)
15	**General Revenue Requirement Adjustment**	2028-2031: line 15_{t-1} escalated by (I - X)	(5.9)	(6.1)	(6.3)	(6.4)	(6.6)
16	**Total Revenue Requirement**	line 8 + (lines 12 to 15)	1,543.6	1,615.8	1,778.8	1,842.8	1,879.9

Notes:

1 Per App. A, Table 1, col. (c).

2 Cols. (b) to (e) per Ex. F4-1-1, Table 1, as adjusted for the Settlement Proposal (Section 2, Part D, v). Adjustments are set out in App. A, Table 16, col. (c) and col. (b): lines 9, 14, 19, and 24.

3 Cols. (b) to (e) determined per App. A, Tables 20-23, Notes 6 and 8, based on the following regulated hydroelectric rate base values:

Line No.	Description	Reference	2027	2028	2029	2030	2031
3a	Net Fixed Assets	App. A, Table 15: lines 5, 10, 15, 20, 25; less App. Table 16: lines 5, 10, 15, 20, 25	8,988.8	9,399.8	10,331.0	10,833.6	11,263.2
3b	Cash Working Capital and Materials & Supplies	Ex. B1-1-1, Table 1, lines 10, 11, 16, 17	19.5	19.5	19.5	19.5	19.5
3c	Rate Base	line 3a + line 3b	9,008.4	9,419.3	10,350.5	10,853.1	11,282.7

4 Per Settlement Proposal, Section 2, Part D, iv.
The GRC Factor is calculated as follows, pursuant to the Settlement Proposal (Section 2, Part A):

Line No.	Description	Reference	2027	2028	2029	2030	2031
4a	GRC Escalated by (I-X)	line 13_{t-1} escalated by (I-X)	358.7	368.1	370.5	371.5	370.1
4b	Variance to Fixed GRC	line 13 less line 4a	0.0	(7.1)	(8.5)	(10.8)	(8.9)
4c	GRC Factor (variance as percentage of prior year revenue requirement)	line $4b_t$ / line 16_{t-1}	0.0	-0.5%	-0.5%	-0.6%	-0.5%

5 Stretch factor and supplemental capital stretch factor per Settlement Proposal, Section 2, Part A.

Numbers may not add due to rounding.

Table 3
Payment Amounts - Blended Nuclear
January 1, 2027 to December 31, 2031

Line No.	Description	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
1	**Revenue Requirement Net of Stretch Factor - OPG Nuclear Facilities**	1	3,856.8	3,970.6	4,335.9	4,464.5	5,189.4
2	**Revenue Requirement - DNNP LP**	2	296.3	364.1	373.1	512.0	962.8
3	**Combined Nuclear Revenue Requirement Net of Stretch Factor ($M)**		4,153.1	4,334.7	4,709.0	4,976.5	6,152.2
4	**OPG Nuclear Revenue Requirement Shaping Adjustment ($M)**	3	(350.0)	350.0	0.0	0.0	0.0
5	**Combined Nuclear Revenue Requirement Net of Stretch Factor After Shaping Adjustment ($M)** (line 3 + line 4)		3,803.1	4,684.7	4,709.0	4,976.5	6,152.2
6	**Production Forecast - OPG Nuclear Facilities (TWh)**	4	19.3	27.6	25.8	27.7	29.9
7	**Production Forecast - DNNP Facilities (TWh)**	5	0.0	0.0	0.0	0.5	2.0
8	**Combined Nuclear Production Forecast (TWh)** (line 6 + line 7)		19.3	27.6	25.8	28.2	32.0
9	**Blended Nuclear Payment Amount ($/MWh)** (line 5 / line 8)		196.62	169.94	182.40	176.64	192.42

Notes:
1 App. A, Tables 2-6: line 30, col. (c).
2 App. A, Tables 8-12: line 22, col. (c).
3 Deferral of $350.0M of OPG's 2027 nuclear revenue requirement to 2028, per Settlement Proposal, Section 2, Part H.
4 Per Settlement Proposal, Section 2, Part C, i.
5 Per Settlement Proposal, Section 3, Part C.

Numbers may not add due to rounding.

Table 4
Annualized Residential Consumer Impact
January 1, 2027 to December 31, 2031

Line No.	Description	Note	2027	2028	2029	2030	2031	Average
			(a)	(b)	(c)	(d)	(e)	(f)
	EB-2020-0290/EB-2023-0336 to EB-2025-0297:							
1	**Typical Consumption (kWh/Month)**	1	787	787	787	787	787	787
2	**Typical Usage of OPG and DNNP LP Generation (kWh/Month)** (line 1 x line 11)		251	291	282	293	312	286
3	**Typical Bill ($/Month)**	1	142.10	142.10	142.10	142.10	142.10	142.10
4	**Typical Bill Impact ($/Month)** (line 2 x line 8 / 1000)		6.29	0.46	1.72	0.53	3.79	2.56
5	**Typical Bill Impact (%)** (line 4 / line 3)		4.4%	0.3%	1.2%	0.4%	2.7%	1.8%
6	Prior Year Weighted Average Total Payments ($/MWh)	2	77.75	102.79	104.39	110.49	112.30	
7	Current Year Weighted Average Total Payments ($/MWh)	2	102.79	104.39	110.49	112.30	124.46	
8	Change in Weighted Average Total Payments ($/MWh) (line 7 - line 6)		25.04	1.60	6.10	1.81	12.16	
9	Total Regulated Production (TWh)	3	52.3	60.5	58.7	61.1	64.9	
10	Forecast of 2027 Provincial Demand (TWh)	4	163.9	163.9	163.9	163.9	163.9	
11	OPG and DNNP LP Proportion of Consumer Usage (line 9 / line 10)		31.9%	36.9%	35.8%	37.3%	39.6%	

Notes:

1 Typical monthly consumption (750 kWh) and typical monthly bill are based on the OEB "Bill Calculator" for estimating monthly electricity bills (using Time of Use pricing), available at: https://www.oeb.ca/consumer-information-and-protection/bill-calculator, accessed November 20, 2025. Typical Consumption includes line losses (Average loss factor of utility rate zones = 1.04996)

2 Per App. B, Table 5, line 9.

3 Per App. B, Table 5, line 3 and line 6.

4 Based on forecast demand for 2027 (163.9 TWh) from Figure 2 of IESO Annual Planning Outlook, released April 2025.

Numbers may not add due to rounding.

Table 4a
Annualized Bill Impact for Typical Alectra (PowerStream) Consumers
January 1, 2027 to December 31, 2031

Line No.	Description	Note	2027		2028		2029		2030		2031	
			Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	**Typical Consumer Usage (kWh/Month)**	1	82,952	2,840,600	82,952	2,840,600	82,952	2,840,600	82,952	2,840,600	82,952	2,840,600
2	**Total Forecast Production (TWh)**	2	52.3	52.3	60.5	60.5	58.7	58.7	61.1	61.1	64.9	64.9
3	**OPG and DNNP LP Portion of Consumer Usage**	3	31.9%	31.9%	36.9%	36.9%	35.8%	35.8%	37.3%	37.3%	39.6%	39.6%
4	**Consumer Usage of OPG and DNNP LP Generation (kWh/Month)** (line 1 x line 3)		26,442	905,475	30,604	1,047,989	29,718	1,017,654	30,910	1,058,494	32,833	1,124,341
5	**Typical Monthly Consumer Bill ($)**	1	19,554	623,417	19,554	623,417	19,554	623,417	19,554	623,417	19,554	623,417
	EB-2020-0290/EB-2023-0336 to EB-2025-0297:											
6	**Increase in Weighted Average Total Payments ($/MWh)**	4	25.04	25.04	1.60	1.60	6.10	6.10	1.81	1.81	12.16	12.16
7	**Percentage Increase in Consumer Bills** (line 6 x (line 4/1000) / line 5)		3.39%	3.64%	0.25%	0.27%	0.93%	1.00%	0.29%	0.31%	2.04%	2.19%
8	**Dollar Increase in Consumer Bills ($)** (line 5 x line 7)		662.11	22,673.10	48.97	1,676.78	181.28	6,207.69	55.95	1,915.87	399.25	13,671.99

Notes:
1 Current Approved Rates and Usage (adjusted for line losses) are taken from the Alectra EB-2025-0055 proceeding, Excel File: Final rate order_Alectra_RGM PRZ_20251222
GS > 50 customer, consumption 80,000 kWh, loss factor 3.69%
Large User customer, consumption 2,800,000 kWh, loss factor 1.45%
2 Per App. B, Table 5, line 3 and line 6.
3 Per App. B, Table 4, line 11.
4 Per App. B, Table 4, line 8.

Numbers may not add due to rounding.

Table 4b
Annualized Bill Impact for Typical Hydro One Networks Consumers
January 1, 2027 to December 31, 2031

Line No.	Description	Note	2027		2028		2029		2030		2031	
			Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	**Typical Consumer Usage (kWh/Month)**	1	38,306	1,655,471	38,306	1,655,471	38,306	1,655,471	38,306	1,655,471	38,306	1,655,471
2	**Total Forecast Production (TWh)**	2	52.3	52.3	60.5	60.5	58.7	58.7	61.1	61.1	64.9	64.9
3	**OPG and DNNP LP Portion of Consumer Usage**	3	31.9%	31.9%	36.9%	36.9%	35.8%	35.8%	37.3%	37.3%	39.6%	39.6%
4	**Consumer Usage of OPG and DNNP LP Generation (kWh/Month)** (line 1 x line 3)		12,210	527,701	14,132	610,756	13,723	593,078	14,274	616,879	15,162	655,254
5	**Typical Monthly Consumer Bill ($)**	1	8,413	269,489	8,413	269,489	8,413	269,489	8,413	269,489	8,413	269,489
	EB-2020-0290/EB-2023-0336 to EB-2025-0297:											
6	**Increase in Weighted Average Total Payments ($/MWh)**	4	25.04	25.04	1.60	1.60	6.10	6.10	1.81	1.81	12.16	12.16
7	**Percentage Increase in Consumer Bills** (line 6 x (line 4/1000) / line 5)		3.63%	4.90%	0.27%	0.36%	1.00%	1.34%	0.31%	0.41%	2.19%	2.96%
8	**Dollar Increase in Consumer Bills ($)** (line 5 x line 7)		305.75	13,213.64	22.61	977.21	83.71	3,617.77	25.84	1,116.55	184.37	7,967.89

Notes:
1 Current Approved Rates and Usage (adjusted for line losses) are taken from EB-2021-0110, Excel file: HONI_JRAP_Settlement Proposal_Attachment Update_Attachment 2_Schedule 7.1_20221116
Medium/Large Business: GSd_Avg customer, consumption 34,334 kWh, loss factor 6.1%
Large Industrial: ST_Avg customer, consumption 1,373,443 kWh, loss factor 3.4%
2 Per App. B, Table 5, line 3 and line 6.
3 Per App. B, Table 4, line 11.
4 Per App. B, Table 4, line 8.

Numbers may not add due to rounding.

Filed: 2026-10-05
EB-2025-0297
Draft Payment Amounts Order
Appendix B
Table 4c

Table 4c
Annualized Bill Impact for Typical Toronto Hydro Consumers
January 1, 2027 to December 31, 2031

Line No.	Description	Note	2027		2028		2029		2030		2031	
			Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	**Typical Consumer Usage (kWh/Month)**	1	81,331	3,967,080	81,331	3,967,080	81,331	3,967,080	81,331	3,967,080	81,331	3,967,080
2	**Total Forecast Production (TWh)**	2	52.3	52.3	60.5	60.5	58.7	58.7	61.1	61.1	64.9	64.9
3	**OPG and DNNP LP Portion of Consumer Usage**	3	31.9%	31.9%	36.9%	36.9%	35.8%	35.8%	37.3%	37.3%	39.6%	39.6%
4	**Consumer Usage of OPG and DNNP LP Generation (kWh/Month)** (line 1 x line 3)		25,925	1,264,554	30,006	1,463,583	29,137	1,421,219	30,306	1,478,255	32,192	1,570,215
5	**Typical Monthly Consumer Bill ($)**	1	14,446	694,406	14,446	694,406	14,446	694,406	14,446	694,406	14,446	694,406
	EB-2020-0290/EB-2023-0336 to EB-2025-0297:											
6	**Increase in Weighted Average Total Payments ($/MWh)**	4	25.04	25.04	1.60	1.60	6.10	6.10	1.81	1.81	12.16	12.16
7	**Percentage Increase in Consumer Bills** (line 6 x (line 4/1000) / line 5)		4.49%	4.56%	0.33%	0.34%	1.23%	1.25%	0.38%	0.39%	2.71%	2.75%
8	**Dollar Increase in Consumer Bills ($)** (line 5 x line 7)		649.17	31,664.43	48.01	2,341.73	177.74	8,669.44	54.85	2,675.64	391.45	19,093.81

Notes:
1 Current Approved Rates and Usage (adjusted for line losses) are taken from EB-2023-0195, excel file THESL_DRO_Schedule 8_OEB_Appendix_2-W_Bill Impacts_20241126
Medium/Large Business: GS 50-999 customer, consumption 79,000 kWh, loss factor 2.95%
Large Industrial : Large Use customer, consumption 3,900,000 kWh, loss factor 1.72%
2 Per App. B, Table 5, line 3 and line 6.
3 Per App. B, Table 4, line 11.
4 Per App. B, Table 4, line 8.

Numbers may not add due to rounding.

Table 5
Computation of Percentage Change in Payment Amounts
EB-2020-0290/EB-2023-0336 to EB-2025-0297

Line No.	Description	Note	2026	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)	(f)
			Note 1					
1	**Hydroelectric Payment Amount (HPA) ($/MWh)**	2	43.88	46.90	48.72	53.30	55.17	56.37
2	**Hydroelectric Payment Rider (HPR) ($/MWh)**	3	3.30	(1.53)	(1.51)	(1.50)	0.00	0.00
3	**Hydroelectric Production Forecast (HPF) (TWh)**	4	33.0	32.9	32.9	32.9	32.9	32.9
4	**Blended Nuclear Payment Amount (NPA) ($/MWh)**	5	111.33	196.62	169.94	182.40	176.64	192.42
5	**Blended Nuclear Payment Rider (NPR) ($/MWh)**	6	12.43	3.88	2.72	2.90	2.40	2.12
6	**Combined Nuclear Production Forecast (NPF) (TWh)**	7	21.9	19.3	27.6	25.8	28.2	32.0
7	**Regulated Hydroelectric Portion of Weighted Average Payment Amount ($/MWh)** (HPA + HPR) x HPF / (NPF+HPF)		28.35	28.58	25.69	29.03	29.72	28.59
8	**Nuclear Portion of Weighted Average Payment Amount ($/MWh)** (NPA + NPR) x NPF / (NPF+HPF)		49.41	74.22	78.70	81.46	82.58	95.86
9	**Weighted Average Payment Amount ($/MWh)** ((NPA + NPR) x NPF) + (HPA + HPR) x HPF) / (NPF + HPF)		77.75	102.79	104.39	110.49	112.30	124.46
10	**Percentage Change in Weighted Average Payment Amount (Year over Year)**			32.2%	1.6%	5.8%	1.6%	10.8%

Notes:
1 Col. (a) per EB-2020-0290 Payment Amounts Order, App. B, Table 3, line 1, col. (f). Lines 2 and 5 also include payment riders per EB-2023-0336 Decision and Order, p. 6.
2 Cols. (b) to (f) per App. B, Table 1, line 12.
3 Cols. (b) to (f) per App. C, Table 1, line 19.
4 Cols. (b) to (f) per Settlement Proposal, Section 2, Part A.
5 Cols. (b) to (f) per App. B, Table 3, line 9.
6 Cols. (b) to (f) per App. D, Table 1, line 32.
7 Cols. (b) to (f) per App. B, Table 3, line 8.

Numbers may not add due to rounding.

Table 1
Calculation of Deferral and Variance Account Payment Rider - Regulated Hydroelectric ($M)

Line No.	Account	Note	Audited Year End Balance 2024	EB-2020-0290 OEB-Approved Amortization (2025-2026)	EB-2023-0336 OEB-Approved Amortization (2025-2026)	(a)-(b)-(c) 2024 Balance Less Approved Amortization	Settlement Adjustments	Amounts Deferred to Future Applications	(d)+(d1)-(e) Amounts Recoverable (Refundable) in Current Application	Disposition Period (months)	Amortization Jan - Dec 2027	Amortization Jan - Dec 2028	Amortization Jan - Dec 2029	Amortization Jan - Dec 2030	Amortization Jan - Dec 2031	(h)+(i)+(j)+(k)+(l) Total Amortization	(d)+(d1)-(m) Unamortized Balance
			(a)	(b)	(c)	(d)	(d1)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
			Note 1	Note 2	Note 3		Note 8	Note 6		Note 7							
1	**Hydroelectric Water Conditions Variance**		(172.6)	0.0	(79.7)	(92.9)		0.0	(92.9)	36	(31.0)	(31.0)	(31.0)	0.0	0.0	(92.9)	0.0
2	**Ancillary Services Net Revenue Variance - Hydroelectric**		(22.2)	0.0	(9.7)	(12.5)		0.0	(12.5)	36	(4.2)	(4.2)	(4.2)	0.0	0.0	(12.5)	0.0
3	**Hydroelectric Incentive Mechanism Variance**		0.0	0.0	0.0	0.0		0.0	0.0	36	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	**Hydroelectric Surplus Baseload Generation Variance**		305.6	0.0	231.7	73.9		37.0	37.0	36	12.3	12.3	12.3	0.0	0.0	37.0	37.0
5	**Income and Other Taxes Variance - Hydroelectric**		(17.3)	0.0	(9.2)	(8.1)		0.0	(8.1)	36	(2.7)	(2.7)	(2.7)	0.0	0.0	(8.1)	0.0
6	**Capacity Refurbishment Variance - Hydroelectric**		162.1	0.0	41.4	120.7	(2.5)	118.2	0.0		0.0	0.0	0.0	0.0	0.0	0.0	118.2
7	**Niagara Tunnel Project Pre-December 2008 Disallowance Variance**		8.6	0.0	4.4	4.2		0.0	4.2	36	1.4	1.4	1.4	0.0	0.0	4.2	0.0
8	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Registered Pension Plan (RPP) - EB-2018-0243 Approved**		16.5	16.5	0.0	0.0		0.0	0.0	36	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Post-2017 Additions - EB-2020-0290 Approved**		17.7	17.7	0.0	0.0		0.0	0.0	36	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Post-2019 Additions**		(8.0)	0.0	22.5	(30.5)		0.0	(30.5)	36	(10.2)	(10.2)	(10.2)	0.0	0.0	(30.5)	0.0
11	**Pension & OPEB Cash Payment Variance - Hydroelectric**		(76.3)	0.0	(41.0)	(35.2)		0.0	(35.2)	36	(11.7)	(11.7)	(11.7)	0.0	0.0	(35.2)	0.0
12	**Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Variance - Carrying Charges - Hydroelectric**		(8.5)	0.0	(1.6)	(6.9)		0.0	(6.9)	36	(2.3)	(2.3)	(2.3)	0.0	0.0	(6.9)	0.0
13	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**		16.7	0.0	11.0	5.6		0.0	5.6	36	1.9	1.9	1.9	0.0	0.0	5.6	0.0
14	**Total Before the Following:**		222.3	34.2	169.8	18.3	(2.5)	155.2	(139.4)		(46.5)	(46.5)	(46.5)	0.0	0.0	(139.4)	155.2
15	**Tax on Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Post-2019 Additions**	4				(10.2)		0.0	(10.2)	36	(3.4)	(3.4)	(3.4)	0.0	0.0	(10.2)	0.0
16	**Sale of Unprescribed Kipling Site Deferral**		(6.3)	0.0	(5.1)	(1.2)		0.0	(1.2)	36	(0.4)	(0.4)	(0.4)	0.0	0.0	(1.2)	0.0
17	**Total Recoverable (Refundable) Amount**					6.9	(2.5)	155.2	(150.8)		(50.3)	(50.3)	(50.3)	0.0	0.0	(150.8)	155.2
18	**Forecast Production (TWh)**	5									32.9	33.2	33.4				
19	**Regulated Hydroelectric Payment Rider ($/MWh)** (line 17 / line 18)										(1.53)	(1.51)	(1.50)				

Notes:
1 Per Ex. H1-1-1 Table 1, col (c).
2 Per EB-2020-0290 Payments Amounts Order, App. C, Table 1, sum of cols. (k), (l).
3 Per EB-2023-0336 Decision and Order, App. A, Table 1, sum of cols. (h), (i).
4 Calculated as: line 10 * tax rate / (1 - tax rate). Tax rate from App. A, Table 29, line 26, col. (c).
5 Per App. B, Table 1, Note 6a.
6 Per Ex. H1-2-1, Table 1, col. (e), other than line 4 which represents a settlement adjustment to defer a portion of the balance in the Hydroelectric Surplus Baseload Generation Variance Account to a subsequent proceeding (Settlement Proposal, Section 2, Part G).
7 Per Ex. H1-2-1, Table 1, col. (g).
8 Represents settlement adjustment to reflect balances which will not be recovered, per Settlement Proposal, Section 4, Issue 11.

Numbers may not add due to rounding.

Table 1
Calculation of Deferral and Variance Account Payment Rider - Nuclear ($M)

Line No.	Account	Note	Audited Year End Balance 2024	EB-2020-0290 OEB-Approved Amortization (2025-2026)	EB-2023-0336 OEB-Approved Amortization (2025-2026)	(a)-(b)-(c) 2024 Balance Less Approved Amortization	Settlement Adjustments	Amounts Deferred to Future Applications	(d)+(d1)-(e) Amounts Recoverable (Refundable) in Current Application	Disposition Period (months)	Amortization Jan - Dec 2027	Amortization Jan - Dec 2028	Amortization Jan - Dec 2029	Amortization Jan - Dec 2030	Amortization Jan - Dec 2031	(h)+(i)+(j)+(k)+(l) Total Amortization	(d)+(d1)-(m) Unamortized Balance
			(a)	(b)	(c)	(d)	(d1)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
			Note 1	Note 2	Note 3		Note 5	Note 6		Note 7							
1	**Nuclear Liability Deferral**		527.3	0.0	150.7	376.6		0.0	376.6	36	125.5	125.5	125.5	0.0	0.0	376.6	0.0
2	**Nuclear Development Variance - DNNP**		61.8	0.0	86.6	(24.9)		0.0	(24.9)	36	(8.3)	(8.3)	(8.3)	0.0	0.0	(24.9)	0.0
3	**Nuclear Development Variance - Non DNNP**		23.5	0.0	0.0	23.5		23.5	0.0		0.0	0.0	0.0	0.0	0.0	0.0	23.5
4	**Ancillary Services Net Revenue Variance - Nuclear**		(13.5)	0.0	(9.0)	(4.5)		0.0	(4.5)	36	(1.5)	(1.5)	(1.5)	0.0	0.0	(4.5)	0.0
5	**Capacity Refurbishment Variance - Nuclear - DRP - Excluding Heavy Water Storage Facility (D2O Storage)**	8	170.2	0.0	0.0	170.2		170.2	0.0	36	0.0	0.0	0.0	0.0	0.0	0.0	170.2
6	**Capacity Refurbishment Variance - Nuclear - Non-DRP**		173.7	0.0	89.4	84.3	(0.6)	0.0	83.7	36	27.9	27.9	27.9	0.0	0.0	83.7	0.0
7	**Capacity Refurbishment Variance - Nuclear - Accelerated Investment Incentive CCA - DRP - EB-2020-0290/EB-2023-0336 Approved**		(16.8)	0.0	(14.5)	(2.3)		0.0	(2.3)	36	(0.8)	(0.8)	(0.8)	0.0	0.0	(2.3)	0.0
8	**Capacity Refurbishment Variance - Nuclear - D2O Storage - EB-2023-0336 Approved**		70.1	0.0	63.5	6.7		0.0	6.7	36	2.2	2.2	2.2	0.0	0.0	6.7	0.0
9	**Bruce Lease Net Revenues Variance - EB-2018-0243/EB-2016-0152 Approved**		42.1	42.1	0.0	0.0		0.0	0.0	36	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	**Bruce Lease Net Revenues Variance - Post-2017 Additions**		(102.0)	0.0	1.4	(103.4)		0.0	(103.4)	36	(34.5)	(34.5)	(34.5)	0.0	0.0	(103.4)	0.0
11	**Income and Other Taxes Variance - Nuclear**		(9.5)	0.0	(7.3)	(2.1)		0.0	(2.1)	36	(0.7)	(0.7)	(0.7)	0.0	0.0	(2.1)	0.0
12	**Pension and OPEB Cost Variance - Nuclear - Post 2021 Additions**		(411.1)	0.0	(98.0)	(313.1)		0.0	(313.1)	36	(104.4)	(104.4)	(104.4)	0.0	0.0	(313.1)	0.0
13	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Registered Pension Plan (RPP) - EB-2018-0243 Approved**		106.4	106.4	0.0	0.0		0.0	0.0	36	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Post-2017 Additions - EB-2020-0290 Approved**		111.3	111.3	0.0	0.0		0.0	0.0	36	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Post-2019 Additions - EB-2023-0336 Approved**		131.9	0.0	131.9	0.0		0.0	0.0	36	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	**Pension & OPEB Cash Payment Variance - Nuclear - EB-2020-0290/EB-2023-0336 Approved**		(244.4)	0.0	(213.8)	(30.6)		0.0	(30.6)	36	(10.2)	(10.2)	(10.2)	0.0	0.0	(30.6)	0.0
17	**Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Variance - Carrying Charges - Nuclear**		(42.1)	0.0	(9.5)	(32.6)		0.0	(32.6)	36	(10.9)	(10.9)	(10.9)	0.0	0.0	(32.6)	0.0
18	**Nuclear Deferral and Variance Over/Under Recovery Variance**		(61.5)	0.0	(46.4)	(15.1)		0.0	(15.1)	36	(5.0)	(5.0)	(5.0)	0.0	0.0	(15.1)	0.0
19	**Fitness for Duty Deferral**		2.5	0.0	0.0	2.5		0.0	2.5	36	0.8	0.8	0.8	0.0	0.0	2.5	0.0
20	**SR&ED ITC Variance**		(25.7)	0.0	(0.4)	(25.2)		0.0	(25.2)	36	(8.4)	(8.4)	(8.4)	0.0	0.0	(25.2)	0.0
21	**Rate Smoothing Deferral**		677.4	0.0	0.0	677.4		0.0	677.4	120	67.7	67.7	67.7	67.7	67.7	338.7	338.7
22	**Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral - EB-2020-0290/EB-2023-0336 Approved**		85.1	0.0	85.1	0.0		0.0	0.0	36	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	**Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral - December 31, 2020**		66.1	0.0	(36.0)	102.1		0.0	102.1	36	34.0	34.0	34.0	0.0	0.0	102.1	0.0
24	**Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral - December 31, 2023**		(2.3)	0.0	0.0	(2.3)		0.0	(2.3)	36	(0.8)	(0.8)	(0.8)	0.0	0.0	(2.3)	0.0
25	**Pickering Closure Costs Deferral**		7.6	0.0	0.0	7.6		0.0	7.6	36	2.5	2.5	2.5	0.0	0.0	7.6	0.0
26	**Clarington Corporate Campus Deferral**		7.7	0.0	0.0	7.7	(7.7)	0.0	0.0	36	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	**Pickering B Variance**		131.1	0.0	0.0	131.1		131.1	0.0		0.0	0.0	0.0	0.0	0.0	0.0	131.1
28	**Total Before the Following:**		1,466.8	259.8	173.6	1,033.4	(8.2)	324.8	700.4		75.4	75.4	75.4	67.7	67.7	361.7	663.5
29	**Sale of Unprescribed Kipling Site Deferral**		(6.3)	0.0	(5.1)	(1.2)		0.0	(1.2)	36	(0.4)	(0.4)	(0.4)	0.0	0.0	(1.2)	0.0
30	**Total Recoverable (Refundable) Amount**					1,032.2	(8.2)	324.8	699.1		75.0	75.0	75.0	67.7	67.7	360.4	663.5
31	**Forecast Production (TWh)**	4									19.3	27.6	25.8	28.2	32.0		
32	**Nuclear Payment Rider ($/MWh)** (line 30 / line 31)										3.88	2.72	2.90	2.40	2.12		

Notes:
1 Per Ex. H1-1-1 Table 1, col (c).
2 Per EB-2020-0290 Payments Amounts Order, App. D, Table 1, sum of cols. (k), (l).
3 Per EB-2023-0336 Decision and Order, App. A, Table 2, sum of cols. (h), (i).
4 From App. B, Table 3, line 8.
5 Represents settlement adjustments to reflect balances which will not be recovered, per Settlement Proposal, Section 2, Part G.
6 Per Ex. H1-2-1, Table 2, col. (e), unless otherwise noted.
7 Per Ex. H1-2-1, Table 2, col. (g).
8 Per Settlement Proposal, pp. 5-6, OPG and intervenors have agreed that the recovery of the December 31, 2024 $170.2M debit balance in the Capacity Refurbishment Variance Account related to the DRP should proceed by way of written hearing.

Appendix E: Clearance and Continuation of Existing Deferral and Variance Accounts

1.0 CLEARANCE OF EXISTING DEFERRAL AND VARIANCE ACCOUNTS

With respect to the deferral and variance accounts established by Ontario Regulation 53/05 ("O. Reg. 53/05") and prior decisions and orders of the OEB, the OEB approves:

1) A disposition credit amount of $140.6M (App. C, Table 1, col. (f), lines 14 and 16) for this proceeding from regulated hydroelectric deferral and variance accounts, reflecting OPG's approved disposition of the applicable audited December 31, 2024 balances in the deferral and variance accounts (App. C, Table 1, col. (a)) less amortization amounts for 2025 and 2026 approved in EB-2020-0290 (App. C, Table 1, col. (b), lines 14 and 16) and EB-2023-0336 (App. C, Table 1, col. (c), lines 14 and 16), plus additional net credit amounts totaling $10.2M (App. C, Table 1, col. (f), line 15) for the income tax impact associated with the repayment of the Pension & OPEB Cash Versus Accrual Differential Deferral Account, for a grand total amount repayable of $150.8M (App. C, Table 1, col. (m), line 17); and

2) A disposition debit amount of $699.1M (App. D, Table 1, col. (f), line 30) for this proceeding from nuclear deferral and variance accounts, reflecting the Applicants' approved disposition of the applicable audited December 31, 2024 balances in the deferral and variance accounts (App. D, Table 1, col. (a) lines 28 and 29) less amortization amounts for 2025 and 2026 approved in EB-2020-0290 (App. D, Table 1, col. (b), lines 28 and 29) and EB-2023-0336 (App. D, Table 1, col. (c), lines 28 and 29).[1]

The OEB approves recovery or repayment of the above approved balances in the regulated hydroelectric deferral and variance accounts, together with the above additional amounts, using payment riders of ($1.53/MWh) from January 1, 2027 to December 31, 2027,

[1] Subject to the OEB's decision on the Outstanding Issue.

($1.52/MWh) from January 1, 2028 to December 31, 2028 and ($1.50/MWh) from January 1, 2029 to December 31, 2029, as determined in App. C, Table 1, line 19.

The OEB approves recovery or repayment of the above approved balances in the nuclear deferral and variance accounts, using payment riders of $3.88/MWh from January 1 to December 31, 2027, $2.72/MWh from January 1, 2028 to December 31, 2028, $2.90/MWh from January 1, 2029 to December 31, 2029, $2.40/MWh from January 1, 2030 to December 31, 2030, and $2.12/MWh from January 1, 2031 to December 31, 2031, as determined in App. D, Table 1, line 32.[2]

Unless otherwise stated in this Payment Amounts Order, the Applicants shall continue to record entries into the deferral and variance accounts established by O. Reg. 53/05 and, as applicable, prior decisions and orders of the OEB pursuant to the methodologies established by O. Reg. 53/05 and applicable proceedings until the effective date of this Payment Amounts Order. Unless otherwise stated, the descriptions for continuing deferral and variance accounts provided below are effective as of the effective date of this Payment Amounts Order, being January 1, 2027.

2.0 CONTINUING DEFERRAL AND VARIANCE ACCOUNTS – OPG

Unless otherwise stated in this Payment Amounts Order, as of the effective date of the payment amounts established in this proceeding, OPG shall continue to record entries in the deferral and variance accounts authorized by O. Reg. 53/05 and the applicable decisions and orders of the OEB pursuant to the methodologies established by O. Reg. 53/05 and such decisions and orders, as set out below.

2.1. Hydroelectric Water Conditions Variance Account

The Hydroelectric Water Conditions Variance Account was originally established by O. Reg. 53/05 and was approved by the OEB in EB-2007-0905 and all subsequent OPG applications. The account shall continue to record the financial impact of differences, including changes in gross revenue charge ("GRC") costs, between the actual production amount for certain

[2] *Ibid.*

regulated hydroelectric facilities and the reference production values, arising from changes in actual water conditions.

For the regulated hydroelectric stations that are listed in Ex. E1-1-1, Attachment 1, OPG will determine the regulated hydroelectric production impact of changes in water conditions by entering the actual flow values into the same models used to calculate the production forecast for these facilities that underpins the 2027 regulated hydroelectric payment amount and the 2028-2031 regulated hydroelectric production growth factors approved by the OEB in this proceeding, holding all other variables constant.[3] Deviations from the forecast will be determined as the difference between the calculated production resulting from entering actual flow for the month into the forecast models and the energy production forecasts approved by the OEB. OPG will continue to exclude the regulated hydroelectric stations listed in Ex. E1-1-1, Attachment 2 from the scope of this account, as these stations do not have modeled energy production forecasts. The reference production forecasts are: 32.347 TWh for 2027, 32.551 TWh for 2028, 32.791 TWh for 2029, 32.761 TWh for 2030, and 32.671 TWh for 2031.

The revenue impact of the production variance recorded in this account will continue to be determined by multiplying the deviation from forecast by the approved regulated hydroelectric payment amount then in effect. OPG shall also record in this account changes in GRC costs from those that underpin the 2027 regulated hydroelectric payment amount and the 2028-2031 regulated hydroelectric GRC factors approved by the OEB in this proceeding as a result of differences in energy production calculated as above. Amounts recorded in the account in respect of these costs shall be determined by multiplying the production deviation as described above by the applicable GRC rates.

OPG shall also continue to record in this account any production related variances due to changes in water conditions in amounts payable to the St. Lawrence Seaway Management Corporation for the conveyance of water in the Welland Ship Canal, as well as any such variances in amounts payable to the Government of Québec for water rentals, from those

[3] For the DeCew Falls generating stations, account entries shall be limited to instances when actual Lake Erie levels reduce water diversion to the stations.

reflected in the 2027 regulated hydroelectric payment amount and underpinning the 2028-2031 regulated hydroelectric GRC factors approved by the OEB in this proceeding.

2.2. Ancillary Services Net Revenue Variance Account

The Ancillary Services Net Revenue Variance Account was originally established by O. Reg. 53/05 and was approved by the OEB in EB-2007-0905 and all subsequent OPG applications. The account shall continue to be divided into the Ancillary Services Net Revenue Variance Account – Hydroelectric and Ancillary Services Net Revenue Variance Account – Nuclear sub-accounts.

Ancillary services for the regulated hydroelectric facilities include black start capability, operating reserve, regulation service, and reactive support/voltage control service. Ancillary services for the OPG nuclear facilities include reactive support/voltage control service.

To determine additions in the Hydroelectric Sub-Account, OPG shall compare actual regulated hydroelectric ancillary services net revenue to the forecast amount reflected in the 2027 regulated hydroelectric revenue requirement approved by the OEB in this proceeding. Such monthly reference amount shall be 1/12 of $57.1M, or $4.8M.[4]

To determine additions in the Nuclear Sub-Account, OPG shall compare actual OPG nuclear ancillary services net revenue to the forecast amount reflected in the OPG nuclear facilities revenue requirements approved by the OEB in this proceeding. Such annual forecast amounts and resulting monthly reference amounts shall be $0.0M for 2027, $0.0M for 2028, $0.0M for 2029, $0.0M for 2030, and $0.0M for 2031.[5]

2.3. Hydroelectric Incentive Mechanism Variance Account

The Hydroelectric Incentive Mechanism Variance Account was originally established in EB-2010-0008 in conjunction with OPG's regulated hydroelectric incentive mechanism ("HIM") and has been approved in all subsequent OPG applications. Pursuant to the Settlement Proposal,

[4] Exhibit G1-1-1, Table 1, line 1, col. (l), as increased by $8.0M as part of the settlement adjusted amount of ancillary services revenues (Settlement Proposal, Section 4, Issue 34).
[5] Exhibit G2-1-1, Table 1, line 6, cols. (h) to (l).

the HIM net revenues shall continue to be shared between ratepayers and OPG using a 50:50 ratio. The resulting offset with respect to the HIM net revenues reflected in the 2027 regulated hydroelectric revenue requirement approved by the OEB in this proceeding is $27.3M. Accordingly, OPG shall record in the variance account a credit to ratepayers equal to 50% of its total regulated HIM net revenues above an annual threshold of $54.5M.[6]

2.4. Hydroelectric Surplus Baseload Generation Variance Account

The Hydroelectric Surplus Baseload Generation Variance Account was originally established in EB-2010-0008 and has been approved in all subsequent OPG applications. The account shall continue to record the financial impact of foregone production at the regulated hydroelectric stations listed in Ex. E1-1-1, Attachment 1 due to surplus baseload generation ("SBG") conditions, excluding foregone production due to local SBG conditions until such time as a different determination with respect to the treatment of such foregone production in this account is made by the OEB on a then-go forward basis, as detailed in the Settlement Proposal, Section 2, Part G.

Entries in the account shall continue to be calculated by multiplying foregone production volume due to SBG conditions (in MWh), determined as per below, by the approved regulated hydroelectric payment amount then in effect. The amount recorded in the account shall be net of the avoided GRC costs calculated by multiplying the foregone production volume by the applicable GRC rates, and net of the avoided amounts payable to the St. Lawrence Seaway Management Corporation for the conveyance of water in the Welland Ship Canal and to the Government of Québec for water rentals.

As detailed in Ex. E1-2-1, Section 4.3, OPG shall calculate foregone production due to SBG by starting with the total volume of spill and subtracting the volume of spill due to:

- water conveyance constraints (e.g., Sir Adam Beck Generating Stations tunnel capacity constraints);
- production capability constraints (e.g., unit outages; operating regulatory requirements etc.); and

[6] Settlement Proposal, Section 4, Issue 34.

- contractual obligations (e.g., regulation service).

The remaining spill volume shall be identified as potential SBG spill. From this potential spill volume, OPG shall exclude spill that occurs when the average hourly energy reference price is above the level of the GRC.[7] The volume of spill remaining after this adjustment is the foregone production due to SBG that shall be used to record entries in the Hydroelectric Surplus Baseload Generation Variance Account.

Should OPG receive a real-time energy make-whole payment from the IESO for any of the foregone production due to SBG that is used to record entries in the Hydroelectric Surplus Baseload Generation Variance Account, OPG shall record such real-time energy make-whole payment as a credit entry in the Hydroelectric Surplus Baseload Generation Variance Account.

2.5. Income and Other Taxes Variance Account (OPG)

The Income and Other Taxes Variance Account was originally established in EB-2007-0905 and has been approved in all subsequent OPG applications. The account shall continue to record the financial impact on OPG's revenue requirements approved by the OEB of the following, to the extent such impact is not recorded in another deferral or variance account:

- Any differences in payments in lieu of corporate income or capital taxes that result from a legislative or regulatory change to the tax rates or rules of the *Income Tax Act* (Canada) and the *Taxation Act*, 2007 (Ontario) (formerly the *Corporations Tax Act* (Ontario), as modified by the regulations under the *Electricity Act, 1998*, and any differences in payments in lieu of property tax to the Ontario Electricity Financial Corporation that result from changes to the regulations under the *Electricity Act, 1998*;
- Any differences in municipal property taxes that result from a legislative or regulatory change to the tax rates or rules for OPG's prescribed assets under the *Assessment Act, 1990*;
- Any differences in payments in lieu of corporate income or capital taxes that result from a change in, or a disclosure of, a new assessing or administrative policy that is published

[7] The Energy Reference Price is the locational marginal price at the RICHVIEW-230.REFERENCE pricing location identified in the IESO's Real-Time 5 Min Energy LMP Report.

in the public tax administration or interpretation bulletins by relevant federal or provincial tax authorities, or court decisions on other taxpayers; and

- Any differences in payments in lieu of income or capital taxes that result from assessments or re-assessments (including re-assessments associated with the application of the tax rates and rules to OPG's regulated operations or changes in assessing or administrative policy including those arising from court decisions on other taxpayers).

The account shall not record the revenue requirement impact of the above in relation to the Scientific Research and Experimental Development investment tax credits ("SR&ED ITCs"), including income taxes payable thereon, for the regulated hydroelectric facilities for taxation periods effective January 1, 2027 and for the OPG nuclear facilities for taxation periods effective June 1, 2017, both which shall be recorded in the SR&ED ITC Variance Account (OPG). The account shall not record the revenue requirement impact of the Clean Electricity Investment Tax Credits ("CEITCs"), which shall be recorded in the respective other deferral and variance accounts.

The forecast income tax provision and the underlying inputs reflected in the payment amounts approved by the OEB shall be used to calculate any variances in income taxes recorded in the Income and Other Taxes Variance Account (OPG). Such reference amounts for the regulated hydroelectric facilities shall be those that are reflected in the 2027 regulated hydroelectric revenue requirement and underpin the 2028-2031 regulated hydroelectric custom capital factors approved by the OEB in this proceeding, as calculated in Appendix A, Tables 29-33, col. (c), line 23. The resulting monthly reference amount for the regulated hydroelectric facilities shall be ($0.27M) for 2027, $1.25M for 2028, $7.20M for 2029, $8.34M for 2030, and $8.04M for 2031, being 1/12 of the respective annual amounts.[8] The reference amount to be used in determining variances for the OPG nuclear facilities shall be the corresponding annual income tax provision reflected in the OPG nuclear facilities revenue requirements approved by the OEB in this proceeding, as calculated in Appendix A, Tables 34-38, col. (c), line 30. The resulting monthly reference amounts for the OPG nuclear facilities shall be ($1.39M) for 2027,

[8] Subject to update for the prevailing ROE rate specified by the OEB as of the effective date of the final Payment Amounts Order in this proceeding.

($1.39M) for 2028, ($1.39M) for 2029, ($1.39M) for 2030, and ($1.39M) for 2031, being 1/12 of the respective annual amounts.

2.6. Capacity Refurbishment Variance Account

The Capacity Refurbishment Variance Account ("CRVA") was originally established in EB-2007-0905 and has been approved in all subsequent OPG applications. Pursuant to Section 6(2)4 of O. Reg. 53/05, the account shall continue to record the financial impacts of variances between the actual capital and non-capital costs incurred and firm financial commitments made by OPG increase the output of, refurbish or add operating capacity to a prescribed generation facility of OPG referred to in Section 2 of O. Reg. 53/05 and those forecast costs and firm financial commitments reflected in OPG's revenue requirements approved by the OEB.[9] The account shall continue to include assessment costs and pre-engineering costs and commitments as required by Section 6(2)4 of O. Reg. 53/05. The account shall also include revenue requirement variances arising from the CEITCs received by OPG in respect of the costs eligible for this account. The account shall not record the revenue requirement impact of the above in relation to the SR&ED ITCs, which shall be recorded in the SR&ED ITC Variance Account (OPG) or the Income and Other Taxes Variance Account (OPG), as applicable, or, effective September 15, 2026, in relation to any changes in the CCA rules or rates, including immediate expensing for tax purposes, which shall be recorded in the Change in CCA Rules or Rates Variance Account (OPG).

<u>Regulated Hydroelectric</u>

For the regulated hydroelectric facilities, the account shall record entries for capital costs relative to the reference amounts that are reflected in the 2027 regulated hydroelectric revenue requirement and underpin the 2028-2031 regulated hydroelectric custom capital factors approved by the OEB in this proceeding, and entries for non-capital costs relative to the reference amount that is reflected in the 2027 regulated hydroelectric revenue requirement approved by the OEB in this proceeding. The monthly reference amounts for the capital component shall be 1/12 of ($57.2M) for 2027, $20.4M for 2028, $171.4M for 2029, $219.3M for 2030, and $255.7M for 2031, as reflected in the 2027 regulated hydroelectric revenue

[9] Effective January 1, 2027, OPG shall not record the revenue requirement impact for projects with a total cost of less than $10M in the CRVA, where such projects have not been previously subject to the CRVA.

requirement and underpinning the 2028-2031 regulated hydroelectric custom capital factors approved by the OEB in this proceeding.[10] The resulting monthly reference amounts shall be ($4.8M) for 2027, $1.7M for 2028, $14.3M for 2029, $18.3M for 2030, and $21.3M for 2031. The monthly reference amount for the non-capital component shall be 1/12 of $24.6M, or $2.0M.[11]

To address the interaction of the CRVA with the Global Hydroelectric Capital Variance Account established in this proceeding, the following limitations shall apply to the CRVA with respect to entries for capital costs for the regulated hydroelectric facilities as of the effective date of this Payment Amounts Order:[12]

- The recoverability of the net debit entries, if any, recorded in the CRVA over the 2027-2031 period will be limited to an amount, if any, by which the actual capital-related revenue requirement ("CRRR") for the regulated hydroelectric facilities exceeds the forecast CRRR that is reflected in the 2027 regulated hydroelectric revenue requirement and underpins the 2028-2031 regulated hydroelectric custom capital factors approved by the OEB in this proceeding; and
- The refundability of the net credit entries, if any, recorded in the CRVA over the 2027-2031 period will be limited to an amount, if any, by which the actual CRRR for the regulated hydroelectric facilities is below the forecast CRRR that is reflected in the 2027 regulated hydroelectric revenue requirement and underpins the 2028-2031 regulated hydroelectric custom capital factors approved by the OEB in this proceeding.

Any adjustments to the recoverable or refundable balances recorded in the CRVA as a result of the above limitations shall be assessed on a cumulative basis over the 2027-2031 period and therefore shall be determined and recorded upon the completion of such period, in conjunction with the balances of the Global Hydroelectric Capital Variance Account as described in Appendix F. In the event that an amount recorded in the CRVA for the regulated hydroelectric facilities in respect of the 2027-2031 period is approved for disposition prior to the determination of the above adjustments, if any, such disposition shall be considered

[10] Refer to Attachment 1. Subject to update for the prevailing ROE rate specified by the OEB as of the effective date of the final Payment Amounts Order in this proceeding.
[11] Exhibit F1-3-1, Table 1, Note 4, as adjusted by Settlement Proposal, Section 4, Issue 11.
[12] Exhibit A1-3-2, Section 2.3.5 and Ex. L-H1-Staff-253.

interim, solely with respect to such adjustments, with any resulting excess or shortfall recovery or repayment arising in connection with such adjustments addressed through a subsequent proceeding.

Nuclear

For the OPG nuclear facilities, the account shall continue to record entries relative to the non-capital and capital reference amounts reflected in the OPG nuclear facilities revenue requirement approved by the OEB.

The monthly reference amounts for the Pickering Refurbishment Program ("PRP") capital component shall be 1/12 of ($109.3M) for 2027, ($268.0M) for 2028, ($383.5M) for 2029, ($340.9M) for 2030, and $269.8M for 2031, as reflected in the OPG nuclear facilities revenue requirements approved by the OEB in this proceeding.[13] The monthly reference amounts for the Darlington Refurbishment Program ("DRP") (excluding the Heavy Water Storage and Drum Handling Facility) capital component shall be 1/12 of $1,147.2M for 2027, $1,120.7M for 2028, $1,105.7M for 2029, $1,085.9M for 2030, and $1,064.3M for 2031, as reflected in the OPG nuclear facilities revenue requirements approved by the OEB in this proceeding.[14] The monthly reference amounts for the non-PRP and non-DRP capital component shall be 1/12 of ($1.9M) for 2027, $25.3M for 2028, $38.8M for 2029, $140.4M for 2030, and $246.3M for 2031, as reflected in the OPG nuclear facilities revenue requirements approved by the OEB in this proceeding.[15]

The monthly reference amounts for the PRP non-capital component shall be 1/12 of $100.3M for 2027, $94.1M for 2028, $84.9M for 2029, $52.7M for 2030, and $46.5M for 2031, as reflected in the OPG nuclear facilities revenue requirements approved by the OEB in this proceeding.[16] The monthly reference amounts for the DRP non-capital component shall be 1/12 of $0.0M for 2027, $0.0M for 2028, $0.0M for 2029, $0.0M for 2030, and $0.0M for 2031,

[13] Refer to Attachment 3. Subject to update for the prevailing ROE rate specified by the OEB as of the effective date of the final Payment Amounts Order in this proceeding.
[14] Refer to Attachment 2. Subject to update for the prevailing ROE rate specified by the OEB as of the effective date of the final Payment Amounts Order in this proceeding.
[15] Refer to Attachment 4. Subject to update for the prevailing ROE rate specified by the OEB as of the effective date of the final Payment Amounts Order in this proceeding.
[16] Exhibit F2-8-1, Table 1, line 2, cols. (h) to (l).

as reflected in the OPG nuclear facilities revenue requirements approved by the OEB in this proceeding.[17] The monthly reference amounts for the non-PRP and non-DRP non-capital component shall be 1/12 of $8.7M for 2027, $0.0M for 2028, $4.7M for 2029, $4.3M for 2030, and $4.4M for 2031, as reflected in the OPG nuclear facilities revenue requirements approved by the OEB in this proceeding.[18]

The resulting monthly reference amounts for the above components shall be:

- For the PRP capital component: ($9.1M) for 2027, ($22.3M) for 2028, ($32.0M) for 2029, ($28.4M) for 2030, and $22.5M for 2031;
- For the DRP capital component: $95.6M for 2027, $93.4M for 2028, $92.1M for 2029, $90.5M for 2030, and $88.7M for 2031;
- For the non-PRP and non-DRP capital component: ($0.2M) for 2027, $2.1M for 2028, $3.2M for 2029, $11.7M for 2030, and $20.5M for 2031.
- For the PRP non-capital component: $8.4M for 2027, $7.8M for 2028, $7.1M for 2029, $4.4M for 2030, and $3.9M for 2031;
- For the DRP non-capital component: $0.0M for 2027, $0.0M for 2028, $0.0M for 2029, $0.0M for 2030, and $0.0M for 2031; and
- For the non-PRP and non-DRP non-capital component: $0.7M for 2027, $0.0M for 2028, $0.4M for 2029, $0.4M for 2030, and $0.4M for 2031.

2.7. Pension and OPEB Cost Variance Account (OPG)

The Pension and OPEB Cost Variance Account was originally established in EB-2011-0090 and was continued in subsequent OPG proceedings. As of the effective date of this Payment Amounts Order, the Pension and OPEB Cost Variance Account shall record the difference between (i) the pension and other post-employment benefit ("OPEB") non-capital costs, plus related income tax impacts, reflected in OPG's revenue requirements approved by the OEB; and (ii) OPG's actual pension and OPEB non-capital costs, and associated income tax impacts, for OPG's prescribed generation facilities; excluding any variances arising from differences in staffing levels (other than changes in long-term disability benefit plan data) and

[17] Exhibit F2-7-1, Table 1, line 4, cols. (h) to (l).
[18] Exhibit F2-3-1, Table 1: cols. (h) to (l), lines 8-15 and Note 3.

compensation levels including pension and benefit plan provisions. Actual pension and OPEB non-capital costs used in the calculation of the difference shall be calculated on an accrual basis using the same accounting standards as those used to derive the reference amount and holding constant staffing levels (other than changes in long-term disability benefit plan data) and compensation levels including pension and benefit plan provisions that are reflected in the reference amount.

For the OPG nuclear facilities, the monthly reference amounts for non-capital pension and OPEB costs shall be 1/12 of $47.3M for 2027, $40.5M for 2028, $42.5M for 2029, $46.9M for 2030, and $89.1M for 2031.[19] For non-capital pension and OPEB costs, the resulting monthly reference amounts shall be $3.9M for 2027, $3.4M for 2028, $3.5M for 2029, $3.9M for 2030, and $7.4M for 2031. The associated income tax impact for the non-capital pension and OPEB costs variances for the OPG nuclear facilities will also be captured in the account.

As the regulated hydroelectric revenue requirement approved by the OEB in this proceeding reflects pension and OPEB costs calculated on an accrual basis, OPG shall resume recording additions to the account for the regulated hydroelectric facilities as of the effective date of this Payment Amounts Order. For non-capital pension and OPEB costs, the monthly reference amount for the regulated hydroelectric facilities shall be 1/12 of $25.1M, or $2.1M.[20] The associated income tax impact for the non-capital pension and OPEB costs variances for the regulated hydroelectric facilities will also be captured in the account.

OPG shall not record any interest on the balance of the account.

2.8. Hydroelectric Deferral and Variance Over/Under Recovery Variance Account

The Hydroelectric Deferral and Variance Over/Under Recovery Variance Account was originally established in EB-2009-0174 and has been approved in all subsequent OPG applications. The account shall continue to record the differences between the amounts approved for recovery or repayment in the regulated hydroelectric deferral and variance accounts and the actual amounts recovered or repaid based on the actual regulated

[19] Per Ex. L-A1-Staff-293, Chart 3a, Note 8.
[20] Per Ex. L-A1-Staff-275, Chart 2, Note 4.

hydroelectric production and approved payment riders. The account shall also continue to include the transfer of the regulated hydroelectric portions of the balances remaining in other deferral and variance accounts as they may terminate from time to time.

2.9. Gross Revenue Charge Variance Account

The Gross Revenue Charge Variance Account was originally established in EB-2013-0321 and has been approved in all subsequent OPG applications. The account shall continue to record the cost impact of a GRC reduction under Ontario Regulation 124/02, once approved by the Ontario Ministry of Natural Resources (or successor Ministry), pertaining to production increases at OPG's Sir Adam Beck hydroelectric generating stations due to the operation of the third Niagara tunnel, so as to allow these amounts to be returned to ratepayers. As of the effective date of this Payment Amounts Order, the account shall similarly record the cost impact of any GRC reduction under Ontario Regulation 124/02, once approved by the Ontario Ministry of Natural Resources (or successor Ministry), pertaining to production increases at any regulated hydroelectric generating station, to the extent that such production increases are reflected in the production forecast or production growth factors underpinning the regulated hydroelectric payment amounts approved by the OEB.

With respect to the production increases at OPG's Sir Adam Beck hydroelectric generating stations due to the operation of the third Niagara tunnel, the above impact shall be calculated as of the later of November 1, 2014 and the effective date of the approved GRC reduction, and, in respect of such production increases during the period prior to the effective date of this Payment Amounts Order, shall be determined by applying the approved reduction to the forecast GRC expenses included in the regulated hydroelectric revenue requirement for 2014 and 2015 approved by the OEB in EB-2013-0321, averaged as applicable, holding all other variables constant. In all other instances, the above impact shall be calculated as of the later of January 1, 2027 and the effective date of the approved GRC reduction, by applying the approved reduction to the forecast GRC expenses that are reflected in the 2027 regulated hydroelectric revenue requirement and underpin the 2028-2031 regulated hydroelectric GRC factors approved by the OEB in this proceeding, holding all other variables constant.

As of the effective date of this Payment Amounts Order, the account shall also record the revenue requirement impact of any differences in GRC expenses that result from a legislative or regulatory change to the GRC rates or rules applicable to the regulated hydroelectric facilities under Section 92.1 of the *Electricity Act, 1998*. The forecast GRC expenses reflected in the regulated hydroelectric payment amounts approved by the OEB shall be used to calculate any variances in GRC expenses recorded in the account. Such reference amounts shall be those that underpin the 2027 regulated hydroelectric revenue requirement and the 2028-2031 regulated hydroelectric GRC factors approved by the OEB in this proceeding, as reflected in Appendix B, Table 2, line 13.

2.10. Pension & OPEB Cash Payment Variance Account

The Pension & OPEB Cash Payment Variance Account was originally established in EB-2013-0321 and was continued in subsequent OPG proceedings. As applicable, the account has been recording the difference between OPG's actual registered pension plan ("RPP") contributions and OPEB plan payments (including the long-term disability benefit plan), and such forecast amounts underpinning the revenue requirements approved by the OEB. As of the effective date of this Payment Amounts Order, the account shall only record amortization and interest, as the approved revenue requirements in this proceeding do not include RPP contributions or OPEB plan payments (including the long-term disability benefit plan) and instead reflect pension and OPEB costs calculated on an accrual basis.

2.11. Pension & OPEB Cash Versus Accrual Differential Deferral Account

The Pension & OPEB Cash Versus Accrual Differential Deferral Account was originally established in EB-2013-0321 and was continued in subsequent OPG proceedings. The account was established to record amounts for OPG's regulated hydroelectric and nuclear facilities pending the outcome of an OEB generic proceeding on the regulatory treatment of pension and OPEB costs, in recognition that OPG's OEB-approved revenue requirements at the time included RPP contributions and OPEB plan payments (including the long-term disability benefit plan), instead of pension and OPEB costs calculated on an accrual basis. As the approved revenue requirements in this proceeding reflect pension and OPEB costs calculated on an accrual basis, the account shall only record amortization as of the effective date of this Payment Amounts Order.

OPG shall not record any interest on the balance of the account.

2.12. Pension and OPEB Forecast Accrual versus Actual Cash Payment Differential Variance Account

The Pension and OPEB Forecast Accrual versus Actual Cash Payment Differential Variance Account was established by the OEB on a generic basis in EB-2015-0040 and was continued in EB-2020-0290. The EB-2015-0040 Report of the OEB: *Regulatory Treatment of Pension and Other Post-Employment Benefits (OPEBs) Costs* ("EB-2015-0040 Report") determined that the account will track the differences between the forecast pension and OPEB accrual amounts recovered in rates and the actual cash payments made for both pension and OPEB plans. The EB-2015-0040 Report also determined that, for utilities for which the OEB previously established accounts to capture the difference between cash and accrual methods as an interim measure pending the outcome of the EB-2015-0040 consultation, this variance account would also record amounts collected relating to these previously approved accounts.

The account shall continue to have three sub-accounts, as described below, which shall apply to both OPG's nuclear and regulated hydroelectric facilities.

The Primary Sub-Account shall track the differences between (i) the forecast pension and OPEB costs on an accrual basis as adjusted for the variances in such costs recorded in the Pension and OPEB Cost Variance Account (OPG), and (ii) OPG's actual RPP contributions and OPEB plan payments (including the long-term disability benefit plan) (i.e., cash payments). The sub-account shall also track amortization amounts for the Pension & OPEB Cash Versus Accrual Differential Deferral Account. When the cumulative accrual amount (including amortization amounts from the Pension & OPEB Cash Versus Accrual Differential Deferral Account) exceeds the cumulative actual cash payments, the sub-account will hold a credit balance. The opening monthly balance of the sub-account will only accrue carrying charges – in favour of ratepayers in the Carrying Charges Sub-Account – when it is in a credit position. The Contra Sub-Account shall record offsetting entries with the Primary Sub-Account to enable book-keeping with offsetting entries. Carrying charges do not apply to the Contra Sub-Account. The Carrying Charges Sub-Account shall record interest, as described above, at the OEB's prescribed Construction Work In Progress rate.

As tracking accounts, neither the Primary Sub-Account nor the Contra Sub-Account are subject to disposition. The Carrying Charges Sub-Account is subject to disposition. OPG shall not record any interest on the balance of the Carrying Charges Sub-Account.

2.13. Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account

The Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account was originally established in EB-2014-0369 and has been approved in all subsequent OPG applications. The account has been recording the difference between the annual revenue requirement impact of the original Niagara Tunnel Project rate base addition disallowance of $28.0 million ordered in EB-2013-0321 and the varied disallowance of $6.4 million per EB-2014-0369.

As the OEB-approved regulated hydroelectric revenue requirement in this proceeding reflects the impact of the above noted varied disallowance, the account shall only record interest and amortization as of the effective date of this Payment Amounts Order.

2.14. Nuclear Liability Deferral Account

The Nuclear Liability Deferral Account has been established in accordance with section 5.2(1) of O. Reg. 53/05. The account shall continue to record the revenue requirement impact for OPG's prescribed facilities of any change in OPG's nuclear decommissioning and used nuclear fuel and other nuclear waste management liabilities ("nuclear liabilities") arising from an approved reference plan under the Ontario Nuclear Funds Agreement ("ONFA"), measured against such forecast impact reflected in the revenue requirement approved by the OEB.[21] OPG shall not record the revenue requirement impact of a change in its nuclear liabilities related to the Bruce facilities or the Darlington New Nuclear Program ("DNNP") facilities in this account.

[21] O. Reg. 53/05 also specifies that the balance recorded in the account is to be recovered on a straight line basis over a period not to exceed three years (section 6(2)7), to the extent that the OEB is satisfied that the revenue requirement impacts are accurately recorded in the account based on the specified terms.

In 2027 and 2028, OPG shall record the return on rate base component in the account using the weighted average accretion rate of 4.72%.[22] As the lesser of the average unfunded nuclear liabilities and the average asset retirement cost for OPG's prescribed facilities has been set to zero beginning in 2029, effective January 1, 2029, OPG shall record the return on rate base component in the account using the OEB-approved weighted average cost of capital rates in this proceeding.[23]

OPG shall not record any interest on the balance of the account.

2.15. Nuclear Development Variance Account

The Nuclear Development Variance Account has been established in accordance with section 5.4(1) of O. Reg. 53/05. The account shall continue to record differences between the revenue requirement impacts arising from the actual non-capital costs and capital costs incurred and firm financial commitments made for OPG's proposed new nuclear generation facilities and such forecast amounts reflected in the revenue requirement approved by the OEB. This includes but is not limited to the costs of planning, preparation, and technology identification for the new facilities, as well as design, development and construction of the new facilities.[24]

The above variance recorded in the account shall be calculated as between the revenue requirement impact of actual eligible non-capital and capital costs and firm financial commitments, including those arising from the CEITCs received by OPG in respect of the costs eligible for this account, and such forecast amounts reflected in the OPG nuclear facilities revenue requirement approved by the OEB. Such annual forecast amounts and resulting monthly reference amounts shall be $0.0M for 2027, $0.0M for 2028, $0.0M for 2029, $0.0M for 2030, and $0.0M for 2031, as reflected in the OPG nuclear facilities revenue requirements approved by the OEB in this proceeding.[25] The account shall not record the revenue requirement impact of the above in relation to the SR&ED ITCs, which shall be recorded in the

[22] Appendix A, Tables 19 and 20: line 7, col. (c).
[23] Appendix A, Tables 21-23: line 4, col. (b) x col. (c) + line 5a, col. (c) x line 5b, col. (b).
[24] O. Reg. 53/05 also specifies that the balance recorded in the account is to be recovered on a straight-line basis over a period not to exceed three years (section 6(2)7.1), to the extent the OEB is satisfied that the costs were prudently incurred and the firm financial commitment were prudently made.
[25] Exhibit F2-1-1, p. 36, lines 14-15.

SR&ED ITC Variance Account (OPG) or the Income and Other Taxes Variance Account (OPG), as applicable, or, effective September 15, 2026, in relation to any changes in the CCA rules or rates, which shall be recorded in the Change in CCA Rules or Rates Variance Account (OPG).

OPG shall not record interest on the December 31, 2024 debit balance in the account of $23.5M that is not related to the DNNP.

2.16. Bruce Lease Net Revenues Variance Account

The Bruce Lease Net Revenues Variance Account was originally established in EB-2007-0905 in order to ensure that the actual difference between OPG's revenues and costs for the Bruce facilities is ultimately reflected in the payment amounts and payment riders and that OPG recovers its actual costs associated with the Bruce facilities. The account has been approved in all subsequent OPG applications.

The account shall continue to record differences between (i) the forecast revenues and costs related to the Bruce lease that are factored into the OPG nuclear facilities revenue requirement approved by the OEB, and (ii) OPG's actual revenues and costs in respect of the Bruce facilities. Such costs will continue to include the impact of any changes in OPG's liabilities for decommissioning the Bruce facilities and the management of used nuclear fuel and other nuclear waste related to the Bruce nuclear generating stations.

For the purpose of recording entries in the account as of the effective date of this Payment Amounts Order, the above variance shall be determined by comparing (i) the quotient of the annual forecast amount of ($5.2M), $11.5M, ($18.1M), $7.3M, and ($17.1M) reflected in the OPG nuclear facilities revenue requirements approved by the OEB in this proceeding for the respective years from 2027 to 2031[26] and the nuclear production forecast for the corresponding years of 19.3 TWh, 27.6 TWh, 25.8 TWh, 27.7 TWh, and 29.9 TWh[27] approved by the OEB in this proceeding ("rate of recovery"), multiplied by OPG's actual nuclear production for each respective year from 2027-2031, and (ii) OPG's actual revenues and costs in respect of the

[26] Appendix A, Tables 2 to 6: line 22, col. (c), for 2027 to 2031, respectively.
[27] Appendix B, Table 3, line 6.

Bruce facilities for the corresponding year. The resulting rate of recovery shall be ($0.27)/MWh for 2027, $0.42/MWh for 2028, ($0.70)/MWh for 2029, $0.26/MWh for 2030, and ($0.57)/MWh for 2031.

2.17. Nuclear Deferral and Variance Over/Under Recovery Variance Account (OPG)

The Nuclear Deferral and Variance Over/Under Recovery Variance Account (OPG) was originally established in EB-2009-0174 and has been approved in all subsequent OPG applications. The account shall continue to record the difference between the amounts approved for recovery or repayment in OPG's nuclear deferral and variance accounts and the actual amounts recovered or repaid based on the actual OPG nuclear production and approved payment riders. The account shall also continue to include the transfer of the nuclear portions of the balances remaining in other OPG deferral and variance accounts as they may terminate from time to time.

2.18. SR&ED ITC Variance Account (OPG)

The SR&ED ITC Variance Account was established in EB-2016-0152 and was continued in EB-2020-0290. The account shall continue to record the difference between actual SR&ED ITCs attributed to the OPG nuclear facilities as determined after any tax audits and the forecast SR&ED ITCs included in the OPG nuclear facilities revenue requirement approved by the OEB, including income taxes payable on the difference, to the extent such difference is not recorded in the Income and Other Taxes Variance Account (OPG). As of the effective date of this Payment Amounts Order, the account shall also record the difference between actual SR&ED ITCs attributed to the regulated hydroelectric facilities as determined after any tax audits and the forecast SR&ED ITCs included in the regulated hydroelectric revenue requirement approved by the OEB, including the income taxes payable on the difference, to the extent such difference is not recorded in the Income and Other Taxes Variance Account (OPG).

For the OPG nuclear facilities, the monthly reference amount for the SR&ED ITCs shall be 1/12 of ($16.6M) for 2027, ($16.6M) for 2028, ($16.6M) for 2029, ($16.6M) for 2030, and ($16.6M) for 2031, as reflected in the OPG nuclear facilities revenue requirements approved

by the OEB in this proceeding.[28] The resulting monthly reference amounts for the SR&ED ITCs shall be ($1.4M) for 2027, ($1.4M) for 2028, ($1.4M) for 2029, ($1.4M) for 2030, and ($1.4M) for 2031. For the regulated hydroelectric facilities, the monthly reference amount shall be 1/12 of ($3.3M) for 2027, ($3.3M) for 2028, ($3.3M) for 2029, ($3.3M) for 2030, and ($3.3M) for 2031, as reflected in the 2027 regulated hydroelectric payment amount and underpinning the 2028-2031 regulated hydroelectric custom capital factors approved by the OEB in this proceeding.[29] The resulting monthly reference amounts for the SR&ED ITCs shall be ($0.3M) for 2027, ($0.3M) for 2028, ($0.3M) for 2029, ($0.3M) for 2030, and ($0.3M) for 2031.

2.19. Fitness for Duty Deferral Account

The Fitness for Duty Deferral Account was established in EB-2016-0152 and was continued in EB-2020-0290. The account has been recording OPG's costs related to implementing the Canadian Nuclear Safety Commission ("CNSC") Fitness for Duty program. Given the conclusion of prior legal challenges regarding the CNSC Fitness for Duty requirements, as of the effective date of this Payment Amounts Order, the account shall only record interest and amortization.

2.20. Rate Smoothing Deferral Account

The Rate Smoothing Deferral Account has been established in accordance with section 5.5 of O. Reg. 53/05. The account has been recording, in connection with the period from January 1, 2017 until the DRP ends, an annual deferral amount as determined by the OEB. With the DRP having returned the last generating unit of the Darlington Nuclear Generating Station to service in 2026, the account shall record only interest and amortization as of the effective date of this Payment Amounts Order.[30]

According to section 5.5(2) of O. Reg. 53/05, the deferral account shall record interest on the balance at the following OEB-approved OPG long-term debt rates, compounded annually: 4.56% for 2027, 4.75% for 2028, 4.86% in 2029, 4.91% in 2030, and 4.92% in 2031.[31]

[28] Appendix A, Tables 34-38: line 29, col. (c).
[29] Appendix A, Tables 29-33: line 22, col. (c).
[30] O. Reg. 53/05, section 6(2)12 also specifies that the balance recorded in the account is to be recovered on a straight line basis over a period not to exceed 10 years commencing at the end of the deferral period.
[31] Appendix A, Tables 19-23: line 3, col. (c).

2.21. Pickering Closure Costs Deferral Account

The Pickering Closure Deferral Account has been established in accordance with section 5.6 of O. Reg. 53/05. The account shall continue to record any employment-related costs and non-capital costs related to third party service providers incurred by OPG that arise from any activities in furtherance of a Pickering closure, whether such costs are incurred before or after a Pickering closure. Pickering closure shall mean the closure or decommissioning of Pickering Nuclear Generating Station's Units 1-4 or Units 5-8, or the retirement of a generating unit at the station from electricity generation. The account shall continue to include costs related to employee termination, layoff, reassignment or retraining, and costs related to the hiring of employees or the engagement of third party service providers to perform Pickering closure activities, and their remuneration.[32]

Pickering closure costs do not include costs that are eligible for recovery by OPG under the ONFA or have already been included in a payment amounts order. The amounts shall be recorded in the account as they are reflected in OPG's audited financial statements approved by OPG's Board of Directors.

The additions recorded in the account shall be calculated as the difference between the actual Pickering closure costs and such forecast amounts reflected in the OPG nuclear facilities revenue requirements approved by the OEB in this proceeding. Such annual forecast amounts and resulting monthly reference amounts shall be $0.0M for 2027, $0.0M for 2028, $0.0M for 2029, $0.0M for 2030, and $0.0M for 2031.

2.22. Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account

The Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account was established in EB-2020-0290. The account shall continue to record the revenue requirement impact for OPG's prescribed facilities arising from any changes to nuclear

[32] O. Reg. 53/05, section 6(2)7.2 specifies that the balance recorded in the account and related income tax effects are to be 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 Nuclear Generating Station permanently stops generating electricity, to the extent that the OEB is satisfied that the costs were prudently incurred and are accurately recorded in the account.

liabilities and depreciation and amortization expense resulting from changes to the Pickering Nuclear Generating Station end-of-life dates, to the extent such impact is not recorded in the Nuclear Liability Deferral Account. OPG will determine the impacts recorded in the account by applying a revised Pickering Nuclear Generating Station end-of-life date to recalculate the corresponding OEB-approved values comprising the nuclear liabilities' revenue requirement impact and the non-asset retirement cost capital-related revenue requirement for OPG's prescribed facilities, including associated income tax impacts, holding all other variables constant.

OPG shall not record any interest on the balance of the account.

2.23. Sale of Unprescribed Kipling Site Deferral Account

The Sale of Unprescribed Kipling Site Deferral Account was established in EB-2020-0290 to track 23% of the net proceeds arising from any sale of OPG's unprescribed site located at 800 Kipling Avenue in Toronto during the 2022-2026 period. With the completion of this sale during the 2022-2026 period and the basis of the account balance disposition determined in EB-2023-0336, the account shall only record amortization as of the effective date of this Payment Amounts Order.

OPG shall not record any interest on the balance of the account.

2.24. Earnings Sharing Deferral Account

The Earnings Sharing Deferral Account was established in EB-2020-0290 to record 50% of any regulated earnings for OPG's combined regulated nuclear and regulated hydroelectric business that exceed 100 basis points above the OEB-approved ROE rate as assessed over a cumulative five-year period from January 1, 2022 to December 31, 2026. As of the effective date of this Payment Amounts Order, the account shall also record 50% of any regulated earnings for OPG's combined regulated nuclear and regulated hydroelectric business that exceed 100 basis points above the OEB-approved ROE rate as assessed over a cumulative five-year period from January 1, 2027 to December 31, 2031. No entries in respect of the January 1, 2027 to December 31, 2031 period shall be recorded in the account until the

completion of such period. Any balance in the account arising from such entries will be considered for disposition following the completion of this period.

2.25. Impact of IFRS Deferral Account (OPG)

The Impact for IFRS Deferral Account (OPG) was established in EB-2020-0290. The account shall continue to record financial impacts of transition to and implementation of International Financial Reporting Standards ("IFRS") from United States Generally Accepted Accounting Principles ("US GAAP") in the event that OPG adopts IFRS for financial reporting purposes to meet the requirements of the *Securities Act* (Ontario). Entries recorded in the account shall include, but not be limited to, any unamortized gains/losses and past service costs/credits balances recorded for pension and OPEB plans in accumulated other comprehensive income/loss under US GAAP, as attributed to OPG's regulated operations.

OPG shall not record any interest on the balance of the account.

2.26. Pickering B Variance Account

The Pickering B Variance Account has been established in accordance with section 5.7(1) of O. Reg. 53/05. The account has been recording the difference between:

(i) OPG's revenues generated from the output of the Pickering Nuclear Generating Station's Units 5-8 during the period from January 1, 2026-September 30, 2026, calculated on the basis of the payment amount for the OPG nuclear facilities that applies on January 1, 2026, and

(ii) the sum of

(a) any foregone revenues of OPG related to foregone output from these units arising from any Pickering Nuclear Generating Station's Units 5-8 extension activities undertaken by OPG,

(b) the revenue requirement impacts from actual non-capital and capital costs incurred by OPG in relation to any Pickering Nuclear Generating Station's Units 5-8 extension activities undertaken by OPG, and

(c) the revenue requirement impacts arising from actual non-capital and capital costs incurred by OPG since January 1, 2024 for Pickering Nuclear Generating Station's Units 5-8 preservation activities before the effective date of the OEB's first

payment amounts order for the OPG nuclear facilities that becomes effective on or after January 1, 2027.

Such extension activities represent any activities undertaken by OPG in furtherance of the operation of these units from January 1, 2026 to September 30, 2026, whether the activities occurred during that period or not. Such preservation activities represent any activities undertaken by OPG to preserve its ability to operate these units following the PRP, regardless of whether the PRP proceeds.

With the conclusion of Pickering Nuclear Generating Station's Units 5-8 extension activities and the issuance of this Payment Amounts Order, the account shall record only interest and amortization as of the effective date of this Payment Amounts Order.

2.27. Pickering B Refurbishment Project Variance Account

The Pickering B Refurbishment Project Variance Account has been established in accordance with section 5.8(1) of O. Reg. 53/05, effective January 1, 2026. The account shall continue to record the difference between: (i) the amount calculated by multiplying actual cumulative capital costs incurred by OPG in respect of the PRP by OPG's long-term debt rate as approved by the OEB; and (ii) the amount calculated by multiplying the forecast of cumulative capital costs incurred by OPG in respect of the PRP by OPG's long-term debt rate, as included in setting nuclear payment amounts.

Section 5.8(2) of O. Reg. 53/05 specifies that the account does not record amounts respecting capital costs related to a generating unit that has been refurbished and returned to service, or related to the refurbishment, construction or acquisition of a structure, equipment or other thing that is part of the PRP that has been returned to service. The account also does not include any amounts included in the Pickering B Variance Account.[33]

For the purpose of recording entries in the account as of the effective date of this Payment Amounts Order, (a) the following OEB-approved OPG long-term debt rates shall be applied to

[33] O. Reg. 53/05, section 6(2)12.1 specifies that the balance recorded in the account is to be recovered on an annual basis following the year in which it is recorded, to the extent that the OEB is satisfied that the amounts are accurately recorded in the account.

the actual cumulative capital costs in respect of the PRP: 4.56% for 2027, 4.75% for 2028, 4.86% in 2029, 4.91% in 2030, and 4.92% in 2031;[34] and (b) the resulting amounts shall be compared to the following forecast amounts as reflected in the OPG nuclear facilities revenue requirements approved by the OEB in this proceeding: $295.0M for 2027, $465.5M for 2028, $626.4M for 2029, $755.0M for 2030, and $576.0M for 2031.[35]

According to section 5.8(3) of O. Reg. 53/05, the variance account shall record interest on the balance at the following OEB-approved OPG long-term debt rates, compounded annually: 4.56% for 2027, 4.75% for 2028, 4.86% in 2029, 4.91% in 2030, and 4.92% in 2031.[36]

2.28. Darlington New Nuclear Project Variance Account

The Darlington New Nuclear Project Variance Account has been established in accordance with section 5.4.1(1) of O. Reg. 53/05. The account has been recording the difference between: (i) the amount calculated by multiplying actual cumulative capital costs incurred by OPG in respect of the DNNP by OPG's long-term debt rate as approved by the OEB; and (ii) the amount calculated by multiplying the forecast of cumulative capital costs incurred by OPG in respect of the DNNP by OPG's long-term debt rate, as included in setting nuclear payment amounts.

Section 5.4.1(2) of O. Reg. 53/05 specifies that the account does not record amounts respecting capital costs related to any small modular reactor that has come into service or been abandoned, or capital costs incurred on or after the effective date of an order issued by the OEB indicating satisfaction that the conditions set out in section 8 of O. Reg. 53/05 relating to the regulation of DNNP LP as a prescribed generator have been met.[37]

With the issuance of the OEB's June 22, 2026 decision and order, effective January 1, 2026, indicating the OEB's satisfaction that the conditions set out in section 8 of O. Reg. 53/05

[34] Appendix A, Tables 19-23: line 3, col. (c).
[35] Appendix A, Table 61, line 7.
[36] Appendix A, Tables 19-23: line 3, col. (c).
[37] O. Reg. 53/05, section 6(2)11.1 also specifies that the balance recorded in the account is to be recovered on an annual basis following the year in which it is recorded, to the extent that the OEB is satisfied that the amounts are accurately recorded in the account.

relating to the regulation of DNNP LP as a prescribed generator had been met, the account shall record only interest and amortization as of the effective date of this Payment Amounts Order.

According to section 5.4.1(3) of O. Reg. 53/05, the variance account shall record interest on the balance at the following OEB-approved OPG long-term debt rates, compounded annually: 4.56% for 2027, 4.75% for 2028, 4.86% in 2029, 4.91% in 2030, and 4.92% in 2031.[38]

3.0 CONTINUING DEFERRAL AND VARIANCE ACCOUNTS – DNNP LP

As of the effective date of the payment amounts established in this proceeding, DNNP LP shall continue to record entries in the deferral and variance accounts authorized by O. Reg. 53/05 pursuant to the methodologies established by O. Reg. 53/05, as set out below.

3.1. Darlington New Nuclear Project Variance Account re Development

The Darlington New Nuclear Project Variance Account re Development has been established in accordance with section 11(1) of O. Reg. 53/05, effective January 1, 2026. The account shall continue to record the differences between the revenue requirement impacts arising from the actual non-capital and capital costs incurred and firm financial commitments made by DNNP LP for the DNNP facilities and such forecast amounts reflected in the revenue requirement approved by the OEB. This includes but is not limited to the costs of planning, preparation, technology identification, design, development, construction, and commissioning with respect to the DNNP facilities. Section 11(2) of O. Reg. 53/05 specifies that the account does not include any amounts included in the Nuclear Development Variance Account. This account is established to record amounts until the effective date of the OEB's first payment amounts order in respect of the DNNP facilities following the completion of the DNNP.

The above variance recorded in the account shall be calculated as between the revenue requirement impact of actual eligible non-capital and capital costs and firm financial commitments and such forecast amounts reflected in the DNNP LP's revenue requirement approved by the OEB. The account shall also include revenue requirement differences arising

[38] Appendix A, Tables 19-23: line 3, col. (c).

from the CEITCs received by DNNP LP or its owners in respect of the costs eligible for this account. The account shall not record the revenue requirement impact of the above in relation to the SR&ED ITCs, which shall be recorded in the SR&ED ITC Variance Account (DNNP), or, effective September 15, 2026, in relation to any changes in the CCA rules or rates, which shall be recorded in the Change in CCA Rules or Rates Variance Account (DNNP). The non-capital costs shall include operational readiness costs, as detailed in Ex. F2-2-1.

The monthly reference amounts for the non-capital component shall be 1/12 of $45.9M for 2027, $46.3M for 2028, $40.0M for 2029, $40.2M for 2030, and $0.0M for 2031, as reflected in DNNP LP's revenue requirements approved by the OEB in this proceeding.[39] The resulting monthly reference amounts for the non-capital component shall be $3.8M for 2027, $3.9M for 2028, $3.3M for 2029, $3.4M for 2030, and $0.0M for 2031. The monthly reference amount for the capital component shall be 1/12 of ($69.3M) for 2027, ($99.6M) for 2028, ($84.0M) for 2029, $79.1M for 2030, and $710.4M for 2031, as reflected in DNNP LP's revenue requirements approved by the OEB in this proceeding.[40] The resulting monthly reference amounts for the capital component shall be ($5.8M) for 2027, ($8.3M) for 2028, ($7.0M) for 2029, $6.6M for 2030, and $59.2M for 2031.

The account shall also record any net revenues earned or forgone by DNNP LP due to deviations from the OEB-approved production forecast for the DNNP facilities due to a difference between the actual in-service date and the OEB-approved forecast in-service date of any DNNP unit. The production deviations due to a difference between the actual in-service date and the OEB-approved forecast in-service date of a DNNP unit shall be calculated by entering the actual in-service date into the same model used to calculate the production forecast for the DNNP facilities that underpins the payment amounts approved by the OEB, holding all other variables constant, including outage plans relative to the in-service date. Deviations from the forecast shall be determined as the difference between the calculated production resulting from entering the actual in-service date into such forecast model and the energy production forecast approved by the OEB. The revenue impact of the production

[39] Exhibit F2-1-1, Table 1b, line 3, cols. (b) to (f).
[40] Refer to Attachment 5. Subject to update for the prevailing ROE rate specified by the OEB as of the effective date of the final Payment Amounts Order in this proceeding.

deviation recorded in the account shall be determined by multiplying the production deviation by the approved nuclear payment amount then in effect.

The account shall also record, as part of net revenue, the impact of a difference between the actual in-service date and the OEB-approved forecast in-service date of a DNNP unit on the forecast nuclear fuel expense and non-capital outage expenses for the DNNP facilities. To calculate the nuclear fuel expense deviation, the production deviation, as determined above, shall be multiplied by the corresponding dollar per MWh nuclear fuel consumption cost rate, as reflected in the OEB-approved revenue requirement for DNNP LP. The non-capital outage expenses deviation shall be determined by comparing such forecast expenses as recalculated based on the outage timing consistent with the calculated production as determined above, holding all other variables constant, and the forecast non-capital outage expenses reflected in the OEB-approved revenue requirement for DNNP LP.

For the purpose of recording entries in the account as of the effective date of this Payment Amounts Order, (i) the OEB-approved forecast in-service date of DNNP Unit 1 shall be October 17, 2030;[41] (ii) the nuclear fuel consumption cost rate shall be $0.0/MWh for 2027, $0.0/MWh for 2028, $0.0/MWh for 2029, $14.4/MWh for 2030, and $14.4/MWh for 2031;[42] and (iii) the forecast non-capital outage expenses shall be $0.0M in 2027, $0.0M in 2028, $0.0M in 2029, $0.1M in 2030, and $47.1M in 2031;[43] in each case, as reflected in DNNP LP's revenue requirements approved by the OEB in this proceeding.

3.2. DNNP Generator Capital Structure Variance Account

The DNNP Generator Capital Structure Variance Account has been established in accordance with section 13(1) of O. Reg. 53/05, effective January 1, 2026. The account shall continue to record, until the effective date of the OEB's first payment amounts order in respect of the DNNP facilities following the completion of the DNNP, differences between: (i) the revenue requirement impacts arising from a capital structure and cost of debt reflecting the amount and cost of borrowing incurred by DNNP LP; and (ii) the amount of the revenue requirement

[41] Ex. D2-4-6, p.8, line 18.
[42] Ex. F2-5-1, Table 1b, line 2, cols. (b) to (f).
[43] Ex. F2-1-1, Table 1b, line 2, cols. (b) to (f), as revised for 2031 per Settlement Proposal, Section 4, Issue 19.

impacts arising from the capital structure and the cost of debt included in the payment amounts approved by the OEB. Section 13(2) of O. Reg. 53/05 specifies that the account does not include any amounts included in the Darlington New Nuclear Project Variance Account re Development.

The above variance recorded in the account shall be calculated as between (a) the revenue requirement impact calculated by applying a debt component of the capital structure and interest cost equal to the actual amount of DNNP LP's debt outstanding and interest cost, respectively, to DNNP LP's actual rate base value, with the OEB-approved ROE rate applied to the remaining portion of such actual rate base value, and (b) the revenue requirement impact calculated by applying the capital structure, interest rate and ROE rate reflected in the OEB-approved revenue requirement for DNNP LP to DNNP LP's actual rate base value. For the purpose of recording entries in the account as of the effective date of this Payment Amounts Order, the OEB-approved capital structure is 100% equity and 0% debt and the OEB-approved ROE rate is 9.11%,[44] as reflected in DNNP LP's revenue requirements approved by the OEB in this proceeding.[45]

3.3. Darlington New Nuclear Project Variance Account re Capital Cost Amounts

The Darlington New Nuclear Project Variance Account re Capital Cost Amounts has been established in accordance with section 12(1) of O. Reg. 53/05, effective January 1, 2026. The account shall continue to record the difference between: (i) the amount calculated by multiplying actual cumulative capital costs incurred by DNNP LP in respect of the DNNP LP by OPG's long-term debt rate as approved by the OEB; and (ii) the amount calculated by multiplying the forecast of cumulative capital costs incurred by DNNP LP in respect of the DNNP by OPG's long-term debt rate, as included in setting nuclear payment amounts.

Section 12(2) of O. Reg. 53/05 specifies that the account does not record amounts respecting capital costs in respect of any small modular reactor that has come into service or been

[44] Subject to update for the prevailing ROE rate specified by the OEB as of the effective date of the final Payment Amounts Order in this proceeding.
[45] Appendix A, Tables 24-28.

abandoned. The account also does not record any amounts included in the Darlington New Nuclear Project Variance Account.[46]

For the purpose of recording entries in the account as of the effective date of this Payment Amounts Order, (a) the following OEB-approved OPG long-term debt rates shall be applied to the actual cumulative capital costs in respect of the DNNP: 4.56% for 2027, 4.75% for 2028, 4.86% in 2029, 4.91% in 2030, and 4.92% in 2031;[47] and (b) the resulting amounts shall be compared to the following forecast amounts as reflected in DNNP LP's revenue requirements approved by the OEB in this proceeding: $214.2M for 2027, $274.2M for 2028, $293.4M for 2029, $244.4M for 2030, and $20.9M for 2031.[48]

According to section 12(4) of O. Reg. 53/05, the variance account shall record interest on the balance at the following OEB-approved OPG long-term debt rates, compounded annually: 4.56% for 2027, 4.75% for 2028, 4.86% in 2029, 4.91% in 2030, and 4.92% in 2031.[49]

4.0 INTEREST

Except where otherwise stated, as of the effective date of this Payment Amounts Order, the Applicants shall record interest on the balances in all deferral and variance accounts using the interest rates set by the OEB from time to time pursuant to its interest policy for deferral and variance accounts. Unless stated otherwise, the Applicants shall apply simple interest to the opening monthly balance of the accounts until the balances are fully recovered or refunded.

[46] O. Reg. 53/05, section 14(2)5 also specifies that the balance recorded in the account is to be recovered on an annual basis following the year in which it is recorded, to the extent that the OEB is satisfied that the amounts are accurately recorded in the account.
[47] Appendix A, Tables 19-23: line 3, col. (c).
[48] Appendix A, Table 62, line 7.
[49] Appendix A, Tables 19-23: line 3, col. (c).

Attachment 1:

Capacity Refurbishment Variance Account - Regulated Hydroelectric - Revenue Requirement (Capital Component) ($M)

Shown below is the derivation of amounts for the regulated hydroelectric CRVA eligible projects capital component that are reflected in the regulated hydroelectric revenue requirements and underpin the regulated hydroelectric custom capital factors approved by the OEB in this proceeding, and form the corresponding reference amounts for the Capacity Refurbishment Variance Account.

Line No.	Description	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
	Rate Base						
1	Regulated Hydroelectric CRVA Eligible Projects	1	728.7	1,137.2	2,085.6	2,620.6	3,069.7
2	Weighted Average Cost of Capital	2, 3	6.62%	6.71%	6.77%	6.80%	6.80%
3	**Cost of Capital** (line 1 x line 2)		48.2	76.3	141.3	178.1	208.8
	Depreciation and Amortization						
4	Regulated Hydroelectric CRVA Eligible Projects (Note 1, lines 1h - 1i - 1j)		12.4	19.4	35.7	45.3	53.6
	Regulatory Taxable Income Impacts						
5	ROE (line 1 x 45% x 9.11%)	3	29.9	46.6	85.5	107.4	125.8
6	Depreciation and Amortization (line 4)		12.4	19.4	35.7	45.3	53.6
7	Capital Cost Allowance (App. A, Table 29a, Note 5 and Tables 30a-33a, Note 6)		(395.6)	(292.2)	(137.7)	(164.9)	(199.5)
8	**Net Decrease in Regulatory Taxable Income**		(353.4)	(226.2)	(16.6)	(12.2)	(20.1)
9	**Income Tax Rate**		25%	25%	25%	25%	25%
10	**Income Tax Impact** (line 8 x line 9/(1 - line 9))		(117.8)	(75.4)	(5.5)	(4.1)	(6.7)
11	**Total Regulated Hydroelectric CRVA Eligible Projects Capital Related Revenue Requirement** (line 3 + line 4 + line 10)	3	(57.2)	20.4	171.4	219.3	255.7

Notes: Refer to Attachment 1a.

Attachment 1a:

Notes to Attachment 1

Capacity Refurbishment Variance Account - Regulated Hydroelectric - Revenue Requirement (Capital Component) ($M)

1 The amounts in line 1 are determined as follows:

Line No.	Description	2027	2028	2029	2030	2031
		(a)	(b)	(c)	(d)	(e)
1a	Gross Plant Opening Balance (col. (a) per Ex. H1-1-1, Att. 5a, Note 1, line 1a, col. (c))*	512.9	934.2	1,689.0	2,410.2	3,066.4
1aa	Less: 2027 Gross Plant Opening Balance Settlement Adjustment - CRVA Eligibility*	44.6	0.0	0.0	0.0	0.0
1ab	Less: 2027 Gross Plant Opening Balance Settlement Adjustment - CEITC Adjustment	2.0	0.0	0.0	0.0	0.0
1ac	Gross Plant Opening Balance - Settlement Adjusted (line 1a - line 1aa - line 1ab)	466.2	934.2	1,689.0	2,410.2	3,066.4
1b	In-Service Additions (Ex. H1-1-1, Att. 5a, Note 1, line 1b)*	507.6	800.0	765.3	678.0	311.9
1c	Less: Settlement Adjustment - CRVA Eligibility*	15.3	0.0	0.0	0.0	0.0
1d	Less: Settlement Adjustment - CEITC Adjustment	24.4	45.2	44.1	21.8	13.4
1e	Gross Plant Closing Balance (line 1ac + line 1b - line 1c- line 1d)	934.2	1,689.0	2,410.2	3,066.4	3,364.9
1f	Gross Plant Rate Base Amount (line 1ac + line 1e)/2**	741.3	1,165.6	2,141.6	2,717.1	3,215.7
1g	Accumulated Depreciation and Amortization Opening Balance (col. (a) per Ex. H1-1-1, Att. 5a, Note 1, line 1e, col. (c))*	7.4	18.8	38.2	73.9	119.2
1ga	Less: 2027 Accumulated Depreciation and Amortization Opening Balance Settlement Adjustment - CRVA Eligibility*	1.0	0.0	0.0	0.0	0.0
1gb	Less: 2027 Accumulated Depreciation and Amortization Opening Balance Settlement Adjustment - CEITC Adjustment	0.0	0.0	0.0	0.0	0.0
1gc	Accumulated Depreciation and Amortization Opening Balance - Settlement Adjusted (line 1g - line 1ga - line 1gb)	6.4	18.8	38.2	73.9	119.2
1h	Depreciation and Amortization (Ex. H1-1-1, Att. 5a, Note 1, line 1f)*	13.5	21.0	38.3	48.4	57.0
1i	Less: Settlement Adjustment - CRVA Eligibility*	0.9	1.0	1.0	1.0	1.0
1j	Less: Settlement Adjustment - CEITC Adjustment	0.2	0.6	1.6	2.1	2.4
1k	Accumulated Depreciation and Amortization Closing Balance (line 1gc + line 1h - line 1i - line 1j)	18.8	38.2	73.9	119.2	172.8
1l	Accumulated Depreciation and Amortization Rate Base Amount (line 1gc + line 1k)/2	12.6	28.5	56.0	96.5	146.0
1m	Net Plant Rate Base Amount (line 1f - line 1l)	728.7	1,137.2	2,085.6	2,620.6	3,069.7

* Per Settlement Proposal, Section 4, Issue 11. Line 1aa, 1c, 1ga and line 1i relates to Project #83194 Frederick House Lake Dam Upgrades (Ex. D1-1-2, Table 1, line 11) and the unallocated investment related to Mistinikon Control Dam Upgrades (Ex. D1-1-2, Table 5b, line 44).

** For years including impacts from in-service additions exceeding $50.0M, the month in which each such addition is reflected is used to determine the gross plant rate base amount, instead of a mid-year average.

2 Calculated as App. A, Tables 19-23: line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).

3 Subject to update for the prevailing ROE rate specified by the OEB as of the effective date of the final payment amounts order in this proceeding.

Attachment 2

Capacity Refurbishment Variance Account - Darlington Refurbishment Program - Revenue Requirement (Capital Component) ($M)

Shown below is the derivation of amounts for the Darlington Refurbishment Program ("DRP") capital component, excluding the Heavy Water Storage and Drum Handling Facility ("D2O Storage"), that are reflected in the revenue requirements for OPG's nuclear facilities approved by the OEB in this proceeding and form the corresponding reference amounts for the Capacity Refurbishment Variance Account.

Line No.	Description	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
	Rate Base						
1	DRP, excluding D2O Storage (App. A, Table 17, col. (g): lines 2 plus 7, 15 plus 20, 28 plus 33, 41 plus 46, 54 plus 59, minus App. A, Table 18, col. (f): lines 2 plus 7, 15 plus 20, 28 plus 33, 41 plus 46, 54 plus 59)		9,736.8	9,222.9	8,836.1	8,449.5	8,063.2
2	Weighted Average Cost of Capital	1,2	6.62%	6.71%	6.77%	6.80%	6.80%
3	**Cost of Capital** (line 1 x line 2)		644.3	619.2	598.5	574.3	548.5
	Depreciation and Amortization						
4	DRP, excluding D2O Storage (App. A, Table 18, sum of cols. (b) and (c), lines 2 plus 7, 15 plus 20, 28 plus 33, 41 plus 46, 54 plus 59)		391.7	386.9	386.8	386.3	386.3
	Regulatory Taxable Income Impacts						
5	ROE (line 1 x 45% x 9.11%)	2	399.2	378.1	362.2	346.4	330.6
6	Depreciation and Amortization (line 4)		391.7	386.9	386.8	386.3	386.3
7	Capital Cost Allowance (App. A, Tables 34a-38a, Note 8)		(457.5)	(421.1)	(387.6)	(356.9)	(328.7)
8	**Net Increase in Regulatory Taxable Income**		333.4	343.9	361.4	375.8	388.2
9	**Income Tax Rate**		25%	25%	25%	25%	25%
10	**Income Tax Impact** (line 8 x line 9/(1 - line 9))		111.1	114.6	120.5	125.3	129.4
11	**Total DRP Capital Related Revenue Requirement** (line 3 + line 4 + line 10)	2	1,147.2	1,120.7	1,105.7	1,085.9	1,064.3

Notes:
1 Calculated as App. A, Tables 19-23: line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).
2 Subject to update for the prevailing ROE rate specified by the OEB as of the effective date of the final payment amounts order in this proceeding.

Attachment 3

Capacity Refurbishment Variance Account - Pickering Refurbishment Program - Revenue Requirement (Capital Component) ($M)

Shown below is the derivation of amounts for the Pickering Refurbishment Program ("PRP") capital component that are reflected in the revenue requirements for OPG's nuclear facilities approved by the OEB in this proceeding and form the corresponding reference amounts for the Capacity Refurbishment Variance Account.

Line No.	Description	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
	Rate Base						
1	PRP (App. A, Table 17, col. (g), lines 5, 18, 31, 44, 57 minus Table 18, col. (f), lines 5, 18, 31, 44, 57)		166.3	172.4	168.4	164.3	5,518.5
2	Weighted Average Cost of Capital	1, 2	6.62%	6.71%	6.77%	6.80%	6.80%
3	**Cost of Capital** (line 1 x line 2)		11.0	11.6	11.4	11.2	375.4
	Depreciation and Amortization						
4	PRP (App. A, Table 18, sum of cols. (b) and (c), lines 5, 18, 31, 44, 57)		3.8	4.1	4.1	4.1	141.0
	Regulatory Taxable Income Impacts						
5	ROE (line 1 x 45% x 9.11%)	2	6.8	7.1	6.9	6.7	226.2
6	Depreciation and Amortization (line 4)		3.8	4.1	4.1	4.1	141.0
7	Capital Cost Allowance (App. A, Tables 34a-38a, Note 8)		(383.0)	(862.1)	(1,207.9)	(1,079.1)	(1,106.9)
8	**Net Decrease in Regulatory Taxable Income**		(372.3)	(851.0)	(1,196.9)	(1,068.3)	(739.7)
9	**Income Tax Rate**		25%	25%	25%	25%	25%
10	**Income Tax Impact** (line 8 x line 9/(1 - line 9))		(124.1)	(283.7)	(399.0)	(356.1)	(246.6)
11	**Total PRP Capital Related Revenue Requirement** (line 3 + line 4 + line 10)	2	(109.3)	(268.0)	(383.5)	(340.9)	269.8

Notes:

1 Calculated as App. A, Tables 19-23: line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).

2 Subject to update for the prevailing ROE rate specified by the OEB as of the effective date of the final payment amounts order in this proceeding.

Attachment 4

Capacity Refurbishment Variance Account - Non-DRP/Non-PRP OPG Nuclear - Revenue Requirement (Capital Component) ($M)

Shown below is the derivation of amounts for the Non-DRP/Non-PRP Nuclear CRVA eligible projects capital component that are reflected in the revenue requirements for OPG's nuclear facilities in this proceeding and form the corresponding reference amounts for the Capacity Refurbishment Variance Account.

Line No.	Description	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
	Rate Base						
1	Non-DRP/Non-PRP OPG Nuclear CRVA Eligible Projects	1	192.9	621.9	712.6	1,325.9	2,117.0
2	Weighted Average Cost of Capital	2, 3	6.62%	6.71%	6.77%	6.80%	6.80%
3	**Cost of Capital** (line 1 x line 2)		12.8	41.8	48.3	90.1	144.0
	Depreciation and Amortization						
4	Non-DRP/Non-PRP OPG Nuclear CRVA Eligible Projects (Note 1, lines 1h - 1i - 1j)		7.6	25.5	30.5	58.6	97.8
	Regulatory Taxable Income Impacts						
5	ROE (line 1 x 45% x 9.11%)	3	7.9	25.5	29.2	54.4	86.8
6	Depreciation and Amortization (line 4)		7.6	25.5	30.5	58.6	97.8
7	Capital Cost Allowance (App. A, Tables 34a-38a, Note 8)		(82.1)	(176.9)	(179.5)	(138.0)	(171.0)
8	**Net Increase (Decrease) in Regulatory Taxable Income**		(66.6)	(125.9)	(119.8)	(25.0)	13.6
9	**Income Tax Rate**		25%	25%	25%	25%	25%
10	**Income Tax Impact** (line 8 x line 9/(1 - line 9))		(22.2)	(42.0)	(39.9)	(8.3)	4.5
11	**Total Non-DRP/Non-PRP OPG Nuclear CRVA Eligible Projects Capital Related Revenue Requirement** (line 3 + line 4 + line 10)	3	(1.9)	25.3	38.8	140.4	246.3

Notes: Refer to Attachment 4a.

Attachment 4a

Notes to Attachment 4

Capacity Refurbishment Variance Account - Non-DRP/Non-PRP OPG Nuclear - Revenue Requirement (Capital Component) ($M)

1 The amounts in line 1 are determined as follows:

Line No.	Description	2027	2028	2029	2030	2031
		(a)	(b)	(c)	(d)	(e)
1a	Gross Plant Opening Balance (col. (a) per Ex. H1-1-1, Att. 8a, Note 1, line 1a, col. (c))*	209.8	356.0	716.6	1,320.7	2,055.6
1aa	Less: 2027 Gross Plant Opening Balance Settlement Adjustment - CRVA Eligibility*	20.0	0.0	0.0	0.0	0.0
1ab	Gross Plant Opening Balance - Settlement Adjusted (line 1a - line 1aa)	189.8	356.0	716.6	1,320.7	2,055.6
1b	In-Service Additions (Ex. H1-1-1, Att. 8a, Note 1, line 1b)*	189.3	386.7	640.4	785.8	536.9
1c	Less: Settlement Adjustment - CRVA Eligibility*	14.7	12.8	12.2	-	-
1d	Less: Settlement Adjustment - CEITC Adjustment	8.4	13.4	24.1	50.9	57.9
1e	Gross Plant Closing Balance (line 1ab + line 1b - line 1c- line 1d)	356.0	716.6	1,320.7	2,055.6	2,534.6
1f	Gross Plant Rate Base Amount (line 1ab + line 1e)/2**	203.6	649.2	767.9	1,425.7	2,295.1
1g	Accumulated Depreciation and Amortization Opening Balance (col. (a) per Ex. H1-1-1, Att. 8a, Note 1, line 1e, col. (c))*	7.3	14.5	40.1	70.5	129.2
1ga	Less: 2027 Accumulated Depreciation and Amortization Opening Balance Settlement Adjustment - CRVA Eligibility*	0.3	0.0	0.0	0.0	0.0
1gb	Accumulated Depreciation and Amortization Opening Balance - Settlement Adjusted (line 1g - line 1ga)	7.0	14.5	40.1	70.5	129.2
1h	Depreciation and Amortization (Ex. H1-1-1, Att. 8a, Note 1, line 1f)*	8.6	27.8	33.5	63.1	105.7
1i	Less: Settlement Adjustment - CRVA Eligibility*	1.0	1.6	2.1	2.4	2.4
1j	Less: Settlement Adjustment - CEITC Adjustment	0.0	0.7	1.0	2.1	5.5
1k	Accumulated Depreciation and Amortization Closing Balance (line 1gb + line 1h - line 1i - line 1j)	14.5	40.1	70.5	129.2	226.9
1l	Accumulated Depreciation and Amortization Rate Base Amount (line 1gb + line 1k)/2	10.8	27.3	55.3	99.8	178.0
1m	Net Plant Rate Base Amount (line 1f - line 1l)	192.9	621.9	712.6	1,325.9	2,117.0

* Per Settlement Proposal, Section 4, Issue 13. Line 1aa, 1c, 1ga and line 1i relates to Project #89462 DN Steam Generator Soft Chemical Clean (Ex. D2-1-3, Table 1c, line 54).

** All years include impacts from in-service additions exceeding $50.0M, with the month in which each such addition is reflected used to determine the gross plant rate base amount, instead of a mid-year average.

2 Calculated as: App. A, Tables 19-23, line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).

3 Subject to update for the prevailing ROE rate specified by the OEB as of the effective date of the final payment amounts order in this proceeding.

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Attachment 5

Darlington New Nuclear Project Variance Account re Development - Darlington New Nuclear Program - Revenue Requirement (Capital Component) ($M)

Shown below is the derivation of amounts for the Darlington New Nuclear Program ("DNNP") capital component that are reflected in the revenue requirements for DNNP LP approved by the OEB in this proceeding and form the corresponding reference amounts for the Darlington New Nuclear Project Variance Account re Development.

Line No.	Description	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
	Rate Base						
1	DNNP (App. A, Table 17, col. (g), lines 13, 26, 39, 52, 65 minus Table 18, col. (f), lines 13, 26, 39, 52, 65)		0.0	0.0	0.0	1,226.3	5,865.5
2	Weighted Average Cost of Capital	1, 3	9.11%	9.11%	9.11%	9.11%	9.11%
3	**Cost of Capital** (line 1 x line 2)		0.0	0.0	0.0	111.7	534.4
	Depreciation and Amortization						
4	DNNP (App. A, Table 18, sum of cols. (b) and (c), lines 13, 26, 39, 52, 65)		0.0	0.0	0.0	20.4	98.9
	Regulatory Taxable Income Impacts						
5	ROE (line 1 x 100% x 9.11%)	3	0.0	0.0	0.0	111.7	534.4
6	Depreciation and Amortization (line 4)		0.0	0.0	0.0	20.4	98.9
7	Capital Cost Allowance (App. A, Tables 40-44, line 8, col. (c))		(268.2)	(385.6)	(325.2)	(337.4)	(334.5)
8	**Net Increase (Decrease) in Regulatory Taxable Income** ([line 5 + line 6 + line 7] x 77.5%)	2	(207.8)	(298.8)	(252.0)	(159.1)	231.5
9	**Income Tax Rate**		25%	25%	25%	25%	25%
10	**Income Tax Impact** (line 8 x line 9/(1 - line 9))		(69.3)	(99.6)	(84.0)	(53.0)	77.2
11	**Total DNNP Capital Related Revenue Requirement** (line 3 + line 4 + line 10)	3	(69.3)	(99.6)	(84.0)	79.1	710.4

Notes:

1 Calculated as App. A, Tables 24-28: line 4, col. (b) x col. (c).

2 DNNP LP is a limited partnership in which non-taxable investors hold a stake of 22.5% and as a result, are not subject to DNNP LP's taxable income or entitled to utilize the corresponding proportion of the entity's tax loss carry-over each year. Therefore, DNNP LP's revenue requirement reflects the impact of the remaining 77.5% interest in determining regulatory income taxes and the tax loss carry-over each year.

3 Subject to update for the prevailing ROE rate specified by the OEB as of the effective date of the final payment amounts order in this proceeding.

Appendix F: Accounting Orders for New Deferral and Variance Accounts

Nuclear Security Regulation and American Eel Impact Deferral Account (OPG)
Ontario Power Generation Inc.
Accounting Order

Basis of Approval

Settlement Proposal, Section 2, Part G

Scope of Account

OPG shall establish the Nuclear Security Regulation and American Eel Impact Deferral Account (OPG), effective January 1, 2027, to record the impacts of the following on OPG's prescribed facilities, to the extent these impacts are not recorded in another deferral or variance account:

- CNSC Nuclear Security Regulations SOR/2025-219, for which the account will capture OPG's nuclear revenue requirement impacts resulting from increased security requirements for high security nuclear sites, to the extent such impacts are not reflected in the OPG nuclear facilities revenue requirement approved by the OEB; and

- Provincial and federal legislative and regulatory changes concerning the American eel, for which the account will capture the revenue requirement impacts resulting from compliance activities, as well as any resulting foregone production revenue impacts, net of the avoided GRC costs, with respect to the regulated hydroelectric facilities, to the extent such impacts are not reflected in the regulated hydroelectric payment amounts.

- The account shall not record the revenue requirement impact of the above in relation to the SR&ED ITCs, which shall be recorded in the SR&ED ITC Variance Account (OPG), or in relation to any changes in the CCA rules or rates, including immediate expensing for tax purposes, which shall be recorded in the Change in CCA Rules or Rates Variance Account (OPG).

The monthly reference amounts for the purpose of recording entries in this account in connection with CNSC Nuclear Security Regulations SOR/2025-219 shall be $0.0M for 2027, $0.0M for 2028, $0.0M for 2029, $0.0M for 2030, and $0.0M for 2031.[1]

The monthly reference amounts for the purpose of recording entries in the account in connection with provincial and federal legislative and regulatory changes concerning the American eel shall be $0.0M for 2027, $0.0M for 2028, $0.0M for 2029, $0.0M for 2030, and $0.0M for 2031.[2]

Entry 1: Impact resulting from specified changes on capital costs

Entry	**Debit**	**Credit**
DR/CR Nuclear Security Regulation and American Eel Impact Deferral Account (OPG)	x,xxx	x,xxx
CR/DR Depreciation Expense	x,xxx	x,xxx
CR/DR Return on Rate Base	x,xxx	x,xxx
CR/DR Income Tax Expense	x,xxx	x,xxx

To record the impact resulting from specified changes on depreciation, the associated impact on the return on rate base, and the associated income tax impacts.

Entry 2: Impact resulting from specified changes on non-capital costs

Entry	**Debit**	**Credit**
DR/CR Nuclear Security Regulation and American Eel Impact Deferral Account (OPG)	x,xxx	x,xxx
CR/DR Non-Capital Expense	x,xxx	x,xxx

To record the impact resulting from specified changes on non-capital expenses.

[1] Exhibit JT5.18.
[2] Exhibit F1-1-1, Section 3.2.3.2, p. 13, lines 4-8.

Entry 3: Impact resulting from change of specified laws on net revenue

Entry	**Debit**	**Credit**
DR/CR Nuclear Security Regulation and American Eel Impact Deferral Account (OPG)	x,xxx	x,xxx
CR/DR Revenue	x,xxx	x,xxx
DR/CR GRC Expense	x,xxx	x,xxx

To record the foregone production net revenue impact resulting from specified changes.

OPG shall record simple interest on the monthly opening balance in this account using the interest rates set by the OEB from time to time pursuant to its interest policy for deferral and variance accounts until the balances are fully recovered or refunded.

OPG shall file the balance in the Nuclear Security Regulation and American Eel Impact Deferral Account (OPG) in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

Global Hydroelectric Capital Variance Account
Ontario Power Generation Inc.
Accounting Order

Basis of Approval

Settlement Proposal, Section 2, Part G

Scope of Account

OPG shall establish the Global Hydroelectric Capital Variance Account ("GHCVA"), effective January 1, 2027, to record a credit to ratepayers equal to the amount, if any, by which the total actual capital-related revenue requirement ("CRRR") for the regulated hydroelectric facilities over the period from January 1, 2027 to December 31, 2031, as adjusted for the amounts of such CRRR recorded in the Income and Other Taxes Variance Account (OPG), Clean Electricity ITC Variance Account (OPG), and Change in CCA Rules or Rates Variance Account (OPG) is lower than the forecast CRRR that is reflected in the 2027 regulated hydroelectric revenue requirement and underpins the 2028-2031 regulated hydroelectric custom capital factors approved by the OEB in this proceeding, as assessed on a cumulative basis over this five-year period and subject to the following adjustment addressing the account's interaction with the Capacity Refurbishment Variance Account ("CRVA") and the Nuclear Security Regulation and American Eel Impact Deferral Account (OPG):[3]

- The refundability of the credit entries, if any, recorded in the GHCVA over the 2027-2031 period will be reduced by the amount of the capital-related net credit entries, if any, recorded in the CRVA and/or the Nuclear Security Regulation and American Eel Impact Deferral Account (OPG) over the 2027-2031 period.

The forecast CRRR underpinning the 2027 regulated hydroelectric payment amount and the 2028-2031 regulated hydroelectric custom capital factors for the purpose of recording entries in the account is equal to $4,860.6M.[4]

[3] Exhibit A1-3-2, Section 2.3.5 and Ex. L-H1-Staff-253.
[4] Sum of Appendix B, Table 2, line 8: cols. (a) to (e). Subject to update for the prevailing ROE rate specified by the OEB as of the effective date of the final Payment Amounts Order in this proceeding.

No entries will be recorded in the account until the completion of the January 1, 2027 to December 31, 2031 period. Any balance in the account arising from such entries will be considered for disposition following the completion of this period.

Entry	**Debit**	**Credit**
DR/CR Depreciation Expense	x,xxx	x,xxx
DR/CR Return on Rate Base	x,xxx	x,xxx
DR/CR Income Tax Expense	x,xxx	x,xxx
CR Global Hydroelectric Capital Variance Account		x,xxx

OPG shall record simple interest on the monthly opening balance in this account using the interest rates set by the OEB from time to time pursuant to its interest policy for deferral and variance accounts until the balances are fully recovered or refunded.

OPG shall file the balance in the Global Hydroelectric Capital Variance Account in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

Clean Electricity ITC Variance Account (OPG)
Ontario Power Generation Inc.
Accounting Order

Basis of Approval

Settlement Proposal, Section 2, Part G

Scope of Account

OPG shall establish the Clean Electricity ITC Variance Account (OPG), effective January 1, 2027, to record differences between the revenue requirement impacts arising from the actual CEITCs received by OPG for OPG's regulated facilities and such forecast amounts reflected in the revenue requirements for OPG's regulated facilities approved by the OEB, including the income tax impacts arising from such differences, to the extent these differences are not recorded in another deferral or variance account.

The monthly reference amounts for the purpose of recording entries in this account for the regulated hydroelectric facilities shall be 1/12 of $0.8M for 2027, ($0.1M) for 2028, ($0.4M) for 2029, ($0.8M) for 2030, and ($1.1M) for 2031.[5] The resulting monthly reference amounts shall be $0.1M for 2027, ($0.0M) for 2028, ($0.0M) for 2029, ($0.1M) for 2030, and ($0.1M) for 2031.

The monthly reference amounts for the purpose of recording entries in this account for the OPG nuclear facilities shall be 1/12 of ($0.0M) for 2027, ($0.1M) for 2028, ($0.2M) for 2029, ($0.6M) for 2030, and ($0.9M) for 2031.[6] The resulting monthly reference amount shall be ($0.0M) for 2027, ($0.0M) for 2028, ($0.0M) for 2029, ($0.1M) for 2030, and ($0.1M) for 2031.

Entry	Debit	Credit
DR/CR Clean Electricity ITC Variance Account (OPG)	x,xxx	x,xxx
CR/DR Depreciation Expense	x,xxx	x,xxx
CR/DR Return on Rate Base	x,xxx	x,xxx
CR/DR Income Tax Expense	x,xxx	x,xxx

[5] Refer to Attachment 1. Subject to update for the prevailing ROE rate specified by the OEB as of the effective date of the final payment amounts order in this proceeding.
[6] Refer to Attachment 2. Subject to update for the prevailing ROE rate specified by the OEB as of the effective date of the final payment amounts order in this proceeding.

OPG shall record simple interest on the monthly opening balance in this account using the interest rates set by the OEB from time to time pursuant to its interest policy for deferral and variance accounts until the balances are fully recovered or refunded.

OPG shall file the balance in the Clean Electricity ITC Variance Account (OPG) in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

Payment Amount Shaping Deferral Account
Ontario Power Generation Inc.
Accounting Order

Basis of Approval

Settlement Proposal, Section 2, Part G

Scope of Account

OPG shall establish the Payment Amount Shaping Deferral Account, effective January 1, 2027, to record, for each respective year of the 2027-2031 period, the payment amount shaping amounts approved by the OEB. The annual payment amount shaping amounts shall be $350.0M in 2027, ($350.0M) in 2028, $0.0M in 2029, $0.0M in 2030, and $0.0M in 2031. The annual payment amount shaping amounts shall be recorded monthly on a straight-line basis.

Entry	Debit	Credit
DR/CR Payment Amount Shaping Deferral Account	x,xxx	x,xxx
CR/DR Revenue	x,xxx	x,xxx

OPG shall record simple interest on the monthly opening balance in this account using the interest rates set by the OEB from time to time pursuant to its interest policy for deferral and variance accounts until the balances are fully recovered or refunded.

OPG shall file the balance in the Payment Amounts Shaping Deferral Account in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

DNNP Nuclear Liability Deferral Account
Ontario Power Generation Inc.
Accounting Order

Basis of Approval

Settlement Proposal, Section 2, Part G

Scope of Account

OPG shall establish the DNNP Nuclear Liability Deferral Account, effective January 1, 2027, to record the difference between: (i) the costs of OPG's nuclear liabilities with respect to the DNNP facilities, as reflected in OPG's audited annual financial statements approved by OPG's Board of Directors; and (ii) the costs of OPG's nuclear liabilities with respect to the DNNP facilities reflected in the OPG nuclear facilities revenue requirement approved by the OEB.

The monthly reference amounts for the purpose of recording entries in the account shall be $0.0M for 2027, $0.0M for 2028, $0.0M for 2029, $0.0M for 2030, and $0.0M for 2031.[7]

Entry	Debit	Credit
DR/CR DNNP Nuclear Liability Deferral Account	x,xxx	x,xxx
CR/DR Asset Retirement Cost Depreciation Expense	x,xxx	x,xxx
CR/DR Used Fuel Storage and Disposal Variable Expense	x,xxx	x,xxx
CR/DR Low & Intermediate Level Waste Management Variable Expense	x,xxx	x,xxx
CR/DR Accretion Expense	x,xxx	x,xxx
CR/DR Earnings on Nuclear Funds	x,xxx	x,xxx
CR/DR Income Tax Expense	x,xxx	x,xxx

OPG shall not record interest on the balance of this account.

OPG shall file the balance in the DNNP Nuclear Liability Deferral Account in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

[7] Exhibit C2-1-1, Section 8.0.

Nuclear Fuel Cost Variance Account (OPG)
Ontario Power Generation Inc.
Accounting Order

Basis of Approval

Settlement Proposal, Section 2, Part G

Scope of Account

OPG shall establish the Nuclear Fuel Cost Variance Account (OPG), effective January 1, 2027, to record the difference, on a dollar per MWh basis, between (i) the actual weighted average cost of manufactured uranium fuel bundles loaded into a nuclear reactor ("nuclear fuel bundle cost") incurred by OPG for its prescribed facilities, and (ii) such forecast nuclear fuel bundle cost reflected in the OPG nuclear facilities revenue requirement approved by the OEB.

For the purpose of recording entries in the account as of the effective date of this Payment Amounts Order, the above variance shall be determined by comparing (i) the quotient of OPG's actual nuclear fuel bundle cost and actual nuclear production for each respective year from 2027 to 2031, multiplied by OPG's forecast nuclear production for the corresponding year of 19.3 TWh, 27.6 TWh, 25.8 TWh, 27.7 TWh, and 29.9 TWh[8] as approved by the OEB this proceeding, and (ii) OPG's forecast nuclear fuel bundle cost of $124.0M for 2027, $183.8M for 2028, $183.2M for 2029, $205.8M for 2030, and $244.7M for 2031[9], as reflected in OPG's revenue requirements approved by the OEB in this proceeding.

Entry	Debit	Credit
DR/CR Nuclear Fuel Cost Variance Account (OPG)	x,xxx	x,xxx
CR/DR Nuclear Fuel Expense	x,xxx	x,xxx

OPG shall record simple interest on the monthly opening balance in this account using the interest rates set by the OEB from time to time pursuant to its interest policy for deferral and variance accounts until the balances are fully recovered or refunded.

[8] Appendix A, Table 7, line 9.
[9] Appendix A, Table 7, line 10.

OPG shall file the balance in the Nuclear Fuel Cost Variance Account (OPG) in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

Darlington Planned Outage Days (2027-2031) Settlement Variance Account
Ontario Power Generation Inc.
Accounting Order

Basis of Approval

Settlement Proposal, Section 2, Part G

Scope of Account

OPG shall establish the Darlington Planned Outage Days (2027-2031) Settlement Variance Account, effective January 1, 2027, to share, between ratepayers and OPG, certain revenues earned or foregone by OPG due to deviations between the actual number of planned outage days at the Darlington Nuclear Generating Station and such forecast number of planned outage days reflected in OPG's nuclear production forecast approved by the OEB in this proceeding, as assessed over a cumulative five-year period from January 1, 2027 to December 31, 2031. The account shall record the following, at the approved nuclear payment amounts:

- a credit for 50% of such revenues earned by OPG with respect to these cumulative revenues that do not exceed an equivalent of 2.675 TWh of nuclear production from the Darlington Nuclear Generating Station over the above period,
- a credit for 75% of such revenues earned by OPG with respect to these cumulative revenues that exceed an equivalent of 2.675 TWh of nuclear production from the Darlington Nuclear Generating Station over the above period, and
- a debit for 50% of such revenues foregone by OPG with respect to these cumulative foregone revenues that do not exceed an equivalent of 4.125 TWh of nuclear production from the Darlington Nuclear Generating Station over the above period.

OPG shall also record in this account changes in OPG's nuclear fuel costs from those reflected in the corresponding OPG nuclear facilities revenue requirement approved by the OEB, as a result of the differences in energy production corresponding to the amounts recorded in the account as described above. Amounts recorded in the account in respect of these costs shall be determined by multiplying such production differences by the applicable actual OPG nuclear fuel cost rates.

For the purpose of recording entries in the account as of the effective date of this Payment Amounts Order, the forecast number of planned outage days at the Darlington Nuclear

Generating Station shall be 481.9 in 2027, 99.9 in 2028, 178.5 in 2029, 98.9 in 2030, and 91.7 in 2031,[10] and such planned outages shall be converted to TWh at a rate of 0.021072 TWh[11] per planned outage day.

No entries will be recorded in the account until the completion of the January 1, 2027-December 31, 2031 period. Any balance in the account arising from such entries will be considered for disposition following the completion of this period.

Entry	**Debit**	**Credit**
DR/CR Darlington Planned Outage Days (2027-2031) Settlement Variance Account	x,xxx	x,xxx
CR/DR Revenue	x,xxx	x,xxx
DR/CR Nuclear Fuel Expense	x,xxx	x,xxx

OPG shall record simple interest on the monthly opening balance in this account using the interest rates set by the OEB from time to time pursuant to its interest policy for deferral and variance accounts until the balances are fully recovered or refunded.

OPG shall file the balance in the Darlington Planned Outage Days (2027-2031) Settlement Variance Account in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

[10] Exhibit E2-1-2, Table 1b, lines 3 and 32, as revised per the Settlement Proposal, Section 2, Part C, subpart (i).
[11] Calculated as the product of the 878 MW generating capacity of a Darlington Nuclear Generating Station unit and 24 hours.

Pickering Refurbishment 2027-2031 Early Return to Service Variance Account
Ontario Power Generation Inc.
Accounting Order

Basis of Approval

Settlement Proposal, Section 2, Part G

Scope of Account

OPG shall establish the Pickering Refurbishment 2027-2031 Early Return to Service Variance Account, effective January 1, 2027, to return to ratepayers 75% of revenues earned by OPG, at the approved nuclear payment amounts, due to deviations between the actual production from the Pickering Nuclear Generating Station and such forecast production reflected in OPG's nuclear production forecast approved by the OEB in this proceeding, as a result of any of the Pickering Nuclear Generating Station units returning to service from refurbishment in the 2027-2031 period earlier than reflected in such forecast. For the purpose of recording entries in the account as of the effective date of this Payment Amounts Order, the forecast in-service date for the first refurbished unit of the Pickering Nuclear Generating Station shall be May 15, 2031. No other Pickering Nuclear Generating Station refurbished units are included in the OEB-approved nuclear production forecast during the 2027-2031 period.

OPG shall also record in this account changes in OPG's nuclear fuel costs from those reflected in the corresponding OPG nuclear facilities revenue requirement approved by the OEB as a result of the differences in energy production corresponding to the amounts recorded in the account as described above. Amounts recorded in the account in respect of these costs shall be determined by multiplying such production differences by the applicable actual OPG nuclear fuel cost rates.

Entry	Debit	Credit
DR Revenue	x,xxx	
CR Nuclear Fuel Expense		x,xxx
CR Pickering Refurbishment 2027-2031 Early Return to Service Variance Account		x,xxx

OPG shall record simple interest on the monthly opening balance in this account using the interest rates set by the OEB from time to time pursuant to its interest policy for deferral and variance accounts until the balances are fully refunded.

OPG shall file the balance in the Pickering Refurbishment 2027-2031 Early Return to Service Variance Account in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

Change in CCA Rules or Rates Variance Account (OPG)
Ontario Power Generation Inc.
Accounting Order

Basis of Approval

Settlement Proposal, Section 2, Part G

Scope of Account OPG shall establish the Change in CCA Rules or Rates Variance Account (OPG), effective September 15, 2026, to record, on a without prejudice basis as stated below, the revenue requirement impact for OPG's prescribed facilities of any changes to the CCA rules or rates. OPG shall record such impacts based on the actual undepreciated capital cost and CCA schedules for OPG's prescribed assets, determined with and without the change, for the period until the effective date of the payment amounts order in OPG's next application seeking to clear the Change in CCA Rules or Rates Variance Account (OPG) balances, at which time a determination with respect to the methodology for determining the entries in the account effective September 15, 2026 will be made. The recording of entries in the account based on the actual undepreciated capital cost and CCA schedules for OPG's prescribed assets, determined with and without the change, up until the date of the payment amounts order in the above proceeding, shall be without prejudice to positions that Parties may take in that proceeding, shall be without prejudice to positions that Parties may take in that proceeding in relation to the methodology for determining entries in the account.

Entry	Debit	Credit
DR/CR Income Tax Expense	x,xxx	x,xxx
CR/DR Change in CCA Rules or Rates Variance Account (OPG)	x,xxx	x,xxx

OPG shall record simple interest on the monthly opening balance in this account using the interest rates set by the OEB from time to time pursuant to its interest policy for deferral and variance accounts until the balances are fully refunded.

OPG shall file the balance in the Change in CCA Rules or Rates Variance Account (OPG) in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

Pension and OPEB Cost Variance Account (DNNP)
DNNP LP
Accounting Order

Basis of Approval

Settlement Proposal, Section 3, Part E

Scope of Account

DNNP LP shall establish the Pension and OPEB Cost Variance Account (DNNP), effective January 1, 2027, to record the difference between (i) the pension and OPEB non-capital costs, as charged by OPG to DNNP LP under the applicable agreements between the parties, reflected in DNNP LP's revenue requirement approved by the OEB, and (ii) DNNP LP's actual pension and OPEB non-capital costs for the DNNP facilities, as charged by OPG to DNNP LP under the applicable agreements between the parties; excluding any variances arising from differences in staffing levels (other than changes in long-term disability benefit plan data) and compensation levels including pension and benefit plan provisions.

The monthly reference amount for the purpose of recording entries in this account shall be 1/12 of $1.7M for 2027, $1.2M for 2028, $1.6M for 2029, $6.7M for 2030, and $9.0M for 2031.[12] The resulting monthly reference amount shall be $0.1M for 2027, $0.1M for 2028, $0.1M for 2029, $0.6M for 2030, and $0.8M for 2031.

Entry	Debit	Credit
DR/CR Pension and OPEB Cost	x,xxx	x,xxx
CR/DR Pension and OPEB Cost Variance Account (DNNP)	x,xxx	x,xxx

DNNP LP shall not record any interest on the balance of this account.

DNNP LP shall file the balance in the Pension and OPEB Cost Variance Account (DNNP) in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

[12] Per Ex. L-A1-Staff-293, Chart 3b, Note 6.

Nuclear Deferral and Variance Over/Under Recovery Variance Account (DNNP)
DNNP LP
Accounting Order

Basis of Approval

Settlement Proposal, Section 3, Part E

Scope of Account

DNNP LP shall establish the Nuclear Deferral and Variance Over/Under Recovery Variance Account (DNNP), effective January 1, 2027, to record the difference between the amounts approved for recovery or repayment in the nuclear deferral and variance accounts and the actual amounts recovered or repaid based on actual nuclear production and approved payment riders. The account shall also capture the transfer of balances remaining in other DNNP LP deferral and variance accounts as they may terminate from time to time.

Entry	Debit	Credit
DR/CR Revenue	x,xxx	x,xxx
CR/DR Nuclear Deferral and Variance Over/Under Recovery Variance Account (DNNP)	x,xxx	x,xxx

DNNP LP shall record simple interest on the monthly opening balance in this account using the interest rate set by the OEB from time to time pursuant to its interest policy for deferral and variance accounts until the balances are fully recovered or refunded.

DNNP LP shall file the balance in the Nuclear Deferral and Variance Over/Under Recovery Variance Account (DNNP) in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

SR&ED ITC Variance Account (DNNP)
DNNP LP
Accounting Order

Basis of Approval

Settlement Proposal, Section 3, Part E

Scope of Account

DNNP LP shall establish the SR&ED ITC Variance Account (DNNP), effective January 1, 2027, to record the difference between actual SR&ED ITCs for the DNNP LP facilities as determined after any tax audits and the forecast SR&ED ITCs included in the DNNP LP's revenue requirement approved by the OEB, including income taxes payable on the difference.

The monthly reference amounts for the SR&ED ITCs for the purpose of recording entries in the account shall be $0.0M for 2027, $0.0M for 2028, $0.0M for 2029, $0.0M for 2030, and $0.0M for 2031.[13]

Entry	Debit	Credit
DR/CR Income Tax Expense	x,xxx	x,xxx
CR/DR SR&ED ITC Variance Account (DNNP)	x,xxx	x,xxx

DNNP LP shall record simple interest on the monthly opening balance in this account using the interest rates set by the OEB from time to time pursuant to its interest policy for deferral and variance accounts until the balances are fully recovered or refunded.

DNNP LP shall file the balance in the SR&ED ITC Variance Account (DNNP) in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

[13] Appendix A, Tables 40-44, line 21 less line 22.

Income and Other Taxes Variance Account (DNNP)
DNNP LP
Accounting Order

Basis of Approval

Settlement Proposal, Section 3, Part E

Scope of Account

DNNP LP shall establish the Income and Other Taxes Variance Account (DNNP), effective January 1, 2027, to record the financial impact on DNNP LP's revenue requirement of the following, to the extent such impact is not recorded in another deferral or variance account:

- Any differences in income or capital taxes, or payments in lieu thereof, that result from a legislative or regulatory change to the tax rates or rules of the *Income Tax Act* (Canada) and the *Taxation Act*, 2007 (Ontario) (formerly the *Corporations Tax Act* (Ontario)), or other equivalent provincial legislation, as may be modified by the regulations under the *Electricity Act, 1998*, as applicable, and any differences in payments in lieu of property tax to the Ontario Electricity Financial Corporation that result from changes to the regulations under the *Electricity Act, 1998*;
- Any differences in municipal property taxes that result from a legislative or regulatory change to the tax rates or rules for DNNP LP or the DNNP LP facilities under the *Assessment Act, 1990*;
- Any differences in income or capital taxes, or payments in lieu thereof, that result from a change in, or a disclosure of, a new assessing or administrative policy that is published in the public tax administration or interpretation bulletins by relevant federal or provincial tax authorities, or court decisions on other taxpayers; and
- Any differences in income or capital taxes, or payments in lieu of thereof, that result from assessments or re-assessments (including re-assessments associated with the application of the tax rates and rules to DNNP LP or the DNNP LP facilities or changes in assessing or administrative policy including those arising from court decisions on other taxpayers).

The account shall not record the revenue requirement impact of the above in relation to the SR&ED ITCs, which shall be recorded in the SR&ED ITC Variance Account (DNNP), or the CEITCs, which shall be recorded in the respective other deferral and variance accounts.

The forecast income tax provision and the underlying inputs reflected in the payment amounts approved by the OEB shall be used to calculate any variances in income taxes recorded in the Income and Other Taxes Variance Account (DNNP). Such reference amounts will be those reflected in the corresponding annual income tax provision reflected in the DNNP LP's revenue requirement approved by the OEB in this proceeding, as calculated in Appendix A, Tables 40-44, col. (c), line 23. The resulting monthly reference amount shall be $0.0M for 2027, $0.0M for 2028, $0.0M for 2029, $0.0M for 2030, and $0.0M for 2031, being 1/12 of the respective annual amounts.

Entry	**Debit**	**Credit**
DR/CR Income Tax Expense	x,xxx	x,xxx
CR/DR Income and Other Taxes Variance Account (DNNP)	x,xxx	x,xxx

DNNP LP shall record simple interest on the monthly opening balance of this account using the interest rates set by the OEB from time to time pursuant to its interest policy for deferral and variance accounts until the balances are fully recovered or refunded.

DNNP LP shall file the balance in the Income and Other Taxes Variance Account (DNNP) in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

Impact for IFRS Deferral Account (DNNP)
DNNP LP
Accounting Order

Basis of Approval

Settlement Proposal, Section 3, Part E

Scope of Account

DNNP LP shall establish the Impact for IFRS Deferral Account (DNNP), effective January 1, 2027, to record financial impacts of transition to and implementation of IFRS from US GAAP in the event that DNNP LP adopts IFRS for general financial reporting purposes.[14]

Entries shall include, but not be limited to, any unamortized gains/losses and past service costs/credits balances recorded for pension and OPEB plans in accumulated other comprehensive income/loss under US GAAP.

Entry	Debit	Credit
DR/CR Impact for IFRS Deferral Account (DNNP)	x,xxx	x,xxx
CR/DR Applicable Financial Statement Elements	x,xxx	x,xxx

DNNP LP shall not record any interest on the balance of this account.

DNNP LP shall file the balance in the Impact for IFRS Deferral Account (DNNP) in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

[14] Ex. L-H1-Staff-261.

Clean Electricity ITC and Other Benefits Variance Account (DNNP)
DNNP LP
Accounting Order

Basis of Approval

Settlement Proposal, Section 3, Part E

Scope of Account

DNNP LP shall establish the Clean Electricity ITC and Other Benefits Variance Account (DNNP), effective January 1, 2027, to record: (i) in the Clean Electricity ITC Sub-Account, differences between the revenue requirement impacts arising from the actual CEITCs received by DNNP LP or its owners for the DNNP LP facilities and such forecast amounts reflected in DNNP LP's revenue requirement approved by the OEB, including the income tax impacts arising from such differences; and (ii) in the Other Benefits Sub-Account, differences between the revenue requirement impacts of reflecting the mechanism described in section 5.14 of the Management, Operations, Maintenance and Administration Services Agreement between DNNP LP and OPG dated April 20, 2026 ("Section 5.14 Mechanism") and such forecast amounts reflected in DNNP LP's revenue requirement approved by the OEB; in each case, to the extent these differences are not recorded in another deferral or variance account.

The monthly reference amounts for the purpose of recording entries in each sub-account of this account shall be $0.0M for 2027, $0.0M for 2028, $0.0M for 2029, $0.0M for 2030, and $0.0M for 2031.[15]

Entry 1: Impact resulting from differences in CEITCs received

Entry	Debit	Credit
DR/CR Clean Electricity ITC and Other Benefits Variance Account (DNNP)	x,xxx	x,xxx
CR/DR Depreciation Expense	x,xxx	x,xxx
CR/DR Return on Rate Base	x,xxx	x,xxx
CR/DR Income Tax Expense	x,xxx	x,xxx

[15] Exhibit JTX 3.21, p. 3, lines 12-14.

To record the revenue requirement impact resulting from differences in CEITCs received.

Entry 2: Impact resulting from differences in Section 5.14 Mechanism impacts[16]

Entry	**Debit**	**Credit**
DR/CR Clean Electricity ITC and Other Benefits Variance Account (DNNP)	x,xxx	x,xxx
CR/DR Applicable Financial Statement Elements	x,xxx	x,xxx

To record the revenue requirement impact resulting from differences with respect to the Section 5.14 Mechanism impacts.

DNNP LP shall record simple interest on the monthly opening balance in this account using the interest rates set by the OEB from time to time pursuant to its interest policy for deferral and variance accounts until the balances are fully recovered or refunded.

DNNP LP shall file the balance in the Clean Electricity ITC and Other Benefits Variance Account (DNNP) in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

[16] Any amounts recorded in the Other Benefits Sub-Account for the 2027-2031 period will only be to the credit of ratepayers as there are no corresponding reference amounts included in the OEB-approved revenue requirement.

Impact of Change in Tax Status Variance Account (DNNP)
DNNP LP
Accounting Order

Basis of Approval

Settlement Proposal, Section 3, Part E

Scope of Account

DNNP LP shall establish the Impact of Change in Tax Status Variance Account (DNNP), effective January 1, 2027, to record the impact on regulatory income taxes or capital taxes reflected in DNNP LP's revenue requirement approved by the OEB of any changes to the income tax status of any of DNNP LP's partners or as a result of a change in the partners of DNNP LP, to the extent such impact is not recorded in the Darlington New Nuclear Project Variance Account re Development. The account shall not record the revenue requirement impact of the above in relation to the SR&ED ITCs, which shall be recorded in the SR&ED ITC Variance Account (DNNP), or in relation to the CEITCs, which shall be recorded in the respective other deferral and variance accounts, or in relation to any changes in the CCA rules or rates, which shall be recorded in the Change in CCA Rules or Rates Variance Account (DNNP).

Entry	Debit	Credit
DR/CR Impact of Change in Tax Status Variance Account (DNNP)	x,xxx	x,xxx
CR/DR Income Tax Expense	x,xxx	x,xxx

DNNP LP shall record simple interest on the monthly opening balance in this account using the interest rates set by the OEB from time to time pursuant to its interest policy for deferral and variance accounts until the balances are fully recovered or refunded.

DNNP LP shall file the balance in the Impact of Change in Tax Status Variance Account (DNNP) in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

Nuclear Security Regulation Impact Deferral Account (DNNP)
DNNP LP
Accounting Order

Basis of Approval

Settlement Proposal, Section 3, Part E

Scope of Account

DNNP LP shall establish the Nuclear Security Regulation Impact Deferral Account (DNNP), effective January 1, 2027, to record DNNP LP's revenue requirement impacts of CNSC Nuclear Security Regulations SOR/2025-219, to the extent such impacts are not reflected in the revenue requirement approved by the OEB or another deferral or variance account.

The account shall not record the revenue requirement impact of the above in relation to the SR&ED ITCs, which shall be recorded in the SR&ED ITC Variance Account (DNNP), or in relation to any changes in the CCA rules or rates, which shall be recorded in the Change in CCA Rules or Rates Variance Account.

The monthly reference amounts for the purpose of recording entries in this account shall be $0.0M for 2027, $0.0M for 2028, $0.0M for 2029, $0.0M for 2030, and $0.0M for 2031.[17]

Entry 1: Impact resulting from specified changes on capital costs

Entry	Debit	Credit
DR/CR Nuclear Security Regulation Impact Deferral Account (DNNP)	x,xxx	x,xxx
CR/DR Depreciation Expense	x,xxx	x,xxx
CR/DR Return on Rate Base	x,xxx	x,xxx
CR/DR Income Tax Expense	x,xxx	x,xxx

[17] Exhibit JT5.18.

To record the impact resulting from specified changes on depreciation, the associated impact on the return on rate base, and the associated income tax impacts.

Entry 2: Impact resulting from specified changes on non-capital costs

Entry	**Debit**	**Credit**
DR/CR Nuclear Security Regulation Impact Deferral Account (DNNP)	x,xxx	x,xxx
CR/DR Non-Capital Expense	x,xxx	x,xxx

To record the impact resulting from specified changes on non-capital expenses.

DNNP LP shall record simple interest on the monthly opening balance in this account using the interest rates set by the OEB from time to time pursuant to its interest policy for deferral and variance accounts until the balances are fully recovered or refunded.

DNNP LP shall file the balance in the Nuclear Security Regulation Impact Deferral Account (DNNP) in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

Change in CCA Rules or Rates Variance Account (DNNP)
DNNP LP
Accounting Order

Basis of Approval

Settlement Proposal, Section 3, Part E

Scope of Account

DNNP LP shall establish the Change in CCA Rules or Rates Variance Account (DNNP), effective September 15, 2026, to record, on a without prejudice basis as stated below, the revenue requirement impact for DNNP LP's prescribed facilities of any changes to the CCA rules or rates. DNNP LP shall record such impacts based on the actual undepreciated capital cost and CCA schedules for DNNP LP's prescribed assets, determined with and without the change, for the period until the effective date of the payment amounts order in DNNP LP's next application seeking to clear the Change in CCA Rules or Rates Variance Account (DNNP) balances, at which time a determination with respect to the methodology for determining the entries in the account effective September 15, 2026 will be made. The recording of entries in the account based on the actual undepreciated capital cost and CCA schedules for DNNP LP's prescribed assets, determined with and without the change, up until the date of the payment amounts order in the above proceeding, shall be without prejudice to positions that Parties may take in that proceeding in relation to the methodology for determining entries in the account.

Entry	Debit	Credit
DR/CR Income Tax Expense	x,xxx	x,xxx
CR/DR Change in CCA Rules or Rates Variance Account (DNNP)	x,xxx	x,xxx

DNNP LP shall record simple interest on the monthly opening balance in this account using the interest rates set by the OEB from time to time pursuant to its interest policy for deferral and variance accounts until the balances are fully refunded.

DNNP LP shall file the balance in the Change in CCA Rules or Rates Variance Account (DNNP) in conjunction with its regular reporting on other deferral and variance accounts approved by the OEB.

Attachment 1

Clean Electricity ITC Variance Account (OPG) - Regulated Hydroelectric - Revenue Requirement ($M)

Shown below is the derivation of the amounts for the Clean Electricity ITCs ("CEITCs") adjustment for regulated hydroelectric projects (other than such CRVA eligible projects) that are reflected in the regulated hydroelectric revenue requirement and underpin the regulated hydroelectric custom capital factors approved by the OEB in this proceeding, and form the corresponding reference amounts for the Clean Electricity ITC Variance Account (OPG).

Line No.	Description	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
	Rate Base						
1	Regulated Hydroelectric CEITC Adjustment	1	(0.8)	(2.2)	(4.9)	(8.4)	(11.4)
2	Weighted Average Cost of Capital	2, 3	6.62%	6.71%	6.77%	6.80%	6.80%
3	**Cost of Capital** (line 1 x line 2)		(0.1)	(0.1)	(0.3)	(0.6)	(0.8)
	Depreciation and Amortization						
4	Regulated Hydroelectric CEITC Adjustment (Note 1, line 1f)		(0.0)	(0.0)	(0.1)	(0.1)	(0.2)
	Regulatory Taxable Income Impacts						
5	ROE (line 1 x 45% x 9.11%)	3	(0.0)	(0.1)	(0.2)	(0.3)	(0.5)
6	Depreciation and Amortization (line 4)		(0.0)	(0.0)	(0.1)	(0.1)	(0.2)
7	Capital Cost Allowance (App. A, Table 29a, Note 5 and Tables 30a-33a, Note 6)		2.5	0.3	0.4	0.2	0.1
8	**Net Increase in Regulatory Taxable Income**		2.5	0.2	0.1	(0.3)	(0.5)
9	**Income Tax Rate**		25%	25%	25%	25%	25%
10	**Income Tax Impact** (line 8 x line 9/(1 - line 9))		0.8	0.1	0.0	(0.1)	(0.2)
11	**Total Regulated Hydroelectric CEITC Adjustment Capital Related Revenue Requirement** (line 3 + line 4 + line 10)	3	0.8	(0.1)	(0.4)	(0.8)	(1.1)

Notes: Refer to Attachment 1a.

Attachment 1a

Notes to Attachment 1

Clean Electricity ITC Variance Account (OPG) - Regulated Hydroelectric - Revenue Requirement ($M)

1 The amounts in line 1 are determined as follows:

Line No.	Description	2027	2028	2029	2030	2031
		(a)	(b)	(c)	(d)	(e)
1a	Gross Plant Opening Balance	(0.3)	(1.3)	(3.1)	(6.9)	(10.3)
1b	CEITC Adjustment*	(1.0)	(1.8)	(3.8)	(3.4)	(2.9)
1c	Gross Plant Closing Balance (line 1a + line 1b)	(1.3)	(3.1)	(6.9)	(10.3)	(13.2)
1d	Gross Plant Rate Base Amount (line 1a + line 1c)/2	(0.8)	(2.2)	(5.0)	(8.6)	(11.7)
1e	Accumulated Depreciation and Amortization Opening Balance	(0.0)	(0.0)	(0.1)	(0.1)	(0.3)
1f	CEITC Adjustment**	(0.0)	(0.0)	(0.1)	(0.1)	(0.2)
1g	Accumulated Depreciation and Amortization Closing Balance (line 1e + 1f)	(0.0)	(0.1)	(0.1)	(0.3)	(0.5)
1h	Accumulated Depreciation and Amortization Rate Base Amount (line 1e + line 1g)/2	(0.0)	(0.0)	(0.1)	(0.2)	(0.4)
1i	Net Plant Rate Base Amount (line 1d- line 1h)	(0.8)	(2.2)	(4.9)	(8.4)	(11.4)

* The amounts in line 1b are determined as follows:

Table to Note 1 - CEITC Adjustment (Gross Plant)						
Line No.	Description	2027	2028	2029	2030	2031
		(a)	(b)	(c)	(d)	(e)
1aa	Total Regulated Hydroelectric CEITC Adjustment (App. A, Table 15, col. (c), lines 5, 10, 15, 20, 25)	(25.4)	(47.0)	(47.9)	(25.2)	(16.3)
1bb	Less: Regulated Hydroelectric CEITC Adjustments for CRVA Eligible Projects (App. E, Att. 1a, line 1d)	(24.4)	(45.2)	(44.1)	(21.8)	(13.4)
1cc	Total Regulated Hydroelectric CEITC Adjustment other than CRVA Eligible Projects (line 1aa - line 1bb)	(1.0)	(1.8)	(3.8)	(3.4)	(2.9)

** The amounts in line 1f are determined as follows:

Table to Note 1 - CEITC Adjustment (Depreciation and Amortization)						
Line No.	Description	2027	2028	2029	2030	2031
		(a)	(b)	(c)	(d)	(e)
1dd	Total Regulated Hydroelectric CEITC Adjustment (App. A, Table 16, col. (c), lines 5, 10, 15, 20, 25)	(0.3)	(0.6)	(1.7)	(2.3)	(2.6)
1ee	Less: Regulated Hydroelectric CEITC Adjustments for CRVA Eligible Projects (App. E, Att. 1a, line 1j)	(0.2)	(0.6)	(1.6)	(2.1)	(2.4)
1ff	Total Regulated Hydroelectric CEITC Adjustment other than CRVA Eligible Projects (line 1dd - line 1ee)	(0.0)	(0.0)	(0.1)	(0.1)	(0.2)

2 Calculated as App. A, Tables 19-23, line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).

3 Subject to update for the prevailing ROE rate specified by the OEB as of the effective date of the final payment amounts order in this proceeding.

Attachment 2

Clean Electricity ITC Variance Account (OPG) - Nuclear - Revenue Requirement ($M)

Shown below is the derivation of the amounts for the Clean Electricity ITC ("CEITCs") adjustment for OPG nuclear projects (other than such CRVA eligible projects) that are reflected in the revenue requirements for OPG's nuclear facilities approved by the OEB in this proceeding and form the corresponding reference amounts for the Clean Electricity ITC Variance Account (OPG).

Line No.	Description	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
	Rate Base						
1	OPG Nuclear CEITC Adjustment	1	(1.9)	(4.0)	(6.7)	(9.8)	(13.0)
2	Weighted Average Cost of Capital	2, 3	6.62%	6.71%	6.77%	6.80%	6.80%
3	**Cost of Capital** (line 1 x line 2)		(0.1)	(0.3)	(0.5)	(0.7)	(0.9)
	Depreciation and Amortization						
4	OPG Nuclear CEITC Adjustment (Note 1, line 1f)		(0.1)	(0.2)	(0.3)	(0.5)	(0.6)
	Regulatory Taxable Income Impacts						
5	ROE (line 1 x 45% x 9.11%)	3	(0.1)	(0.2)	(0.3)	(0.4)	(0.5)
6	Depreciation and Amortization (line 4)		(0.1)	(0.2)	(0.3)	(0.5)	(0.6)
7	Capital Cost Allowance (App. A, Tables 34a-38a, Note 8)		0.7	1.4	2.1	2.4	2.9
8	**Net Increase in Regulatory Taxable Income**		0.5	1.0	1.6	1.5	1.7
9	**Income Tax Rate**		25%	25%	25%	25%	25%
10	**Income Tax Impact** (line 8 x line 9/(1 - line 9))		0.2	0.3	0.5	0.5	0.6
11	**Total OPG Nuclear CEITC Adjustment Capital Related Revenue Requirement** (line 3 + line 4 + line 10)	3	(0.0)	(0.1)	(0.2)	(0.6)	(0.9)

Notes: Refer to Attachment 2a.

Attachment 2a

Notes to Attachment 2

Clean Electricity ITC Variance Account (OPG) - Nuclear - Revenue Requirement ($M)

1 The amounts in line 1 are determined as follows:

Line No.	Description	2027	2028	2029	2030	2031
		(a)	(b)	(c)	(d)	(e)
1a	Gross Plant Opening Balance	(1.2)	(2.8)	(5.6)	(8.6)	(12.7)
1b	CEITC Adjustment*	(1.6)	(2.9)	(2.9)	(4.2)	(3.3)
1c	Gross Plant Closing Balance (line 1a + line 1b)	(2.8)	(5.6)	(8.6)	(12.7)	(16.0)
1d	Gross Plant Rate Base Amount (line 1a + line 1c)/2	(2.0)	(4.2)	(7.1)	(10.6)	(14.4)
1e	Accumulated Depreciation and Amortization Opening Balance	(0.0)	(0.1)	(0.3)	(0.6)	(1.0)
1f	CEITC Adjustment**	(0.1)	(0.2)	(0.3)	(0.5)	(0.6)
1g	Accumulated Depreciation and Amortization Closing Balance (line 1e + 1f)	(0.1)	(0.3)	(0.6)	(1.0)	(1.6)
1h	Accumulated Depreciation and Amortization Rate Base Amount (line 1e + line 1g)/2	(0.1)	(0.2)	(0.4)	(0.8)	(1.3)
1i	Net Plant Rate Base Amount (line 1d- line 1h)	(1.9)	(4.0)	(6.7)	(9.8)	(13.0)

* The amounts in line 1b are determined as follows:

Table to Note 1 - CEITC Adjustment (Gross Plant)

Line No.	Description	2027	2028	2029	2030	2031
		(a)	(b)	(c)	(d)	(e)
1aa	Total OPG Nuclear CEITC Adjustment (App. A, Table 17, col. (c), lines 12, 25, 38, 51, 64)	(259.5)	(16.2)	(27.0)	(55.0)	(1,066.5)
1bb	Less: OPG Nuclear CEITC Adjustments for DRP (App. A, Table 17, col. (c), lines 2, 15, 28, 41, 54)	(249.1)	0.0	0.0	0.0	0.0
1cc	Less: OPG Nuclear CEITC Adjustments for PRP (App. A, Table 17, col. (c), lines 5, 18, 31, 44, 57)	(0.4)	0.0	0.0	0.0	(1,005.3)
1dd	Less: OPG Nuclear CEITC Adjustments for Non-DRP/Non-PRP Nuclear CRVA Eligible Projects (App. E, Att. 4a, line 1d)	(8.4)	(13.4)	(24.1)	(50.9)	(57.9)
1ee	Total OPG Nuclear CEITC Adjustment other than CRVA Eligible Projects (line 1aa - line 1bb - line 1cc - line 1dd)	(1.6)	(2.9)	(2.9)	(4.2)	(3.3)

** The amounts in line 1f are determined as follows:

Table to Note 1 - CEITC Adjustment (Depreciation and Amortization)

Line No.	Description	2027	2028	2029	2030	2031
		(a)	(b)	(c)	(d)	(e)
1ff	Total OPG Nuclear CEITC Adjustment (App. A, Table 18, col. (c), lines 12, 25, 38, 51, 64)	(5.0)	(10.6)	(11.0)	(12.3)	(31.6)
1gg	Less: OPG Nuclear CEITC Adjustments for DRP (App. A, Table 18, col. (c), lines 2, 15, 28, 41, 54)	(4.9)	(9.7)	(9.7)	(9.7)	(9.7)
1hh	Less: OPG Nuclear CEITC Adjustments for PRP (App. A, Table 18, col. (c), lines 5, 18, 31, 44, 57)	(0.0)	(0.0)	(0.0)	(0.0)	(15.7)
1ii	Less: OPG Nuclear CEITC Adjustments for Non-DRP/Non-PRP Nuclear CRVA Eligible Projects (App. E, Att. 4a, line 1j)	(0.0)	(0.7)	(1.0)	(2.1)	(5.5)
1jj	Total OPG Nuclear CEITC Adjustment other than CRVA Eligible Projects (line 1ff - line 1gg - line 1hh - line 1ii)	(0.1)	(0.2)	(0.3)	(0.5)	(0.6)

2 Calculated as App. A, Tables 19-23: line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).

3 Subject to update for the prevailing ROE rate specified by the OEB as of the effective date of the final payment amounts order in this proceeding.

ATTACHMENT 1 – IESO PRE-SETTLEMENT CLARIFICATION QUESTION

Independent Electricity System Operator (IESO) Clarification Question

IESO-1

Question:

Issue 20: Is the proposed Hydroelectric Surplus Baseload Generation Variance Account spill calculation methodology appropriate?

Overview of Requested Clarification

Ontario Power Generation (OPG) submits that, following the implementation of the Renewed Market, it can no longer distinguish between local and global surplus baseload generation (SBG) and therefore proposes to calculate surplus baseload generation variance account (SBGVA) amounts based on total SBG spill rather than global SBG spill alone.

The IESO requests that OPG undertake to assess whether local SBG spill can be distinguished from global SBG spill under the Renewed Market by analyzing intervals where (i) the real-time locational marginal price (LMP) is below the application (GRC) threshold, (ii) the congestion component of the LMP is negative, and (iii) spill occurs, and provide the results of that analysis or explain why such an approach is not feasible.

The IESO's request arises from Mr. Chidiac's technical conference testimony, in which he acknowledged, in response to an OEB staff question, that a negative congestion component in the Renewed Market could be a potential indicator of local SBG spill[31].

Basis of IESO Request and Example Calculation

The IESO observes that the Renewed Market design may provide a means of identifying local SBG conditions using available price and operational data. Specifically, OPG's evidence indicates that SBG conditions are expected when the real-time LMP for a given resource falls below its applicable GRC price threshold (Exhibit E1, Tab 2, Schedule 1, p. 6). Building on this, the IESO notes that where the real-time LMP for a resource is below the GRC threshold, the congestion component of the LMP is negative, and spill occurs, this combination of factors may be indicative of localized surplus conditions associated with transmission constraints.

Collectively, these factors may provide a workable basis for identifying local SBG conditions and distinguishing them from global SBG for SBGVA purposes. Accordingly, the IESO requests that OPG assess the proposed methodology using available market

[31] EB-2025-0297, Technical Conference Day 1, May 27, 2026 at p. 23.

and operational data and determine whether it can be used to reasonably distinguish local spill from global SBG spill for SBGVA purposes. As part of that assessment, OPG should provide, to the extent feasible, the hours of spill, spill quantities, and corresponding local spill estimates by facility for the period from June 2025 to present.

The IESO further requests that OPG quantify the associated SBGVA impacts of this analysis, including the dollar amounts attributable to spill identified as local spill under the methodology. If OPG concludes that the methodology is not workable, the IESO requests that OPG provide a detailed explanation of the analytical, operational, or data limitations that prevent its implementation.

To assist in this assessment, the IESO has prepared an illustrative example demonstrating how the proposed methodology could be applied in practice. This example is provided for guidance purposes only and is not intended to prescribe a specific approach. OPG may refine the methodology or propose an alternative approach, provided it is better suited to identifying and tracking local SBG spill for SBGVA purposes.

Illustrative Example

The purpose of this methodology is to estimate the portion of hydroelectric spill at OPG facilities that is attributable to global SBG versus local constraints, for inclusion in the SBGVA.

Consistent with the high-level approach described at Exhibit E1, Tab 2, Schedule 1, p. 6, the calculation conceptually:

1. Starts with the total volume of water spilled; and
2. Removes spill attributable to:
    - water conveyance constraints,
    - production capability constraints, and
    - contractual obligations.

The IESO does not have data to perform the calculations in Steps 1 and 2 above, however, the IESO believes that spill due to local constraints can be estimated in two steps.

Step 1: Identification of Locally Constrained Spill

The subset of spill attributed to local constraints can be determined using market price signals. An interval is classified as exhibiting local (non-SBG) spill where both of the following conditions are met:

<u>Condition 1: System is Not in Global SBG</u>

Energy Reference Price$_t$ > OPG Offer Price$_t$

This indicates that, at the system level, energy is still economically valued above the generator's offer price. Therefore, the system is not experiencing a global SBG condition.

Condition 2: Local Congestion Exists

LMP_t <OPG Offer Price ≤GRC

The LMP at the hydroelectric facility is below the offer price and less than or equal to the GRC. When combined with Condition 1, this implies that the unit would be economic at the system level, but it is not being dispatched due to local conditions.

Step 2: Calculation of Local and Global Spill

Local Spill

$$\text{Local Spill} = \sum_{t \in \text{Intervals satisfying Conditions 1 and 2}} \text{Actual Spill}_t$$

Global (SBG) Spill

Global Spill (SBG) = Total Spill − Local Spill

This residual represents spill attributable to system-wide surplus baseload conditions.

Example Calculation

Interval	Offer Price	Total Volume Spilled (MWh)	LMP	Reference Price	Congestion Price	Loss Price	Condition 1	Condition 2	Spill Type
1	5.5	10	4	8	-3	-1	Yes	Yes	Local
2	5.5	10	4	8	-3	-1	Yes	Yes	Local
3	5.5	10	4	8	-3	-1	Yes	Yes	Local
4	5.5	10	4	8	-3	-1	Yes	Yes	Local
5	5.5	10	4	8	-3	-1	Yes	Yes	Local
6	5.5	0	9	10	0	-1	No	Yes	N/A
7	5.5	0	9	10	0	-1	No	Yes	N/A
8	5.5	10	4	8	-3	-1	Yes	Yes	Local
9	5.5	10	0	0	0	0	No	Yes	SBG
10	5.5	10	0	0	0	0	No	Yes	SBG
11	5.5	10	0	0	0	0	No	Yes	SBG
12	5.5	10	0	0	0	0	No	Yes	SBG
Total		100							

Note: This assumes no spill occurred due to water conveyance constraints, production capability constraints, and contractual obligations.

In this example, total spill is 100 MWh. Applying the formula from step 2, global spill can be calculated as total spill (100 MWh) less local spill (60 MWh), resulting in 40 MWh global spill.

Note that a hydroelectric resource might not be dispatched even when its LMP exceeds its offer price when the resource submits forbidden regions. For example, a resource might have a forbidden region between 0 and 100 MW. In this case, the resource can only be scheduled at either 0 MW or above 100 MW. If the spill is caused due to binding forbidden region, then that spill should also be excluded from global spill calculation

Response:

In this Application, OPG is proposing to set payment amounts for its regulated hydroelectric facilities. As explained in Ex. E1-1-1, and consistent with prior applications, OPG's regulated hydroelectric production forecast has no deductions made for SBG. As such, consistent with the approach approved by the OEB in EB-2010-0008 and each subsequent payment amounts proceeding, the SBGVA continues to provide a mechanism for OPG to record the impacts of foregone generation resulting from SBG conditions not reflected in its regulated hydroelectric production forecast. It is the total SBG spill that is relevant and the requested analysis as to the distinction between local and global SBG spill is not relevant and has no probative value.

In addition to the significant time needed to perform the proposed analysis, the treatment of foregone generation relating to SBG has been examined in prior applications, most recently in EB-2023-0336, and multiple studies conducted in consultation with the IESO.