HYDROELECTRIC INCENTIVE MECHANISM, SURPLUS BASELOAD GENERATION AND MAKE WHOLE PAYMENTS

1.0 PURPOSE

This evidence explains OPG's proposal for the continuation of changes to OPG's regulatory framework as a result of the implementation of IESO's Market Renewal Program ("MRP" or "Renewed Market"), as established and settled in EB-2023-0336, based on quantitative results from the first five months of OPG's experience in the Renewed Market. It also proposes changes to the sharing of Hydroelectric Incentive Mechanism ("HIM") revenues for the IR term. Additionally, as committed in EB-2023-0336, OPG has attached the Hydroelectric Surplus Baseload Generation Variance Account Study ("SBGVA Study") as Attachment 1.

2.0 OVERVIEW

In this application OPG is seeking the following approvals, as established and settled in EB-2023-0336, further supported by OPG's experience in the Renewed Market:

1. To continue to book amounts in the SBGVA based on the revised local and global Surplus Baseload Generation ("SBG") spill methodology, as described in Section 4.0;
2. To continue to be settled according to the revised HIM, which includes separate day-ahead and real-time incentives and uses locational prices based on daily average, as described in Section 5.0;
3. To continue the revised HIM adjustment for spill ("unintended benefit") as described in Section 5.0; and
4. To continue to retain Real-Time Energy Make Whole Payments as described in Section 6.0.

These approvals will continue the alignment of certain ratemaking methodologies related to production from OPG's prescribed hydroelectric generating facilities, as approved by the OEB, with the design and operations of the Renewed Market.

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

3.0 OVERVIEW OF THE RENEWED MARKET

While the Renewed Market introduced many operational changes,[1] the impacts on OPG's Regulated Framework addressed in this Exhibit are outlined in Chart 1 and are described further below.

Chart 1: Mapping of MRP Design Elements to Impacted OPG Regulated Framework Addressed in this Application

MRP Changes		Impacts to OPG Regulated Framework: SBGVA	HIM	Other Revenues	MWP/CMSC
Single Schedule Market	Uniform price to Locational Prices	☑	☑	☑	
	Eliminate Unconstrained schedule	☑		☑	☑
	Changes to MWP				☑
DAM & RTM	DAM & RTM Settlement		☑	☑	

3.1 Single schedule market ("SSM")

In the Legacy Market (referring to the market prior to MRP), the IESO used two dispatch algorithms: one to schedule and dispatch resources to meet demand and another to determine prices.[2] The dispatch setting "constrained" algorithm included transmission constraints and losses, while the "unconstrained", uniform price-setting algorithm did not. In comparison, the Renewed Market includes a single schedule optimization that utilizes the same dispatch algorithm for both dispatch scheduling and pricing. The Locational Marginal Prices ("LMP")

[1] A complete list of contemplated changes can be found in the IESO's high-level design documents: <https://www.ieso.ca/en/Market-Renewal/Energy-Stream-Designs/High-Level-Designs>.
[2] For purposes of this exhibit, a 'resource' refers to a single or group of generating units that connect to the IESO controlled grid at a specific node.

published in the Renewed Market incorporate the cost of congestion and losses to reflect the marginal cost of energy at each electrical node on the system. These prices typically reflect dispatch schedules received at each resource and are used for market settlement, subject to a floor price.

3.2 Financially binding Day-Ahead Market ("DAM") and Real-Time Balancing Market

Unlike the Legacy Market, where only non-quick start generators received a Day-Ahead guarantee via a day-ahead commitment process, the Renewed Market includes a financially binding Day-Ahead Market for all participants and balances deviations that occur between the day-ahead and real-time through a Real-Time Balancing Market. The IESO's stated benefits of a financially binding DAM include certainty for participating resources through a guaranteed schedule and price in the day-ahead timeframe and greater market scheduling certainty for the market operator by shifting scheduling of supply quantities to the day-ahead timeframe.[3] A real-time balancing settlement is used for deviations between a resource's day-ahead schedule and its real-time output based on the real-time LMP to incentivize market participants to respond to incremental, post day-ahead system changes.

3.3 Changes to Make Whole Payments ("MWP")

Make Whole Payments, a type of out-of-market compensation, ensure market participants are paid appropriately when resources are dispatched uneconomically in relation to their market payments. The Legacy Market used Congestion Management Settlement Credits ("CMSC") to keep market participants whole when a resource's constrained run schedule differed from the unconstrained schedule used in the uniform price setting run. As such, CMSCs facilitated revenue sufficiency for hydroelectric resources related to inefficient operation and in some instances forgone generation due to system constraints. In the Renewed Market, MWPs compensate hydroelectric resources for lost cost and lost opportunity cost in day-ahead and real-time. As the LMPs include the cost of congestion, according to the IESO's high-level

[3] IESO, Day-Ahead Market High-Level Design ("DAMHLD"), August 2019, p. 3 <https://www.ieso.ca/en/Market-Renewal/Stakeholder-Engagements/Market-Renewal-Day-Ahead-Market>.

design,[4] the transition to the single schedule market largely removes the underlying causes of divergence between dispatch and price that previously created the need for out-of-market payments. While MWPs are a part of both the day-ahead and real-time market, the circumstances that lead to MWPs in the Renewed Market are expected to be infrequent by design.

4.0 SURPLUS BASELOAD GENERATION

While both global SBG and local SBG can lead to hydroelectric spill, this section explains why global SBG conditions were used to quantify SBG spill when calculating SBGVA entries in the Legacy Market and why global SBG conditions can no longer be differentiated from local SBG conditions in the Renewed Market. This section details OPG's proposal to continue to quantify SBG spill and make entries to the SBGVA on a total SBG basis (i.e., include spill due to global and local SBG conditions).

4.1 Overview

In its 2012 Renewable Integration Stakeholder Engagement, the IESO described that SBG conditions can occur on both a global and local level, with global SBG defined as "a condition that occurs when Ontario's electricity production from baseload facilities, if not managed, would otherwise be greater than demand".[5] Local SBG was similarly defined as "a condition that occurs when a region's electricity production from baseload facilities, if not managed, would otherwise be greater than the local demand and the transmission system's ability to move the excess generation out of the area".[6] Both types of SBG conditions can cause hydroelectric spill at OPG's hydroelectric resources when storage is not available.

4.2 SBG Spill Calculation in the Legacy Market

As explained in Ex. E1-1-1, similar to all prior applications, OPG's hydroelectric production forecast has no deductions made for SBG and therefore its ability to recover its revenue

[4] IESO, Single Schedule Market High-Level Design ("SSMHLD"), August 2019, p. 55 https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/ssm/SSM-High-Level-Design-Aug2019.ashx>.
[5] SE-91 Document "Surplus Baseload Generation (SBG)", August 7, 2012.
[6] *Ibid.*

requirement is reduced when SBG conditions occur.[7] To address the impact of SBG on OPG's regulated hydroelectric production, the OEB approved the SBGVA in EB-2010-0008 and each subsequent payment amounts proceeding.

As detailed in EB-2013-0321[8] and most recently set out in the EB-2020-0290 Payment Amounts Order, OPG calculated forgone production due to SBG in the Legacy Market by starting with the total volume of spill and subtracting the volume of spill due to water conveyance constraints, production capability, market constraints and contractual obligations.

SBGVA entries were then calculated using the volume of spill remaining after excluding the spill amounts incurred by OPG that were not attributable to the impact of SBG conditions based on a comparison of OPG's Gross Revenue Charge ("GRC") and the uniform price. The uniform price is an indicator of global SBG, as it does not consider the impact of congestion.

4.3 SBG Spill Calculation in the Renewed Market

As explained in EB-2023-0336, the Renewed Market's SSM necessitated an update to OPG's methodology for calculating forgone production due to SBG conditions. Specifically, the Renewed Market does not calculate and publish a uniform, "unconstrained" price, thereby eliminating OPG's ability to evaluate market conditions without the impact of local market constraints. As a result, OPG is unable to accurately distinguish between spill due to global and local SBG conditions as defined in IESO's Renewable Integration Stakeholder Engagement.

The use of a SSM also impacts the calculation of SBG-related spill. As described in Section 4.2, in the Legacy Market OPG isolated global SBG spill from other market constraints that can cause OPG to forgo generation, which at times included spill caused by local SBG. OPG assessed market constraints by comparing the constrained and unconstrained schedules published in the Legacy Market. This process ensured that forgone generation due to market

[7] Where OPG expects that losses due to SBG will be addressed by the SBGVA as approved in EB-2010-0008 and modified in EB-2023-0336.
[8] EB-2013-0321, Ex. E1-2-1, Section 3.2 and Ex. L-5.4-17 SEC-070.

constraints, including those related to local SBG, were not booked in the SBGVA, as they may also attract CMSC payments. The Renewed Market's use of a single schedule eliminates OPG's ability to identify spill attributable to market constraints as it also eliminates CMSC payments.

To address these changes, in EB-2023-0336 OPG proposed adjustments to the methodology used to calculate spill due to SBG conditions. OPG's proposal aligned with the structure of the Renewed Market while maintaining OPG's revenue sufficiency when impacted by surplus conditions outside of OPG's control. OPG's proposal was accepted at the conclusion of OPG's MRP application in EB-2023-0336 and implemented as proposed as of May 1, 2025, the go-live date of the Renewed Market.

OPG's methodology to calculate forgone production due to SBG maintains the process of starting with the actual volume of water spilled. OPG then removes spill related to water conveyance constraints, production capability constraints and contractual obligations. This methodology differs from the one used in the Legacy Market. Specifically, spill associated with market constraints is no longer removed as these amounts are unquantifiable in the Renewed Market. This remaining spill volume is considered as potential SBG spill. SBG conditions are generally expected to be present when the applicable real-time LMP for a given resource falls below its applicable GRC price threshold.[9] OPG's use of LMP as an indicator for SBG conditions could indicate the presence of global or local SBG conditions, unlike the uniform price in the Legacy Market, which signaled the presence of global SBG.

In the course of pre-implementation testing of OPG's proposed methodology using Legacy Market proxy LMPs (also known as Shadow Prices) OPG observed instances when the locational price did not fall below GRC while GRC-based generation was scheduled down and OPG incurred spill. OPG anticipated that LMPs in the Renewed Market could be subject to similar exceptions. After the implementation of the Renewed Market, OPG continued to

[9] Per IESO's SSMHLD, p. 8, footnote 4, the applicable LMP by location is based on the connection point (node) of a market participant supplier.

observe spill ineligible for SBGVA recovery. As noted in the IESO's *Update on Renewed Market Performance and Operations*: "LMP prices do not tell the whole story and cannot always be used to determine if an offer/bid should or should not have cleared the market at their submitted prices".[10] As such, while the Renewed Market introduced LMPs that generally reflect system conditions, certain operational and optimization constraints continue to result in spill outcomes that are not captured under the SBGVA framework. This impact is included as an adjustment to OPG's hydroelectric production forecast as reflected in Ex. E1-1-1, Section 3.1.

4.4 SBG Spill and Make Whole Payments

As explained in Section 3.3, the use of a Single Schedule in the Renewed Market eliminated CMSCs but continued the general use of MWPs in instances when the IESO takes out-of-market actions. OPG notes that MWPs related to lost opportunity resulting from the IESO taking out-of-market actions can coincide with the occurrence of SBG spill at its hydroelectric facilities. To prevent duplicate payment related to the same quantity of forgone generation, OPG's SBGVA methodology identifies instances when, on an hourly resolution, a resource books SBGVA amounts and receives a MWP from the IESO. OPG reduces the SBGVA entry associated with the respective resource by the value of the MWP received, ensuring the entry does not fall below zero dollars. OPG notes that for the first five months of the Renewed Market, the MWP associated reduction of OPG's SBGVA has been negligible.

4.5 SBG Spill Observations in the Renewed Market

Consistent with its OEB-approved EB-2023-0336 Settlement Proposal, OPG has presented SBGVA amounts from the five months in the Renewed Market as well as monthly data for the 2021-2025 period in Chart 2. This data demonstrates the expected persistence of seasonal patterns with higher SBGVA entries during freshet months. While OPG is unable to isolate spill that is attributable solely to the SBGVA methodology changes implemented under the Renewed Market, spill volumes observed to date have remained generally consistent on a

[10] IESO, Update on Renewed Market Performance and Operations https://ieso.ca/-/media/Files/IESO/Document-Library/engage/renewed-market/rmo-20250821-presentation-renewed-market-update.pdf>.

month-over-month basis with levels recorded since 2021. OPG expects that total SBG spill will continue to remain at these recently observed lower levels, subject to hydrological conditions.

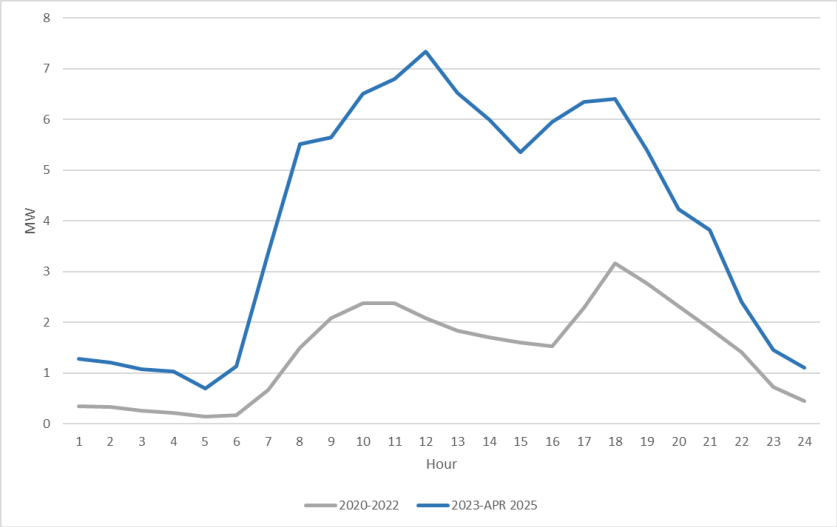
Chart 2: SBG Spill Booked to SBGVA (MWh)[11]						
	2021	**2022**	**2023**	**2024**	**2025**	**Average**
January	195	51	54	3	5	61
February	118	72	152	15	0	72
March	258	74	85	20	48	97
April	399	276	199	77	131	216
May	299	353	289	44	**398**	278
June	134	283	31	68	**84**	121
July	108	32	1	13	**33**	37
August	32	30	18	9	**12**	20
September	130	77	9	17	**20**	58
October	99	65	92	17		68
November	48	216	40	49		88
December	62	62	6	17		37

4.6 Use of Sir Adam Beck Pump Generating Station ("PGS") During SBG Conditions

As demonstrated in the SBG and related PGS annual reporting and record-keeping requirement, Ex. H1-1-1 Attachments 3 and 4, and Chart 3 below, PGS utilization continues to increase since the SBGVA was last cleared.

[11] The SBGVA amounts associated with spill for May to September 2025 as presented in Chart 1 are subject to a monthly $0.6M reduction in accordance with the OEB-approved EB-2023-0336 Settlement Proposal, which is applicable until the effective date of the payment amounts order in this Application.

Chart 3 - Average Pumped Generating Station Output by Hour (January 2020 - April 2025)



The number of coincident hours where SBGVA additions were made and the PGS was not pumping have decreased significantly since the 2020 high of 6,437, at 1,856 in 2023 and 1,006 in 2024. The value of SBGVA additions in coincident hours when the PGS was not operated in pump mode exclusively to prevent economic loss to OPG have also significantly decreased from the 2020 high of $11.5M to $0.7M in 2023 and $0.4M in 2024. OPG attributes the increase in PGS utilization and the concomitant decline in hours with SBGVA bookings when the PGS is not pumping to the absence of very high flows on the Niagara river and sufficient price spread in the market.

4.7 Conclusion

OPG proposes to continue to book amounts in the SBGVA based on the revised local and global SBG spill methodology as settled in EB-2023-0336 and described above. The continuation of this process is supported by data observed in the first five months of the Renewed Market. The SBGVA provides a mechanism for OPG to record the impacts of foregone generation not reflected in its forecast, and the entries are adjusted for interactions with Real-Time MWPs, ensuring no additional reductions are required.

5.0 HYDROELECTRIC INCENTIVE MECHANISM

This section sets out OPG's proposals related to the HIM. Sections 5.1-5.3 describe the HIM and OPG's proposal to continue the updates to the HIM methodology and the spill adjustment that align the HIM with the Renewed Market as settled in EB-2023-0336. Section 5.4 presents the customer benefit analysis associated with the HIM, and Section 5.5 outlines OPG's proposed revisions to HIM revenue sharing.

5.1 HIM Overview

The HIM was proposed and approved in EB-2007-0905 to provide OPG with an incentive to respond to market signals in a manner that also benefits consumers. Under the HIM, if in a given hour OPG produces more energy than a monthly average-based hourly volume, it receives market prices for this incremental amount of energy. If OPG's energy production is less than the hourly volume in a given hour, the amount payable to OPG is reduced by the production shortfall multiplied by the market price. Consumers benefit from the placement of hydroelectric energy in high priced hours, which typically reflects higher demand for electricity.

In EB-2010-0008, the OEB required OPG to address the interaction between HIM revenues and the SBGVA in its next application. In EB-2013-0321, the OEB directed OPG to include an offset to the HIM to reflect the interaction between the HIM and the SBGVA (known as the Unintended Benefit).

5.2 HIM Redesign for the Renewed Market

5.2.1 Day Ahead and Real Time HIM

In EB-2023-0336, OPG proposed revisions to the HIM with the objective of maintaining a similar design as the previously approved HIM while incorporating design features of the Renewed Market. Specifically, the redesigned HIM includes:

- A formula that incorporates a separate day-ahead ("DA") and real-time ("RT") incentive to reflect the new financially binding DA and RT balancing settlement design;
- Locational Market Price settlement;

- Daily production averaging to better align the HIM with daily market scheduling timeframes and operational storage horizons; and
- Continuation of a revised Unintended Benefit.

Figure 1 - Incentive Payment Calculation

$$Incentive\ Payment = DA\ Incentive + RT\ Incentive$$

$$= \sum_{t} \left(MW_{DA}(t) - MW_{DAavg}\right) \times LMP_{DA}(t)$$

$$+ \sum_{t} \left(MW_{diff}(t) - MW_{diff,avg}\right) \times LMP_{RT}(t)$$

Where:

$$MW_{diff}(t) = MW_{RT}(t) - MW_{DA}(t)$$

$$MW_{diff,avg} = MW_{RTavg} - MW_{DAavg}$$

Where:

$MW_{DA}(t)$: hourly production schedule from the IESO day-ahead market for each hour, *t*, of the day

MW_{DAavg}: average of hourly energy schedule from the IESO day-ahead market over the day

$LMP_{DA}(t)$: the day-ahead LMP for the resource for each hour, *t*, of the day

$MW_{RT}(t)$: net energy production supplied to the IESO real-time market for each hour, *t*, of the day

MW_{RTavg}: average of hourly net energy production over the day

$LMP_{RT}(t)$: the real-time LMP for the resource for each hour, *t*, of the day

OPG's HIM proposal provides an incentive for OPG to time-shift energy to high-price periods in the day-ahead timeframe in alignment the Renewed Market's financially binding DAM. The redesigned HIM also aligns with the RT Balancing Market as it provides OPG with an incentive to respond to real-time signals in the form of an incremental payment for further deviations from the day-ahead average. The use of daily averaging better aligns with the IESO's daily

scheduling timeframe of resources in the Renewed Market and more closely reflects OPG's storage and time shifting capabilities. This redesigned HIM's day-ahead component is expected to be more material than the real-time one, which is consistent with the Renewed Market's intent of the Day Ahead being used to schedule most of the supply.[12]

5.2.2. Unintended Benefit

The Renewed Market does not change the potential interactions of SBG spill booked in the SBGVA and the HIM as outlined in EB-2013-0321. OPG's EB-2023-0336 application included a revised Unintended Benefit calculation that reflected the redesigned HIM and its use of a daily average and Locational Marginal Prices. Specifically, OPG proposed the following revised formula for the unintended benefit adjustment:

Figure 2: Revised Formula for Unintended Benefit Adjustment

$$Unintended\ Benefit\ Adjustment = \sum_{t} \left(MW_{Spill\ RTM}(t) - MW_{Spill\ RTM\ Avg}\right) \times LMP_{RTM\ Hourly}(t)$$

Where:

$MW_{Spill\ RTM}(t)$: hourly forgone production due to spill for each hour, *t*, of the real-time market day

$MW_{Spill\ RTM\ Avg}$: average of hourly spill over the real-time market day

$LMP_{RTM\ Hourly}(t)$: the real-time market LMP for the resource in the hour, *t*

5.3 HIM Analysis

5.3.1 HIM Results in the Renewed Market

Consistent with its OEB-approved EB-2023-0336 Settlement Proposal, OPG has presented HIM amounts from the five months in the Renewed Market in Chart 4.

[12] IESO, Day-Ahead Market High-Level Design ("DAMHLD"), August 2019, p. 3 <https://www.ieso.ca/en/Market-Renewal/Stakeholder-Engagements/Market-Renewal-Day-Ahead-Market>.

Chart 4 – HIM Payments in Market Renewal 2025 ($M)

	May	June	July	Aug	Sept
DA HIM	2.0	4.0	8.6	8.8	1.8
RT HIM	1.9	3.3	2.0	0.1	(0.3)
UIB	(4.6)	(1.0)	(0.6)	(0.1)	(0.2)
Net HIM	$(0.7)	$6.3	$10.0	$8.8	$1.3

These results capture the period immediately following the launch of the Renewed Market. OPG has taken a measured approach in interpreting these results alongside its longer-term modelled expectations of market operations. As the IESO noted in its update on Renewed Market performance and operations: the ability to draw conclusions at this point is still limited due to (1) short duration the renewed market has been in operation; (2) participants learning how the renewed market works and adjusting their strategies; and (3) experience in only two seasons.[13] OPG's observations include IESO's comments and contemplate a moderation of market outcomes as participants adjust their strategies and the IESO fine-tunes its systems based on real-life experience in the Renewed Market.

OPG's HIM observations are consistent with the overall expectation that the Day-Ahead HIM component would be higher than the Real-Time HIM, in keeping with the design of the Renewed Market. In the first month of the Renewed Market, OPG recorded negative HIM net revenue of $0.7M. This was mainly driven by high SBG spill that occurred during spring freshet which resulted in an unintended benefit adjustment that offset the DA and RT HIM payments earned during that period. In the following three summer months, OPG recorded a positive net HIM, followed by more moderate HIM revenues in September, which included a small negative RT HIM.

OPG expects an overall moderation of its HIM revenues as some of the early price volatility in the Renewed Market dampens with participants gaining experience in the new market. Further, as energy storage facilities continue to come online between 2025 and 2028, OPG expects

[13] https://ieso.ca/-/media/Files/IESO/Document-Library/engage/renewed-market/rmo-20250821-presentation-renewed-market-update.pdf

the increased arbitrage balancing supply to apply downward pressure on LMP price spreads, further moderating OPG's ability to earn HIM net revenues. Some of these assumptions are discussed further in Section 5.4, which details OPG's net HIM revenue forecast for 2027, the forward test year underpinning the regulated hydroelectric revenue requirement in this Application.

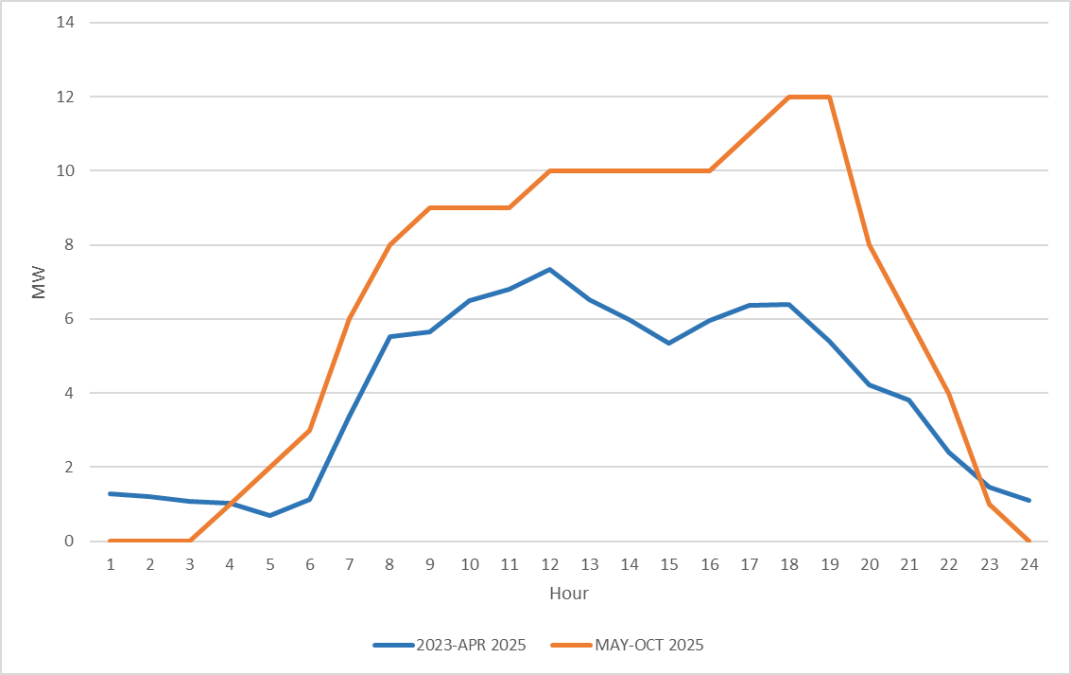
5.3.2 Impact of HIM on PGS Operating Decisions

The PGS supports the safe and efficient operation of the Sir Adam Beck complex while its time-shifting of water provides consumer benefit.[14] While the HIM approved in EB-2007-0905 was eventually applied to the additional hydroelectric stations prescribed in EB-2013-0321, its original design was specifically for the PGS to provide consumer benefit through incentivizing time shifting.

Chart 5 below illustrates that the HIM has continued to result in sustained high utilization of PGS in the first five months of the renewed market when compared to its utilization in the Legacy Market.

[14] EB-2023-0336, Ex. M1-1-1, Section 3.5 Customer Benefit.

Chart 5 - Average Pumped Generating Station Output by Hour (2023 - October 2025)



These results indicate the continued adequacy of the incentive provided by the HIM for the PGS to time-shift water. Further discussion of the impact on HIM on PGS operating decisions in the renewed market can be found in Section 5.5.

5.4 HIM Forecast Customer Benefit

Consistent with OPG's prior applications, OPG has conducted modelling analysis to forecast the HIM benefits in the Renewed Market for the test year. OPG's models use locational prices and are based on OPG's understanding of the design of the Renewed Market through IESO design documents prior to this application. By comparing to a flatter scheduling profile, OPG's model demonstrates the value of time-shifting hydroelectric resources, a relatively low-cost generation source, which displaces the need for more expensive generation sources during high price periods, and minimize system needs to curtail other sources during low price periods.

Chart 6 illustrates OPG's modelled changes in customer costs arising from the relevant factors for the test period, demonstrating that the cost of the incentive provides a net consumer benefit. These figures represent "all-in" customer costs including changes in Global Adjustment payments which reflects OPG's understanding of Ontario's hybrid market, where some suppliers are settled based on contracts.

Chart 6 – HIM Customer Benefit Analysis

Line No.	Customer Cost Changes ($M)	2026	2027*
1	Payments for Non-OPG Supplier Generation	(46)	(137)
2	Payments for OPG Generation (excluding incentive payment)	3	(13)
3	Payments for SBG-related Generation Curtailment	(7)	(3)
4	Export Revenues	2	2
5	**Change in Customer Cost excl. OPG Incentive (line 1+ line 2 + line 3 - line 4)**	**(52)**	**(154)**
6	**Additional Payments to OPG**		
7	DA HIM	19	19
8	RT HIM	7	4
9	Unintended Benefits Adjustment	(6)	(6)
10	**Total Additional Payments to OPG (line 7 + line 8 + line 9)**	**20**	**18**
11	**Net Customer Cost Change (line 5 + line 10)**	**$(32)**	**$(136)**

*Totals may not add due to rounding

OPG's assessment of consumer benefits from the HIM concludes that economic time-shifting of its regulated hydroelectric generation reduces modelled consumer costs before OPG incentive payments by $154M in the 2027 test year (See Chart 6, Line 5). The HIM-driven, incremental time-shifting of production results in a modelled net incentive payment to OPG of $18M (See Chart 6, Line 10), creating a $136M net consumer benefit (See Chart 6, Line 11).

The analysis accounts for the market effects of time shifting: the displacement of more expensive generation[15] (i.e., on-peak gas and imports) by hydroelectric production; increases in production and consequent GRC payments for additional on-peak generation at the regulated hydroelectric facilities; reduced payments for SBG-related forgone generation (as determined under OPG's proposal); and changes in exporter payments[16] made to the IESO for off-peak exports that result in changes in customer costs.

The higher customer benefit in 2027 relative to 2026 is due to forecasted increases in Ontario Zonal Prices. In 2027, OPG forecasts approximately 5 TWh of incremental demand relative to 2026, and no Pickering B generation after it comes offline for refurbishment in September 2026. Together, these factors are expected to increase reliance on gas-fired generation and imports. As a result, Ontario Zonal Prices are projected to rise, increasing the value of incremental time-shifted hydro production and the customer benefit in 2027.

Discussion on HIM forecasting can be found in Ex. G1-01-01, Section 7.0 HIM Revenue Requirement Adjustment.

5.5 Revisions to HIM Revenue Sharing

5.5.1 Impact of HIM Revenue Sharing on PGS Price Spread

OPG's SBGVA Study in Attachment 1 considered reasonable options to better incentivize OPG to minimize total system costs in consultation with stakeholders. As described in Section 3.3.3 of the study, OPG explored whether any changes to the HIM could meet this objective.

In the SBGVA Study, OPG noted that under the current HIM revenue-sharing regime, the price spread required to economically cycle the PGS would escalate when HIM revenues exceed the HIM threshold. While OPG's historic HIM revenues have not created such conditions, as

[15] The analysis accounts for impacts on generation costs resulting from displacement of generation but does not account for potential additional benefits related to carbon emission reductions.

[16] Sales of exports in the off-peak are typically made from contracted generation sources with contract prices that are independent of market prices. These volumes are effectively "take or pay". The consumer benefit arises from increasing the off-peak price for export sales so as to generate additional revenues that, in turn, reduce Global Adjustment payments by consumers.

the threshold is reset in the application, OPG believes it is important to pre-emptively address any structural barriers that may impede the operation of the PGS against the objective of reducing SBGVA entries and maximizing consumer benefit.

To illustrate the impact of sharing HIM revenues above the threshold, OPG calculated the spread required to economically cycle the PGS under two scenarios:

- **Scenario 1:** HIM net revenue sharing arrangement with 50% sharing of HIM net revenues above threshold; and
- **Scenario 2:** Alternative HIM net revenue sharing arrangement where 50% sharing above threshold is eliminated. This scenario is also reflective of PGS spread when the threshold has not been reached.

The PGS price spread is identical between both scenarios when OPG's HIM revenues are below the threshold. When the HIM revenues exceed the threshold, in both scenarios OPG continues to incur the same load charges, gross revenue charges, energy costs, and efficiency losses, but in Scenario 1 is limited to retaining only 50% of HIM net revenues to offset these costs. The resulting reduction in revenues must be recovered from the market for PGS operations to remain economic. This materially increases the spread required to justify time-shifting and, in practice, would impede the PGS's ability to shift generation, even though OPG has demonstrated that such operation provides a clear consumer benefit.

While OPG treats the sharing of forecast HIM revenues with customers as a fixed cost and does not build it into the variable cost formulas that guide market offers, once HIM net revenues exceed the threshold the obligation to share 50% effectively introduces an incremental variable cost that must be reflected in PGS offer decisions. OPG's proposal to remove the sharing of HIM revenues, ensures that PGS economics are consistent and not subject to a discrete change that impedes operations based on OPG's overall HIM revenues.

5.5.2 Market Surveillance Panel (MSP) Observations

As noted in the SBGVA Study, in its Monitoring Report 32[17] published on July 16, 2020 and a subsequent State of the Market Report 2022, the MSP expressed concern that the current revenue-sharing structure may be suppressing the efficiency benefits of the HIM. Specifically, in its Monitoring Report 32, the MSP recommended the OEB consider revisiting the sharing with consumers of HIM net revenue exceeding a threshold. The Market Surveillance Panel raised multiple arguments in support of the elimination of sharing. Consistent with OPG's analysis in Section 5.5.1, the MSP stated that the sharing is a dilution of OPG's incentive to time-shift production. The MSP also noted the lack of historical sharing of revenues on account of actual HIM revenues being lower than the threshold and raised the possibility that the sharing has had a negative impact on time-shifting.

The panel stated that eliminating or revising the revenue-sharing mechanism would give OPG a stronger, undiluted incentive to time-shift hydro production, which could improve overall market efficiency and benefit consumers through lower prices during peak periods. Additionally, although the revenue-sharing threshold has not been reached recently, because future market conditions will change, the Panel believes the HIM design should be robust for all plausible scenarios, ensuring OPG always has a clear incentive to operate efficiently.

5.6 Conclusion

Based on OPG's assessment, the enhanced HIM has demonstrated overall effectiveness in the Renewed Market. The majority of HIM revenues have been earned in Day Ahead and the PGS has operated in accordance with market signals. To position the HIM as a consistent driver for OPG to realize consumer benefits by time-shifting its flexible hydroelectric generation, OPG proposes to:

1. Establish a HIM forecast for 2027 (as described in Ex. G1-1-1);
2. Share 50% of the forecast HIM revenues with customers as an offset to the revenue requirement; and
3. Retain 100% of actual HIM revenues, including amounts above the forecast.

By eliminating the sharing of HIM revenues above the Hydroelectric Incentive Mechanism Variance Account threshold, OPG's proposal better aligns incentives with efficient market outcomes, provides customers with an upfront benefit through the forecast offset, and enhances OPG's ability to pursue cost-saving opportunities for ratepayers.

6.0 REAL-TIME ENERGY MAKE WHOLE PAYMENTS

This section explains MWPs in the Renewed Market and details OPG's proposal to continue to retain Real Time MWPs as payments that ensure OPG revenue sufficiency for events outside of its control.

6.1 Impacts of MRP on Make Whole Payments

According to the IESO's SSM high-level design, relative to the previous two schedule market, the need for MWPs in the new market is expected to be infrequent and immaterial.[17] This is due to the introduction of the single schedule market and locational marginal pricing which the IESO believes have eliminated the most significant cause of divergence between dispatch and price (congestion and losses) that resulted in out-of-market payments. CMSCs, the previous form of MWPs, have also been eliminated under MRP.

Conditions where resources are needed to be scheduled or dispatched out-of-merit that result in lost cost or lost opportunity requiring MWPs continue in the Renewed Market, albeit in a more limited way. Consequently, the introduction of a DAM and RTM have resulted in both DA MWPs and RT MWPs, for both Energy and Operating Reserve.

6.1.1 MWP Observations Since MRP Implementation

Chart 7 covers total make whole payments received by OPG's regulated hydroelectric facilities since market opening:

[17] SSMHLD, p. 50.

Chart 7 – OPG Regulated Hydroelectric MWPs ($M)

	May 2025*	June 2025	July 2025	Aug 2025	Sept 2025
RT Energy MWP	0.8	2.2	2.6	0.5	0.2
RT OR MWP	1.7	3.2	2.3	0.5	0.5
DA Energy MWP	0.0	0.0	0.0	0.0	0.0
DA OR MWPs	0.1	0.0	0.0	0.0	0.0
Total MWP	**$2.5**	**$5.4**	**$4.9**	**$1.0**	**$0.7**

*Total may not add due to rounding

As seen in Chart 7, the overall trend in MWPs points to a decrease in MWP magnitude since the start of the market. OPG is generally unable to isolate specific causes of instances when hydroelectric generators receive MWPs in day-ahead, which may be due to a variety of reasons, including constraint violations, co-optimization of energy with operating reserve, or the commitment of a non-quick start resource in the reliability pass of the DAM engine.[18] OPG notes that all day-ahead MWPs received by its regulated hydroelectric facilities in the Renewed Market have been immaterial as demonstrated in Chart 7.

Real-Time Energy and Operating Reserve comprise the majority of MWP revenues received by OPG's regulated hydroelectric resources in the Renewed Market. MWPs may occur in real-time for a variety of reasons, including special instructions related to constraint violations, multi-interval optimization, co-optimization with operating reserve, or emergency control actions. These dispatch instructions may be issued automatically by the IESO's optimized dispatch tools or manually by the control room in response to real-time operating conditions. In the Real Time Market, OPG's OR MWPs have exceeded Energy MWPs in four out of the five months in the Renewed Market. While OPG attributes this trend to a number of possible market factors including joint optimization and the introduction of an Operating Reserve Demand Curve, OPG has taken a measured approach in its expectation of how MWPs may develop as the Renewed Market matures. Operating Reserve MWPs ("OR MWPs") are part of OPG's Operating Reserve revenues, as discussed in Ex G1-1-1.

[18] SSMHLD, p. 50.

Similarly, while OPG received comparatively higher Energy MWPs in two summer months, its longer-term view is informed by IESO's expectation of these payments to be infrequent and immaterial as well as the IESO's recognition that certain aspects of the market may require fine tuning before reaching a steady state. On November 21, 2025, the IESO launched a stakeholder engagement that identified targeted corrections to the Market Rules that would be made to address specific circumstances under which unwarranted MWPs are calculated. While the engagement is still in preliminary stages, OPG expects the outcome of these changes to further lower MWPs.

Overall, OPG expects that day-ahead MWPs will remain immaterial and real-time MWPs will moderate with experience in the new market to levels that meet IESO's expectations of infrequency and low materiality.

6.2 Continuation of Current Treatment of Make Whole Payments

In EB-2023-0336, OPG proposed and received approval to retain Real-Time Energy MWPs consistent with the principle that OPG is compensated with respect to output generated at its regulated facilities in accordance with Section 78.1 of the *Ontario Energy Board Act, 1998*. OPG did not seek approval with respect to the treatment of Day-Ahead Energy MWPs as they form part of the Day-Ahead Market settlement and have no impact on OPG's actual output. OPG's proposal included an underlying assumption that OPG will receive OR MWPs – both Day-Ahead and Real-Time as part of its Operating Reserve revenues. During implementation, the IESO raised certain consideration regarding the calculation and settlement of MWPs, which led to OPG receiving all MWPs, including Day-Ahead Energy MWPs as presented in Chart 6. To fulfill its obligations under the OEB-approved EB-2023-0336 Settlement Proposal, OPG has been crediting all received Day-Ahead Energy MWPs in the Ancillary Services Net Revenue Variance Account, which records OPG's OR Day-Ahead and Real-Time MWPs.

OPG proposes that the treatment of Real-Time Energy MWPs under OPG's Regulated Framework as settled in EB-2023-0336 continue throughout the upcoming rate-setting period. Such payments are not reflected in the setting of payment amounts and would serve to

compensate OPG for IESO dispatch related losses from inefficient operation or possible loss of production in the form of hydroelectric spill. OPG also expects to continue to receive Real-Time OR MWPs as part of its OR revenues. Given the insignificant Day-Ahead Energy and OR MWPs received in the first five months of the Renewed Market – $0.1M and $0.2M total, respectively – for administrative efficiency, OPG proposes to forgo receiving all Day-Ahead Energy and OR MWPs during the IR term.

LIST OF ATTACHMENTS

Attachment 1: Surplus Baseload Generation Variance Account Study

Surplus Baseload Generation Variance Account Study

Response to EB-2023-0336 Settlement Agreement

ONTARIO POWER GENERATION

1.0 Introduction and Purpose of Study 2
2.0 Stakeholder & Rightsholder Engagement 3
3.0 Methodology & Study Options 5
3.1 Guiding Principles 5
3.2 Surplus Baseload Generation in the Renewed Market 6
3.3 Study Options 7
3.3.1 Option #1: Potential benefit of removing variable load charges applicable to PGS cycling 8
3.3.1.1 Methodology 9
3.3.1.2 Results 10
3.3.1.3 Implementation 12
3.3.2 Option #2: Potential benefit of removing GRC applicable to PGS cycling 12
3.3.2.1 Methodology 13
3.3.2.2 Results 13
3.3.2.3 Potential Benefit of Removing Variable Load Charges and GRC Applicable to PGS Cycling 15
3.3.2.4 Implementation 16
3.3.3 The Hydroelectric Incentive Mechanism 16
3.3.3.1 HIM Background 16
3.3.3.2 HIM Calculation 18
3.3.3.3 LMP Spread Required to Economically Cycle the PGS 19
3.3.3.4 Market Surveillance Panel Monitoring Report 32 Summary 21
3.3.3.5 Changes to the HIM 22
4.0 Conclusions 23

1.0 Introduction and Purpose of Study

In EB-2023-0336, OPG applied to the Ontario Energy Board ("OEB") for approval to dispose of balances in several deferral and variance accounts, including the Surplus Baseload Generation Variance Account ("SBGVA"). In that application OPG also sought approvals to address impacts of the Independent Electricity System Operator's ("IESO") Market Renewal Program ("MRP") on its regulated framework, including revisions to calculation of amounts booked to the SBGVA. Specifically, OPG sought approval to record the financial impact of foregone production due to global and local surplus baseload generation conditions using locational marginal prices ("LMP").

Following a settlement conference, the parties reached an agreement on all issues in the proceeding, including the disposal of the SBGVA balances as of December 31, 2022. This agreement was documented in a Settlement Proposal filed with the OEB and was adopted through a Decision and Order.[1]

As part of the Settlement Proposal, OPG committed to conduct and file, as part of its next rebasing application, a study assessing options to reduce SBGVA amounts on a forward-looking basis:

> *OPG shall study options to reduce SBGVA amounts on a going forward basis and in light of the MRP with the aim of minimizing total electricity system costs to ratepayers including market payments and regulated payments, with assistance from the IESO as available and necessary. The study shall consider reasonable options to better incentivize OPG to minimize total system costs, utilizing the Sir Adam Beck Pump Generating Station ("PGS") to reduce spillage at OPG's hydroelectric facilities, and other structural changes, including changes that may require OEB approval. OPG shall fund a stakeholder process to obtain input on options to be considered in the study. OPG shall file its report as part of its next rebasing application for the prescribed facilities.*[2]

This study is in response to the OEB-approved Settlement Proposal. The study primarily considers options to reduce SBGVA amounts on a going forward basis by adjusting economic

[1] EB-2023-0336, Decision and Order, June 13, 2024.
[2] Ibid., page 5

factors to increase output at the existing PGS facility in its existing configuration. Results of the study should be viewed in the context of PGS's primary function within the Sir Adam Beck Complex, where it supports safety, operational efficiency and provides capacity by time-shifting water to the benefit of the ratepayer.[3]

2.0 Stakeholder & Rightsholder Engagement

On March 21, 2025, OPG hosted a Stakeholder and Rightsholder Engagement Process to inform the scope of this study. OPG circulated the meeting notes and materials for this session to participants on April 24 and May 27, respectively (see also Appendix A). Chart 1.0 below summarizes the action items assigned to OPG at that session (#1-4), as well as an action received from Environmental Defence via email following the stakeholder session (#5). The chart further describes how OPG has responded to each of those actions and provides a cross reference to where further details are provided within this study.

In September 2025, OPG met with the IESO to provide an overview of the study's findings and share a draft of the SBGVA study for feedback. The IESO has reviewed this report and provided their comments in Appendix B.

Chart 1.0: Action Items from Stakeholder and Rightsholder Engagement

#	Action Item	OPG's Response	Reference
1	Consider whether changes to the HIM would meet the study's objectives.	*Eliminating the requirement to share HIM net revenues[4] beyond a threshold would better incentivize OPG to time-shift water to the benefit of the ratepayer in all market conditions.*	See **Section 3.3.3** *The Hydroelectric Incentive Mechanism*
2	Consider the best available information available at the time of conducting the study, including the	*This study uses the most up-to-date market inputs available & assumptions are aligned with the*	See **Section 3.0**

[3] EB-2023-0336, M1-1-1, section 3.5 Customer Benefit
[4] Net of unintended benefit adjustment

	potential impact of tariffs on the system, if applicable.	*business plan that underpins OPGs EB-2025 application to the OEB.*	*Methodology & Study Options*
3	Consider whether and how Global Adjustment could be included as a factor in the evaluation of the study options.	*Impacts to Global Adjustment are calculated as part of OPG's analysis and incorporated into the results in this report.*	See **Section 3.0** *Methodology & Study Options*
4	Clearly link how each study option meets the study objective(s) outlined in the settlement agreement, including whether and how it reduces spillage, and what structural changes would or would not be required.	*Options 1 & 2 include sections to discuss the impacts on PGS utilization, SBG spill, Total Customer Cost (TCC), and implementation considerations. Option 3 analyzes the price spread required to economically time-shift water using the PGS under different HIM net revenue sharing scenarios. More frequent time-shifting of water has been demonstrated by OPG to be beneficial to the ratepayer.*	See **Section 3.3** *Study Options*
5	With respect to the GRC, Environmental Defence asks that OPG's analysis account for the fact that the GRC is returned to ratepayer pockets via the provincial government as it displaces other tax revenue.	*OPG's analysis shows reducing GRC payable by PGS yields incremental reduced total customer cost when combined with the removal of load charges. OPG has accounted for displaced GRC payments as a reduction in TCC benefit for the ratepayer.*	See **Sections 3.3.2.2** *Results and* **3.3.2.3** *Implementation*

3.0 Methodology & Study Options

OPG conducted this study in accordance with guiding principles ensuring that outcomes are consistent with the EB-2023-0336 Settlement Agreement and considering the authority and mandate of each of the OEB and the IESO. OPG first developed the necessary guiding principles of the study and then identified study options that adhered to these principles and presented both as part of the Stakeholder and Rightsholder Engagement Process.

3.1 Guiding Principles

The IESO is responsible for the reliability of Ontario's power system and the efficiency of the electricity market. In the early 2010s, the IESO established a "dispatch order for generation"[5] to optimize generation dispatch during SBG conditions by introducing floor prices for variable generation. As noted in the IESO stakeholder engagement that set these floor prices, OPG's hydroelectric offer strategy uses Gross Revenue Charge ("GRC")-based offers to reflect storage unavailability. OPG follows the IESO's dispatch in accordance with the IESO Market Rules.

Additionally, based on fundamental principles of rate regulation, OPG must be provided with a reasonable opportunity to recover its approved revenue requirement and should not be required to operate at an economic loss, due to system-level operating decisions or market outcomes that are beyond its control.

With consideration to the above, OPG created the following four guiding principles to help identify viable study options:

1. Recognize the IESO's fundamental role in managing SBG.
2. Recognize that the objective of IESO's dispatch scheduling and optimization algorithm is to "maximize the gains from trade to ensure consumers of electricity receive the highest value based on electricity supply offers.[6] OPG supports this objective by offering its resources economically into the IESO's market.

[5] IESO, Dispatch Order for Baseload Generation, A Discussion Paper for Stakeholder Engagement 91 (Renewable Integration), dated November 2, 2011
[6] 1. IESO Market Rules Chapter 7, ss 4.3.2

3. Ensure OPG is following IESO market signals and dispatches.
4. Maintain OPG's ability to recover its approved revenue requirement and not operate at an economic loss.

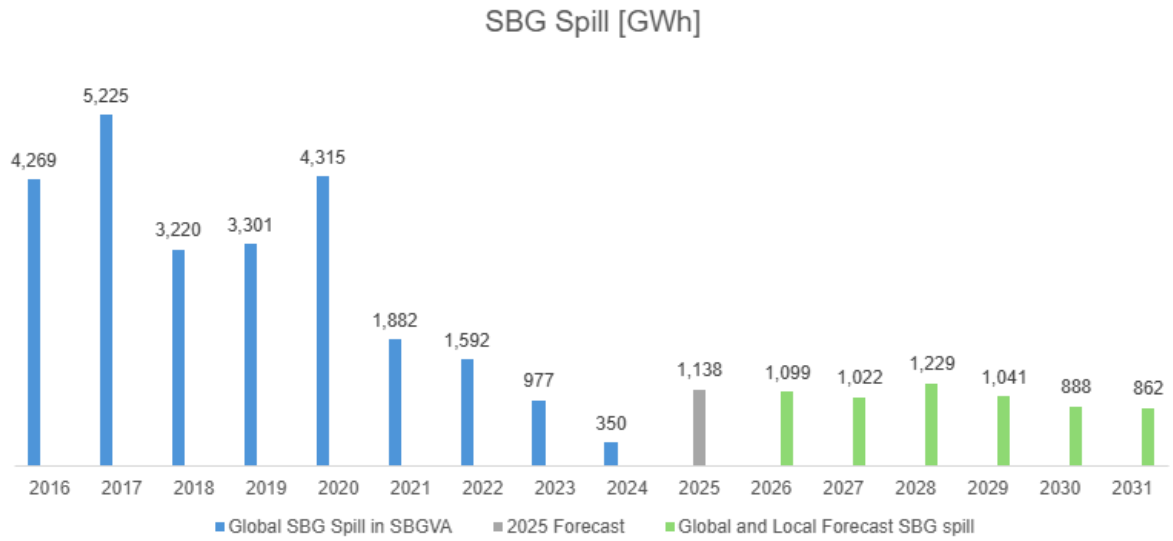
3.2 Surplus Baseload Generation in the Renewed Market

The IESO's Market Renewal Program ("MRP") replaced the previous two-schedule market with a single schedule market ("SSM") and introduced Locational Marginal Prices ("LMP"). Where SBG conditions were previously a global condition indicated by the Hourly Ontario Energy Price ("HOEP"), the replacement of HOEP with LMP under the Market Renewal Program eliminated OPG's ability to differentiate between global and local SBG conditions. As a result, OPG updated its methodology for making entries to the SBGVA, basing it on instances where a resource's LMP falls below the level of its GRC. This approach was approved by the OEB in EB-2023-0336[7] and forms the basis for OPG's forecast of SBG Spill (see Figure 1.0).

Using the EB-2023-0336 approved methodology, OPG projects total SBG spill to remain significantly below historical levels for the remainder of the study period. The reduction in forecast SBG spill is primarily due to changes in the supply and demand outlook in the province combined with expected efficiencies in the renewed market.

[7] EB-2023-0336 Decision and Order, issued June 13, 2024

Figure 1.0 - OPG Surplus Baseload Generation Spill: Historical Actuals and Forecast[8]



3.3 Study Options

This study examined the following three options based on the guiding principles outlined in Section 3.1:

1. Potential benefit of removing variable load charges applicable to PGS cycling;
2. Potential benefit of removing GRC applicable to PGS generation; and
3. Potential modifications to the HIM.

Options 1 and 2 focus specifically on the PGS and the economic considerations that could impact its utilization. These options assess economic reasons PGS does not cycle, which have been discussed in prior applications and are presented in OPG's PGS Reporting and Record-keeping Requirements. Other factors that limit PGS utilization (e.g., physical limitations, safety, equipment, or applicable law) were not considered in scope for this study.

Options 1 and 2 use an analytical framework designed to measure the impact of changes to PGS load charges and PGS GRC on PGS utilization, SBGVA additions, and TCC, when

[8] 2016-2024 shows actual SBG spill amounts included in SBGVA on a global basis. 2025 is an OPG forecast value based on global SBG conditions pre-MRP, and both global and local SBG conditions post-MRP. 2026-2031 OPG forecasts are based on both global and local SBG conditions.

compared to a base case.[9] The base case is a calculation of PGS utilization, SBGVA additions and TCC based on OPG's business plan. TCC is a calculation of all payments made by the IESO to generators including the impact of imports and exports, equal to market payments plus Global Adjustment costs. The negative TCC values in this report represent a reduction in customer cost while positive values represent an increase in customer cost.

Options 1 and 2 are calculated using the same assumptions as the base case, with only one independent variable changed: the load charge factor in PGS economics for option 1 ("The Load Charge Case"), and the GRC factor in PGS economics in option 2 ("The GRC Case").

Option 3 was identified as part of the Stakeholder and Rightsholder Engagement Process and considers whether changes to the HIM would meet the study's objectives. As described in section 3.3.3.4, the analytical framework to assess option 3 differs from the TCC based approach used for Options 1 and 2. For Option 3, the price spread required to economically cycle the PGS was calculated and compared under two HIM net revenue sharing scenarios.

3.3.1 Option #1: Potential benefit of removing variable load charges applicable to PGS cycling

The PGS is subject to variable load charges when operating in pump mode. Network Service Rate charge ("NSC") applies when the PGS operates in pump mode on weekdays between 7am and 7pm. If operated in pump mode during a NSC applicable hour, the PGS can incur significant NSC based on the NSC rate, the efficient operating point of a PGS pump, and the number of PGS pump units. As such, OPG does not operate the PGS in pump mode during NSC hours, unless it must do so for safety or operational reasons such as crossover control during periods of low diversion, equipment testing or rescue procedures.

The PGS operating in pump mode is also subject to the IESO Administration Charge in the form of a rate applied to the total PGS load in each month. Other market uplifts applicable to PGS load are subject to offsetting settlement reimbursements and are therefore excluded from

[9] The framework assumes the normally expected weather variations and unit commitments with no real-time price volatility owing to discrete events.

PGS economics. The NSC and IESO Administration Charges incurred by OPG are collectively referred to as the "PGS load charges" and are included as a single variable in the PGS economic formulas.

To determine the economics of generating with the PGS, OPG compares the breakeven generation price to the latest LMP. If that LMP is greater than the breakeven generation price, OPG concludes it is economic to generate. The formula for the breakeven PGS generation price is provided below, with the PGS load charges highlighted:

$$\frac{\begin{array}{c}\textit{PGS Pump Efficiency} \times (\textit{Forecast Pump Price} + \textbf{\textit{PGS Load Charges}}) + \\ \textit{Beck Gen Efficiency} \times (\textit{Forecast Pump Price} - \textit{Beck GRC}) + \\ (\textit{PGS Gen Efficiency} \times \textit{PGS GRC}) + (\textit{Beck Gen Efficiency} \times \textit{Beck GRC})\end{array}}{\textit{PGS Gen Efficiency} + \textit{Beck Gen Efficiency}}$$

To determine the economics of pumping with the PGS, OPG compares the breakeven pump price to the latest LMP. If that LMP is less than the breakeven pump price, OPG concludes it is economic to pump. The formula for the breakeven PGS pump price is provided below, with the PGS load charges highlighted:

$$\frac{\begin{array}{c}\textit{PGS Gen Efficiency} \times (\textit{Forecast Gen Price} - \textit{PGS GRC}) + \\ \textit{Beck Gen Efficiency} \times (\textit{Forecast Gen Price} - \textit{Beck GRC}) + \\ (\textit{Beck Gen Efficiency} \times \textit{Beck GRC}) - (\textit{PGS Pump Efficiency} \times \textbf{\textit{PGS Load Charges}})\end{array}}{\textit{PGS Pump Efficiency} + \textit{Beck Gen Efficiency}}$$

For the purpose of this study, OPG has examined the impact of PGS load charges on pumping and generating at the PGS.

3.3.1.1 Methodology

The results in Section 3.2.1.2 were derived by comparing the forecast values for PGS utilization, SBGVA additions, and TCC for the base case and Load Charge Case.[10]

[10] The analysis includes impact of battery energy storage systems expected to come online between 2025-2028.

3.3.1.2 Results

The results of the Load Charge Case compared to the base case are presented in Chart 2.0 and Chart 3.0 and discussed below.

Chart 2.0: Results of Option #1: Load Charge Case

	Incremental PGS Generation		Impact on SBG Spill	
	GWh	**%**	**GWh**	**%**
2026	4.1	11.4%	(5.3)	(1.7%)
2027	0.7	2.1%	(9.2)	(4.1%)
2028	0.6	3.6%	2.9	0.7%
2029	5.7	27.0%	(6.9)	(2.9%)
2030	3.6	16.7%	(2.1)	(2.7%)
2031	5.6	24.8%	(4.6)	(5.5%)
Total	**20.3**		**(25.2)**	
Average Annual	**3.4**		**(4.2)**	

Impact on PGS Generation

OPG's analysis indicates that removing variable load charges from PGS cycling economics would increase PGS generation by an average of 3.4 GWh annually, primarily due to the following two factors:

1. The PGS would be free to operate in pump mode at all hours of the day; and
2. The price spread required to economically cycle the PGS is reduced.

The inability to economically pump during NSC hours is the most significant impediment to incremental PGS cycling. As OPG does not operate the PGS in pump mode during NSC hours, the PGS is unable to pump during midday price dropouts which may allow the reservoir to be refilled before the evening peak.

Impact on SBGVA additions

The Load Charge Case results in 4.2 GWh average annual decrease of SBG spill when compared to the base case. This is primarily related to the incremental PGS pump mode

operations during NSC hours, which reduced instances of on-peak SBG spill during those applicable hours.

Impact on Total Customer Cost

OPG's analysis also measures the impact on the TCC. The impact on TCC in the Load Charge Case compared to the base case is shown in Chart 3.0 and discussed below:

Chart 3.0: Option # 1 Impact to TCC: Load Charge Case

	2026	2027	2028	2029	2030	2031	Total	Annual Avg
Incremental Values:	$M	$M	$M	$M	$M	$M	$M	$M
(a) HIM payments to OPG	0.4	0.8	0.3	0.5	0.3	0.5	2.7	0.5
(b) SBGVA entries	0.1	(0.3)	0.3	(0.6)	(0.1)	(0.2)	(0.7)	(0.1)
(c) Imports and gas cost	(0.5)	4.1	0.7	(14.0)	(0.4)	0.3	(9.9)	(1.6)
(d) Incremental other costs	(0.2)	(0.5)	(0.2)	0.4	0.0	0.0	(0.6)	(0.1)
(e) Incremental export revenue	0.0	0.2	0.2	0.0	(0.1)	(0.0)	0.4	0.1
(f) Impact on TCC [a + b + c + d - e]	**(0.3)**	**3.8**	**0.8**	**(13.7)**	**(0.0)**	**0.6**	**(8.8)**	**(1.5)**

OPG's analysis of the Load Charge Case shows a cumulative $8.8M reduction in TCC over the study period when compared to the base case.

The largest contributor to the reduction in TCC in the Load Charge Case is the reduction in imports and gas generation. OPG's analysis demonstrates that incremental PGS utilization means a greater quantity of less expensive water is available to offset more expensive gas for more hours of the day when compared to the base case. This effect is especially prevalent in years where there are greater price spreads and more gas generation in the base case, as seen in 2029.

The other contributor to the reduction in TCC in the Load Charge Case is the reduction in SBG spill, as explained in the "Impact on SBGVA additions" section above.

The decrease in TCC related to reductions in imports, gas generation and SBG spill is partially offset by higher OPG HIM revenues associated with incremental on-peak generation at Sir Adam Beck 1 and 2 GS and the PGS.

3.3.1.3 Implementation

On March 27, 2025, the OEB issued a Decision and Order in EB-2022-0325 which ordered "transmission-connected energy storage facilities shall be exempt from transmission charges under any of the following circumstances: when scheduled to provide operating reserve, when providing reactive support, when providing regulation service, when responding to an IESO energy dispatch in the real-time electricity market, or when responding to an IESO directive in support of transmission system reliability."[11]

OPG is in the process of determining the feasibility of implementing an NSC exemption for PGS by designating it as an energy storage facility. If the PGS receives the transmission charge exemption, the PGS would be available to pump in all hours of the day without incurring the NSC, and the load charge factor in the PGS economic formulas would be reduced. OPG expects a decision to be reached in 2026. OPG is also in the process of evaluating the feasibility of an IESO Administration Charge exemption for the PGS.

3.3.2 Option #2: Potential benefit of removing GRC applicable to PGS cycling

Gross Revenue Charge is calculated on an annual basis based on the actual production of any hydroelectric generating station in Ontario, including the PGS and the Sir Adam Beck complex. The GRC is a variable cost of generation and is expressed in the PGS economic decision making as a single value.

To determine the economics of generating with the PGS, OPG compares the breakeven generation price to the latest LMP. If that LMP is greater than the breakeven generation price, OPG concludes it is economic to generate.

The formula for the breakeven PGS generation price is provided below, with the GRC impacts highlighted:

[11] EB-2022-0325 Decision and Order, issued March 27, 2025, section 4.2 Implementation of Decision on Issue 5

$$\frac{\begin{array}{c}\textit{PGS Pump Efficiency} \times (\textit{Forecast Pump Price} + \textit{PGS Load Charges}) + \\ \textit{Beck Gen Efficiency} \times (\textit{Forecast Pump Price} - \textit{Beck GRC}) + \\ (\textit{PGS Gen Efficiency} \times \textbf{\textit{PGS GRC}}) + (\textit{Beck Gen Efficiency} \times \textit{Beck GRC})\end{array}}{\textit{PGS Gen Efficiency} + \textit{Beck Gen Efficiency}}$$

To determine the economics of pumping with the PGS, OPG compares the breakeven pump price to the latest LMP. If that LMP is less than the breakeven pump price, OPG considers it economic to operate in pump mode.

The formula for the breakeven PGS pump price is provided below, with the PGS GRC impacts highlighted:

$$\frac{\begin{array}{c}\textit{PGS Gen Efficiency} \times (\textit{Forecast Gen Price} - \textbf{\textit{PGS GRC}}) + \\ \textit{Beck Gen Efficiency} \times (\textit{Forecast Gen Price} - \textit{Beck GRC}) + \\ (\textit{Beck Gen Efficiency} \times \textit{Beck GRC}) - (\textit{PGS Pump Efficiency} \times \textit{PGS Load Charges})\end{array}}{\textit{PGS Pump Efficiency} + \textit{Beck Gen Efficiency}}$$

For the purpose of this study, OPG has examined what the impact GRC has on pumping and generating at the PGS.

3.3.2.1 Methodology

Option #2 was studied using the same methods, inputs, and assumptions as described in Section 3.2.

The GRC Case results in Section 3.2.2.2 below were derived through a separate analysis by setting the “PGS GRC” factor, as shown in the equations in Section 3.2.2, to zero. The forecast values for PGS utilization and SBGVA additions for the GRC Case were then compared to the base case and included in the charts in Section 3.2.2.2.

3.3.2.2 Results

The results of the GRC study case compared to the base case are presented in Chart 4.0 and discussed below.

Chart 4.0: Results of Option #2: GRC Case

	Incremental PGS Generation		Impact on SBG Spill	
	GWh	**%**	**GWh**	**%**
2026	2.6	7.2%	(0.5)	(0.2%)
2027	2.6	8.6%	0.1	0.1%
2028	1.2	6.8%	1.8	0.4%
2029	2.5	11.7%	(0.7)	(0.3%)
2030	0.9	4.3%	0.2	0.2%
2031	2.7	11.6%	0.2	1.1%
Total	**12.5**		**1.1**	
Average Annual	**2.1**		**0.2**	

While the GRC Case results in 2.1 GWh average annual increases in PGS generation compared to the base case, it does not result in SBG spill reduction. OPG notes that the analysis has accounted for decreased GRC payments to the provincial government as a reduction of TCC benefit. This additional TCC adjustment accounts for Environmental Defense's argument that higher GRC revenues for the provincial government offset other tax revenue and as such are not ultimately realized as final ratepayer savings.

In this GRC Case, the PGS was only able to operate in pump mode during non-NSC hours to avoid prohibitively high NSC. As such, the GRC Case resulted in a reduction in the price spread required to economically cycle the PGS, deriving only a marginal increase in PGS generation, with no significant TCC benefit when evaluated on its own (see Chart 5.0 below).

Chart 5.0: Option # 2 Impact to TCC: GRC Case

	2026	2027	2028	2029	2030	2031	Total	Annual Avg
Incremental Values:	$M	$M	$M	$M	$M	$M	$M	$M
(a) HIM payments to OPG	(0.0)	(0.1)	(0.2)	(0.1)	(0.1)	(0.2)	**(0.7)**	**(0.1)**
(b) SBGVA entries	0.0	0.1	0.2	(0.2)	0.0	0.0	**0.1**	**0.0**
(c) Imports and gas cost	(0.1)	0.1	0.0	0.8	0.1	(0.0)	**1.0**	**0.2**
(d) Other costs	(0.1)	(0.1)	(0.1)	0.2	0.0	(0.0)	**(0.1)**	**(0.0)**
(e) Export revenue	0.1	0.0	0.0	0.0	0.0	0.0	**0.2**	**0.0**
(f) Impact on TCC [a + b + c + d - e]	(0.2)	0.0	(0.2)	0.7	(0.0)	(0.2)	**0.1**	**0.0**
(g) Displaced GRC revenue	(0.2)	(0.2)	(0.1)	(0.1)	(0.1)	(0.1)	**(0.9)**	**(0.2)**
(h) Impact on TCC net of displaced GRC revenue [f - g]	**(0.0)**	**0.2**	**(0.1)**	**0.8**	**0.1**	**(0.0)**	**1.0**	**0.2**

3.3.2.3 Potential Benefit of Removing Variable Load Charges and GRC Applicable to PGS Cycling

OPG evaluated a scenario where both variable load charges and GRC applicable to PGS cycling were removed from the PGS formulas and observed the following results:

Chart 6.0: Combined Impacts of Option #1 and Option # 2

	Incremental PGS Generation		Impact on SBG Spill	
	GWh	%	GWh	%
2026	9.0	24.7%	(8.5)	(2.8%)
2027	3.4	11.2%	(9.4)	(4.2%)
2028	3.8	22.1%	(0.5)	(0.0%)
2029	7.3	34.6%	(6.0)	(2.5%)
2030	5.6	26.2%	(1.9)	(2.4%)
2031	8.6	37.6%	(9.0)	(10.7%)
Total	**37.7**		**(35.3)**	
Average Annual	**6.3**		**(5.9)**	

In this combined scenario, OPG calculated an incremental TCC savings net of GRC of $6.0M (see Chart 7) over the study period when compared to Load Charge Case alone. This more favourable result is driven by the reduced spread (from removing GRC) applied to PGS in all hours of every day and removal of pumping restrictions during NSC hours (from removing load charges).

Chart 7.0: Combined Impact of Option #1 and Option #2 to TCC

	2026	2027	2028	2029	2030	2031	Total	Annual Avg
Incremental Values:	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
(a) HIM payments to OPG	0.6	1.6	0.4	0.2	0.2	0.6	**3.6**	**0.6**
(b) SBGVA cost	(0.2)	(0.2)	0.1	(0.5)	(0.0)	(0.2)	**(1.1)**	**(0.2)**
(c) Imports and gas cost	(0.7)	3.6	0.1	(20.1)	(0.4)	0.3	**(17.2)**	**(2.9)**
(d) Other costs	(0.0)	(0.6)	(0.1)	0.3	(0.0)	(0.1)	**(0.5)**	**(0.1)**
(e) Export revenue	0.1	0.3	0.4	(0.1)	(0.1)	0.0	**0.7**	**0.1**
(f) Impact on TCC [a + b + c + d - e]	(0.4)	4.1	0.1	(19.9)	(0.2)	0.5	**(15.9)**	**(2.6)**
(g) Displaced GRC revenue	(0.3)	(0.2)	(0.1)	(0.2)	(0.2)	(0.2)	**(1.0)**	**(0.2)**
(h) Impact on TCC net of displaced GRC revenue [f - g]	**(0.2)**	**4.2**	**0.2**	**(19.8)**	**0.0**	**0.7**	**(14.8)**	**(2.5)**
(i) Impact to TCC of option 1 [Chart 3.0, line (f)]	(0.3)	3.8	0.8	(13.7)	(0.0)	0.6	**(8.8)**	**(1.5)**
(j) Incremental TCC reduction from GRC removal when combined with load charge removal [h - i]	**0.1**	**0.4**	**(0.6)**	**(6.1)**	**0.0**	**0.1**	**(6.0)**	**(1.0)**

OPG has accounted for the impact of removing GRC in the same manner as in section 3.3.2.2.

3.3.2.4 Implementation

OPG would require a GRC exemption for the PGS in order to exclude GRC from the economic decision making for PGS cycling. OPG will explore the feasibility of this option.

3.3.3 The Hydroelectric Incentive Mechanism

This section explores potential changes to the HIM that may satisfy the objective of reducing SBGVA amounts.

3.3.3.1 HIM Background

The HIM supports the efficiency of the wholesale electricity market by providing OPG's regulated hydroelectric generators with the appropriate driver to follow market signals while receiving a regulated payment for their output. While the HIM formula has necessarily evolved

with the changing design of the Ontario electricity market since its initial approval in EB-2007-0905, this fundamental objective has not changed. This mechanism ultimately benefits customers by creating an economic driver for OPG to shift hydroelectric generation from low-price hours to high-price hours.[12]

Since the HIM was first approved in EB-2007-0905, OPG receives the applicable OEB-approved payment amount for the average hourly net energy produced ("hourly volume") from its regulated hydroelectric facilities. If OPG produces more energy than the hourly volume in a given hour, it is compensated at market prices for the incremental amounts of energy above this hourly volume. If OPG's actual energy production from its regulated hydroelectric facilities is less than the hourly volume in a given hour, the amount payable to OPG at the regulated hydroelectric payment amount is reduced by the production shortfall multiplied by the market price.

In EB-2010-0008, the OEB required that 50% of the forecast amount of HIM proceeds be returned to customers and incorporated this as a reduction to the revenue requirement. OPG was allowed to retain 50% of the HIM net revenue with any excess above the retained amount tracked in the Hydroelectric Incentive Mechanism Variance Account ("HIMVA") and shared equally between OPG and ratepayers. The OEB also required OPG to address the interaction between HIM revenues and SBGVA in its next application. In EB-2013-0321, the HIM was expanded to include the newly prescribed facilities, using the same formula. The OEB also increased the variance account threshold to reflect the inclusion of the newly regulated facilities,[13] a 50% revenue requirement offset and a 50% sharing of additional net revenues above the threshold. In the same decision, the OEB directed OPG to include an adjustment to the HIM to reflect the interaction between the HIM and the SBGVA (the unintended benefit).

In EB-2023-0336, OPG proposed an updated HIM formula to reflect the impact of MRP. OPG's HIM formula was adopted as part of a settlement agreement in this case and was implemented with the launch of the Renewed Market on May 1, 2025. OPG's HIM calculation is discussed further in Section 3.3.3.2.

[12] EB-2023-0336, M1-1-1, section 3.5 Customer Benefit
[13] EB-2013-0321 Decision with Reasons, November 20, 2014, p. 13.

Under the current framework, OPG shares 50% of HIM net revenues with customers as established in EB-2010-0008 and EB-2013-0321. Under the HIM sharing approach, if the annual HIM net revenues exceed the pre-determined threshold, OPG records 50% of the HIM net revenues in the HIMVA as a credit to ratepayers. OPG's HIM net revenues have never exceeded the current applicable threshold that was established in EB-2013-0321.

3.3.3.2 HIM Calculation

The HIM is calculated using the following formula, established in EB-2023-0336:

$$Incentive\ Payment = DA\ Incentive + RT\ Incentive$$
$$= \sum_{t} \left(MW_{DA}(t) - MW_{DAavg}\right) \times LMP_{DA}(t)$$
$$+ \sum_{t} \left(MW_{diff}(t) - MW_{diff,avg}\right) \times LMP_{RT}(t)$$

Where:

$$MW_{diff}(t) = MW_{RT}(t) - MW_{DA}(t)$$
$$MW_{diff,avg} = MW_{RTavg} - MW_{DAavg}$$

Where:

$MW_{DA}(t)$: hourly production schedule from the IESO day-ahead market for each hour, t, of the day

MW_{DAavg}: average of hourly energy schedule from the IESO day-ahead market over the day

$LMP_{DA}(t)$: the day-ahead LMP for the resource for each hour, t, of the day

$MW_{RT}(t)$: net energy production supplied to the IESO real-time market for each hour, t, of the day

MW_{RTavg}: average of hourly net energy production over the day

$LMP_{RT}(t)$: the real-time LMP for the resource for each hour, t, of the day

An illustrative example of the HIM calculation for two hours is provided in Chart 8.0 below.

Chart 8.0: Illustrative Example for 2 hours of HIM Calculation including Adjustment for Unintended Benefit

Hour	Day-ahead Price	Day-ahead Schedule	Real-time Price	Real-time Output	SBG Spill	Daily Avg. Day-ahead Dispatch	Daily Avg. Real-time Output	Daily Avg. SBG Spill	Day-ahead HIM Payment	Real-time HIM Payment	Adjustment for Unintended Benefit
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
A	$5/MWh	0MW	$5/MWh	0MW	60	80MW	85MW	10MW	$(400)	$(25)	$250
B	$30/MWh	300MW	$40/MWh	300MW	0	80MW	85MW	10MW	$6,600	$(200)	$400

Sources for actual monthly calculation:

- **(a)** Published in IESO reports
- **(b)** Published in IESO reports
- **(c)** Published in IESO reports
- **(d)** OPG revenue meter data (utilized in settlement statements)
- **(e)** Per OEB approved SBG methodology
- **(f)** Daily simple average of (b) for all hours of the day
- **(g)** Daily simple average of (d) for all hours of the day
- **(h)** Daily simple average of (e) for all hours of the day
- **(i)** Calculated as: (b-f)*a
- **(j)** Calculated as: [(d-b)-(g-f)]*c
- **(k)** Calculated as: (e-h)*c

3.3.3.3 LMP Spread Required to Economically Cycle the PGS

Under the current HIM net revenue sharing arrangement, the price spread required to economically cycle the PGS will notably increase if actual HIM net revenues exceed the HIM threshold. To illustrate this, OPG calculated the spread required to economically cycle the PGS under two scenarios, summarized in Chart 9 below. Both scenarios assume that 50% of the forecast amount of HIM proceeds have already been returned to customers as a reduction to the revenue requirement, and that actual HIM net revenues have exceeded the threshold.

Scenario 1: HIM net revenue sharing arrangement with 50% sharing of HIM net revenues above threshold; and

Scenario 2: Alternative HIM net revenue sharing arrangement where 50% sharing above threshold is eliminated. This scenario is also reflective of PGS spread when the threshold has not been reached.

Section 3.3.1 provides the formulas governing PGS economics. The components of this formula were categorized as costs or revenues, as seen below.

Cost Components:

- Pump energy costs[14]
- Load charges
- GRC
- Adjustment for Incremental HIM Net Revenue Sharing*

Revenue Components:

- PGS revenue
- SAB revenue

*included once HIM net revenues exceed HIM threshold

Chart 9.0: Illustrative Calculations of Economic Price Spreads when HIM Net Revenues Exceed HIM Threshold

	Scenario 1 (50% HIM Sharing above threshold)	**Scenario 2 (No HIM Sharing)**
Energy Cost to SAB GRC	$14.40	$14.40
Revenue	Regulated Rate X Generation + (HIM Net Revenue X 50%)	Regulated Rate X Generation + HIM Net Revenue
Resulting Economic Offer Price	$29.30	$22.60
Economic Price Spread	$29.30-$14.40 = $14.90	$22.60-$14.40 = $8.20

In Scenario 1, OPG is required to share 50% of HIM net revenues on a variable basis with the ratepayer, while incurring the same amount of load charges, GRC, energy charges and efficiency losses. With OPG retaining only half of the incremental HIM net revenue, these costs must be recovered in the market to ensure OPG does not incur an economic loss when cycling the PGS. As such, a higher spread is required to economically cycle the PGS when the threshold is exceeded.

In Scenario 2, OPG continues to retain all HIM net revenues and does not need to adjust the economic spread for the PGS if HIM net revenues exceed the threshold. This scenario reflects the historical operation of the PGS as HIM net revenues have never exceeded the current

[14] Efficiency losses are inherently reflected in pump energy costs

applicable threshold that was established in EB-2013-0321. Compared to this Scenario 2, OPG estimates it would need to increase the spread by approximately 80%[15] when HIM net revenues exceed the threshold. Such an increase may impede the ability for PGS to time-shift under certain market conditions and will directionally lead to a higher SBG spill and reduced customer benefit.[16] OPG expects to reset its HIM forecast and associated threshold as part of its current application.

3.3.3.4 Market Surveillance Panel Monitoring Report 32 Summary

In its Monitoring Report 32[17] published on July 16, 2020 and a subsequent State of the Market Report 2022, the Market Surveillance Panel (MSP) expressed concern that the current revenue-sharing structure may be suppressing the efficiency benefits of the HIM. The MSP recommended "the OEB consider revisiting the sharing with consumers of net HIM net revenue exceeding a threshold" citing the following reasons:

- **Dilution of Incentive**: The Panel finds that sharing HIM net revenues above the threshold (i.e., the 50/50 split) reduces OPG's incentive to time-shift production because OPG bears all the costs and risks but only receives half the benefit above the threshold. This could lead OPG to pass up profitable and efficient time-shifting opportunities, diminishing the intended efficiency gains of the HIM.
- **Recent Revenue Trends**: Actual HIM net revenues have consistently fallen short of the 2013 forecast used to set the sharing threshold. Since at least 2016, OPG has not generated enough incentive payments to cover the first 50% of the forecast, meaning the revenue-sharing provision has not been triggered in recent years.
- **Market Changes**: Factors such as flatter price curves, increased environmental regulations, and higher water levels have contributed to the decline in time-shifting, but the Panel cannot rule out that the revenue-sharing mechanism itself is a significant factor.

[15] Based on a pump energy cost of $14.40
[16] EB-2023-0336, M-1-1-1, section 3.5, Customer Benefit
[17] Market Surveillance Panel Report 32 - July 16, 2020

The panel stated that eliminating or revising the revenue-sharing mechanism would give OPG a stronger, undiluted incentive to time-shift hydro production, which could improve overall market efficiency and benefit consumers through lower prices during peak periods. Additionally, although the revenue-sharing threshold has not been reached recently, because future market conditions will change, the Panel believes the HIM design should be robust for all plausible scenarios, ensuring OPG always has a clear incentive to operate efficiently.

3.3.3.5 Changes to the HIM

OPG treats the sharing of the HIM net revenue forecast with the ratepayer as a fixed cost and as such, has not built it into the variable costs included in the economic formulas that govern how PGS is offered in the market. However, if HIM net revenues were to exceed the HIMVA threshold, the requirement to share 50% of HIM net revenues with the ratepayer represents an incremental variable cost that would have to be considered when offering the PGS to the market.

While the benefits of options 1 and 2 were analyzed by changing specific input variables and assessing changes in TCC, OPG cannot assess the benefits of removing the requirement to share HIM net revenues beyond the HIM threshold using the same method. As the probability of OPG's HIM net revenues exceeding the threshold differs over a large range of possible outcomes, OPG's model cannot deterministically produce an assessment of benefit. Instead, OPG relies on the conclusions from option 1, specifically that minimizing the price spread required to cycle the PGS increases PGS cycling which lowers TCC. OPG's analysis of a typical scenario demonstrates that including the marginal cost of sharing increases the spread required to cycle the PGS from $8.20 to $14.90[18]. This increase in spread can be demonstrated across the full range of pump energy prices as the overall need to earn more market revenues to offset the reduced marginal 50% HIM is consistent.

Based on the above, OPG concludes that eliminating sharing of HIM net revenues that exceed the HIMVA threshold would meet the study objectives by more effectively incentivizing OPG to engage in cost-saving opportunities for the ratepayer and would be consistent with MSP's Monitoring Report 32, which recommended that "… the OEB consider revisiting the sharing

[18] Based on a pump price of $14.40

with consumers of net HIM net revenue exceeding a threshold". OPG has thus proposed to eliminate sharing of HIM net revenues that exceed the HIMVA threshold in this application.

4.0 Conclusions

This study was undertaken in accordance with the OEB-approved Settlement Proposal in EB-2023-0336 to assess and recommend options to reduce SBGVA amounts on a forward-looking basis, with the aim of minimizing total electricity system costs to ratepayers. The analysis was conducted in the context of the MRP, with input from stakeholders and rightsholders, and with the support of the IESO as required. Stakeholder engagement played a critical role in shaping the study's scope and recommendations. Key action items from the engagement process were addressed, including ensuring the study's alignment with the latest market information, considering the impact of tariffs and Global Adjustment, and clearly linking each option to the study objectives.

The study evaluated three options: (1) removing load charges applicable to PGS cycling, (2) removing the GRC as a PGS pumping cost, and (3) modifying the HIM. Each option was assessed for its impact on PGS utilization, SBGVA reductions, and Total Customer Cost. Results from OPG's analysis are summarized in the following key findings:

- **Removing the Network Service Charge and IESO Administration Fees** as a PGS pump costs would increase PGS generation by 20.3 GWh and reduce SBG spill by 25.2 GWh over the study period, resulting in a forecast $8.8M reduction in Total Customer Costs. This would be achieved primarily by enabling more flexible, economic use of the PGS, particularly during hours currently restricted by the Network Service Rate charge. OPG is currently exploring the feasibility of implementing this option.
- **Removing GRC** as a PGS generation cost does not have a material impact on Total Customer Cost when done so in isolation, but when removed in addition to load charges, an incremental reduction in Total Customer Costs of $6.0M is calculated over the study period. OPG will explore the feasibility of this option.

- **Eliminating HIM sharing** above the established HIMVA threshold would provide a clear and consistent incentive for OPG to time-shift water, including if HIM net revenues are higher than the threshold. This proposed change is supported by the MSP as the Panel has previously stated that the current sharing mechanism may dilute OPG's incentive to time-shift hydro production for system benefit.

In conclusion, the options presented in this study offer pathways to reduce SBGVA amounts and total system costs, while respecting the operational realities of Ontario's electricity system. The findings demonstrate that targeted adjustments to PGS cost treatment and HIM net revenue sharing can improve incentives for OPG to time-shift generation in ways that lower spill and benefit ratepayers.

ONTARIO POWER GENERATION

Ontario Power Generation (OPG) Stakeholder and Rightsholder Consultation – Surplus Baseload Generation (SBG) Study

→ Meeting Minutes

optimus sbr

Table of Contents

1.0 Meeting Details 1

2.0 Meeting Minutes 1

2.1 Introductions and Opening Remarks 1
2.2 Purpose of the Meeting 1
2.2.1 Presentation of Guiding Principles and Study Options 2
2.3 Facilitated Discussion 2
2.3.1 Consideration of Additional Study Options 2
2.3.2 Evaluation Criteria and Ratepayer Impacts 3
2.3.3 Scope of OPG's Control and IESO's Role 3
2.3.4 Role of IESO in Supporting the Study 3
2.3.5 Consideration of Tariffs 3
2.3.6 Inclusion of Other Hydroelectric Facilities 4
2.3.7 Global Adjustment as a Factor 4
2.3.8 Market Renewal Program and Operational Considerations 4
2.3.9 Scope of Structural Changes 4
2.3.10 Jurisdiction and Feasibility of Proposed Options 5
2.3.11 Expectations for Final Report 5
2.4 Next Steps 5

3.0 Summary of Action Items 6

4.0 Participant List 7

4.1 Attended 7
4.2 Did Not Attend 8

Prepared by Optimus SBR © 2025 All Rights Reserved

1.0 Meeting Details

Date: March 21, 2025

Duration: 10:00 AM – 10:45 AM ET

Modality: Virtual (Microsoft Teams)

Facilitator: Ishma Zahur, Optimus SBR

2.0 Meeting Minutes

2.1 Introductions and Opening Remarks

Ishma Zahur from Optimus SBR welcomed attendees and introduced the Ontario Power Generation (OPG) staff present on the call, including Herman Mo (Senior Manager, Regulatory Affairs) and Saba Zadeh (Vice President, Regulatory Affairs). Ishma invited attendees to introduce themselves and outlined the agenda, which included:

1. A land acknowledgement
2. Purpose of the meeting
3. Facilitated discussion
4. Next steps

2.2 Purpose of the Meeting

Ishma explained that the meeting is part of OPG's commitment under the EB-2023-0336 settlement agreement. She highlighted that the agreement requires OPG to conduct and file a study assessing options to reduce Hydroelectric Surplus Baseload Generation Variance Account (SBGVA) amounts on a forward-looking basis. She emphasized that today's meeting is to gather input on options to be considered in the study. It was noted that two proposed study options were included in OPG's March 7 invitation and participants will have an opportunity to provide input on these. Ishma clarified that the study has not yet been conducted, and so there may be questions that OPG may not be able to answer at this stage. She also confirmed that feedback outside of the proposed options is welcome.

Ishma introduced Herman Mo from OPG to provide further context.

Prepared by Optimus SBR © 2025 All Rights Reserved

2.2.1 Presentation of Guiding Principles and Study Options

Herman outlined the following four guiding principles used to select OPG's proposed study options:

1. Recognizes the Independent Electricity System Operator's (IESO) fundamental role in managing Surplus Baseload Generation (SBG).
2. Recognizes that the objective of IESO's dispatch scheduling and optimization algorithm is to "maximize the gains from trade to ensure consumers of electricity receive the highest value based on electricity supply offers". OPG supports this objective by offering its resources economically into the IESO's market.
3. Ensures following IESO market signals and dispatch.
4. Maintains OPG's ability to recover its approved revenue requirement and not operate at an economic loss.

Herman explained that based on these principles, OPG proposes to study two scenarios related to reducing the price spread needed for economic cycling of the Sir Adam Beck Pump Generating Station (PGS). Currently the PGS is subject to variable load charges when it operates as a load, and to the Gross Revenue Charge (essentially a fuel cost for the water used for generation) when it operates as a generator. Both of these charges contribute to the market price spread required between pumping and generating so that OPG can recover these costs. Below are the two options that OPG proposes to study:

- Option 1: Study the potential benefit of removing variable load charges applicable to PGS cycling.
- Option 2: Study the potential benefit of removing Gross Revenue Charge ("GRC") applicable to PGS generation.

2.3 Facilitated Discussion

Ishma presented two discussion questions to participants:

1. What feedback or considerations for OPG do stakeholders and rightsholders have specific to the two options OPG proposes to study?
2. Do stakeholders and rightsholders have any other input for OPG outside of the two options OPG proposes to study?

2.3.1 Consideration of Additional Study Options

One participant questioned whether OPG had considered other study options that were ultimately not pursued beyond the two presented. In particular, OPG was asked why revisions to the Hydroelectric Incentive Mechanism (HIM) had not been included among the proposed study options.

OPG explained that a list of excluded options was not available but noted that the two selected options were identified based on the guiding principles. However, OPG confirmed it is open to considering additional suggestions and agreed to revisit whether incremental changes to the HIM could meet the study's objectives.

2.3.2 Evaluation Criteria and Ratepayer Impacts

There was discussion around how the proposed options would be evaluated and whether the study would analyze impacts on ratepayers.

OPG confirmed that the primary criterion, as defined in the EB-2023-0336 settlement agreement, is to reduce SBGVA amounts on a forward-looking basis, in light of the new market, with the aim of minimizing total electricity system costs to ratepayers. OPG confirmed that the study will demonstrate how each option satisfies that objective.

2.3.3 Scope of OPG's Control and IESO's Role

Stakeholders asked whether the study would also examine actions that the IESO could take to minimize SBG. Additionally, there were comments on how variable generation, such as wind generation and solar, influence SBG events.

OPG confirmed that the study will only focus on actions within OPG's control, in line with the first guiding principle.

2.3.4 Role of IESO in Supporting the Study

Some participants interpreted the settlement language—referring to IESO assistance—as an indication that OPG would engage the IESO on all scenarios, including those involving potential actions outside of OPG's control but within the IESO's purview and inquired whether either of OPG's proposed study options seeks to do that. Participants also suggested there may be options that fall within both OPG and IESO's shared control, and that collaboration could help enable such options. Furthermore, some participants understood the intent to be that while OPG can account for its own costs, it lacks visibility into total system costs. For example, when time-shifting generation using PGS, OPG may know how its own costs change, but not who is next in the dispatch order or how the shift would affect overall system costs. In such cases, participants suggested that OPG would require the IESO's assistance to gather the necessary data and model broader system cost impacts—believing this to be the primary reason for consulting the IESO as part of the study.

In response, OPG clarified that the study will focus on options within its control but emphasized the need to ensure that the proposed options do not conflict with the design of the new market. Since this is a forward-looking study, OPG's modelling will utilize OPG's assumptions and not be dependent on IESO data which would be commercially sensitive. Engagement with the IESO is intended as a check and balance—to confirm that OPG's proposals align with the IESO's framework. The study is not intended to examine options that fall entirely outside of OPG's control. OPG also reiterated that it will ensure the proposed options do not conflict with the IESO's principles or market rules.

2.3.5 Consideration of Tariffs

Participants raised the potential impact of tariffs, noting that although tariffs may only affect a small portion of OPG's operations, they are a growing concern among manufacturers and could become a factor that indirectly impacts the study.

Prepared by Optimus SBR © 2025 All Rights Reserved

OPG acknowledged this point and stated that the study would be based on the best available information at the time. OPG recognized if there is a known impact of tariffs, they may be considered in ongoing discussions.

2.3.6 Inclusion of Other Hydroelectric Facilities

Participants were interested to know if OPG is considering time-shifting opportunities beyond the PGS—such as other hydroelectric assets with time-shifting capability—and whether those were part of the study options.

OPG clarified that the HIM applies to PGS as well as other OPG hydroelectric assets. OPG stated that its review of changes to the HIM will include all hydroelectric resources subject to the incentive mechanism.

2.3.7 Global Adjustment as a Factor

Participants highlighted the distinction between minimizing system costs and minimizing Global Adjustment (GA) charges. They noted that even if a proposed option results in a reduction in total system costs, it does not necessarily translate into a benefit for some ratepayers due to the way GA is allocated.

OPG stated that the study will focus on minimizing total system costs, in accordance with the language in the settlement agreement. However, OPG acknowledged the point about GA and confirmed it will consider whether and how it could be included as an evaluation factor for the study options.

2.3.8 Market Renewal Program and Operational Considerations

Participants noted that the Market Renewal Program (MRP) has not yet come into effect, and the operation of the market in the future may differ from current expectations. Additionally, stakeholders raised the need to examine operational trade-offs between maximizing output through the Niagara tunnel and optimizing the use of the PGS facility.

In response, OPG confirmed that the study will be forward-looking and based on the best available information regarding how the new market is expected to operate. OPG clarified that the modeling will incorporate up-to-date physical attributes of the Beck complex, including the Niagara tunnel infrastructure. OPG also noted that it already optimizes operations across the entire Beck complex.

Following a prior comment that GA may change under MRP, one participant clarified that MRP affects only market prices and, therefore, only the quantum of GA would be impacted. OPG acknowledged this distinction and re-confirmed that it would consider whether and how GA could be included as a factor in the evaluation of study options.

2.3.9 Scope of Structural Changes

Referring to the settlement agreement language regarding the study, participants requested clarification on how OPG interpreted “structural changes” and whether this included potential

Prepared by Optimus SBR © 2025 All Rights Reserved

future infrastructure changes (e.g., transmission) that may be required depending on how the plant continues to operate going forward.

OPG explained that the term encompasses a broad range of possibilities but clarified it has not considered capital investments or changes to physical assets. Instead, OPG believes the focus as being on regulatory or market mechanisms, including those requiring further approval by external entities such as those in OPG's two proposed options.

2.3.10 Jurisdiction and Feasibility of Proposed Options

Participants commented that the proposed options – removal of variable load charges and GRC – fall outside the OEB's jurisdiction. Participants suggested that OPG consider including options it can pursue unilaterally or with OEB approval, with the possibility there may be none, to ensure that actionable options are included in the final report.

In response, OPG agreed to consider the point raised.

2.3.11 Expectations for Final Report

Participants requested that the final report explicitly demonstrate how each proposed option meets the objectives outlined in the settlement agreement, including whether and how it reduces spillage, and what structural changes would or would not be required.

OPG confirmed that the final report will address how each option satisfies the settlement requirements, and that if an option requested by intervenors does not meet those requirements, the report will explain why. OPG also noted that both of its proposed options are intended to support increased PGS cycling, which could result in reduced spillage, and that this assumption would be validated during the modeling phase of the study.

2.4 Next Steps

Ishma thanked participants for their feedback and outlined the following next steps:

1. Meeting minutes will be issued and shared with attendees.
2. OPG will assess all feedback and incorporate it into the study design.
3. OPG will engage IESO as available and needed.
4. A final study report will be drafted.
5. The report will be filed as part of OPG's upcoming rate application.

3.0 Summary of Action Items

The table below captures the action items for OPG to consider following the meeting.

#	Action Item
1.	Consider whether changes to the HIM would meet the study's objectives.
2.	Consider the best available information available at the time of conducting the study, including the potential impact of tariffs on the system, if applicable.
3.	Consider whether and how Global Adjustment could be included as a factor in the evaluation of the study options.
4.	Clearly link how each study option meets the study objective(s) outlined in the settlement agreement, including whether and how it reduces spillage, and what structural changes would or would not be required.

Prepared by Optimus SBR © 2025 All Rights Reserved

4.0 Participant List

4.1 Attended

Organization / Affiliation	Stakeholder
Association of Major Power Consumers in Ontario (AMPCO)	Shelley Grice
Coalition of Concerned Manufacturers and Businesses of Canada (CCMBC)	Tom Ladanyi
Environmental Defense (ED)	Amanda Montgomery
Power Workers Union (PWU)	Bayu Kidane
Quinte Manufacturers Association (QMA)	Michael D. McLeod
School Energy Coalition (SEC)	Mark Rubenstein
Society of United Professionals (SUP)	Bohdan Dumka
Vulnerable Energy Consumers Coalition (VECC)	Mark Garner
Ontario Energy Board (OEB)	Chris Cincar
	Thomas Eminowicz
	Jeffrey Sauer
	Fiona O'Connell
On behalf of Minogi Corp., a wholly owned subsidiary of Mississaugas of Scugog Island First Nation ("MSIFN")	Daniel Vollmer
Six Nations Council	Peter Graham
Ministry of Energy (MOE)	Shehrzad Shehrzad
	Maya Super
Independent Electricity System Operator (IESO)	Phillip Chisulo
Ontario Power Generation (OPG)	Herman Mo, Senior Manager, Regulatory Affairs
	Saba Zadeh, Vice President, Regulatory Affairs

Organization / Affiliation	Stakeholder
	Other observing members
Optimus SBR	Ishma Zahur, Facilitator (Principal, Industries & Government Practice)
	Vrinda Oberoi, Note-taker (Senior Analyst, Industries & Government Practice)

4.2 Did Not Attend

Organization / Affiliation	Participant
Consumers Council of Canada (CCC)	Julie Girvan
Ontario Energy Board	Michael Millar
	Ritchie Murray
	Tina Li
	Musab Qureshi
	Theodore Antonopoulos
Chiefs of Ontario	Chris Hoyos

Appendix B

Independent Electricity System Operator
1600-120 Adelaide Street West
Toronto, ON M5H 1T1
t 416.967.7474
www.ieso.ca

November 24, 2025

Herman Mo
Senior Manager, Regulatory Affairs
Ontario Power Generation
1908 Colonel Sam Dr.
Oshawa, ON L1H 8W8

Dear Mr. Mo:

Re: Surplus Baseload Generation Variance Account (SBGVA) Study

In preparation for its 2027-2031 Payment Amounts for Prescribed Assets application, Ontario Power Generation (OPG) engaged the Independent Electricity System Operator (IESO) beginning in September 2024 regarding its requirement to prepare an SBGVA study.

In March 2025, OPG conducted a stakeholder session to gather input from stakeholders and rights holders on two proposed study options related to the SBGVA study, as well as to invite feedback on any additional considerations beyond the proposed options. This process allowed all participants – including the IESO – the opportunity to provide feedback on the options to be explored as part of the SBGVA study.

In September 2025, OPG met with the IESO to provide an overview of the study's findings and shared a draft of the 2025 SBGVA study**.** Following our review of the study, from a market efficiency perspective, the IESO acknowledges that the proposed options appear directionally appropriate. However, we would like to clarify that the IESO did not participate in the development or execution of the study and while the IESO has no concerns with OPG's analysis, we have not conducted an independent validation of the results.

If you have any questions or would like to discuss further, please let us know.

Sincerely,

Carrie Aloussis

Carrie Aloussis
Senior Manager, Regulatory Affairs

COMPARISON OF PRODUCTION FORECASTS – NUCLEAR

1.0 PURPOSE

This evidence presents period-over-period comparisons of actual and forecast nuclear production for 2020-2031, in support of the approval of OPG's nuclear facilities' production forecast for the IR term. In addition, this evidence separately sets out the production forecast for the Darlington New Nuclear Program ("DNNP") facilities, the first unit of which will enter commercial operation during the IR term.

2.0 OPG NUCLEAR FACILITIES

2.1 Overview

Variances between actual and forecast production in the 2022-2026 term are primarily the result of the successful execution of the Darlington Refurbishment Program ("DRP"), including the implementation of lessons learned and unit over unit efficiencies, and the Province of Ontario's decision to extend Pickering Units 5-8 operations from 2025 to 2026.[1] Other reasons for variances are attributed to changes in the following: station planned outage ("PO") days,[2] forced outages ("FO"), planned or forced derates and unbudgeted POs. Variances may also arise due to station consumption, grid losses and impacts on thermal performance resulting from high lake water temperature.

Period-over-period variances are presented in Ex. E2-1-2, Tables 1a and 1b, and are explained below.

2.2 Period-Over-Period Changes – IR Term

As discussed in Ex. E2-1-1, Section 3.0, Pickering will be fully offline as of September 30, 2026. While Units 1 and 4 have ended commercial operation, Units 5-8 will transition to

[1] Under *Ontario Regulation 53/*05, OPG will return to ratepayers net revenues generated between January 1, 2026, to September 30, 2026, resulting from the extended operations of Pickering Units 5-8. See Ex. H1-1-1, Section 5.28, for information regarding the Pickering B Variance Account.

[2] PO days excludes a) outage days for Darlington units out of service during refurbishment, and b) outage equivalent planned derate days.

refurbishment, with Unit 5 returning to service towards the end of the IR term in May 2031. Until such point, there is no Pickering station generation during the IR term.

Also as discussed in Ex. E2-1-1, the DRP will conclude in 2026, with all four Darlington units operating throughout the IR term for the first time since 2016. Darlington's generation is impacted during this IR term by a four-unit vacuum building outage in 2027, and major equipment replacements and rehabilitations works requiring extended outages during the IR term as discussed below.

2027 Plan versus 2026 OEB-Approved

The 2027 Plan nuclear production of 18.7 terawatt-hours ("TWh") is 3.2 TWh lower than the 2026 OEB-approved plan production of 21.9 TWh. Since both the 2027 Plan and 2026 OEB-approved do not include any Pickering generation, the lower 2027 Plan production relative to 2026 OEB-approved is attributed to Darlington:

- Higher production in 2027 Plan compared with 2026 OEB-approved due to the completion of the DRP in 2026. The 2026 OEB-approved plan assumed that the last Darlington Unit 4 refurbishment would be complete in October 2026 (288 days).
- Lower production in 2027 Plan due to higher PO days (316.5 days) required primarily to execute major equipment replacements and rehabilitation associated with the Primary Moisture Separator ("PMS") Replacement on all four Steam Generators in Darlington Unit 2 in 2027, as well as the Unit 2 Turbine Control and Auxiliary Systems Upgrade ("TG Controls") project being executed in parallel. Both projects are described in Ex. D2-1-3, Section 3.1.3.
- Lower production in 2027 Plan due to planned Vacuum Building Outage ("VBO"; 45.9 days per unit (137.7 days total)) which necessitates shutdown of Units 1, 3, and 4. OPG has strategically overlapped the VBO with the above Unit 2 planned outage to optimize the outages.
- Higher production in 2027 Plan due to 19.5 fewer FLR equivalent days in 2027 Plan when compared with 2026 OEB-approved.
- Higher production in 2027 Plan compared with 2026 OEB-approved due to Unit 3 bulkhead derates not required upon refurbishment completion (savings of 15.1 equivalent days).

2028 Plan versus 2027 Plan

The 2028 Plan nuclear production of 26.7 TWh is 8.0 TWh higher than the 2027 Plan production of 18.7 TWh. The higher production of 2028 relative to 2027 is primarily due to 371.2 fewer PO days at Darlington as summarized below:

- Higher production in 2028 Plan compared with 2027 Plan as VBO (137.7 days impact) is completed in 2027.
- Two POs in 2028 totaling 141.5 days as compared to two POs in 2027 totaling 375.0 days for the extended outage duration associated with the Unit 2 PMSR and TG Controls PO.

2029 Plan versus 2028 Plan

The 2029 Plan nuclear production of 25.1 TWh is 1.6 TWh lower than the 2028 Plan production of 26.7 TWh. The lower production in 2029 relative to 2028 is due to Darlington having 72.7 more PO days than in 2028 as summarized below:

- Three POs in 2029 totaling 214.1 days as compared to two POs totaling 141.5 days in 2028.

2030 Plan versus 2029 Plan

The 2030 Plan nuclear production of 26.8 TWh is 1.8 TWh higher than the 2029 Plan production of 25.1 TWh. The higher production in 2030 relative to 2029 is primarily due to higher production at Darlington as summarized below:

- Two POs in 2030 totaling 139.2 days as compared to three POs totaling 214.1 days in 2029.

2031 Plan versus 2030 Plan

The 2031 Plan nuclear production of 28.9 TWh is 2.1 TWh higher than the 2030 Plan production of 26.8 TWh. The higher production in 2031 relative to 2030 is primarily due to the return of Pickering Unit 5 from refurbishment and impacts of unit uprates at Darlington as summarized below:

- Higher production from Pickering Unit 5 return to service post-refurbishment in May 2031 (+1.9 TWh).

2.3 Period-Over-Period Changes – Bridge Years

2026 Budget versus 2026 OEB-Approved

The 2026 planned nuclear production of 32.5 TWh is 10.5 TWh higher than the 2026 OEB-approved production of 21.9 TWh. The higher 2026 planned production is primarily due to a combination of the following:

- Lower production at Darlington relative to OEB-approved due to Unit 3 planned outage shifted from 2027 to 2026 and extended outage duration to conduct emergent work associated with the SG PMSR (-4.8 TWh).
- Higher production at Darlington due to planned early return to service of Unit 4 resulting in 183.0 fewer refurbishment days (+3.9 TWh).
- Higher production at Pickering due to Pickering Units 5-8 extended operation from January 1, 2026 to September 30, 2026 (+11.4 TWh).

2026 Budget versus 2025 Budget

The 2026 planned nuclear production of 32.5 TWh is 4.4 TWh lower than the 2025 planned nuclear production of 36.9 TWh. The lower 2026 planned production is primarily due to:

- Lower production at Pickering due to the planned shutdown of Units 5-8 on September 30, 2026 compared with entire year of production in 2025 (-4.4 TWh).

2025 Budget versus 2025 OEB-Approved

The 2025 planned nuclear production forecast of 36.9 TWh is 5.8 TWh higher than the 2025 OEB-approved production of 31.1 TWh. The higher 2025 planned production is primarily due to:

- Higher production at Darlington due to:
  - 107 fewer refurbishment days with Unit 1 having returned to service on November 27, 2024 versus OEB-approved assumption of April 18, 2025 (+2.2 TWh).
  - 182.0 fewer PO days due to shifting the Unit 2 Turbine Controls scope from 2025 to 2027 (see Ex. E2-1-1, Section 3.0 for further discussion) (+3.8 TWh).
  - 61 fewer post-refurbishment PO days attributed to Unit 3 (removal of 31-day post-refurbishment PO) and Unit 1 (reduced post-refurbishment PO from 55 days to 25 days) (+1.3 TWh). As a result of Unit 3's early return to service from refurbishment, a Unit 3

planned outage was shifted from 2027 into 2026, which eliminated the need for the Unit 3 post-refurbishment PO. Unit 1's reduced forecast for its post-refurbishment outage reflects operating experience from successful operation of Darlington Units 2, 3, and 1 post-refurbishments to-date.

- Lower planned production at Pickering primarily due to 80.0 additional planned PO days required to address Unit 6 equipment inspection and maintenance issues associated with life extension to September 31, 2026, partially offset by 5.0 fewer Equipment Aging Outage days (-0.8 TWh).
- Production Settlement adjustment (-0.9 TWh)

2025 Budget versus 2024 Actual

The 2025 planned nuclear production of 36.9 TWh is 3.9 TWh higher than the 2024 production of 33.0 TWh. The higher 2025 planned production is primarily due to:

- Higher planned production at Darlington (+9.4 TWh) due to:
  - 333 fewer refurbishment days (365 days in 2025 for Unit 4 compared to 698 days in 2024 for Units 1 and 4 combined);
  - 74 fewer PO days (25 days in 2025 planned production compared to 99 days in 2024); and
  - 41.2 fewer FLR equivalent days (38.6 days in 2025 planned production compared to 79.8 days in 2024).
- Lower planned production at Pickering (-5.5 TWh) primarily due to Units 1 and 4 end of commercial operations in 2024, with only Units 5-8 operating through 2025, partially offset by 172.7 fewer PO days in 2025 (110.3 PO days in the 2025 planned production compared to 283 PO days in 2024).

2.4 Period-Over-Period Changes – Historical Years

2024 Actual versus 2024 OEB-Approved

The 2024 actual nuclear production of 33.0 TWh is 1.1 TWh lower than the 2024 OEB-approved production of 34.1 TWh. The lower 2024 production is primarily due to a combination of the following:

- Lower production at Darlington due to 31.4 additional PO days in 2024 (86.4 days actual compared to 55 days in OEB-approved) reflecting a Unit 2 PO that was shifted from 2023 to 2024 to support grid reliability and manage resource constraints during concurrent nuclear outages (-0.7 TWh).
- Lower production at Darlington due to higher actual FLR of 12.1% compared to 6.0% OEB-approved (-0.9 TWh), primarily due to the following forced outages
    - 26.3 days to repair boiler tube leak in Unit 3;
    - 4.4 days to address circulating cooling water pump issues on Unit 3;
    - 32.7 days to address loss of excitation related issues on Unit 2; and
    - 11.1 days to repair boiler feed water suction pipe leaks on Unit 1.
- Higher production at Darlington due to 35 fewer refurbishment days with Unit 1 available for commercial operations on November 27, 2024 (698 days actual for Units 1 and 4 combined compared to 733 days in OEB-approved). This was driven by improvements in refurbishment schedules based on implementing prior unit lessons learned (+0.7 TWh),
- Higher production at Darlington as no derates were required during installation of the Bulkhead to isolate Unit 4 for refurbishment from the operating units as well as during the removal of the Bulkhead while bringing Unit 1 from refurbishment (+0.8 TWh).
- Production Settlement adjustment (-0.7 TWh).

2024 Actual versus 2023 Actual

The 2024 nuclear production of 33.0 TWh is 3.1 TWh lower than the 2023 production of 36.1 TWh. The lower 2024 production is primarily due to lower production at Darlington (-3.0 TWh):

- 99 higher PO days (99 days in 2024 and no PO days in 2023);
- 69.3 higher FLR equivalent days (79.8 days in 2024 compared to 10.5 days in 2023); and
- 32 fewer refurbishment days (698 days in 2024 for Unit 1 and 4 combined compared to 730 days in 2023 for Units 1, 3, and 4 combined).

2023 Actual versus 2023 OEB-Approved

The 2023 actual nuclear production of 36.1 TWh is 4.9 TWh higher than the 2023 OEB-approved production of 31.2 TWh. The higher 2023 production is primarily due to higher production at Darlington:

- Higher production at Darlington due to 108 fewer days required for refurbishment of Darlington units. Darlington Unit 3 was returned to service 166 days earlier than the OEB-approved plan as a result of the incorporation of significant operating experience and lessons learned from Unit 2 (+3.5 TWh). This was partially offset by the refurbishment of Darlington Unit 4 being advanced by 58 days to start immediately after Unit 3's return to service (-1.2 TWh).
- Higher production at Darlington due to fewer PO equivalent days, including a regular planned outage (82.2 days) that was shifted from 2023 to 2024 to support grid reliability and manage resource constraints during concurrent nuclear outages (+1.8 TWh).

2023 Actual versus 2022 Actual

The 2023 nuclear production of 36.1 TWh is 0.8 TWh higher than the 2022 production of 35.3 TWh. The higher 2023 production is primarily due to higher production at Darlington:

- Higher production at Darlington due to 45 fewer PO days in 2023 compared to 2022 (+0.9 TWh).
- Higher production at Darlington due to better FLR in 2023 compared to 2022 (+0.8 TWh).
- Lower production at Darlington due to 45 more refurbishment days at Darlington in 2023. There were 730.0 refurbishment days in 2023 with Unit 1 under refurbishment throughout the year (365 days) and Unit 4 refurbishment starting after Unit 3 returned to service. In comparison, there were 685.0 refurbishment days in 2022 as Unit 1 refurbishment began in February 2022 while Unit 3 refurbishment was already in progress (-0.9) TWh.

2022 Actual versus 2022 OEB-Approved

The nuclear production of 35.3 TWh in 2022 was 1.7 TWh higher than the 2022 OEB-approved production of 33.6 TWh. The higher 2022 production is primarily due to a combination of the following:

- Higher production at Darlington due primarily to:
  - 27.9 fewer PO days in 2022 compared to OEB-approved (+0.6 TWh);
  - Savings of 22.3 days as no derates were required during the installation of the Bulkhead to isolate Unit 1 for refurbishment from the operating units. This was the result

of implementation of Enriched Boric Acid project,[3] coupled with refurbishment schedule optimization based on lessons learned changes in operating unit fueling strategy (+0.5 TWh).

- Lower production at Darlington due to 40.6 more FLR equivalent days. Darlington's actual FLR was 7.5% versus 2022 OEB-approved of 2.1% (-0.8 TWh).
- Higher production at Pickering primarily due to 93.4 fewer PO days where regular PO were completed ahead of schedule with more efficient outage execution. One PO started later and was completed in early 2023 to mitigate execution overlap challenges of parallel execution of VBO (+1.2 TWh).

2022 Actual versus 2021 Actual

The 2022 nuclear production of 35.3 TWh is 4.3 TWh lower than the 2021 production of 39.6 TWh. The lower 2022 production is primarily due to a combination of the following:

- Lower production at Darlington due to 320.0 more refurbishment days in 2022. There were 365.0 refurbishment days in 2021 for Unit 3 compared with 685.0 refurbishment days in 2022 for Unit 3 during the entire year and Unit 1 refurbishment beginning in February (-6.7 TWh).
- Higher production at Darlington primarily due to 110.4 fewer PO days required in 2022 compared with 2021 (+2.3 TWh).

2021 Actual versus 2021 OEB-Approved

The 2021 nuclear production of 39.6 TWh was 4.2 TWh higher than the 2021 OEB-approved production of 35.4 TWh. The higher 2021 production is primarily due to a combination of the following:

- Higher production at Darlington due to 200.0 fewer refurbishment days. The OEB-approved production forecast reflected a six-month period when two units would be refurbished in parallel. Following revisions to the DRP schedule, this overlap began February 15, 2022 when Unit 1 began its refurbishment as opposed to June 15, 2021 (+4.2 TWh).

[3] The implementation of the Enriched Boric Acid project improves fueling reliability, allowing OPG to do longer maintenance windows on the fueling machine while a unit is operating.

- Lower production at Darlington due to 104.3 higher PO days. The OEB-approved production forecast reflected a post-refurbishment outage and a primary heat transport pump motor replacement mini outage, and no regular POs. In comparison, the 2021 Actual had two regular POs with 155.5 days. As a result of the revised DRP schedule, OPG had to move a Darlington Unit 1 outage from 2020 to 2021 and also add a PO in 2021 to support Unit 4 operation until its start of refurbishment (-2.2 TWh).
- Higher production at Pickering due to 227.3 fewer PO days. The Pickering VBO was moved to 2022 following Canadian Nuclear Safety Commission approval, accounting for 120.0 fewer PO days required at Pickering (+1.5 TWh).
- Higher production at Pickering due to the number of POs at Pickering being reduced from three to two due to the transition from a 24-month to a 30-month outage cycle (+1.3 TWh).

2021 Actual versus 2020 Actual

The 2021 nuclear production of 39.6 TWh is 4.3 TWh lower than the 2020 production of 43.9 TWh. The lower 2021 production is primarily due to a combination of the following:

- Lower production at Darlington primarily due to:
  - 122.5 higher PO days for 2021 (155.5 PO days) compared to 2020 (33 PO days) (-2.6 TWh).
  - 90 higher Darlington refurbishment days for 2021. Unit 3 was undergoing refurbishment for the entire 2021 compared with 275 refurbishment days in 2020 as Unit 2 completed refurbishment on June 4, 2020 and Unit 3 commenced refurbishment on September 3, 2020 (-1.9 TWh).
- Higher production at Pickering due to 114.6 fewer PO days for 2021 (335.5 PO days) compared with 2020 (450 PO days) (+1.4 TWh). This was partly offset by lower production at Pickering due to higher actual FLR for 2021 at 6.2% compared with 2020 FLR of 2.7% (-0.9 TWh).

2020 Actual versus 2020 OEB-Approved

The 2020 nuclear production of 43.9 TWh is 6.6 TWh higher than the 2020 OEB-approved production of 37.4 TWh. The higher 2020 production is primarily due to higher production at Darlington:

- Higher production at Darlington due to 91.1 fewer refurbishment days. In the 2020 OEB-approved production forecast, there was no gap between Unit 2 and Unit 3 refurbishments. Following revisions to the DRP schedule in response to the COVID-19 pandemic, there was a two-month gap between the return to service of Unit 2 and the start of the refurbishment of Unit 3 (+1.9 TWh).
- Higher production at Darlington due to the primary heat transport pump motor replacement mini outage included in EB-2016-0152 was cancelled as the work was completed in a prior year (+0.8 TWh).
- Higher production at Darlington from 150.2 fewer PO days due to a combination of the following:
    - The later return to service date for Unit 2 necessitated revisions to the outage schedule, which resulted in the rescheduling of the first Unit 2 post-refurbishment outage from 2020 to 2021 (+1.3 TWh); and
    - The shifting of the Unit 1 PO from September 2020 to February 2021 (+1.9 TWh);
    - Partly offset by a regulatory requirement to perform a single fuel channel replacement outage in advance of the Unit 3 refurbishment (-0.7 TWh).

3.0 DNNP FACILITIES

3.1 Overview

The first of four DNNP facilities' units is planned to be commercially available and generating starting in October 2030. Prior to this, there is no planned generation for the DNNP facilities. As such, there are no period-over-period comparison available for the historical or bridge years.

3.2 Period-Over-Period Changes – IR Term

2027 Plan versus 2026 OEB-Approved

There is no planned production from the DNNP facilities during this timeframe.

2028 Plan versus 2027 Plan

There is no planned production from the DNNP facilities during this timeframe.

2029 Plan versus 2028 Plan

There is no planned production from the DNNP facilities during this timeframe.

2030 Plan versus 2029 Plan

The 2030 DNNP facilities production forecast includes 0.5 TWh as DNNP facilities Unit 1 is planned to enter commercial operations in October 2030. There is no planned production during 2029 for the DNNP facilities.

2031 Plan versus 2030 Plan

The 2031 DNNP facilities production of 1.9 TWh is 1.4 TWh higher than 2030 Plan production of 0.5 TWh.

- There is higher production forecasted in 2031 with DNNP facilities' Unit 1 operating for a full year. This production increase is partly offset by the first PO at the DNNP facilities' Unit 1 as well as the warranty outage, both scheduled in 2031.

Numbers may not add due to rounding.

Table 1a
Comparison of Production Forecast - Combined Nuclear

Line No.	Business Unit	2020 OEB Approved[3]	(c)-(a) Change	2020 Actual	(g)-(c) Change	2021 OEB Approved[3]	(g)-(e) Change	2021 Actual	(k)-(g) Change	2022 OEB Approved	(k)-(i) Change	2022 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Darlington NGS											
1	**TWh**	17.7	5.7	23.4	(4.9)	16.6	1.9	18.5	(4.6)	13.4	0.5	13.9
2	**Unit Capability Factor (%)**	79.4	13.7	93.1	(10.4)	90.9	(8.3)	82.7	4.3	85.8	1.2	87.0
3	**PO Days[1,2]**	183.2	(150.2)	33.0	122.5	51.2	104.3	155.5	(110.4)	73.0	(27.9)	45.1
4	**Refurb PO Days**	366.0	(91.1)	274.9	90.1	565.0	(200.0)	365.0	320.0	685.0	0.0	685.0
5	**FEPO Days**	0.0	1.3	1.3	(1.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	**FLR (%)**	4.2	(2.6)	1.5	2.0	3.0	0.5	3.5	4.0	2.1	5.4	7.5
7	**FLR Days Equivalent**	38.1	(20.4)	17.7	15.3	25.0	8.1	33.0	22.0	14.4	40.6	55.0
	Pickering NGS											
8	**TWh**	19.6	0.9	20.5	0.6	18.8	2.3	21.1	0.3	19.8	1.6	21.4
9	**Unit Capability Factor (%)**	73.4	2.8	76.3	2.7	70.6	8.3	78.9	1.1	74.1	5.9	80.0
10	**PO Days[2]**	498.9	(48.9)	450.0	(114.6)	562.8	(227.3)	335.5	58.3	487.2	(93.4)	393.8
11	**Refurb PO Days**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	**FEPO Days**	0.0	13.0	13.0	(13.0)	0.0	0.0	0.0	1.1	0.0	1.1	1.1
13	**FLR (%)**	5.0	(2.3)	2.7	3.6	5.0	1.2	6.2	(4.4)	3.5	(1.7)	1.8
14	**FLR Days Equivalent**	84.9	(39.2)	45.6	69.1	81.4	33.4	114.7	(82.4)	58.9	(26.5)	32.3
	OPG Nuclear Facilities Totals											
15	**Unit Capability Factor (%)**	76.2	8.3	84.5	(3.8)	79.0	1.6	80.7	2.0	78.5	4.2	82.7
16	**PO Days[1,2]**	682.1	(199.1)	483.0	7.9	614.0	(123.1)	491.0	(52.1)	560.2	(121.3)	438.9
17	**FEPO Days**	0.0	14.3	14.3	(14.3)	0.0	0.0	0.0	1.1	0.0	1.1	1.1
18	**FLR (%)**	4.6	(2.5)	2.1	2.9	4.0	0.9	5.0	(0.8)	2.9	1.3	4.2
19	**FLR Days Equivalent**	122.9	(59.6)	63.3	84.4	106.3	41.4	147.7	(60.4)	73.2	14.1	87.3
20	**TWh before Adjustments**	37.4	6.6	43.9	(4.3)	35.4	4.2	39.6	(4.3)	33.2	2.1	35.3
21	**OEB/Settlement Adjustments[4]**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	(0.4)	0.0
22	**TWh including Adjustments**	37.4	6.6	43.9	(4.3)	35.4	4.2	39.6	(4.3)	33.6	1.7	35.3
	DNNP Facilities											
23	**TWh**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	**Unit Capability Factor (%)**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25	**PO Days[2]**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
26	**FEPO Days**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	**FLR (%)**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	**FLR Days Equivalent**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	**Total TWh Including Adjustments**	37.4	6.6	43.9	(4.3)	35.4	4.2	39.6	(4.3)	33.6	1.7	35.3

Line No.	Business Unit	2022 Actual	(e)-(a) Change	2023 OEB Approved	(e)-(c) Change	2023 Actual	(i)-(e) Change	2024 OEB Approved	(i)-(g) Change	2024 Actual	(k)-(i) Change	2025 Budget
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Darlington NGS											
30	**TWh**	13.9	0.7	9.6	5.0	14.6	(3.0)	12.0	(0.3)	11.7	9.4	21.1
31	**Unit Capability Factor (%)**	87.0	10.0	78.1	18.9	97.0	(22.4)	81.8	(7.2)	74.6	19.6	94.2
32	**PO Days[1,2]**	45.1	(45.1)	112.2	(112.2)	0.0	99.0	55.0	44.0	99.0	(74.0)	25.0
33	**Refurb PO Days**	685.0	45.0	838.0	(108.0)	730.0	(32.0)	733.0	(35.0)	698.0	(333.0)	365.0
34	**FEPO Days**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	**FLR (%)**	7.5	(6.1)	1.2	0.2	1.4	10.6	6.0	6.1	12.1	(8.5)	3.6
36	**FLR Days Equivalent**	55.0	(44.5)	5.9	4.6	10.5	69.3	38.0	41.8	79.8	(41.2)	38.6
	Pickering NGS											
37	**TWh**	21.4	0.1	21.2	0.3	21.5	(0.2)	21.4	(0.1)	21.3	(5.5)	15.8
38	**Unit Capability Factor (%)**	80.0	0.6	79.4	1.3	80.7	2.6	83.3	(0.0)	83.3	5.8	89.1
39	**PO Days[2]**	393.8	(38.2)	371.1	(15.5)	355.6	(72.6)	270.2	12.8	283.0	(172.7)	110.3
40	**Refurb PO Days**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
41	**FEPO Days**	1.1	0.9	0.0	2.0	2.0	(2.0)	0.0	0.0	0.0	0.0	0.0
42	**FLR (%)**	1.8	1.0	3.5	(0.7)	2.8	(0.2)	3.5	(0.9)	2.6	0.9	3.5
43	**FLR Days Equivalent**	32.3	18.1	63.1	(12.6)	50.5	(4.4)	66.8	(20.7)	46.1	1.1	47.2
	OPG Nuclear Facilities Totals											
44	**Unit Capability Factor (%)**	82.7	4.0	79.0	7.7	86.7	(6.8)	82.8	(2.9)	79.9	12.1	92.0
45	**PO Days[1,2]**	438.9	(83.3)	483.3	(127.7)	355.6	26.4	325.2	56.8	382.0	(246.7)	135.3
46	**FEPO Days**	1.1	0.9	0.0	2.0	2.0	(2.0)	0.0	0.0	0.0	0.0	0.0
47	**FLR (%)**	4.2	(1.9)	2.8	(0.6)	2.2	4.0	4.4	1.8	6.3	(2.7)	3.6
48	**FLR Days Equivalent**	87.3	(26.4)	69.0	(8.0)	61.0	64.9	104.8	21.1	125.9	(40.1)	85.8
49	**TWh before Adjustments**	35.3	0.8	30.8	5.3	36.1	(3.1)	33.4	(0.4)	33.0	3.9	36.9
50	**OEB/Settlement Adjustment[4]**	0.0	0.0	0.4	(0.4)	0.0	0.0	0.7	(0.7)	0.0	0.0	0.0
51	**TWh including Adjustments**	35.3	0.8	31.2	4.9	36.1	(3.1)	34.1	(1.1)	33.0	3.9	36.9
	DNNP Facilities											
52	**TWh**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
53	**Unit Capability Factor (%)**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
54	**PO Days[2]**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
55	**FEPO Days**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
56	**FLR (%)**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
57	**FLR Days Equivalent**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
58	**Total TWh Including Adjustments**	35.3	0.8	31.2	4.9	36.1	(3.1)	34.0	(1.1)	33.0	3.9	36.9

Notes:

1 PO days excludes planned outage days for units out of service during refurbishment.

2 PO days excludes planned outage equivalent days for planned derating of units or staggered unit shutdown.

3 OEB Approved amounts are per EB-2016-0152, Ex. E2-1-2, Table 1, and approved in the Decision and Order, pp. 11-13.

4 Production Settlement Adjustment Amounts per OPG Settlement Proposal, Filed 20210716, Table 17 - 2022-2026 Settled Production Forecast (TWh), p. 25.

Table 1b
Comparison of Production Forecast - Combined Nuclear

Line No.	Business Unit	2025 OEB Approved	(c)-(a) Change	2025 Budget	(g)-(c) Change	2026 OEB Approved	(g)-(e) Change	2026 Budget	(i)-(g) Change	2027 Plan	(k)-(i) Change	2028 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Darlington NGS											
1	**TWh**	13.5	7.5	21.1	(0.0)	21.5	(0.4)	21.1	(2.4)	18.7	8.0	26.7
2	**Unit Capability Factor (%)**	68.2	26.0	94.2	(18.2)	89.4	(13.4)	76.0	(13.1)	62.9	25.7	88.6
3	**PO Days**[1]	268.0	(243.0)	25.0	261.7	59.1	227.6	286.7	226.0	512.7	(371.2)	141.5
4	**Refurb PO Days**	472.0	(107.0)	365.0	(260.0)	288.0	(183.0)	105.0	(105.0)	0.0	0.0	0.0
5	**FEPO Days**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	**FLR (%)**	6.4	(2.8)	3.6	(0.1)	4.3	(0.7)	3.5	(0.6)	2.9	(0.7)	2.2
7	**FLR Days Equivalent**	46.2	(7.6)	38.6	(0.9)	46.8	(9.1)	37.7	(10.4)	27.3	1.5	28.9
	Pickering NGS											
8	**TWh**	16.6	(0.8)	15.8	(4.4)	0.0	11.4	11.4	(11.4)	0.0	0.0	0.0
9	**Unit Capability Factor (%)**	93.2	(4.1)	89.1	(2.1)	0.0	87.1	87.1	(87.1)	0.0	0.0	0.0
10	**PO Days**[2]	35.0	75.3	110.3	0.5	0.0	110.8	110.8	(110.8)	0.0	0.0	0.0
11	**Refurb PO Days**	0.0	0.0	0.0	368.0	0.0	368.0	368.0	1,092.0	1,460.0	4.0	1,464.0
12	**FEPO Days**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	**FLR (%)**	3.5	0.0	3.5	(0.0)	0.0	3.5	3.5	(3.5)	0.0	0.0	0.0
14	**FLR Days Equivalent**	49.4	(2.1)	47.2	(12.9)	0.0	34.3	34.3	(34.3)	0.0	0.0	0.0
	OPG Nuclear Facilities Totals											
15	**Unit Capability Factor (%)**	79.7	12.3	92.0	(12.5)	89.4	(9.9)	79.5	(16.6)	62.9	25.7	88.6
16	**PO Days**[1,2]	303.0	(167.7)	135.3	262.2	59.1	338.4	397.5	115.2	512.7	(371.2)	141.5
17	**FEPO Days**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	**FLR (%)**	5.0	(1.4)	3.6	(0.0)	4.3	(0.8)	3.5	(0.6)	2.9	(0.7)	2.2
19	**FLR Days Equivalent**	95.6	(9.8)	85.8	(13.8)	46.8	25.2	72.0	(44.7)	27.3	1.5	28.9
20	**TWh before Adjustments**	30.2	6.7	36.9	(4.4)	21.5	10.9	32.5	(13.8)	18.7	8.0	26.7
21	**OEB/Settlement Adjustments**[3]	0.9	(0.9)	0.0	0.0	0.4	(0.4)	0.0	0.0	0.0	0.0	0.0
22	**TWh including Adjustments**	31.1	5.8	36.9	(4.4)	21.9	10.5	32.5	(13.8)	18.7	8.0	26.7
	DNNP Facilities											
23	**TWh**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	**Unit Capability Factor (%)**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25	**PO Days**[2]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
26	**FEPO Days**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	**FLR (%)**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	**FLR Days Equivalent**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	**Total TWh Including Adjustments**	31.1	5.8	36.9	(4.4)	21.9	10.5	32.5	(13.8)	18.7	8.0	26.7

Line No.	Business Unit	2028 Plan	(c)-(a) Change	2029 Plan	(e)-(c) Change	2030 Plan	(g)-(e) Change	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Darlington NGS							
30	**TWh**	26.7	(1.6)	25.1	1.8	26.8	0.3	27.1
31	**Unit Capability Factor (%)**	88.6	(5.1)	83.5	5.1	88.6	0.1	88.7
32	**PO Days**[1]	141.5	72.7	214.1	(74.9)	139.2	0.0	139.2
33	**Refurb PO Days**	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	**FEPO Days**	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	**FLR (%)**	2.2	(0.2)	2.0	(0.0)	2.0	0.0	2.0
36	**FLR Days Equivalent**	28.9	(4.0)	24.9	1.5	26.4	0.0	26.4
	Pickering NGS							
37	**TWh**	0.0	0.0	0.0	0.0	0.0	1.9	1.9
38	**Unit Capability Factor (%)**	0.0	0.0	0.0	0.0	0.0	67.0	67.0
39	**PO Days**[2]	0.0	0.0	0.0	0.0	0.0	55.0	55.0
40	**Refurb PO Days**	1,464.0	(4.0)	1,460.0	0.0	1,460.0	(230.0)	1,230.0
41	**FEPO Days**	0.0	0.0	0.0	0.0	0.0	0.0	0.0
42	**FLR (%)**	0.0	0.0	0.0	0.0	0.0	12.0	12.0
43	**FLR Days Equivalent**	0.0	0.0	0.0	0.0	0.0	21.0	21.0
	OPG Nuclear Facilities Totals							
44	**Unit Capability Factor (%)**	88.6	(5.1)	83.5	5.1	88.6	(2.8)	85.8
45	**PO Days**[1,2]	141.5	72.7	214.1	(74.9)	139.2	55.0	194.2
46	**FEPO Days**	0.0	0.0	0.0	0.0	0.0	0.0	0.0
47	**FLR (%)**	2.2	(0.2)	2.0	0.2	2.2	1.2	3.4
48	**FLR Days Equivalent**	28.9	(4.0)	24.9	1.5	26.4	21.0	47.4
49	**TWh**	26.7	(1.6)	25.1	1.8	26.8	2.1	28.9
	DNNP Facilities							
50	**TWh**	0.0	0.0	0.0	0.5	0.5	1.4	1.9
51	**Unit Capability Factor (%)**	0.0	0.0	0.0	88.0	88.0	(15.3)	72.7
52	**PO Days**	0.0	0.0	0.0	0.0	0.0	64.9	64.9
53	**FEPO Days**	0.0	0.0	0.0	0.0	0.0	0.0	0.0
54	**FLR (%)**	0.0	0.0	0.0	12.0	12.0	(0.6)	11.4
55	**FLR Days Equivalent**	0.0	0.0	0.0	9.1	9.1	25.2	34.3
56	**Total TWh Including Adjustments**	26.7	(1.6)	25.1	2.3	27.3	3.6	30.9

Notes:
1 PO days excludes planned outage days for units out of service during refurbishment.
2 PO days includes staggered shutdown days in 2026.
3 Production Settlement Adjustment Amounts per OPG Settlement Proposal, Filed 20210716, Table 17 - 2022-2026 Settled Production Forecast (TWh), p. 25.

BUSINESS PLANNING AND BENCHMARKING - REGULATED HYDROELECTRIC

1.0 PURPOSE

This evidence presents the business planning, performance measures, and benchmarking for OPG's regulated hydroelectric business and provides a summary of the regulated hydroelectric operating costs from OPG's 2025-2031 Business Plan (the "Plan") in support of the Application.

In accordance with the rate-setting proposal for the regulated hydroelectric facilities, as described in Ex. A1-3-2, forecast information for the test year (2027) is provided for all operating cost exhibits, and forecast information for the full forecast period (2027-2031) is provided for capital-related exhibits.

2.0 OVERVIEW

This Application is based on the Plan, which in respect of the regulated hydroelectric business, was prepared reflecting the business planning process outlined in Ex. A2-2-1 and Section 3.0 below. The Application reflects significant changes in OPG's regulated hydroelectric operations since the last rebasing in EB-2013-0321 and supports OPG's mandate to provide safe and reliable hydroelectric power in line with the energy objectives of the Province of Ontario as described in Ex. A2-2-1. Highlights of the Plan as it pertains to the regulated hydroelectric operations include:

- Increased capital investment necessary to sustain an aging fleet, with a focus on turbine-generator refurbishment projects (Section 3.2.1) and civil infrastructure projects (Sections 3.2.3.1, 3.2.4, and 3.2.5);
- Redevelopment of select regulated hydroelectric stations, including increasing forecasted production (Section 3.2.2);
- Strategic resource planning, including increased headcount (Section 3.3) and programmatic vendor contracts to effectively support a growing work program (Section 3.2.1); and
- A Renewable Generation Excellence Plan that focuses on enhancing safety, operational performance, and future readiness through targeted initiatives and ongoing improvements at the hydroelectric stations (Section 3.4.1).

Overall, the planned investments will support both near-term and longer-term energy supply objectives:

- Providing Ontario with a clean and reliable source of baseload and peaking electricity for both everyday energy needs and periods of high seasonal demand; and
- Ensuring supply adequacy and stability to support meeting Provincial demand forecasts, including during nuclear station refurbishments.

The Plan, as it relates to the regulated hydroelectric facilities, is discussed in Section 3.0 and includes a description of historical and planned Operations, Maintenance and Administration ("OM&A") and capital expenditures. OPG's regulated hydroelectric operations are carried out by the Company's Renewable Generation ("RG") organization, as further described in Ex. A1-4-2 and Ex. F1-2-1.

3.0 REGULATED HYDROELECTRIC BUSINESS PLAN

The Plan reflects, as it relates to the regulated hydroelectric facilities, increased OM&A and capital expenditures to continuously improve safety, uphold regulatory compliance, preserve aging assets, sustain the existing fleet capacity while increasing forecasted production where opportunity exits, and improve equipment reliability. The Plan was prepared as described in Ex. A2-2-1 and Section 3.1 below.

The Plan reflects a significant evolution in OPG's regulated hydroelectric business since EB-2013-0321, including organizational changes (Ex. F1-2-1) and increased capital investment. This is necessary to meet the objectives stated above, and to support meeting the overall projected growth in Ontario's net energy demand of 65% by 2050.[1] At the same time, while it continues to exhibit overall strong reliability and cost performance compared to peers, OPG's regulated hydroelectric fleet now has an average age of approximately 90 years (ranging from 2-127 years old). The Plan reflects the increased investment necessary to manage the risks, sustain these assets, and maintain reliable operations for the longer term.

[1] IESO, Annual Planning Outlook: 2026 Demand Forecasts & 2027 Demand Scenario, November 2025, p. 6.

3.1 Regulated Hydroelectric Business Planning Process

3.1.1 Gap-Based Business Planning Process

The business planning cycle for OPG's RG business is undertaken annually as part of the overall OPG business planning process (Ex. A2-2-1). This cycle is focused on establishing strategic direction and performance targets for the RG business, in alignment with OPG's enterprise-wide objectives, and identifying the initiatives and resources required to achieve these targets.

OPG uses a gap-based business planning process for the RG business which consists of the following steps:

- **Performance Review**: Process of comparing actual performance to the previously approved business plan in order to identify areas to sustain or improve performance.
- **Setting Strategic Direction**: Process of goal alignment by establishing the level of performance and targets to sustain performance or drive continuous improvement within the business planning period.
- **Gap Closure Planning**: Process of planning gap closure initiatives as required to achieve targeted performance. The strategic initiatives to support gap closures are highlighted in the RG Excellence Plan as discussed in Section 3.4.1.
- **Developing Detailed Business Plan:** Process where generation, financial, and resource plans are developed based on the approved corporate strategic direction, performance targets, priorities, and resources, ensuring integration with corporate business planning processes.
- **Performance Reporting**: Continuous performance management reporting to ensure effective monitoring and execution of the approved business plan with careful consideration of safety, environment, financial, operational, and project performance.

Once the detailed business plan is developed and approved, OPG tracks performance against targets on a scorecard.

3.1.2 Auditor General Value for Money Audit

During 2022, the Office of the Auditor General of Ontario ("OAGO") conducted a Value for Money audit of OPG's Management and Maintenance of Hydroelectric Generating Stations. The OAGO recognized OPG as a reliable provider of hydroelectric power to the province, highlighting further opportunities for improvement, including the importance in maintaining its hydroelectric assets given the forecasted increase in energy demand. The audit also outlined recommendations to enhance OPG's maintenance planning and management systems, most of which have now been fully implemented or substantially progressed and the resources for which are included in the Plan. In December 2024, the OAGO released a Follow-Up Report on its 2022 Value for Money Audit, and identified OPG as one of the three auditees, out of the total of 16 auditees, that made the most progress toward fully implementing the recommended actions.

3.2 Key Business Plan Focus Areas

The business plan expenditures reflect investments in the following key focus areas, discussed in Sections 3.2.1-3.2.6 below: turbine-generator overhaul and refurbishment projects, redevelopment projects, portfolio projects, the Sir Adam Beck 1 canal rehabilitation and the Abitibi Canyon GS concrete and sluiceway rehabilitation. Details on OPG's initiatives to explore expansion opportunities at its existing regulated hydroelectric stations are provided in Section 3.2.6.

3.2.1 Turbine-Generator Overhaul and Refurbishment Projects

While hydroelectric facilities enjoy operating lifespans that generally exceed other generating technologies, they require cyclical renewal to ensure continued optimal performance. With the age of OPG's regulated hydroelectric assets averaging 90 years, many degraded components are at or approaching end-of-life and require significant investment during the forecast period to ensure that the assets can continue to help meet the province's energy needs for future decades. The Plan reflects these important investments, which accounts for $2,193.6M of capital expenditures on refurbishment projects in the 2027-2031 forecast period. These investments are necessary to address the aging condition of the fleet and the need to sustain asset performance. Without this investment, the reliability and generating capacity of these assets will decline.

Overall, for the 53 regulated hydroelectric refurbishment projects that are expected to come into service during the 2027-2031 forecast period, OPG expects to sustain approximately 1,500 MW of the existing regulated hydroelectric fleet capacity and add an estimated incremental capacity of approximately 50 MW; further highlighting the importance of ensuring these assets meet the province's energy needs. This includes turbine-generator refurbishments at OPG's three largest hydroelectric generating stations (Sir Adam Beck 1 GS, Sir Adam Beck 2 GS,[2] and R.H. Saunders GS),[3] supported by recent announcements from the Province of Ontario and reaffirmed in the 2025 Integrated Energy Plan.[4]

Major work on turbine-generator units falls into two categories: overhauls and refurbishments. Overhaul projects are typically required every 25-30 years and involve significant OM&A maintenance activities to sustain reliable operations of the turbine-generator equipment and related systems. Refurbishment projects are capital investments aimed at extending useful life of the equipment. Components may be refurbished, replaced, or upgraded. Refurbishments may also include design improvements that increase forecasted production. The scope and timing of refurbishment work is unique for each generating unit at a station and typically depends on the age and condition of the component, refurbishment/overhaul history, and any additional work necessary to sustain reliability. The scope of an overhaul or refurbishment project typically consists of the following components:

- Main powertrain components of the generating unit, such as generator (rotor and stator) windings, field poles, generator shaft, thrust bearing, upper and lower guide bearings.
- Turbine runner, headcover, seals, embedded components, wicket gates, operating ring, servomotors, bushings and linkages, turbine bearing and stationary and rotational alignment.

[2] Province of Ontario, News Release: *Ontario Refurbishing Hydroelectric Stations in Niagara*, April 16, 2024 <https://news.ontario.ca/en/release/1004449/ontario-refurbishing-hydroelectric-stations-in-niagara>.
[3] Province of Ontario, News Release: *Ontario Refurbishing Hydroelectric Station in Cornwall*, May 10, 2024 <https://news.ontario.ca/en/release/1004572/ontario-refurbishing-hydroelectric-station-in-cornwall>.
[4] "Energy for Generations: Ontario's Integrated Plan to Power the Strongest Economy in the G7", Ministry of Energy and Mines, p.9, 40, 54.

- Minor generator auxiliary systems, such as turbovent, cooling water radiators and controls, and minor control and instrumentation changes.
- Civil work that may include scroll case, draft tube, and discharge ring.

The specific scope of work on a component will determine if it is categorized as an overhaul or refurbishment, in accordance with OPG's capitalization policy (see Ex. D4-1-1). For example, a runner weld repair is considered overhaul (OM&A) scope, while a runner replacement would be refurbishment (capital) scope. The refurbishment or overhaul outage is often used to perform additional work, such as upgrading generation control equipment (governors and exciters) and installing new equipment for technology modernization, including sensors for online monitoring and diagnostics.

Overhaul and refurbishment project funding and outage requirements are identified during RG's business planning cycle, and the projects are prioritized in accordance with overall asset management processes (as described in Ex. D2-1-1) based on defined criteria, including but not limited to asset condition, risk, and value. Project scheduling and timing requires coordination with external stakeholders (such as Hydro One and the IESO) to minimize production losses where possible, while considering geographical and seasonal constraints. Regional factors are also considered, such as resource availability, materials delivery time, installation, and commissioning requirements.

At the same time as OPG needs to undertake this work, the global demand for hydropower supply chains and contractors is expected to surpass the already high levels of generation capacity added over the past 20 years. This will put significant pressure on the hydropower industry and create a market constrained by limited supply capacity. To mitigate this anticipated risk and facilitate the execution of its refurbishment program, OPG completed a competitive process with qualified large hydroelectric Original Equipment Manufacturers ("OEM") and implemented the Renewable Generation Programmatic Collaboration Agreement ("RG PCA") strategic initiative. The RG PCA is aimed at securing OEM execution capacity by way of long-term collaboration agreements with two hydroelectric OEMs, GE Renewable Energy Canada Inc. ("GE") and Andritz

Hydro Canada Inc. This initiative secures the specialized resources and stability OPG requires to meet the forecasted refurbishment workload in the tightening market, as well as the benefits of unit-over-unit project efficiencies expected within or across facilities with similar characteristics. While the primary objective of the RG PCA initiative is to address the anticipated OEM capacity challenges, it will seek to leverage potential additional opportunities, such as:

- Early OEM engagement
- Optimal project solutions
- Increases to unit efficiency, output, or capacity (MW)
- Resource stability
- Cost optimization
- End-to-end system assessments
- Integration of lessons learned

One of the cornerstones of the RG PCA initiative is to facilitate early OEM engagement. Each OEM has been allocated a group of refurbishment projects for various stations and units, with assignments based on work continuity and geographical proximity (such as shared river systems) to support more consistent project execution and efficient use of resources. OPG and the OEMs will adopt a similar “OneTeam” approach used at the Darlington Refurbishment Program to facilitate collaboration in refurbishment performance.

For each refurbishment project, lessons learned are identified for the purpose of continuous improvement. In addition, lessons learned are shared through team collaboration, refurbishment forums, and the Refurbishment Oversight Committee. The application of these insights inform the planning and execution of upcoming refurbishment activities, supporting unit-over-unit improvements in efficiency and project performance.

Details of the regulated hydroelectric refurbishment projects are provided in Ex. D1-1-2, Section 3.2.1.

3.2.2 Station Redevelopment Projects

The primary goal of a redevelopment is to extend operations for stations where investment is necessary to address a population of deteriorated and otherwise end-of-life assets. This includes the replacement of a significant portion of the generating station equipment, which may also include the replacement of existing civil infrastructure (partial or full). For some redevelopment projects, there may be opportunities to add incremental generation capacity. Without these planned redevelopments, OPG would ultimately need to decommission[5] these stations.

In support of the 2025 Integrated Energy Plan,[6] OPG is redeveloping five regulated hydroelectric stations in the 2027-2031 forecast period: one currently in the development phase (Bingham Chute GS) and four currently in the execution phase (Kakabeka Falls GS, Matabitchuan GS, Coniston GS, and Stinson GS). Capital expenditures for these redevelopment projects are expected to total $911.0M, with an expenditure of $176.0M in the 2027-2031 forecast period. The first redeveloped Coniston GS unit is expected to come into service in late 2026. All of the remaining planned redevelopment projects are expected to come into service during the forecast period. These investments will extend the life of these facilities by an additional 80-90 years and sustain approximately 43 MW of the existing regulated hydroelectric fleet capacity and add an estimated incremental 13 MW of capacity. Further details on redevelopment projects are provided in Ex. D1-1-2, Section 3.2.2.

OPG is continuing to explore options for other small regulated hydroelectric assets that are nearing end of life, including possible redevelopment projects. Funding to support these preliminary assessments is captured in Project OM&A, as detailed in Ex. F1-3-1, Section 3.2.

[5] Ongoing costs to maintain site infrastructure and water control structures would still be required if the station was decommissioned.
[6] "Energy for Generations: Ontario's Integrated Plan to Power the Strongest Economy in the G7", Ministry of Energy and Mines, Chapter 2.

3.2.3 Portfolio Projects

OPG plans to invest $1,581.3M capital in the 2027-2031 forecast period, and $90.7M Project OM&A in the 2027 test year in regulated hydroelectric portfolio projects. Major categories of work for the portfolio in the period include investments in concrete and dam restoration and rehabilitation projects, regulatory commitments and contractual obligations (such as large infrastructure projects on joint works assets), and other portfolio projects including: electrical and protection and controls upgrades, cranes and lifting devices, and gates, which are further detailed below.

3.2.3.1 Concrete and Dam Restoration and Rehabilitation Projects

The business plan includes funding to address concrete deterioration through rehabilitation and restoration projects. Examples of such capital projects include Otto Holden GS Refurbish Stop Log Sluice Piers and Aguasabon Dam Rehabilitation. Further details on concrete rehabilitation capital projects are provided in Ex. D1-1-2.

Over time, civil structures deteriorate due to various environmental factors such as thermal expansion-contraction, water seepage, freeze-thaw damage, corrosion of reinforcements, and abrasion. An additional cause of deterioration is the unexpected expansion of concrete due to long-term chemical reactions, specifically Alkali Aggregate Reaction ("AAR").[7] The presence of AAR in the concrete causes deterioration to occur more rapidly than would normally be experienced for the age of the infrastructure. This can disrupt the operation of sluicegates, affect the crucial alignment of generators in dams, and potentially lead to structural concrete cracking. Concrete structures are monitored and inspected regularly through equipment reliability, dam safety, or bridge inspection programs. Any discovered deficiencies or risks are reported and mitigated, as necessary, through maintenance or capital investments.

[7] AAR is a reaction between alkali hydroxides and certain concrete aggregates. This reaction causes the expansion of the altered aggregate, leading to accelerated concrete deterioration, spalling, and loss of strength.

Examples of OPG's stations and structures showing signs of AAR include the R.H. Saunders GS and Otto Holden GS (see Figure 1), Manitou Falls GS, Pine Portage GS, and Chat Falls GS. There is no cure for AAR; ongoing restoration, guided by engineering assessments and monitoring, is required. OPG has installed civil and mechanical instrumentation and continues to monitor generator air gaps, runner clearances, spillway gate and/or log operations and other potentially affected equipment to assess if remedial action is required.

In 2018, concrete restoration was completed at the Chats Falls GS to address AAR and freeze-thaw damage. At the R.H. Saunders GS, concrete growth has impacted the integrity of critical structural members and has also led to deformation of the concrete around the generating unit. This deformation impacts the runner clearances, an issue being addressed through the restoration program. To relieve AAR stress, slot cutting was performed to re-establish expansion joints in the concrete between the units, allowing for concrete expansion while minimizing impact to components. Slot cutting is completed before unit refurbishments to maximize refurbishment benefits. In addition to mitigating the impact on the generating units, OPG is undertaking modifications of impacted structural members and repairs to maintain the integrity of the powerhouse.

Figure 1 – AAR Illustrative Examples



Left: Spalling concrete and exposed rebar at Otto Holden GS. Right: Spalling and cracked concrete column at R.H. Saunders GS.

3.2.3.2 Regulatory Commitments and Contractual Obligations

OPG has regulatory and contractual obligations that form part of the work program and are included in the business plan. This includes dam and public safety obligations, environmental obligations with Fisheries and Oceans Canada ("DFO"), the Ministry of Environment, Conservation and Parks ("MECP") and the Ministry of Natural Resources ("MNR"), IESO requirements, and contractual obligations with partners through joint works agreements (such as New York Power Authority), as described in Ex. A1-4-2.

The 2019 amendments to the *Fisheries Act*[8] include prohibitions on killing fish by means other than fishing[9] and causing the harmful alteration, disruption or destruction of fish habitat.[10] As a result of these amendments, both existing and newly built, or redeveloped, hydroelectric stations are required to obtain authorizations from the DFO. This authorization requirement applies to all of OPG's regulated hydroelectric generating stations, and the authorization process involves studies, stakeholder engagement, Indigenous consultations, and long-term monitoring. Once

[8] *Fisheries Act*, R.S.C. 1985, c. F. 14, as amended by S.C. 2019, c. 14.
[9] *Ibid*., s. 34.3.
[10] *Ibid*., s. 35.

initiated, the authorization process for each station may take up to three years to successfully complete.

While OPG mitigates impacts on fish through compliance with Water Management Plans set by MNR or under agreements with the MECP for stations that have compliance requirements under an *Endangered Species Act* (Ontario), OPG will also pursue authorizations for stations under redevelopment. Additional applications for authorizations at existing stations are anticipated during the forecast period for a Base OM&A cost of $5.7M; this funding reflects the costs necessary to seek the authorizations. Although the DFO authorization conditions are currently unknown, they are expected to include construction or alteration of fish habitat and/or potential facility alterations. Investments to address DFO compliance activities in the 2027-2031 forecast period have been included in the unallocated portfolio (Ex. D1-1-2, Table 5b).

The American eel is considered "endangered" under current provincial legislation in Ontario.[11] Under Section 11.1 of O. Reg. 242/08 of the *Endangered Species Act, 2007*, OPG has a formal agreement with the MECP which establishes an implementation plan to minimize adverse effects on the American eel that includes examining potential options to improve passage for migrating eels at the R.H. Saunders GS. Additionally, a pilot project is planned for execution in 2027-2028 at the Iroquois Dam on the St. Lawrence River and, pending successful implementation and acceptance by the MECP, a full-scale design and deployment project has been included in the unallocated portfolio (Ex. D1-1-2, Table 5a). The American eel was also under consideration to be listed as a "threatened" species under the federal *Species at Risk Act*. On December 2, 2025, the Government of Canada announced that the American eel was not to be listed, and that the best way to conserve the species was to manage the species and its habitat under the *Fisheries Act* through "adaptive management approaches".[12] The DFO will continue to implement measures aimed at minimizing the negative impacts of habitat alteration and improving the species' migration passages. OPG will continue to monitor any DFO compliance activities, as specific

[11] Ontario Regulation 230/08: *Species at Risk in Ontario List*, Schedule 2. (n.d.). Government of Ontario. <https://www.ontario.ca/laws/regulation/080230>

[12] Government of Canada, News Release: Government of Canada commits to adaptive management approach to conserve and protect American Eel, December 2, 2025. <Government of Canada commits to adaptive management approach to conserve and protect American Eel - Canada.ca>

adaptive management activities and/or actions have not yet been explicitly identified. This may result in additional activities at certain regulated facilities such as R.H. Saunders G.S.

As the potential cost or impact to OPG's hydroelectric operations resulting from existing or future regulations pertaining to the American eel are currently unknown (and therefore not included in the business plan), OPG proposes capturing any future costs associated with potential provincial and/or federal regulatory impacts in a new deferral account. Further details are discussed in Ex. H1-1-1, Section 7.1.2.

3.2.3.3 Other Portfolio Projects

The balance of the regulated hydroelectric portfolio projects primarily consists of the following categories of work:

- Electrical and protection and controls upgrades which generally includes AC and DC station service equipment, breaker and switchgear, transformer and battery replacements;
- Cranes and lifting devices, which generally includes replacement of powerhouse cranes, many of which are original to the stations and required ahead of the turbine-generator refurbishment projects to mitigate the risk of delays to these extensive programs. This also includes head gate and sluice gate hoists and superstructures that are essential for protecting assets and maintaining proper water levels around dams;
- Gates, which generally include sluice gates, head gates, sectional gates and trashracks;
- Sustaining building/infrastructure work on aging powerhouses to ensure their integrity and ability to house the generating equipment, which generally includes roof replacements and structural work; and
- Other sustaining investments, such as work on non-concrete dams, surge tanks, and public safety booms, network upgrades, and the Northwest Operations Work Centre.

3.2.3.4 Unallocated Projects

OPG employs a portfolio management approach to capital investments for the nuclear business and for digital technology projects, which includes an unallocated portfolio based on the candidate projects identified through a prioritization process during business planning. The RG business

has now aligned the management of its capital and OM&A project portfolios with the rest of the Company, as described in Ex. D2-1-1. This includes the use of unallocated portfolio funding in the Plan, as approved by OPG's Board of Directors, based on the expectation of future projects but with the recognition that they have not yet been fully scoped or approved. The alignment of the RG business to this approach in part reflects the more extensive capital program as well as a longer business planning horizon of up to seven years, compared to EB-2013-0321. Similar to OPG's other lines of business, the proportion of a project portfolio that is unallocated naturally tends to increase further into the forecast period, as later projects have yet to complete scoping and engineering required for a business case summary ("BCS") to be developed and approved. As discussed in Ex. D2-1-1, RG reviews the project portfolios as part of the business planning process and prioritizes projects for execution.

3.2.4 Sir Adam Beck 1 GS Canal Rehabilitation

The business plan includes funding in 2027-2029 for the first two phases of major work on the 100+ year-old canal that supplies water from the Welland and Niagara Rivers to the Sir Adam Beck generating complex, passing through the City of Niagara Falls. The canal has experienced canal wall deterioration, debris accumulation, and weed growth causing a reduction in flow to the Sir Adam Beck generating complex. The investment will ensure the capability to isolate and drain the canal, which will facilitate future rehabilitation work on the canal liner and associated structures. Isolation capability is also required to enable maintenance on non-OPG structures along the canal, such as the Highway 420 culvert. Further details on the SAB1 Canal Rehabilitation are provided in Ex. D1-1-2, Section 3.2.4.

3.2.5 Abitibi Canyon GS Concrete and Sluiceway Rehabilitation

The business plan includes funding for the rehabilitation of the Abitibi Canyon GS concrete structures and sluiceway in Northeastern Ontario. Concrete degradation on the upstream and downstream faces includes surface scaling, spalling, cracking, staining and delamination. All exposed downstream and upstream faces are affected; therefore, isolated repairs are no longer feasible for maintaining the long-term integrity of the structures. These investments include funding to address concrete deterioration, improve sluiceway and superstructure equipment

reliability, and addressing equipment risks at this 92-year-old, 349 MW station. The higher expenditures in later years of the plan account for the anticipated size and complexity of these works, including dam repairs and upstream concrete rehabilitation, the specific scope for which is being developed.

3.2.6 Regulated Hydroelectric Expansion Opportunities

In keeping with the Province's 2023 Powering Ontario's Growth report[13] and the 2025 Integrated Energy Plan,[14] OPG continues to identify opportunities to increase generation at its existing regulated hydroelectric facilities. One such initiative is the proposed addition of a new 33 MW generating unit at the existing Chats Falls GS. This work is currently in the initiation phase, following an initial evaluation which determined there is sufficient excess inflow in the Ottawa River for the addition of a generating unit. By leveraging the existing powerhouse and transmission infrastructure, the project is expected to be more economical and the permitting requirements more streamlined than a new hydroelectric station. Subject to completing the necessary planning, the current forecast assumes that the project commences execution in 2028 and is completed beyond the 2027-2031 forecast period. Chats Falls GS is jointly owned by OPG and Hydro-Québec and its costs are shared between the two organizations in accordance with the OPG/Hydro-Québec O&M Agreement (described in Ex. A1-4-2). It is anticipated that project costs and future revenues will be shared via the existing partnership by both organizations. There are no forecast in-service amounts for this project during the 2027-2031 period.

3.3 Staffing Levels to Support Key Business Plan Focus Areas

Renewable Generation forecasts a full-time equivalent ("FTE") workforce of approximately 1,520 in 2027 that is expected to remain stable throughout the 2027-2031 forecast period. FTEs have increased consistently over the historical period, reflecting the addition of personnel across project management, operations, maintenance, engineering and training functions to effectively support capital and OM&A work programs, strategic initiatives, continued safe and reliable operation of the facilities and major capital projects ongoing over the period, such as the Sir Adam Beck 1 GS

[13] Province of Ontario, Powering Ontario's Growth: Ontario's Plan for a Clean Energy Future, July 7, 2023.
[14] "Energy for Generations: Ontario's Integrated Plan to Power the Strongest Economy in the G7", Ministry of Energy and Mines, p.56.

and Sir Adam Beck 2 GS refurbishment programs. The details of the FTEs are shown in Ex. F1-1-1, Table 2b.

3.4 Continuous Improvement Initiatives

3.4.1 RG Excellence Plan

The RG Excellence Plan sets the strategic initiatives and improvement plans, reviewed annually, aimed at enhancing safety, operational performance, and future readiness across the RG organization. The plan is structured around three main categories: People, Plant, and Future, each with specific goals, key focus areas, and measures of success.

In the **People category**, the primary goal is to drive a strong safety culture. Key focus areas include promoting clear and simple safety messaging, working with vendor partners to enhance safety. Success will be measured through safety incident rates and engagement results. To address the changing workforce supporting the key business plan focus areas described in Section 3.2, RG is focused on developing and sustaining employee proficiency including a training program to develop new leaders within the business. The primary focus of this program is to reinforce key leadership behaviours and skills, accelerating their development as leaders in the organization to influence the workforce.

The **Plant category** aims to maximize equipment performance, with key focus areas such as advancing the equipment reliability program and strengthening asset planning consistency. Success will be gauged through plant reliability metrics, including Availability Factor, discussed in Section 4.3 below. Another goal within this category is to strengthen work planning and execution, focusing on streamlining maintenance strategies and work management practices in support of the Enterprise Asset Management (“EAM”) system modernization (described in Ex. D3-1-1, Section 2.1.2). Measures of success for this goal include work management performance and project milestone adherence.

Lastly, the **Future category** seeks to facilitate future development by building training programs, ensuring a proficient workforce through succession planning and knowledge sharing, and supports the EAM modernization efforts. Success measures will include training completion metrics and succession planning readiness. Further details on RG's staffing and training initiatives are provided in Ex. F1-2-1.

3.4.2 Technology Based Improvements

Renewable Generation has also implemented several initiatives aimed at opportunities to use technology to drive efficiency and improvement, in keeping with OPG's digital strategy (as described in Ex. D3-1-1). Some of these initiatives include:

1. Improving equipment reliability by progressing the installation of new sensors on key equipment and components, while also leveraging existing instrumentation. By using both new and current data sources, OPG is able to detect and address equipment issues earlier, which is one of the enablers from shifting from traditional time-based maintenance programs to more advanced condition-based maintenance strategies. As additional sensors are installed and more data is gathered and trended, analytics and artificial intelligence/machine learning models (built from historical and real-time information) are expected to further improve overall asset performance.
2. Reviewing work management and preventative maintenance strategies across the fleet to drive consistency, where practical and appropriate, and also to improve quantity and quality of data needed to ensure integrated processes and reliable data across the fleet.
3. Implementing PowerBI reporting, including transitioning manual metrics, where possible, into automated reporting. Online reporting dashboards provide managers with the ability to see up-to-date operational and cost information to facilitate timely resource and cost-management decision-making.

4.0 REGULATED HYDROELECTRIC KEY PERFORMANCE METRICS

OPG measures the performance of its regulated hydroelectric operations across four main outcomes: Safety, Environment, Reliability, and Cost Effectiveness. The measures of performance for each outcome are described in Sections 4.1-4.4 below, along with the historical

performance and performance targets for the bridge (2025-2026) and forecast (2027-2031) periods, where applicable.

4.1 Safety

Total Recordable Injury Frequency ("TRIF") is defined as the number of injuries that result in fatalities, lost time, restricted work or medical treatment per 200,000 hours worked. Electricity Canada ("EC") is OPG's main benchmark for evaluating safety performance within Canada. EC implemented a change from All Injury Rate ("AIR") to TRIF as TRIF is more widely accepted and utilized by most industries outside of the electrical utility sector. In 2018, OPG replaced AIR with TRIF as a measure for evaluating health and safety performance to align with EC. Chart 1 describes RG's historical All Injury Rate/TRIF 2016-2024 performance. Chart 2 describes the 2025-2031 forecasted TRIF performance targets.[15]

Chart 1 – Renewable Generation All Injury Rate / Total Recordable Injury Frequency (2016-2024 Actuals)

		2016	2017	2018	2019	2020	2021	2022	2023	2024
All Injury Rate/Total Recordable Injury Frequency	Actual	1.82	2.05	1.68	1.32	1.21	1.02	1.56	0.46	0.77
	Target	1.32	1.23	1.23	1.21	1.21	1.21	1.21	1.20	1.11

Note: Low AIR/TRIF is good.

There was a notable improvement in safety performance, particularly in 2023 (0.46) and 2024 (0.77), which were RG's best and second-best performance years since OPG's inception. The general downward trend in TRIF over the years reflects successful safety initiatives and efforts to reduce injuries, including increasing supervisory presence in the field, safe work planning, expanding corrective action tracking and targeting specific areas (such as hand injuries) that have historically led to recordable events.

[15] TRIF performance is measured at the RG fleet level; as such, values include regulated hydroelectric and unregulated station performance.

Chart 2 – Renewable Generation Total Recordable Injury Frequency (2025-2031 Targets)

		2025	2026	2027	2028	2029	2030	2031
Total Recordable Injury Frequency	Target	1.05	1.00	0.95	0.90	0.85	0.80	0.75

Note: Low AIR/TRIF is good.

OPG is committed to safety, as demonstrated by its progressively lower TRIF targets. However, the expansion of the work program across RG introduces greater operational complexity, a larger workforce, and a broader range of activities, all of which present additional challenges to sustaining and advancing safety performance. OPG remains dedicated to achieving its ambitious TRIF targets through strengthened safety initiatives. To further support continuous improvement, the RG Excellence Plan (Section 3.4.1) includes initiatives to further strengthen safe work planning, pre-job briefing skills, and tailboard best practices.

4.2 Environment

Renewable Generation has historically utilized an Environmental Performance Index ("EPI") to assess the environmental performance of its fleet.[16] EPI is a composite, weighted index that incorporates multiple measures, including the number of environmental spills, regulatory infractions, and the implementation of other environmental initiatives such as the Polychlorinated Biphenyl ("PCB") equipment removal program. Results also account for third-party spills and infractions in instances where OPG is designated as Constructor.[17] Chart 3 provides a summary of the historical EPI performance for all of OPG's hydroelectric facilities.

Chart 3 – Renewable Generation Historic Environmental Performance Index (%, 2016-2024 Actuals)

		2016	2017	2018	2019	2020	2021	2022	2023	2024
Environmental Performance Index (%)	Actual	100	98	96	100	100	83	100	94	99
	Target	80	80	80	80	80	80	80	80	80

Note: High EPI is good.

[16] Environmental performance is measured at the RG fleet level; as such, targets and values include regulated hydroelectric and unregulated station performance.

[17] Role of Constructor is defined under the *Ontario Occupational Health and Safety Act* and administered by the Ministry of Labour, Immigration, Training and Skills Development, previously known as the Ministry of Labour.

OPG's regulated hydroelectric facilities have consistently demonstrated strong environmental performance, as reflected in the EPI results. In 2021, while EPI remained above target (actual 83 versus target of 80), a temporary decrease was observed due to an increase in spills and infractions. In response to this decline, RG successfully implemented corrective actions and performance quickly improved. Renewable Generation implements robust programs to prevent category A or B spills, has maintained an ISO 14001-certified Environmental Management System since 2020, and tracked and removed all known PCB-containing equipment as per legislated requirements.[18] In addition to the EPI calculation, OPG further demonstrates its commitment to the environment through key biodiversity initiatives. The Wildlife Habitat Council has recognized the Niagara Region, the R.H. Saunders GS, and the hydroelectric facilities along the Ottawa/Madawaska River for their various biodiversity programs.

The removal of PCB-containing equipment was completed in 2025. As a result, the composite weightings previously applied to the EPI metric will no longer apply. Beginning in 2026, RG is revising its environmental performance metric to track and report the number of spills and regulatory infractions under a new measure, Total Recordable Environmental Events ("TREE"). As OPG has historically tracked annual spills and infractions as part of the EPI metric, historical TREE values can be back-cast to trend performance; these values are provided in Chart 4. From 2016 to 2024, TREE performance was consistently better than target, with the number of spills and infractions lower than the established thresholds, even as targets became more stringent over the years.

Chart 4 – Total Recordable Environmental Events (2016-2024 Actuals)

		2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Recordable Environmental Events	Actual	11	4	9	5	8	11	8	7	7
	Target	18	17	15	14	14	14	14	13	12

Note: Low TREE is good.

[18] Government of Canada. (2008). *PCB Regulations (SOR/2008-273)*. *Canadian Environmental Protection Act, 1999*. https://laws-lois.justice.gc.ca/eng/regulations/SOR-2008-273/index.htm

The 2025 TREE target is set at 11, and for 2026 through 2031 the TREE target is set, and will be maintained, at 10 annually as shown in Chart 5. This recognizes that, as the implementation of the work program described in this exhibit expands across RG, achieving this target will become increasingly challenging. OPG remains committed to maintaining strong environmental performance despite the anticipated growth in activity.

Chart 5 – Total Recordable Environmental Events (2025-2031 Targets)

		2025	2026	2027	2028	2029	2030	2031
Total Recordable Environmental Events	Target	11	10	10	10	10	10	10

Note: Low TREE is good.

4.3 Reliability

Reliability performance is assessed using two metrics, Availability Factor ("Availability") and Equivalent Forced Outage Rate ("EFOR"). Historical performance for the period 2016-2024 as well as business plan targets for 2025-2031 are outlined below. Both Availability (Section 4.3.1) and EFOR (Section 4.3.2) are calculated on a weighted basis, using each regulated hydroelectric unit's Maximum Continuous Rating ("MCR").[19] The EFOR metric, in particular, is influenced by the number of hours a unit operates.

Consequently, the overall reliability performance of the regulated hydroelectric fleet is primarily driven by 12 stations with both high MCR and a five-year average generation of greater than 500GWh. Together, these 12 stations account for approximately 87% of all regulated hydroelectric generation. Given their substantial influence on fleet-wide results, the historical performance and targets of these 12 stations are highlighted in Charts 6-9, alongside the performance and targets of each Region and the overall regulated hydroelectric fleet.

[19] MCR is the maximum electrical power output that can be continuously generated, provided adequate inflow is available. The unit is assumed to be operating at unity power factor and at the indicated reference gross head. MCR observes generator and turbine limitations.

4.3.1 Availability

Availability is the percentage of a given operating period (typically 8,760 hours in a year) in which a generating unit is available without any outages. This metric does not account for the availability of water and is therefore independent of hydrological constraints.[20] Unit hours that are not spent in outage states are weighted by the respective unit's MCR. Outages caused by external factors such as severe weather, fish spawning, active wildfires, and Hydro One equipment outages are not considered. Chart 6 presents historical and target Availability performance for the years 2016-2024.

Chart 6 – Regulated Hydroelectric Historic Availability (%, 2016-2024)

Station	Station Age		2016	2017	2018	2019	2020	2021	2022	2023	2024
DeCew Falls 2 GS	81	Actual	88.9%	45.5%	47.6%	61.0%	93.4%	93.7%	96.1%	78.2%	54.5%
		Target	85.3%	45.2%	84.6%	94.2%	93.8%	96.2%	96.9%	82.6%	67.1%
Sir Adam Beck 1 GS	103	Actual	73.2%	78.0%	91.1%	81.6%	92.7%	88.1%	94.1%	92.8%	93.2%
		Target	82.3%	81.1%	88.1%	84.4%	86.0%	75.0%	81.7%	86.6%	92.2%
Sir Adam Beck 2 GS	71	Actual	95.2%	96.3%	95.6%	93.5%	96.0%	96.4%	94.7%	94.6%	95.8%
		Target	93.8%	92.2%	95.2%	97.0%	96.6%	95.8%	92.1%	89.7%	95.4%
Niagara Region (5 Stations)	**90 (average)**	Actual	84.7%	85.8%	88.4%	86.2%	91.7%	91.2%	91.8%	90.0%	89.6%
		Target	85.4%	84.4%	91.4%	91.4%	92.7%	90.3%	88.5%	87.2%	91.9%
Cameron Falls GS	105	Actual	96.2%	97.0%	98.9%	79.9%	99.4%	89.0%	97.7%	96.3%	78.8%
		Target	97.1%	92.4%	89.4%	90.3%	94.8%	90.0%	97.5%	91.2%	82.6%
Pine Portage GS	75	Actual	94.9%	96.4%	96.0%	99.0%	86.0%	94.3%	95.9%	91.4%	88.0%
		Target	95.1%	95.2%	91.7%	97.8%	88.2%	92.9%	98.3%	91.4%	97.2%
Western Region (27 Stations)	**95 (average)**	Actual	92.3%	87.6%	87.6%	90.1%	88.0%	80.3%	88.3%	84.3%	85.3%
		Target	92.2%	90.2%	89.0%	90.7%	83.5%	84.6%	92.2%	87.2%	91.7%
Abitibi Canyon GS	92	Actual	92.4%	96.4%	86.5%	91.9%	71.5%	94.2%	71.0%	62.1%	71.4%
		Target	90.5%	93.4%	90.2%	85.2%	78.1%	75.3%	74.6%	68.4%	64.1%
Chats Falls GS	94	Actual	88.0%	87.8%	89.7%	95.3%	92.9%	90.5%	79.7%	87.4%	86.7%
		Target	90.4%	87.3%	87.4%	91.4%	88.9%	89.1%	95.2%	93.6%	89.4%
Chenaux GS	75	Actual	93.2%	90.6%	81.6%	80.0%	97.9%	73.1%	81.5%	80.5%	82.4%
		Target	90.2%	91.4%	86.3%	88.2%	89.7%	87.3%	93.6%	89.1%	84.4%
Des Joachims GS	75	Actual	90.6%	90.1%	78.3%	78.5%	79.4%	78.1%	81.7%	82.3%	90.0%
		Target	91.8%	90.8%	86.9%	80.9%	77.2%	77.6%	68.7%	83.8%	81.7%
Otter Rapids GS	64	Actual	97.3%	95.5%	90.2%	94.2%	91.8%	90.7%	93.7%	88.9%	80.8%
		Target	93.0%	93.0%	88.7%	85.9%	92.8%	91.5%	93.1%	83.5%	72.9%
Otto Holden GS	73	Actual	88.8%	90.1%	76.5%	77.4%	76.9%	80.8%	76.8%	80.0%	87.1%
		Target	89.6%	88.3%	95.1%	73.5%	70.5%	66.6%	59.9%	80.5%	81.2%
R.H. Saunders GS	67	Actual	90.8%	92.8%	94.5%	89.0%	95.5%	92.4%	89.4%	85.6%	82.7%
		Target	91.0%	90.2%	91.3%	85.0%	90.5%	92.5%	89.2%	91.3%	85.5%
Eastern Region (22 Stations)	**83 (average)**	Actual	91.1%	89.6%	84.0%	86.1%	87.2%	88.3%	85.0%	82.4%	82.1%
		Target	89.1%	88.5%	87.7%	85.1%	84.3%	83.9%	82.6%	85.9%	82.8%
All 54 Regulated Hydroelectric Stations	**90 (average)**	Actual	89.0%	88.0%	86.0%	86.6%	88.8%	88.4%	87.8%	85.4%	85.2%
		Target	88.1%	87.3%	89.2%	88.0%	87.3%	86.2%	85.8%	86.6%	87.1%

Note: High Availability is good.

[20] Hydroelectric generation is intrinsically linked to the amount of water in reservoirs or rivers as this determines the potential for electricity generation. If water levels are low or flow rates are insufficient, a station may not be able to generate power, even if it is technically available in terms of equipment.

Overall Regulated Hydroelectric Performance

When analyzing trends in Availability, it is important to distinguish whether unavailability is driven by planned or forced outages, as each factor has different implications for operational reliability and asset management. Unavailability across the regulated hydroelectric fleet is consistently attributed more to planned activities than forced outage events.

Between 2016-2024, approximately 70% of total unavailability was attributable to planned outages, demonstrating that the majority of unavailability was anticipated and proactively managed, rather than resulting from unexpected equipment failures. The regional distribution of weighted planned outage hours over this period was as follows: Eastern Region accounted for 61%, Niagara Region 28%, and Western Region 11% of the total planned outage-related unavailability. The remaining 30% of unavailability during this period was attributable to forced outages. Notably, forced outages peaked in 2019, primarily driven by large stations such as R.H. Saunders GS and Sir Adam Beck 1 GS.

Forecasted Availability Targets

Chart 7 provides the annual Availability targets for the 2025-2031 period. Availability targets are directly informed by the forecasted multi-year outage plan and historical forced outage and operation hours. As discussed earlier, there is an increased number of maintenance and refurbishment projects planned during the forecast period to address aging infrastructure and to sustain long-term reliability. These planned outages are essential for proactively managing asset health and minimizing the risk of forced outages in the future. As a result, the forecasted Availability targets have been adjusted to reflect the expected impact of these necessary planned outages. With this approach, performance metrics remain transparent and achievable, given the known scope of work. While this results in lower short-term Availability targets, it represents a deliberate strategy to support the long-term sustainability and reliability of the regulated hydroelectric fleet. OPG expects to return to higher Availability levels once this critical period of asset renewal is complete.

Fleet annual targets remain above the five-year (2019-2023) historical median industry benchmark of 82.6% as referenced in Section 5.2. Additionally, the RG Excellence Plan (Section 3.4.1) aims to sustain Availability by enhancing outage planning processes and shortening unit-over-unit refurbishment outages, where possible.

Chart 7 – Regulated Hydroelectric Availability (%, 2025-2031 Targets)

Station	Station Age	2025	2026	2027	2028	2029	2030	2031
DeCew Falls 2 GS	81	94.1	90.9	96.0	94.0	95.7	67.0	76.3
Sir Adam Beck 1 GS	103	86.5	84.4	83.1	85.3	84.6	88.7	94.2
Sir Adam Beck 2 GS	71	94.8	95.2	84.4	83.9	83.5	83.8	83.9
Niagara Region (5 Stations)	**90 (average)**	**89.9**	**90.8**	**84.3**	**83.8**	**83.4**	**82.8**	**84.1**
Cameron Falls GS	105	84.3	79.3	97.0	93.7	95.1	92.0	98.2
Pine Portage GS	75	92.3	99.1	93.9	97.6	72.7	98.5	78.6
Western Region (27 Stations)	**95 (average)**	**87.9**	**89.3**	**84.0**	**81.7**	**85.1**	**89.8**	**83.2**
Abitibi Canyon GS	92	80.5	93.1	90.9	87.0	89.4	82.0	75.2
Chats Falls GS	94	90.3	91.8	87.1	84.9	84.4	85.2	94.3
Chenaux GS	75	83.5	89.1	89.7	82.8	79.6	79.3	80.9
Des Joachims GS	75	94.7	82.5	83.9	90.3	91.2	95.0	89.8
Otter Rapids GS	64	71.2	72.8	71.7	62.4	81.6	82.0	82.3
Otto Holden GS	73	83.8	81.2	75.0	78.7	80.2	75.8	82.8
R.H. Saunders GS	67	84.1	87.6	85.7	84.2	84.3	79.7	82.0
Eastern Region (22 Stations)	**83 (average)**	**85.7**	**84.7**	**83.4**	**84**	**85.9**	**84.4**	**83.5**
All 54 Regulated Hydroelectric Stations	**90 (average)**	**87.5**	**87.4**	**83.8**	**83.7**	**84.9**	**84.4**	**83.7**

Note: High Availability is good.

4.3.2 Equivalent Forced Outage Rate

EFOR is an indicator of generating unit reliability measured by the ratio of time the unit was forced out-of-service (completely or partially) to the total time the unit was operating and forced out-of-service (completely or partially). Unit hours are weighted by MCR.

Increases to planned outage hours or states when the unit is available but not operating will reduce the total potential operating hours, thereby increasing the relative impact of any forced outages on the metric. This relationship is a significant consideration when interpreting reliability

performance data. Additionally, a forced outage or derate[21] does not always result in a loss of electricity generation as water may not be available. In other instances, alternative units at the same station may be dispatched to maintain production.

Chart 8 presents EFOR performance over 2016-2024 for the aggregate of the 54 regulated hydroelectric generating stations, as well as each Region. Chart 8 also highlights the performance of the 12 highest generating stations because of their substantial influence on fleet-wide results.

Chart 8 – Regulated Hydroelectric Historical EFOR (%, 2016-2024)

Station	Station Age		2016	2017	2018	2019	2020	2021	2022	2023	2024
DeCew Falls 2 GS	81	Actual	0.3%	0.5%	0.5%	11.3%	3.6%	5.3%	1.7%	2.0%	1.0%
		Target	2.5%	2.1%	1.7%	1.8%	1.6%	1.6%	1.9%	2.2%	1.8%
Sir Adam Beck 1 GS	103	Actual	8.6%	6.4%	0.4%	15.7%	4.7%	2.6%	0.8%	0.7%	1.6%
		Target	3.5%	3.2%	3.6%	4.1%	3.7%	3.9%	4.0%	3.3%	3.3%
Sir Adam Beck 2 GS	71	Actual	0.6%	0.2%	2.0%	2.9%	2.2%	1.0%	2.4%	0.4%	1.3%
		Target	0.4%	0.4%	0.4%	0.4%	0.4%	0.6%	0.8%	0.9%	0.9%
Niagara Region (5 Stations)	**90 (average)**	**Actual**	**2.1%**	**2.5%**	**2.9%**	**8.4%**	**5.1%**	**4.6%**	**4.6%**	**3.5%**	**4.2%**
		Target	**1.3%**	**1.2%**	**1.3%**	**1.4%**	**1.4%**	**1.9%**	**2.3%**	**2.5%**	**2.5%**
Cameron Falls GS	105	Actual	0.2%	0.3%	0.5%	1.0%	0.4%	3.5%	0.1%	0.5%	3.0%
		Target	0.9%	0.7%	0.6%	0.8%	0.9%	0.9%	0.5%	0.5%	0.5%
Pine Portage GS	75	Actual	1.3%	2.6%	0.8%	0.4%	0.2%	0.5%	0.5%	0.4%	14.0%
		Target	0.8%	0.6%	0.7%	1.2%	1.4%	1.3%	0.7%	0.6%	0.6%
Western Region (27 Stations)	**95 (average)**	**Actual**	**2.1%**	**6.5%**	**4.0%**	**2.7%**	**4.2%**	**7.1%**	**4.9%**	**2.3%**	**10.0%**
		Target	**1.8%**	**1.8%**	**2.0%**	**2.5%**	**2.5%**	**2.9%**	**2.0%**	**2.4%**	**2.4%**
Abitibi Canyon GS	92	Actual	1.4%	0.4%	8.6%	1.1%	7.3%	3.1%	2.7%	1.1%	2.1%
		Target	3.1%	3.0%	2.8%	2.4%	2.4%	1.8%	2.4%	2.4%	2.4%
Chats Falls GS	94	Actual	4.1%	3.3%	1.8%	0.9%	1.2%	1.4%	1.5%	0.4%	0.5%
		Target	1.1%	1.1%	1.6%	1.6%	1.7%	1.6%	1.6%	1.6%	1.6%
Chenaux GS	75	Actual	3.2%	0.5%	3.0%	2.8%	0.7%	0.6%	2.2%	2.1%	0.6%
		Target	0.4%	0.7%	1.1%	0.9%	1.0%	1.7%	1.7%	1.6%	1.6%
Des Joachims GS	75	Actual	1.9%	1.3%	0.2%	0.5%	5.1%	0.8%	0.6%	1.7%	0.2%
		Target	0.7%	0.8%	1.0%	0.9%	1.0%	1.2%	1.7%	1.5%	1.4%
Otter Rapids GS	64	Actual	0.5%	0.3%	0.4%	2.1%	2.7%	6.1%	2.9%	3.1%	2.9%
		Target	3.9%	3.7%	3.2%	2.8%	2.8%	1.7%	1.7%	2.1%	2.0%
Otto Holden GS	73	Actual	1.9%	2.9%	3.3%	3.5%	10.0%	2.8%	1.0%	1.0%	0.8%
		Target	0.4%	0.5%	0.7%	0.7%	0.7%	1.7%	2.0%	2.1%	2.1%
R.H. Saunders GS	67	Actual	4.4%	4.6%	1.2%	9.8%	2.0%	0.4%	5.1%	3.5%	3.2%
		Target	0.4%	0.4%	0.6%	0.9%	1.0%	1.9%	2.1%	2.2%	2.2%
Eastern Region (22 Stations)	**83 (average)**	**Actual**	**2.7%**	**3.2%**	**5.2%**	**6.1%**	**6.5%**	**1.8%**	**3.6%**	**2.6%**	**5.6%**
		Target	**1.9%**	**2.0%**	**2.0%**	**2.1%**	**2.1%**	**2.6%**	**3.1%**	**3.0%**	**3.0%**
All 54 Regulated Hydroelectric Facilities	**90 (average)**	**Actual**	**2.4%**	**3.3%**	**4.2%**	**6.7%**	**5.7%**	**3.5%**	**4.1%**	**2.9%**	**5.5%**
		Target	**1.6%**	**1.7%**	**1.7%**	**1.8%**	**1.8%**	**2.3%**	**2.7%**	**2.6%**	**2.7%**

Note: Low EFOR is good.

[21] A derate is a reduction of a generating unit's capacity. The generating unit can run but cannot run at MCR. Derates can be planned or unplanned.

Overall Regulated Hydroelectric EFOR Performance

The overall fleet EFOR performance fluctuated during the 2016-2024 period, ranging from 2.4% to 6.7% and often exceeding targets, which have remained consistently lower (1.6%-2.7%), reflecting higher-than-expected forced outages at larger capacity stations, especially in 2019, 2020, and 2024. Over the 2016-2024 historical period, Eastern Region accounted for 46% of the total weighted forced outage hours, primarily due to forced outages at R.H. Saunders GS. Niagara Region represented 43% of forced outage hours, largely attributed to Sir Adam Beck Pump GS. Western Region contributed the remining 11% of forced outage hours, with Manitou Falls GS being the primary contributor within the Region.

EFOR performance of the largest capacity stations, Sir Adam Beck 1 GS, Sir Adam Beck 2 GS, R.H. Saunders GS, and Des Joachims GS, has remained generally stable over the historical period. Sir Adam Beck 1 GS and R.H. Saunders GS experienced challenges in 2019, contributing to a notable fleet-wide increase in EFOR that year. R.H. Saunders GS also experienced challenges in 2022 with some improvements observed in 2023 and 2024.

Forecasted EFOR Targets

Target setting for EFOR is conducted through a review of historical performance data,[22] including forced outage hours, in conjunction with the forecasted multi-year outage plan. Historical EFOR data specific to each station is used to project the expected impact of forced outage hours. Historical available but not operating hours specific to each station is used to project the impact of such hours on the estimated operating hours. The forecasted outage plan for each station is incorporated to account for the influence of planned outages on estimated operating hours. Operating hours are estimated using the planned outage schedule, projected forced outage hours, and available but not operating hours. These estimated operating hours provide the foundation for establishing EFOR performance targets, as presented in Chart 9.

[22] To set EFOR targets, OPG reviews the past 10 years of historical data for each station, such as EFOR, available but not operating hours, and forced outage hours. The highest and lowest annual values are excluded, and the average is calculated using the remaining eight years. This approach helps to set targets that reflect typical performance while minimizing the impact of unusual years.

The EFOR targets for the 2025-2031 period, ranging from 3.2% to 3.6%, are higher than the historical period, reflecting the anticipated increase in both planned outages and forced outage hours resulting from the condition of aging equipment across the regulated hydroelectric fleet. As many units approach refurbishment and overhaul milestones, a higher incidence of equipment-related outages is expected, which will reduce overall operating hours. In addition to accounting for the expected increase in planned outages, the elevated targets are intended to account for these forecasted equipment-related challenges, so that performance expectations remain realistic and aligned with the current state of asset health and the planned work program schedule.

Despite the above challenges, the regulated hydroelectric fleet targets remain below (i.e., more stringent) than the benchmarked five-year (2019-2023) industry median of 4.05% (see Section 5.2). In addition to undertaking planned investments to refurbish and rehabilitate aging assets, the RG Excellence Plan (Section 3.4.1) further aims to sustain EFOR performance by focusing efforts to advance key areas of equipment reliability and improving work management.

Chart 9 – Regulated Hydroelectric Equivalent Forced Outage (%, 2025-2031 Targets)

Station	Station Age	2025	2026	2027	2028	2029	2030	2031
DeCew Falls 2 GS	81	3.2	2.0	1.9	2.0	2.0	2.2	1.8
Sir Adam Beck 1 GS	103	3.7	3.5	3.3	3.4	3.4	3.4	3.4
Sir Adam Beck 2 GS	71	1.4	1.4	1.3	1.4	1.4	1.4	1.4
Niagara Region (5 Stations)	**90 (average)**	**3.1**	**3.5**	**3.5**	**3.4**	**3.4**	**3.5**	**3.3**
Cameron Falls GS	105	0.4	0.7	0.8	0.8	0.8	0.8	0.8
Pine Portage GS	75	0.5	0.8	0.8	0.8	0.9	0.9	0.9
Western Region (27 Stations)	**95 (average)**	**2.4**	**3.0**	**3.0**	**3.0**	**3.0**	**3.0**	**3.0**
Abitibi Canyon GS	92	2.7	2.9	2.7	2.7	2.7	2.7	2.7
Chats Falls GS	94	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Chenaux GS	75	2.4	2.5	2.5	2.4	2.5	2.5	2.5
Des Joachims GS	75	1.8	1.7	1.7	1.7	1.7	1.7	1.7
Otter Rapids GS	64	2.0	2.3	2.2	2.0	2.1	2.1	2.1
Otto Holden GS	73	2.8	2.9	2.9	2.8	2.8	2.7	2.8
R.H. Saunders GS	67	3.4	4.0	4.0	3.9	3.9	3.9	3.9
Eastern Region (22 Stations)	**83 (average)**	**3.5**	**3.9**	**3.9**	**3.9**	**3.9**	**3.9**	**3.9**
All 54 Regulated Hydroelectric Facilities	**90 (average)**	**3.2**	**3.6**	**3.6**	**3.6**	**3.6**	**3.6**	**3.6**

Note: Low EFOR is good.

4.4 Regulated Hydroelectric Cost Effectiveness

4.4.1 Unit Energy Cost

OM&A Unit Energy Cost ("UEC") is a measure of financial productivity. It measures the OM&A costs per unit of energy produced (MWh), calculated as the total OM&A costs (Base and Project), divided by the annual regulated hydroelectric generation.

By focusing on Base and Project OM&A costs, the UEC calculation excludes capital costs, gross revenue charge and any other expenses not directly related to operations, maintenance, and administration. The gross revenue charge (see Ex. F1-4-1) is excluded because it is determined by provincial regulation and therefore not within the direct control of OPG. Chart 10 shows UEC for the historical 2016-2024 period.

Chart 10 – Regulated Hydroelectric Historical Unit Energy Cost ($/MWh, 2016-2024)

	2016	2017	2018	2019	2020	2021	2022	2023	2024
Regulated Hydroelectric Unit Energy Cost ($/MWh)	8.10	8.10	8.70	8.50	8.50	10.00	9.60	10.20	10.00
Target as per Business Plan	N/A	8.70	8.30	8.40	8.70	8.80	9.20	9.30	11.00

Note: SBG, NYPA water transactions and related Gross Revenue Charge are excluded from UEC.

UEC increased from $8.10/MWh in 2016 to $10.00/MWh in 2024, representing an approximate 23% increase over this period. This upward trend in UEC is primarily attributable to investments related to unit overhauls and removal costs associated with capital projects, labour cost escalation, and post-COVID inflationary impacts.

Chart 11 shows the forecast regulated hydroelectric UEC for the 2025-2027 period. UEC is forecast to increase over the period, rising from $11.01/MWh in 2025 to $13.20/MWh in 2027. This increase reflects the following:

- A planned increase in Project OM&A costs associated with overhauls and removals of aging infrastructure (described in Ex. F1-3-1).
- A reduction in forecast production beginning in 2026 due to:
  - The return of Niagara River flows to their long-term average (described in E1-1-2), which is projected to continue into 2027.

- An increase in outages necessary to complete major projects such as refurbishments, particularly at large-capacity generating stations (e.g., Sir Adam Beck 1 GS, Sir Adam Beck 2 GS, and R.H. Saunders GS), as well as the ongoing maintenance program (as described in Section 3.2).

Chart 11 – Regulated Hydroelectric Unit Energy Cost Forecast ($/MWh, 2025-2027)

	2025	2026	2027
Regulated Hydroelectric Unit Energy Cost ($/MWh)	$11.01	$11.51	$13.20

Note: SBG, NYPA water transactions and related Gross Revenue Charge are excluded from UEC.

The combination of increased OM&A costs and reduced production drives the upward trend in UEC. These projections are intended to maintain an appropriate balance between supporting grid reliability and ongoing operational needs, and executing the necessary investments associated with managing an aging fleet.

4.4.2 Total Generation Cost

Total Generating Cost ("TGC") is defined as the total cost of operating the regulated hydroelectric facilities, encompassing operations, maintenance and administration (OM&A), fuel (water) and sustaining[23] capital, divided by total generation (MWh). To mitigate the impact of year-over-year fluctuations in capital expenditures, TGC is measured as a three-year historical average.

As illustrated in Chart 12, TGC increased from $22.40/MWh in 2016 to $32.00/MWh in 2024, representing an approximate 43% increase over this period. This upward trend is primarily attributable to higher capital investments related to turbine-generator refurbishment projects, labour cost escalation, and post-COVID inflationary impacts.

Chart 12 – Regulated Hydroelectric Total Generation Cost Performance ($/MWh, 2016-2024)

	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Generation Cost ($/MWh)	22.40	23.00	23.60	24.10	25.30	27.60	28.70	31.00	32.00

[23] Redevelopment projects are excluded from TGC.

5.0 REGULATED HYDROELECTRIC SAFETY AND RELIABILITY BENCHMARKING

OPG recognizes the value of cost and performance benchmarking, both for identifying areas of strength and for highlighting challenges that inform business planning and continuous improvement initiatives. Benchmarking within the hydroelectric sector presents unique challenges due to several factors, including:

- Limited stable peer groups
- Considerable variations in asset capacity factors (i.e., MW)
- Differences in asset age (equipment and life cycle considerations)
- Diverse operating contexts (geographical area, regulatory regimes, water availability, etc.)

Unlike other segments of the electricity industry, hydroelectric facilities exhibit considerable variability due to these and other factors, making direct, “apples-to-apples” comparisons difficult. As a result of these inherent differences in station and utility profiles, hydroelectric benchmarking efforts generally focus on isolating reasonably comparable peer groups and/or making adjustments for uncontrollable differences. These approaches can reduce the size of the peer population and may introduce assumptions into the benchmarking analysis. Hydroelectric benchmarking is therefore generally used to guide understanding of general performance trends or relative positioning, not as an absolute measure of performance. Unique factors of significance (peaking versus baseload station, regulatory constraints, grid supporting role for frequency regulation, etc.) that impact reliability and associated investment requirements should also be taken into consideration when assessing performance. The value of hydroelectric benchmarking performance also needs to be appropriately balanced with the engineering assessments that inform investment requirements to sustain future performance.

OPG’s regulated hydroelectric stations are benchmarked for safety, reliability, and cost performance. Three main data sets for hydroelectric benchmarking are used:

- Electric Utility Cost Group (“EUCG”)
- EC (formerly Canadian Electrical Association)
- Edison Electric Institute (“EEI”)

5.1 Total Recordable Injury Frequency Benchmarking

OPG is committed to the safety of its employees. Safety performance is benchmarked through industry associations in Canada and the United States. These associations collect safety performance data annually from their members who report their injury statistics based on standardized guidelines.

OPG participates in the annual EEI Safety Survey which is an industry-leading benchmarking tool. A varying number of utilities participate in the EEI safety benchmarking including Duke Energy, Tennessee Valley Authority, and Pacific Gas and Electric Company. Aggregated results for OPG's renewable generation facilities[24] are compared to the aggregated results of the hydroelectric utilities in the entire group.

Furthermore, OPG participates in Safety Surveys with participants from EUCG and National Hydropower Association. Participating utilities include entities such as Hydro-Québec, New Brunswick Power, Tennessee Valley Authority, and Duke Energy. Aggregated results for OPG's renewable generation stations are compared to the aggregated results of the hydroelectric utilities in the entire group.

OPG also participates in EC's safety benchmarking. Participants include utilities such as Manitoba Hydro, SaskPower, Nova Scotia Power, and British Columbia Hydro. Aggregated results for OPG's renewable generation stations are compared to the aggregated results of a subset of all EC member organization with more than 1,500 employees.

In 2023, the most recent benchmarked year, RG's TRIF was 0.46. This performance ranks in the first quartile of EC utilities and second quartile in both EEI and EUCG benchmarking. Training and awareness programs have been established to ensure the safety of employees. To sustain good benchmarking performance, RG will continue to advance safety performance by promoting clear safety messages, championing continuous improvement in work protection and corrective action culture, and strengthening safe work planning and best practices.

[24] Includes both regulated and unregulated facilities.

5.2 Reliability Benchmarking

OPG has been participating in the EUCG Hydroelectric Productivity Committee benchmarking program (cost and reliability) since 2006. The EUCG benchmarking initiative includes a broad cross-section of Canadian and American utilities, with past and current participants such as New Brunswick Power, Hydro-Québec, Pacific Gas and Electric Company, U.S. Army Corps of Engineers, U.S. Bureau of Reclamation, Tennessee Valley Authority, Seattle City Light, Chelan County Public Utility District, Duke Energy, and Bonneville Power Authority. As noted above, the composition of participating utilities often varies from year to year, which can present challenges in establishing consistent, long-term comparative trends.

EUCG organizes its reliability benchmarking using standardized categories to facilitate comparisons among hydroelectric generating stations. EUCG's key reliability metrics include Availability[25] and Forced Outage Rate ("FOR").[26] For comparability, EUCG classifies generating stations according to their installed capacity (MW), using the following categories:

- Greater than 500MW
- Between 100 and 500MW
- Between 30 and 100MW
- Under 30MW

This categorization facilitates more meaningful benchmarking by enabling comparisons between facilities of similar scale.

The most recent benchmarking results, as shown in Chart 13 below, compare Availability and FOR performance across various station capacity categories against industry quartiles. As there can be broad fluctuation in a single year, an aggregate of the last five years (2019-2023) of EUCG

[25] The definition of "Availability" as used in the context of EUCG benchmarking differs from the "Availability Factor" referenced in the Performance section of this report. Specifically, the Availability metric as applied in EUCG benchmarking does not account for derates, whereas the Availability Factor in the Performance section does include the impact of derates.

[26] Forced Outage Rate ("FOR") is the percentage of time the generating station is forced out of service due to unexpected equipment failures or other unplanned events, relative to the total time the unit is operating. It differs from EFOR in that it does not include derates.

benchmarking data is considered to smooth out year-to-year fluctuations and provide a more representative measure of performance. The data set consists of 15 member utilities, including OPG. All data is blind, meaning the identities of the specific utilities providing data are not disclosed to participants. Of OPG's 54 regulated hydroelectric stations, two stations under 30MW capacity (Calabogie GS and Nipissing GS) are not included in the data set as they were not in-service during the period.

Chart 13 – Regulated Hydroelectric Availability and Forced Outage Rate Benchmarking Results Aggregate Five-Year (2019-2023) Performance

Station	Average OPG Station Age	Number of OPG Stations	OPG Capacity (MW)	Availability EUCG Median	OPG Availability Results	FOR EUCG Median	OPG FOR Results
All Stations <30MW	101	28	174	82.27%	82.72%	5.28%	14.70%
All Stations 30-100MW	76	9	766	85.45%	85.30%	2.39%	2.66%
All Stations 100-500MW	73	12	2609	85.39%	83.37%	5.11%	5.40%
All Stations >500MW	80	3	3102	83.15%	93.26%	3.13%	2.61%
OPG Regulated Hydroelectric Facilities	**90**	**52**	**6651**	**82.60%**	**87.53%**	**4.05%**	**4.05%**

Note: High Availability is Good. Low FOR is Good.
For the purposes of EUCG Benchmarking, Chat Falls GS full station capacity is considered in this table (192MW).

Availability Benchmarking Results

OPG's regulated hydroelectric fleet demonstrates strong operational performance, ranking very closely to the first quartile (EUCG first quartile 87.65% vs. OPG actual 87.53%) for the 52 benchmarked stations. Facilities with capacities greater than 500MW exhibit particularly robust availability, with actual performance of 93.26% significantly outperforming the industry median of 83.15%. Stations with capacities under 30MW and those in the 30-100MW range perform near the industry median with actual availability rates of 82.72% and 85.30%, compared to the median benchmarks of 82.27% and 85.45%, respectively. Generating stations within the 100-500MW category are positioned in the third quartile with an actual availability of 83.37% versus a median of 85.39%. Overall, the fleet's performance reflects a high standard of reliability and operational excellence, particularly among the largest stations.

Forced Outage Rate Benchmarking Results

For stations with greater than 500MW capacity, the regulated hydroelectric FOR is 2.61%, indicating performance is better than industry median (3.13%) for these stations. When considering all regulated hydroelectric stations, FOR is 4.05%, which places it at industry median (4.05%). FOR performance at stations in the 30-100 MW range (actual 5.40% versus median 5.11%), and the 100-500MW range (actual 2.66% versus median 2.39%) was slightly below the median. Stations under 30MW show a larger gap in performance from median (actual 14.70% versus median 5.28%), which resulted in third quartile performance. However, stations under 30MW capacity represent only 2.6% of OPG's total regulated hydroelectric capacity in the dataset.

These results demonstrate that the largest stations in OPG's regulated hydroelectric fleet are performing at or above the industry median for reliability and, on average, the entire fleet is performing at the industry median. Diligent maintenance and execution of unit refurbishments and replacement of aging equipment is necessary to sustain performance over time.

5.3 REGULATED HYDROELECTRIC COST BENCHMARKING

As discussed in Ex. A1-3-2, OPG has performed total cost benchmarking through a third party, London Economics International LLC ("LEI"). This benchmarking, provided as Ex. A1-3-2, Attachment 3, performed an econometric analysis comparing the total cost performance of OPG's regulated hydroelectric facilities to comparable industry peers in North America. LEI's econometric analysis controls for factors[27] that may impact costs and may differ across utilities. Similar to OPG's internal benchmarking, LEI utilized data from EUCG to compare OPG's efficiency to other North American utilities[28] using both OPG's OM&A-only spending, and OM&A plus sustaining capital ("OM&A + SC").

[27] These factors were determined by LEI to be prices of inputs, station capacity, control room staffing, number of active units, and time.

[28] As noted in Ex. A1-3-2, Attachment 3, LEI excluded some utilities from the dataset as they had not provided valid data for some of the expense categories or other independent variables for the entire study timeframe. The final comparable dataset included 253 stations owned/operated by 13 hydroelectric operators, including OPG.

LEI's findings, shown in Charts 14 and 15, indicate that OPG is a cost-efficient hydroelectric generator compared to the peer group. Specifically, OPG ranked 3rd (1st quintile) for OM&A and 4th (second quintile) for OM&A + SC, showing that, on average, OPG's expenditures for the regulated hydroelectric facilities are lower than other utilities.

Chart 14 – LEI's Findings: Relative Efficiency Ranking (OM&A)

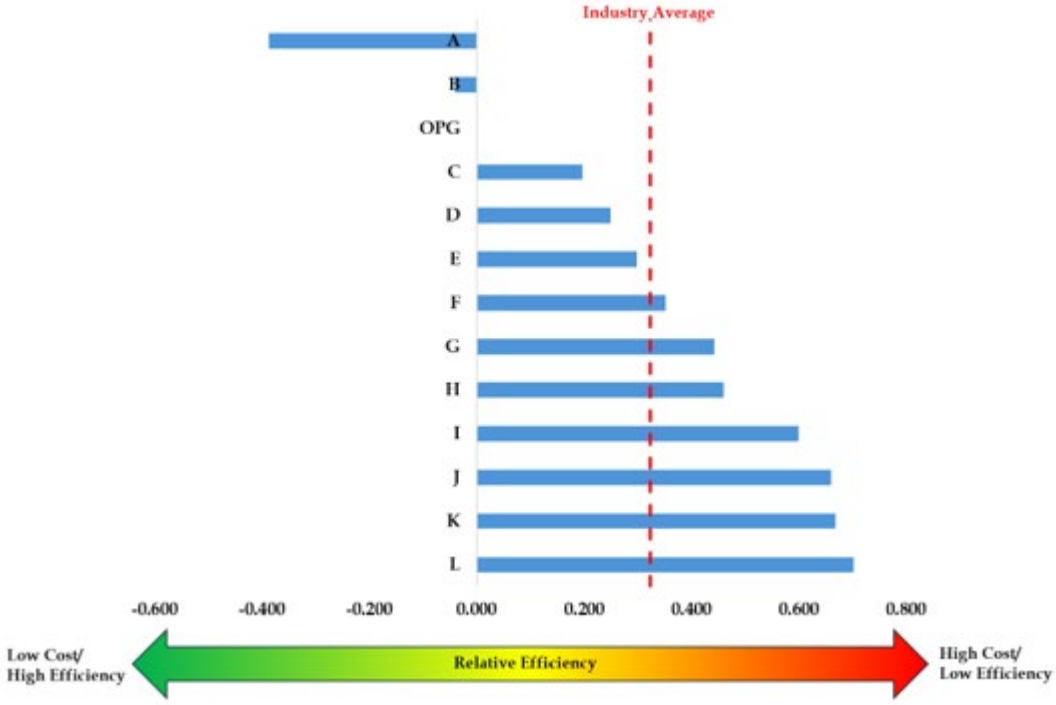
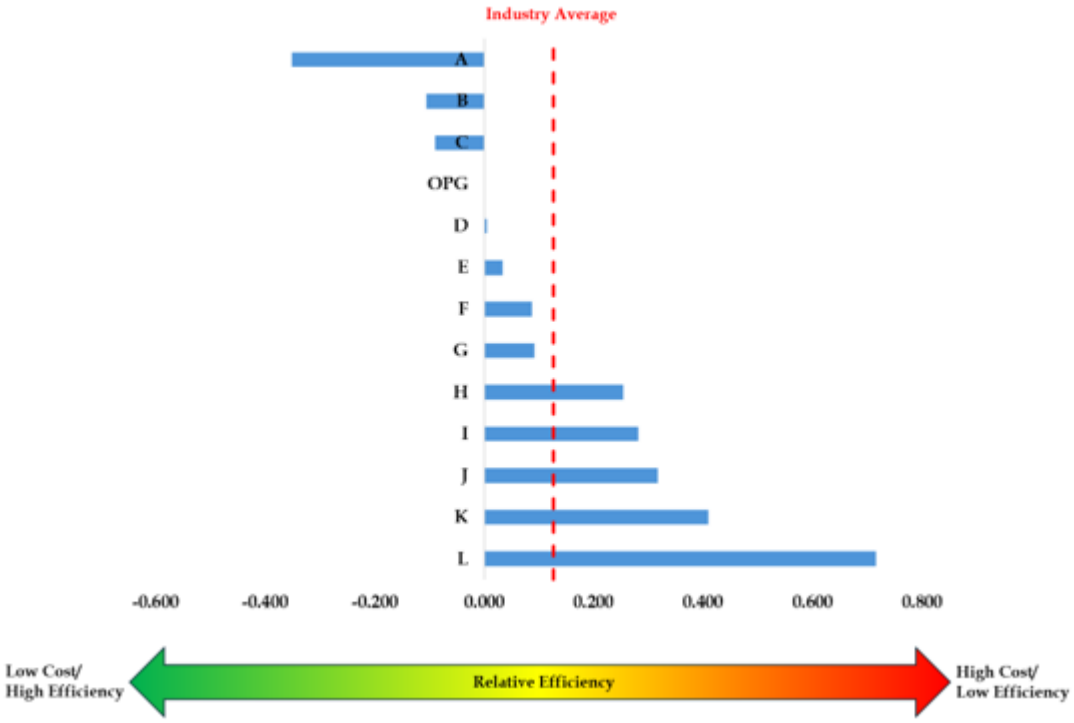


Chart 15 – LEI's Findings: Relative Efficiency Ranking (OM&A + SC)



Combined with the reliability benchmarking results discussed above, LEI's econometric total cost benchmarking analysis demonstrates that OPG continues to be an efficient hydroelectric generator while maintaining levels of reliability consistent with industry median, despite the challenges associated with sustaining an aging fleet. OPG will continue to strive for efficient operations while executing the work program necessary to sustain its regulated hydroelectric assets for future decades.

Numbers may not add due to rounding.

Updated: 2026-03-10
EB-2025-0297
Exhibit F1
Tab 1
Schedule 1
Table 1

Table 1
Operating Costs Summary - Regulated Hydroelectric ($M)

Line No.	Cost Item	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	OM&A:												
1	**Base OM&A**	205.8	208.1	205.6	203.4	204.5	205.4	215.5	236.5	251.2	264.3	274.2	286.2
2	**Project OM&A**	39.0	42.3	53.8	54.3	53.6	81.1	74.1	75.3	69.7	92.6	90.5	127.0
3	**Allocation of Corporate Costs**	51.0	48.4	47.1	47.1	38.4	38.7	39.9	45.3	50.0	50.7	54.0	55.3
4	**Allocation of Centrally Held Costs**	44.6	26.2	29.2	24.1	15.9	28.8	8.0	(12.0)	12.6	1.6	(0.7)	5.6
5	**Asset Service Fee**	6.8	7.5	7.1	9.1	8.6	10.6	13.7	15.0	16.0	18.7	21.5	25.2
6	**Total OM&A**	347.2	332.5	342.8	338.1	321.1	364.6	351.1	360.0	399.5	427.9	439.4	499.3
7	**Gross Revenue Charge**	312.7	319.7	319.2	324.5	323.4	315.7	330.3	336.7	348.6	357.2	354.3	352.2
	Other Operating Cost Items:												
8	**Depreciation and Amortization**	145.2	140.2	145.9	147.3	148.1	153.4	162.7	173.1	174.1	190.8	194.8	215.4
9	**Income Tax**	17.4	10.3	87.7	77.5	93.0	87.9	103.8	60.2	(3.3)	68.8	(3.3)	27.3
10	**Property Tax**	0.9	0.9	0.9	1.0	1.1	1.1	1.0	1.1	1.1	1.1	1.0	2.1
11	**Total Operating Costs**	823.4	803.6	896.6	888.5	886.7	922.6	948.8	931.0	920.0	1,045.8	986.2	1,096.3

Numbers may not add due to rounding.

Table 2a

Regulated Hydroelectric Staff Summary - Regular and Non-Regular (FTEs) [1] - 2016-2019

Line No.	Group[2]	2016 Actual	2017 Actual	2018 Actual	2019 Actual
		(a)	(b)	(c)	(d)
1	**Regular Staff**	980.2	963.6	1,026.0	1,024.4
2	**Non-Regular Staff**	35.2	44.3	52.6	48.8
3	**Total Regulated Hydroelectric**	1,015.4	1,008.0	1,078.6	1,073.2

Notes:

1 Staff FTEs include staff deployed on Base OM&A, Project OM&A, and capital projects.

2 Consistent with OPG's letter dated June 11, 2024, issued in EB-2024-0136, data is provided at the regulated hydroelectric level for 2016-2019.

Numbers may not add due to rounding.

Table 2b

Regulated Hydroelectric Staff Summary - Regular and Non-Regular (FTEs)[1] - 2020-2031

Line No.	Group	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Regulated Hydroelectric Capital:												
1	**Regular Staff**	186.0	203.2	194.7	202.0	244.4	340.7	362.6	374.6	380.5	379.8	369.6	364.2
	Non-Regular Staff												
2	Temporary	6.1	7.3	7.8	13.6	13.5	36.1	64.8	72.9	73.9	79.3	77.9	77.8
3	**Total Regulated Hydroelectric Capital**	192.1	210.5	202.5	215.6	258.0	376.8	427.4	447.5	454.4	459.1	447.5	442.0
	Regulated Hydroelectric OM&A:												
4	**Regular Staff**	855.0	822.0	831.1	840.4	908.8	1004.7	1027.0	1028.3	1018.7	1020.8	1037.5	1041.7
	Non-Regular Staff												
5	Temporary	44.2	60.4	74.4	91.4	69.8	46.9	48.1	45.7	50.3	51.9	44.0	41.9
6	**Total Regulated Hydroelectric OM&A**	899.2	882.4	905.5	931.8	978.6	1,051.6	1,075.0	1,074.0	1,069.0	1,072.7	1,081.5	1,083.6
7	**Total Regulated Hydroelectric**	1,091.4	1,093.0	1,108.0	1,147.4	1,236.6	1,428.3	1,502.4	1,521.5	1,523.4	1,531.8	1,529.0	1,525.6

Notes:

1 Staff FTEs include staff deployed on Base OM&A, Project OM&A, and capital projects.

PROJECT OM&A COSTS – REGULATED HYDROELECTRIC

1.0 PURPOSE

This evidence provides a summary of the Operations, Maintenance and Administration ("OM&A") project expenses ("Project OM&A") within the regulated hydroelectric portfolio for the historical period (2016-2024), bridge period (2025-2026), and test year (2027).

Consistent with the OEB's letter dated September 17, 2024, issued in EB-2024-0136, OPG has included nine years of historical data for its regulated hydroelectric business below, for the period 2016-2024.

2.0 OVERVIEW

The OM&A projects within the regulated hydroelectric portfolio are largely sustaining expenditures for repairs and maintenance, including turbine-generator overhaul projects and projects related to aging civil infrastructure. OPG defines a project (whether capital or OM&A) as a temporary, unique endeavour undertaken outside the routine base activities of the normal work program. The final decision on whether work will be classified as a capital project or an OM&A project is based on OPG governance. OPG's capitalization policy is set out in Ex. D4-1-1.

OPG is requesting the approval of forecasted regulated hydroelectric Project OM&A expenditures of $127.0M for the 2027 test year. This represents an increase of $46.8M from the annual average of the 2022-2026 term of $80.2M, and reflects the increased Project OM&A portfolio necessary to maintain aging assets, as described in Ex. F1-1-1. Summaries of the regulated hydroelectric Project OM&A expenditures for the historical period, bridge period, and test year can be found in Ex. F1-3-1, Table 1.

As detailed in Ex. F1-1-1, Section 3.2.3.4, Renewable Generation has aligned the management of its OM&A project portfolios with the rest of the company, which includes establishing an unallocated OM&A project portfolio to provide funding in the business plan for

potential projects expected to start in the future but that are not yet fully scoped or approved. Allocated Tier 1 OM&A projects are listed in Ex. F1-3-3.

Unallocated regulated hydroelectric OM&A projects amount to $68.8M in expenditures in the test year, and are primarily composed of planned major maintenance investments to sustain existing site assets and equipment. Unallocated OM&A projects with a potential cost over $5M are presented in Ex. F1-3-3, Tables 4a and 4b. OPG expects that throughout the forecast period, some of these projects (or other projects yet to be identified) will move from the project identification and initiation phases into the project planning and execution phase as part of the ongoing portfolio management process (refer to Ex. D2-1-1, Section 3.1), thus transitioning from unallocated projects to allocated projects. All projects, both allocated and unallocated, have been reviewed and approved to be entered into OPG's business plan in alignment with its asset management and investment planning processes (Ex. D2-1-1, Section 3.2).

The management of regulated hydroelectric OM&A projects uses the same process as for the capital projects as described in Ex. D1-1-1 and Ex. D2-1-1.

3.0 MAJOR CATEGORIES OF OM&A PROJECTS

Regulated hydroelectric Project OM&A expenditures are organized into three categories: portfolio projects, conceptual work for regulated hydroelectric development initiatives, and infrastructure expenditures.

3.1 Portfolio Projects

Project portfolios are developed and tailored to ensure the safety and reliability of OPG's assets, address issues of obsolescence, optimize unit/station generation, or meet regulatory requirements. The regulated hydroelectric Project OM&A portfolio primarily consists of routine sustaining investments to ensure ongoing equipment reliability, with major categories including turbine-generator unit overhaul projects and concrete restoration.

3.1.1 Turbine-Generator Overhaul Projects

Turbine-generator overhaul projects ("overhaul projects") consist of OM&A maintenance activities to sustain reliable operations of the turbine-generator equipment and related systems. Overhaul projects involve work on components that do not yet require replacement but require maintenance to ensure continued operability. Overhaul projects are generally performed every 25-30 years. Over the business plan period, many units will undergo equipment overhauls executed in parallel with capital refurbishments to minimize the number of required outage days.

OPG plans to progress approximately 20 overhaul projects in support of the turbine-generator refurbishment program in the test year, with significant projects at Otter Rapids GS, R.H. Saunders GS, and Stewartville GS. For more information on turbine-generator overhaul projects, refer to Ex. F1-1-1, Section 3.2.1.

3.1.2 Concrete Restoration

OPG plans to progress approximately 30 concrete restoration initiatives in the 2027 test year, with significant work taking place at Stewartville GS and R.H. Saunders GS.

The OM&A work performed as part of concrete restoration programs involves repairs of aging concrete, such as crack repairs and parging,[1] which do not extend the overall life of an asset but allow it to perform its intended function. Conversely, capital work performed to rehabilitate concrete structures involves extensive work including major demolition, concrete replacement, and the integration of new structural supports. Details on capital concrete projects are provided in Ex. D1-1-2.

As discussed in Ex. F1-1-1, Section 3.2.3, concrete restoration work is a critical aspect of OPG's regulated hydroelectric portfolio, particularly in addressing the phenomenon of Alkali-Aggregate Reaction at stations including the R.H. Saunders GS, Otto Holden GS, and Chats

[1] Concrete parging is the application of mortar over walls to provide durability and protection against environmental factors.

Falls GS. OPG is required to spend significant amounts of effort and funding to mitigate the impacts of Alkali-Aggregate Reaction, which has led to increased Project OM&A expenditures.

3.2 Conceptual Work for Hydroelectric Development Investments

In alignment with the Province's expectations detailed in the 2023 Powering Ontario's Growth report[2] and the 2025 Integrated Energy Plan,[3] OPG is continuing to assess the viability of potential development investments in regulated hydroelectric assets. This includes evaluating the options to redevelop stations at or nearing end of life, as well as opportunities to add substantial generation capacity to an existing regulated asset (e.g., via adding new units at existing generating stations).

This conceptual work includes site selection, feasibility analysis, interfacing with key government stakeholders, and engaging with Indigenous communities. Once an investment is deemed viable for progression, it proceeds from the identification and initiation phases into the project planning and ultimately execution phase as part of the ongoing portfolio management process. OPG forecasts to spend $3.7M in Project OM&A on regulated hydroelectric development initiatives in the test year. A summary of historical and forecasted expenditures is provided in Ex. F1-3-1, Table 1.

3.3 Infrastructure

Regulated hydroelectric infrastructure expenditures consist of removal costs associated with capital projects. Removal costs include costs associated with dismantling, crating, tearing down, or disassembling equipment formerly in service. These costs are expensed to Project OM&A in accordance with OPG's capitalization policy (Ex. D4-1-1, Section 2.0). A summary of historical and forecasted removal costs can be found in Ex. F1-3-1, Table 1.

---

[2] Government of Ontario, *Powering Ontario's Growth: Ontario's Plan for a Clean Energy Future*, July 10, 2023 <https://www.ontario.ca/page/powering-ontarios-growth>.
[3] Government of Ontario, *Energy for Generations: Ontario's Integrated Plan to Power the Strongest Economy in the G7*, June 12, 2025, p. 56 <https://www.ontario.ca/page/energy-generations>.

Numbers may not add due to rounding.

Table 1
Project OM&A Summary - Regulated Hydroelectric ($M)

Line No.	Business Unit[1]	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Portoflio Projects (Allocated)												
1	**Niagara Region**	11.9	6.5	6.1	7.4	7.7	5.0	3.9	11.7	6.5	3.0	3.6	3.3
2	**Eastern Region**	16.5	24.3	34.6	34.7	26.7	47.9	58.1	51.4	43.8	47.4	35.2	18.0
3	**Western Region[2]**	9.3	7.3	2.9	1.7	2.9	14.8	4.1	2.0	2.7	3.6	2.9	0.7
4	**Subtotal Portfolio Projects (Allocated)**	37.7	38.1	43.6	43.8	37.3	67.7	66.1	65.1	53.0	53.9	41.7	21.9
5	**Infrastructure[3 4]**	0.7	4.1	10.1	10.5	15.5	13.4	7.9	10.0	14.9	29.1	22.1	32.7
	Portfolio Projects (Unallocated)												
6	**Niagara Region[4]**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.6	2.4	13.5
7	**Eastern Region**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.7	19.3	47.9
8	**Western Region**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.6	1.3	7.4
9	**Subtotal Portfolio Projects (Unallocated)**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.9	22.9	68.8
10	**Small Hydro Redevelopment[4,5]**	0.7	0.1	0.0	0.1	0.8	0.0	0.1	0.2	1.8	1.7	3.8	3.7
11	**Total**	39.0	42.3	53.8	54.3	53.6	81.1	74.1	75.3	69.7	92.6	90.5	127.0

Notes:

1 Operating Region descriptions effective 2021 (see Ex. A1-4-2).

2 Western Region 2021 total includes recognition of a provision of $9.5M in connection with a Final Settlement Agreement with a First Nation to perform remediation work to address shoreline erosion impacts related to work performed by the Hydro-Electric Power Commission of Ontario (Ontario Hydro) at Lake Nipigon in 1925.

3 Reflects all removal costs regardless of related capital project CRVA eligibility.

4 2027 amounts include $25.3M of non-capital costs related to CRVA-eligible projects.

5 Conceptual work to assess the viability of proposed regulated hydroelectric development projects. See F1-3-1, Section 3.2.

Numbers may not add due to rounding.

Table 2
Project OM&A Summary - Regulated Hydroelectric ($M) (Allocated)

Line No.	OM&A Project Category	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	**Regulatory**	3.8	3.3	5.9	3.9	1.9	5.3	3.8	2.5	4.2	4.6	2.6	0.6
2	**Sustaining**	33.9	34.8	37.8	39.8	35.4	62.4	62.3	62.6	48.7	49.4	39.1	21.3
3	**Value Enhancing/Strategic**	0.7	0.1	0.0	0.1	0.8	0.0	0.1	0.2	0.4	0.0	0.0	0.0
4	**Total**	38.3	38.2	43.7	43.8	38.1	67.7	66.2	65.2	53.3	53.9	41.7	21.9

BUSINESS PLANNING AND BENCHMARKING - NUCLEAR

1.0 PURPOSE

This evidence presents the business planning and benchmarking results for OPG's Nuclear Operations and provides a summary of the nuclear operating costs from the 2025-2031 Business Plan in support of the Application.

As used in this evidence, OPG's Nuclear Operations includes Darlington, Pickering and Darlington New Nuclear Program ("DNNP") facilities. As discussed in Ex. A1-4-4, DNNP LP is entering into a lease for the DNNP facilities with OPG. DNNP LP will undertake the development, construction, and operation of the DNNP facilities, with OPG contracted to act as the project manager and operator of the facilities. The Application assumes that DNNP LP enters into the lease and associated arrangements at the end of 2025. DNNP LP will not have its own workforce and will contract for all applicable services with OPG, who will in turn leverage its workforce and organizational infrastructure to provide such services. DNNP LP will reimburse OPG for its fully allocated costs of providing the services. As such, the evidence regarding OPG's Nuclear Operations supports both OPG and DNNP LP's proposed revenue requirements in this Application.

In accordance with the rate-setting proposal for the regulated nuclear facilities, as described in Ex. A1-3-2, forecast information for the IR term (2027-2031) is provided for all operating cost exhibits and capital-related exhibits.

2.0 OVERVIEW

This Application is based on OPG's 2025-2031 Business Plan, which in respect of the regulated nuclear operations was prepared reflecting the business planning process outlined in Ex. A2-2-1 and Section 3.1 below. The methodology employed as part of that process is unchanged from OPG's previous payment amounts application. This Application reflects significant changes in OPG's Nuclear Operations, which pose unique challenges and opportunities in terms of business planning and benchmarking. Highlights of OPG's 2025-2031 Business Plan as it pertains to Nuclear Operations include the following:

- Ensuring the success of the extension of Pickering Units 5-8 to 2026, which will continue to provide Ontario with a clean and reliable source of baseload power while supporting summer capacity needs through to 2026 (Section 4.0).
- Ensuring an effective transition of OPG nuclear operations from ten-unit on-line operations to four unit on-line operations (at Darlington) post-2026, until the first Pickering unit returns to service in May 2031.
- Ensuring transition following Pickering Refurbishment Program ("PRP") to first unit coming on-line on May 2031. Executing initiatives impacting "our people, our plant and our future" to drive station operational performance improvements over the IR term (Section 3.4).
- Maintaining high standards of safety and environmental stewardship by targeting best quartile performance and/or maximum Nuclear Performance Index ("NPI") points at both Pickering and Darlington relative to the Company's Safety Cornerstone (Section 3.3).
- Improving the identification and execution of project portfolio investments to enhance performance, reliability and overall value of the nuclear assets through a strengthened asset management program and Enterprise Project Management Office (Ex. D2-1-1).
- Continue with planning and execution work in support of DNNP's facilities generating station with first unit available for commercial operations in October 2030.
- Investing in life cycle management and other sustaining infrastructure investments at Darlington and Pickering that will help to prepare stations for their second life safely and reliably (Ex. D2-1-3).

Achieving success on the business plan priorities will require building and continuing on the success of major programs undertaken within OPG over the past several years, which include; a) The final Darlington Unit refurbishment completed and back in-service, b) safely extending the life of Pickering Units 5-8 beyond its previously planned end of commercial operations date, c) progressing the PRP execution including returning Unit 5 to service, applying lessons learned from Darlington Refurbishment, d) best practices of the Enterprise Project Management Office, which further enhance the competency and process of managing and executing large project refurbishments (i.e., Darlington and Pickering), Nuclear Operations' capital and OM&A projects, e) DNNP Unit 1 coming online, and f) implementing initiatives that

will improve Nuclear operational performance. The completed gap closure initiatives, and their results are described in Attachment 1 to this exhibit.

A summary of actual and planned operating costs over the 2020-2031 period are presented in Ex. F2-1-1, Table 1a and 1b.

3.0 NUCLEAR BUSINESS PLANNING AND BENCHMARKING

3.1 Gap-Based Business Planning Process

The business planning cycle for OPG's Nuclear Operations is undertaken as part of the overall OPG business planning process (Ex. A2-2-1). This cycle is focused on establishing strategic and performance targets for the nuclear business, in alignment with OPG's corporate-wide objectives, and identifying the initiatives and resources required to achieve these targets.

OPG Nuclear continues to use a gap-based business planning process which consists of the following steps:

- **Performance Review**: Process of comparing nuclear performance to the previous approved business plan and industry benchmarks in order to identify areas for improvement.
- **Setting Strategic Direction**: Process of goal alignment by establishing the level of performance and targets that are expected to be achieved within the business planning period.
- **Gap Closure Planning**: Process of planning gap closure initiatives as required to achieve targeted performance.
- **Developing Detailed Business Plan:** Process where generation, financial and staff plans are developed based on the approved corporate strategic direction, performance targets, priorities and resources ensuring integration with corporate business planning processes.
- **Performance Reporting**: Process for robust performance management reporting by effectively monitoring the execution of the first year of the approved business plan with careful consideration of risks, costs and execution.

Once the detailed business plan is developed and approved, OPG uses operational and financial measures to track its performance against target.

3.2 Gap-Based Business Planning – Benchmarking

The 2024 Nuclear Benchmarking Report (Attachment 2) shows OPG's benchmarking performance against industry peers based on 2023 data and uses various indicators aligned with the cornerstone values of Safety, Reliability, Value for Money and Human Performance.

The 2024 Nuclear Benchmarking Report uses the same methodology and format as the previous nuclear benchmarking reports filed with the OEB based on a benchmarking initiative undertaken by OPG in 2009 with the assistance of ScottMadden, Inc. ("ScottMadden"), a consulting firm. OPG has, from time to time, advised the OEB of updates to its benchmarking metrics that were required to reflect changes in industry reporting or other factors (e.g., amalgamation of Pickering A and Pickering B). In 2024, OPG engaged ScottMadden to conduct an independent review of the 2024 Nuclear Benchmarking Report to highlight areas of opportunity for better alignment with leading practices. ScottMadden has found the modifications made to the 2024 report to have increased the clarity and the efficiency of the report's production. The improvements to the 2024 Nuclear Benchmarking Report relative to the 2020 Nuclear Benchmarking Report filed in EB-2020-0290 are as follows:

- Discontinued the "Major Operator Summary" section of the Report to support ScottMadden's earlier recommendation (EB-2020-0290, Ex. F2-1-1, Attachment 3) that OPG focus on site-level comparisons of performance for Pickering and Darlington rather than operator-level comparisons in the future as site-to-site comparisons provide a larger and more comparable data set resulting in a more robust and accurate view of OPG performance relative to the industry which better informs the target-setting process.
- Various improvements to clarity and conciseness of the report (e.g., Executive summary in the 2024 Report addresses performance cornerstones, like Reliability, rather than each individual metric and discontinued unit-level analysis and plant and unit-level bar charts)
- Enhanced online deficient and corrective maintenance backlog reporting by including current performance year and the prior five years of performance with benchmarking,

creating a visual representation of the trend. The 2020 Nuclear Benchmarking Report only had the current performance year.

In addition, OPG engaged ScottMadden in 2024 to ensure continued accuracy of reporting and consistency with industry best practices. ScottMadden's assessment found that OPG's current benchmarking methods align with previous guidance and current leading practices in the industry. The evaluation found no issues with benchmarking report calculations or presentations of data and the review noted that OPG's Nuclear business planning processes remain consistent with established OPG governance and industry leading practice. ScottMadden's assessment is filed as Attachment 3.

3.2.1 Benchmarking – Supporting Studies

In the EB-2016-0152 Decision and Order,[1] the OEB agreed that OPG's benchmarking methodology was appropriate, with the exception of OPG's provided methodology for normalizing Total Generating Cost per MWh ("TGC/MWh") for the effects of Darlington Refurbishment Program ("DRP"). The OEB noted that ScottMadden had suggested that there were alternative approaches to account for the impact of refurbishment on TGC/MWh and indicated an expectation that OPG would file a review from ScottMadden regarding OPG's nuclear benchmarking methodologies.

In prior studies, ScottMadden has identified various differences between CANDU reactors and Pressurized Water Reactors and Boiling Water Reactors as well as age-related differences that impact value for money performance comparisons with peers. OPG has consistently identified these factors in its Benchmarking Reports as contributing to the benchmarking gap, but, prior to EB-2020-0290, was unable to quantify their impact.[2] While OPG's gap-based business planning process relies upon benchmarking to compare OPG's nuclear performance against industry leaders in order to identify areas with the greatest potential for improvement,

[1] Decision and Order, EB-2016-0152, December 28, 2017, p. 49.
[2] EB-2016-0152, Ex. F2-1-1, Attachment 1, 2015 Benchmarking Report, p. 72.

OPG understands that there are limitations in assessing benchmarking results. The OEB has also recognized the limitations of benchmarking.[3]

In EB-2020-0290, OPG engaged ScottMadden to conduct an independent review of Nuclear's 2019 Benchmarking Report and process to ensure continued accuracy of reporting and consistency with industry best practices. The 2020 Benchmarking Report included four material updates relative to the 2015 Nuclear Benchmarking Report filed in EB-2016-0152, which are the inclusion of the following metrics Total Recordable Injury Frequency ("TRIF"), 1-year On-Line Deficient Critical Backlogs and 1-year On-Line Corrective Critical Backlogs and the normalization of several value for money metrics (Normalized 3-Year Total Generating Cost per MWh; Normalized 3-year Non-Fuel Operating Costs per MWh; Normalized 3-Year Capital Cost per MW Design Electrical Rating ("DER")). In the EB-2020-0290 OEB-approved settlement proposal,[4] the parties accepted the nuclear benchmarking methodology, results and targets as reasonable.

Based on the OEB's expectations and in an effort to improve the usefulness of benchmarking results and address the benchmarking limitations described above, for this Application, OPG engaged ScottMadden to undertake an independent study to revisit the normalization methodology of OPG's value for money metrics to enable closer comparisons with peers (OPG Nuclear Cost Performance Benchmarking – A Study of Factors Impacting TGC/MWh Performance with Normalizing Adjustments to Facilitate Closer Comparison – Attachment 4).

In addition, the EB-2016-0152 Decision and Order[5] and the EB-2020-0290 OEB-approved settlement proposal[6] require OPG to file a staffing benchmarking study following the Goodnight Consulting ("Goodnight") methodology. OPG engaged Indeavor Inc. ("Indeavor") to undertake this Nuclear Staffing Benchmarking Study (Attachment 5).

Each of the three supporting studies referenced above are discussed in greater detail below.

[3] Decision and Order, EB-2016-0152, December 28, 2017, p. 49.
[4] Decision and Order, EB-2020-0290, November 15, 2021, p. 99.
[5] Decision and Order, EB-2016-0152, December 28, 2017, p. 84.
[6] Decision and Order, EB-2020-0290, November 15, 2021, p. 118.

3.2.1.1 OPG Nuclear Cost Performance Benchmarking - Methodology to Adjust for Refurbishment and Validation of Implementation

As noted in EB-2020-0290 evidence, the purpose of ScottMadden's Methodology to Adjust for Refurbishment and Validation of Implementation study was to facilitate useful comparisons to past performance and industry peers for the operating plant at Darlington during the extended time periods in which certain units would be offline due to the DRP.

ScottMadden's views on adjusting TGC/MWh for DRP are summarized below:

- DRP is a unique "mega-program" and there is no established practice for normalizing cost metrics for this unique program.
- Normalization is necessary to facilitate benchmark comparisons to past performance and industry peers.
- OPG should continue to report unadjusted (i.e., not normalized) version of the cost metrics along with any normalized version.
- A more strongly supported and conventional approach to normalization of cost metrics is to adjust actual costs in the numerator while using unadjusted actual MWhs generated in the denominator.

ScottMadden examined various OPG cost items and OPG's corporate and nuclear support cost attributions in order to identify costs that should be adjusted to create a normalized TGC/MWh, Non-Fuel Operating Cost per MWh ("NFOC/MWh"), and Capital Cost per MW Design Electrical Rating while maintaining generation. ScottMadden's methodology indicated how each type of Darlington Station, Nuclear Support (now Operations and Project Support), allocated corporate support OM&A (i.e., Support Services) costs and sustaining capital expenditures could be removed for the purpose of normalizing TGC/MWh and its applicable sub-components for refurbishment. The study ultimately established a methodology to allow OPG to adjust the distribution of OM&A and capital costs while using actual generation to estimate what TGC/MWh, NFOC/MWh, and Capital Cost per MW Design Electrical Rating would be if Darlington was operating fewer than four units.

OPG independently applied ScottMadden's methodology to normalize TGC/MWh and its sub-components based on 2017 data. ScottMadden then reviewed OPG's work on the 2017 data (Attachment 3, Section 4) and validated that the approach OPG followed was in accordance with ScottMadden's guidance and that OPG accurately performed the calculations. ScottMadden found that OPG correctly interpreted and implemented the guidance provided.

OPG continued to apply ScottMadden's normalization methodology in deriving Darlington's Value for Money metrics in subsequent years. The 2023 results are shown in Chart 1 below.

3.2.1.2 OPG Nuclear Cost Performance Benchmarking – A Study of Factors Impacting TGC/MWh Performance with Normalizing Adjustments to Facilitate Closer Comparison

As noted in the EB-2020-0290 evidence, OPG engaged ScottMadden in 2018 with the objective of ScottMadden's Study of Factors Impacting TGC/MWh Performance with Normalizing Adjustments to Facilitate Closer Comparison in determining whether and to what extent certain site characteristics of OPG's CANDU units influence TGC/MWh performance relative to industry peers, and if possible quantify and adjust these characteristics to produce normalized TGC/MWh values. ScottMadden's CANDU and age-related normalization methodology included:

- An econometric analysis of Electric Utility Cost Group ("EUCG") data; and
- A custom nuclear outage benchmarking study that sought to determine and normalize expected impacts on generation between CANDU and non-CANDU plants.

In its econometric analysis, ScottMadden analyzed nine years of EUCG data (from 2009 to 2017) for OPG and its industry peers to understand which site characteristics most influenced TGC over a sustained period and to what extent. ScottMadden's analysis indicated that CANDU technology increases predicted TGC by over $250M per year relative to non-CANDU plants, and each month of average unit age increases predicted TGC by $346,000 per year. ScottMadden then adjusted the EUCG data to normalize for these factors.[7]

[7] In addition, the ScottMadden analysis found that site capacity was a driver of TGC variability. However, ScottMadden did not adjust for site capacity to be conservative and to ensure that adjustments were easy to understand as such an adjustment would also have required a complex adjustment to generation.

In the case of Darlington, ScottMadden's econometric analysis included Refurbishment costs. Since 2017, OPG has calculated an adjustment for Refurbishment costs based on the previously established methodology that continues to be applied until the DRP is completed.

ScottMadden also undertook a custom nuclear outage benchmarking study, including a confidential direct survey of nuclear operators representing 47 nuclear plants. The custom nuclear outage benchmarking study methodology quantified and adjusted for the impact of regularly recurring, planned maintenance outages on power generation, taking steps to arrive at an average annual value for days offline due to these planned outages.

In 2024, OPG reengaged ScottMadden to refresh the study performed in 2018 (Ex. F2-1-1, Attachment 4). The objective of ScottMadden's Study of Factors Impacting TGC/MWh Performance with Normalizing Adjustments to Facilitate Closer Comparison remained unchanged: to assess whether, and to what extent, specific site characteristics of OPG's CANDU units influence TGC/MWh performance relative to industry peers, and if possible, quantify and adjust for these characteristics to produce normalized TGC/MWh values. ScottMadden's CANDU and age-related normalization methodology included:

- An econometric analysis of Electric Utility Cost Group ("EUCG") data; and
- A nuclear planned outage analysis of EUCG data.

In its econometric analysis, ScottMadden analyzed eighteen years of EUCG data (from 2006-2023) for OPG and its industry peers to understand which site characteristics most influence TGC over a sustained period and to what extent. ScottMadden's analysis indicated that CANDU technology increases predicted TGC by over $539M per year relative to non-CANDU plants and each month of average unit age increases predicted TGC by $77,000 per year. ScottMadden then adjusted the EUCG data to normalize for these factors.[8]

[8] In addition, the ScottMadden analysis found that site capacity was a driver of TGC variability. However, ScottMadden did not adjust for site capacity to be conservative and to ensure that adjustments were easy to understand as such an adjustment would also have required a complex adjustment to generation.

The econometric analysis relied on unadjusted (other than for inflation) TGC data. In the case of Darlington, this analysis included costs associated with units in Refurbishment. Since 2017, OPG has calculated an adjustment for Refurbishment costs based on the previously established methodology that continues to be applied until DRP is completed. To avoid the possibility of making an adjustment for Darlington that is overly influenced by Refurbishment costs, Darlington adjustments were reduced associated with the econometric model. Specifically, the refurbishment adjustment was applied on a year-by-year basis and proportionally reduced the econometric model adjustments for Darlington by the corresponding annual factors for CANDU and age-related factors.

In its nuclear outage analysis, ScottMadden analyzed eighteen years of EUCG data (from 2006-2023) for OPG and its industry peers to identify the plant with the lowest average percentage of planned outages. Utilizing the lowest average planned outage percentage as the benchmark, MWh was adjusted for each plant/year to match the benchmark rate, adding MWh when outages are longer and subtracting when outages are shorter.

Chart 1 below summarizes the application of normalization methodologies for refurbishment (described in Section 3.2.1.1), and CANDU and age-related factors from the 2018 and 2025 ScottMadden study (described in Section 3.2.1.2), to the main 2023 Value for Money metrics.

OPG does not apply CANDU and age-related normalization, consistent with ScottMadden's methodology, to the sub-components of TGC/MWh (i.e., Non-fuel Operating Cost per MWh or Capital Cost per MW DER). OPG accepts ScottMadden's normalization methodologies as described above as this achieves a closer comparison of OPG's TGC/MWh performance to peers.

Chart 1 - Summary of Normalization Methodology Adjustments

Value for Money Metrics (2023)

Indicator	Non-Normalized	Refurbishment Normalization	Original Methodology (2018)		Updated Methodology (2025)	
			CANDU, Age-related, Outage Duration Normalization	CANDU, Age-related, Outage Duration, & Refurbishment Normalization	CANDU, Age-Related, Outage Duration Normalization	CANDU, Age-related, Outage Duration, & Refurbishment Normalization
3-year Total Generation Cost per MWh	PN: $64.93 DN: $95.04	PN: N/A DN: $62.11	PN: $44.12 DN: $70.08	PN: $44.12 DN: $39.29	PN: $33.62 DN: $58.17	PN: $33.62 DN: $38.11
3- year Total Generating Cost per Unit	PN: $230.73 DN: $627.40	PN: N/A DN: $409.98	PN: $168.77 DN: $494.92	PN: $168.77 DN: $277.51	PN: $138.50 DN: $398.79	PN: $138.50 DN: $261.26
3- Year Non-Fuel Operating Cost per MWh	PN: $58.31 DN: $62.76	PN: N/A DN: $43.89	N/A	N/A	N/A	N/A
3-year Capital Cost per MW DER	PN: $19.54 DN: $212.29	PN: N/A DN: $106.57	N/A	N/A	N/A	N/A

3.2.1.3 Nuclear Staffing Benchmarking Study

As required by the EB-2016-0152 Decision and Order[9] and the EB-2020-0290 OEB-approved settlement proposal,[10] a Nuclear Staffing Benchmarking Study was undertaken by Indeavor and is included as Attachment 5. Indeavor is a company with workforce analytics expertise in the energy sector, and the study was led by a consultant who supported similar studies in the past, performed for OPG by Goodnight, which is a company no longer in business.

The main conclusions of the 2025 Indeavor Nuclear Staffing Study are as follows:

- Indeavor compared OPG Nuclear staffing levels to other North American nuclear operators using an approach similar[11] to the methodology used by Goodnight to evaluate OPG in 2011, 2013, 2014, and 2019.

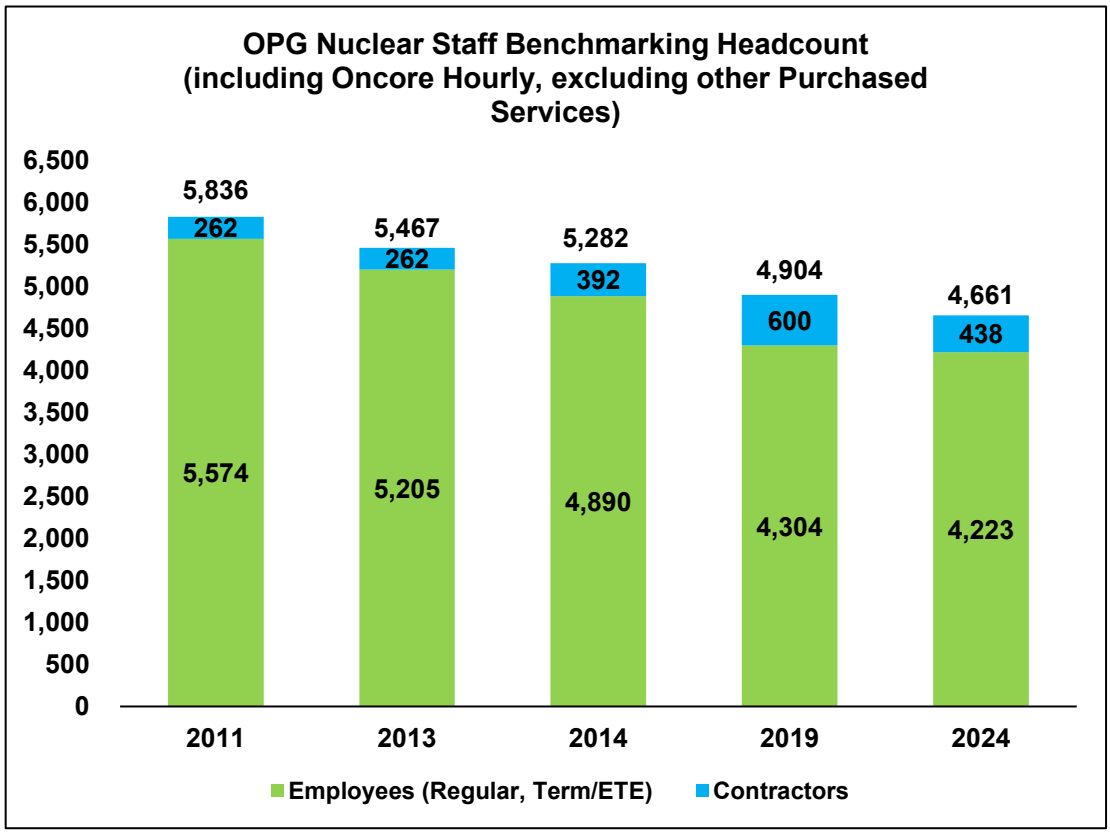
[9] Decision and Order, EB-2016-0152, December 28, 2017, p. 88.
[10] Decision and Order, EB-2020-0290, November 15, 2021, p. 118.
[11] The previous staff benchmarking studies included external purchased services (managed tasks), which are excluded from the current study due to the self-reported nature and data visibility from benchmarked peers.

- The analysis showed that OPG, as of December 2024, is 455 Full-Time Equivalents ("FTEs") (9.3%) better than (below) the total North America nuclear operator benchmark of 4,913 FTEs.
- 4,458 OPG Nuclear staff were benchmarked; 2,386 OPG Nuclear personnel were excluded from benchmarking consistent with the methodology applied in prior studies.
- OPG is above benchmark staffing in 16 job functions, and below benchmark staffing in 25 functions.

OPG benchmarked staffing levels have continued to show significant improvement by closing the gap identified initially by Goodnight in 2011 then continuing to improve even after the gap was eliminated in 2016.[12] The latest study completed by Indeavor in 2025 confirms that actions taken by OPG have been effective in achieving favourable performance compared to benchmarked nuclear operators. Refer to Figure 1 below for historical trend analysis on OPG benchmarked staffing levels, including Oncore hourly contractors, but excluding external purchased services.

[12] In 2011, Goodnight indicated that OPG Nuclear was 17% above its industry peers, with a later update by Goodnight demonstrating that OPG Nuclear had narrowed the gap to 7.6% per EB-2013-0321, Ex. JT1.13. The Goodnight Nuclear Staffing Benchmarking Analysis published in December 2014 (EB-2016-0152, Ex. F2-1-1 Attachment 2) showed that staff reductions had further narrowed the gap to 4.1%, and as stated in EB-2016-0152, Ex. F2-1-1, OPG had eliminated the gap in 2016.

Figure 1 – OPG Nuclear Staff Benchmarking Headcount



	2011	2013	2014	2019	2024
Total OPG Benchmarked	5,956	5,587	5,421	5,016	4,458
Contractors: Purchased Services	(120)	(120)	(139)	(112)	0
Contractors: Oncore Hourly					203
	5,836	**5,467**	**5,282**	**4,904**	**4,661**

3.2.2 Benchmarking Results

Chart 2 is a reproduction of Table 1 from OPG's 2024 Nuclear Benchmarking Report (Attachment 2) and provides a summary of OPG's 2023 plant-level performance for each of the key performance indicators benchmarked.

Chart 2 - Comparison of OPG Nuclear Performance to Industry Benchmarks

Metric	2023 Actuals					
	NPI Max	Best Quartile	Median	Third Quartile	PN	DN
Safety						
Total Recordable Injury Frequency (#/200k hours worked)		0.95	1.48	2.21	0.20	0.00
Rolling Average[2] Industrial Safety Accident Rate (#/200k hours worked)[1]	0.20	0.00	0.00	0.05	0.00	0.00
Rolling Average[2] Collective Radiation Exposure (Person-rem per unit)[1]	80.00	46.00	72.13	94.67	67.33	20.61
Airborne Tritium Emissions (Curies) per Unit[3]		3,131	6,068	6,845	2,164	1,027
Fuel Reliability (microcuries per gram)[1]	0.000500	0.000001	0.000094	0.000239	0.000239	0.000106
2-Year Reactor Trip Rate (# per 7,000 hours)[1]	0.500	0.000	0.215	0.430	0.247	0.430
3-Year Auxiliary Feedwater System Unavailability (#)[1]	0.0200	0.0000	0.0006	0.0021	0.0019	0.0000
3-Year Emergency AC Power Unavailability (#)[1]	0.0250	0.0002	0.0004	0.0030	0.0000	0.0000
3-Year High Pressure Safety Injection Unavailability (#)[1]	0.0200	0.00000	0.00000	0.00000	0.0000	0.0002
Reliability						
Rolling Average[2] WANO NPI (Index)[1]		89.44	87.02	82.78	82.78	89.44
Rolling Average[2] Forced Loss Rate (%)[1]	1.00	1.05	1.41	2.29	2.29	5.03
Rolling Average[2] Unit Capability Factor (%)[1]	92.00	90.46	87.43	86.59	80.34	90.46
Rolling Average[2] Chemistry Performance Indicator (Index)[1]	1.01	1.00	1.01	1.01	1.20	1.01
1-Year Online Deficient Critical Backlog (work orders per unit) [1]		0.00	0.00	0.50	0.67	0.00
1-Year Online Deficient Non-Critical Backlog (work orders per unit) [3]		1.33	7.66	22.00	29.50	29.00
1-Year Online Corrective Critical Backlog (work orders per unit) [1]		0.00	0.00	0.00	0.00	0.00
1-Year Online Corrective Non-Critical Backlog (work orders per unit) [3]		0.00	0.33	1.00	0.83	0.00
Value for Money						
3-Year Total Generating Costs per MWh ($ per Net MWh)[1]		33.44	39.66	49.23	64.93	95.04
Normalized 3-Year Total Generating Cost per MWh ($ per Net MWh)[4]		27.95	33.51	42.57	44.12	39.29
3-Year Total Generating Cost per Unit (M $ per Unit)		283.01	313.31	358.44	230.73	627.40
Normalized 3-Year Total Generating Cost per Unit (M $ per Unit)[4]		236.12	276.78	320.69	168.77	277.51
3-Year Non-Fuel Operating Costs per MWh ($ per Net MWh)[1]		19.64	24.64	32.22	58.31	62.76
3-Year Normalized Non-Fuel Operating Cost per Net MWh ($/MWh)		19.64	24.64	32.22	--	43.89
3-Year Fuel Costs per MWh ($ per Net MWh)[1]		6.11	6.68	7.44	3.79	4.05
3-Year Capital Costs per MW DER ($ per MW)[1]		33.87	60.01	107.30	19.54	212.29
Normalized 3-Year Capital Cost per MW DER ($ per MW)		33.87	60.01	107.30	--	106.57
Human Performance						
18-Month Human Performance Error Rate (# per 200k ISAR and contractor hours) [1]		0.0000	0.0000	0.0410	0.0600	0.0000

[1] Best Quartile, Median and Third Quartile are from Q4 2023 best available information.

[2] Indicates a 2-Year Rolling Average for Pickering and a 3-Year Rolling Average for Darlington.

[3] Best Quartile, Median, Third Quartile are from Q4 2022 which is the most current available benchmark for these metrics.
[4] Reflects original technology, age-related, and outage duration normalization methodology, as described in Ex. F2-1-1, Section 3.2.1.2

Legend

4th Quartile Performance	3rd Quartile Performance	2nd Quartile Performance	Maximum NPI points achieved or Best Quartile

Detailed discussion of the 2023 performance trends and drivers by cornerstone is provided in the OPG 2024 Nuclear Benchmarking Report (Attachment 2), and is summarized as follows:

- **Safety**

  Overall, OPG's nuclear generating stations continue to demonstrate strong safety performance, achieving green ratings for all safety metrics in 2023. Darlington and Pickering continued to demonstrate first quartile performance in Total Recordable Injury Frequency ("TRIF"), with OPG achieving its best TRIF performance in the history of the company in 2023 since the company's inception in 1999 and having the best TRIF performance in 2023 compared to its peer group.

  Darlington and Pickering generating stations achieved maximum NPI results or best quartile performance for all seven NPI safety sub-metrics.

  The Collective Radiation Exposure ("CRE") remained in the top quartile for Pickering and Darlington resulting in maximum NPI points. Continued performance reflects implementation of specialized source term agents, source term controls and improved shielding to reduce does rates.

  The Airborne Tritium Emissions remained in first quartile for Darlington while Pickering has improved from second to first quartile. Improved performance reflects emission reduction initiatives driven by a High Impact Team, enhancing focus on tritium sources identification and enhanced management oversight. In addition, collaboration between both sites to exchange operating experience, innovation activities on tritium mitigation, and benchmark performance.

The Fuel Reliability Index remained in the first quartile at both Darlington and Pickering achieving maximum NPI points due to continual efforts to enhance performance at both sites including completing the fuel design manual and drawing update which strictly controls the manufacturing process as well as the fuel operating, fuel handling and fuel performance limits.

- **Reliability**

  Several key reliability indicators at both stations noted sustained or improved quartile performance in 2023.

  Significant improvements were recorded for On-line Deficient Maintenance Backlogs, and On-line Corrective Maintenance Backlogs for both stations in 2023. Darlington's On-line Deficient Non-Critical Backlogs registered a 52% reduction compared to the previous year, while Pickering improved by 26%. Both stations continue to work down the backlog priorities through Fix It Now and Work Management process.

  The Unit Capability Factor ("UCF") improved to achieve first quartile at Darlington which is attributable to reduced planned outage days in 2023, partially offset by forced outage events impacting post-refurbishment Unit 2. Pickering remained in fourth quartile with improved performance attributable to improved FLR due to 2021's elevated FLR no longer included in the rolling average window, partially offset by increased planned outage days in 2023.

  The Chemistry Performance Indicator sustained first quartile performance at Darlington achieving maximum NPI points. Pickering's Chemistry Performance Indicator remained in the fourth quartile in 2023, attributable to condenser tube leaks on Unit 4 and Unit 8 and boiler level transient. Both stations continue to have a Chemistry Outage Single Point of contact to provide improved coordination and planning.

  The Forced Loss Rate ("FLR") decreased from the third to fourth quartile at Darlington in 2023 due to forced outage events impacting post-refurbishment Unit 2 on Turbines and Main Power Output (2022) and Primary Heat Transport (2023). As this metric is a rolling

average, in 2023, only Unit 2 results are included (Units 1, 3, and 4 were in refurbishment). Pickering remained in the fourth quartile with improved performance due to 2021's elevated FLR no longer included in the rolling average window. Fuel Handling contribution reduced in 2023 and remains a focus area to build sustainability.

- **Value for Money**

  Darlington's TGC/MWh performance was in the third quartile in 2023 after normalizing for refurbishment costs, CANDU technology, age-related and outage duration factors (as described in Section 3.2.1.1 and Section 3.2.1.2). Darlington's TGC/MWh performance (non-normalized) was in the fourth quartile. These non-normalized results were driven largely by significant capital expenditures, which are necessary for reliable post-refurbishment operation, and reduced generation during the DRP. Darlington achieved top quartile performance in Fuel Cost per MWh.

  Pickering's normalized TGC/MWh was in fourth quartile (normalized and non-normalized). Pickering's performance reflects reduced capital investment while maintaining reliable operations leading up to the end of commercial operations. Pickering maintained best quartile performance in Fuel Cost per MWh and Capital Cost per MW DER. Pickering units are the smallest in the peer group, with a capacity of 540 MW per unit compared to the peer group average of 1,026 MW.

- **Human Performance**

  OPG Nuclear's human performance strategy focuses on and reinforces the correct behaviors during all phases of station operations and maintenance. Darlington maintained top quartile performance in its Human Performance Error Rate in 2023. Pickering Human Performance Error Rate was in the fourth quartile in 2023. OPG is targeting building industry-leading Human Performance practices through it being a focus across the fleet with actions taken to further improve performance by continuously improving the Observations & Coaching program as well as integration of Fail-Safe strategies and trending processes to strengthen values and behaviours of Nuclear Professionals.

OPG has made improvements in many areas and continues to identify and implement opportunities for further improvement as discussed in Section 3.4 below.

3.3 Gap-Based Business Planning – Target Setting

OPG's operating and financial targets are designed to drive continuous improvement in OPG Nuclear Operations' performance. Targets are set for each year of the business plan and are monitored each year to assess performance for the given year.

2025-2031 Targets

OPG's Chief Nuclear Officer, in consultation with OPG's Nuclear leadership team, provided direction on the operating and financial performance targets for each nuclear station for the 2025-2031 business planning period, based on the applicable corporate targets. The operating and financial targets for this business plan recognize the following drivers of operating costs and generation, including:

a) The need for capital expenditures within the Nuclear Operations' project portfolio and, where appropriate, for non-portfolio projects to position Darlington and Pickering for strong performance post refurbishment, including addressing emergent reliability risks at Darlington (as discussed at Ex. D2-1-2).
b) Pickering Units 5-8 investments and resources that are being optimized and planned outages are being undertaken to ensure the station safely operates towards its planned pre-refurbishment shutdown on September 30, 2026 and is prepared for an effective transition into the four-unit refurbishment outage and subsequent post-refurbishment operations.

The operating and financial targets for OPG's facilities are also informed by historical performance, targets set in prior years and the latest benchmarking results. Charts 3 (Pickering) and Chart 4 (Darlington) set out OPG's nuclear operational and financial targets for 27 benchmark performance indicators for the 2027-2031 period. OPG views these targets as challenging but achievable. Performance measures and targets for the DNNP facilities will be developed as Unit 1 approaches commercial operation.

Chart 3 - Annual Operational and Financial Targets for Pickering

Benchmarking Indicators	WANO Max NPI	Best Quartile[1]	Median Quartile[1]	Third Quartile[1]	Pickering Annual Targets						
					2025	2026	2027	2028	2029	2030	2031
					Targets Only						
Safety											
Total Recordable Injury Frequency (#/200k hours worked)		0.95	1.48	2.21	0.20	0.20	N/A	N/A	N/A	N/A	0.20
Total Industrial Safety Accident Rate (#/200k hours worked)[2]	0.20	0.00	0.00	0.05	0.00	0.00	N/A	N/A	N/A	N/A	0.00
Collective Radiation Exposure (person-rem per unit)	80.00	46.00	72.13	94.67	59.30	41.82	N/A	N/A	N/A	N/A	45.30
Airborne Tritium Emissions (Curies) per Unit		3,131	6,068	6,845	2,000	1,870	N/A	N/A	N/A	N/A	1,336
Fuel Reliability (microcuries per gram)	0.0005	0.000001	0.000094	0.000239	0.0005	0.0005	N/A	N/A	N/A	N/A	0.0005
Reactor Automatic and Manual Trip Rate (# per 7,000 hours)[3]	0.500	0.000	0.215	0.430	0.5000	0.5000	N/A	N/A	N/A	N/A	0.5000
Auxiliary Feedwater System Unavailability (#)	0.0200	0.0000	0.0006	0.0021	0.0000	0.0000	N/A	N/A	N/A	N/A	0.0000
Emergency AC Power Unavailability (#)	0.0250	0.0002	0.0004	0.0030	0.0250	0.0250	N/A	N/A	N/A	N/A	0.0250
High Pressure Safety Injection Unavailability (#)	0.0200	0.0000	0.0000	0.0000	0.0200	0.0200	N/A	N/A	N/A	N/A	0.0200
Reliability											
Rolling Average WANO NPI (Index)[4]		89.44	87.02	82.78	78.4	81.8	N/A	N/A	N/A	N/A	N/A
Forced Loss Rate (%)	1.00	1.05	1.41	2.29	3.50	3.50	N/A	N/A	N/A	N/A	12.00

Benchmarking Indicators	WANO Max NPI	Best Quartile[1]	Median Quartile[1]	Third Quartile[1]	Pickering Annual Targets						
					2025	2026	2027	2028	2029	2030	2031
					Targets Only						
Unit Capability Factor (%)[5]	92.0	90.46	87.43	86.59	89.14	87.06	N/A	N/A	N/A	N/A	68.16
Unit Capability Rate (%)[5]	98.0	98.68	98.17	97.35	98.71	96.07	N/A	N/A	N/A	N/A	87.52
Chemistry Performance Indicator (Index)	1.01	1.00	1.01	1.01	1.07	1.01	N/A	N/A	N/A	N/A	1.00
On-line Deficient Non-Critical Backlog (work orders/unit)		1.33	7.66	22.00	14.00	14.00	N/A	N/A	N/A	N/A	10.00
On-line Deficient Critical Backlog (work orders/unit)		0.00	0.00	0.50	0.00	0.00	N/A	N/A	N/A	N/A	0.00
On-Line Corrective Non-Critical Backlog (work orders/unit)		0.00	0.33	1.00	0.00	0.00	N/A	N/A	N/A	N/A	1.00
On-Line Corrective Critical Backlog (work orders/unit)		0.00	0.00	0.00	0.00	0.00	N/A	N/A	N/A	N/A	0.00
Value for Money											
Normalized Total Generating Cost per MWh – Updated Methodology ($/MWh)**[6]		29.51	34.09	41.78	31.72	38.95	N/A	N/A	N/A	N/A	N/A
Normalized Total Generating Cost per MWh – Original Methodology ($/MWh) **[6]		27.95	33.51	42.57	41.99	54.19	N/A	N/A	N/A	N/A	N/A
Total Generating Cost per MWh ($/MWh)**		33.44	39.66	49.23	71.57	97.94	N/A	N/A	N/A	N/A	N/A
Normalized Total Generating Cost per Unit –		257.91	284.30	328.93	141.60	143.88	N/A	N/A	N/A	N/A	N/A

Benchmarking Indicators	WANO Max NPI	Best Quartile[1]	Median Quartile[1]	Third Quartile[1]	Pickering Annual Targets						
					2025	2026	2027	2028	2029	2030	2031
					Targets Only						
Updated Methodology (M$ per Unit)**[6]											
Normalized Total Generating Cost per Unit – Original Methodology (M$ per Unit)**[6]		236.12	276.78	320.69	178.44	168.83	N/A	N/A	N/A	N/A	N/A
Total Generating Cost per Unit (M$ per Unit)**		283.01	313.31	358.44	284.63	278.48	N/A	N/A	N/A	N/A	N/A
Normalized Non-Fuel Operating Cost per MWh ($/MWh) **(6)		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Non-Fuel Operating Cost per MWh ($/MWh) **		19.64	24.64	32.22	59.67	78.05	N/A	N/A	N/A	N/A	N/A
Fuel Cost per MWh ($/ MWh)		6.11	6.68	7.44	5.15	5.75	N/A	N/A	N/A	N/A	N/A
Normalized Capital Cost per MW DER (k$/MW) ***[6]		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Capital Cost per MW DER (k$/MW) ***		33.87	60.01	107.30	34.71	77.90	N/A	N/A	N/A	N/A	N/A
Human Performance											
Human Performance Error Rate (# per 200k ISAR hours)		0.0000	0.0000	0.0410	0.0000	0.0000	N/A	N/A	N/A	N/A	0.0000

** TGC/MWh and Non-Fuel Operating Cost per MWh exclude OPEB, Pension and Asset Service Fees to align with the industry standard.

*** Design Electrical Rating (DER)

Note 1: Indicates a 2-Year Rolling Average for Pickering and a 3-Year Rolling Average for Darlington.

Note 2: Industrial Safety Accident Rate (ISAR2) has been replaced by Total Industrial Safety Accident Rate (TISA2) in Q1 2024 to align with NPI methodology transition from Method 4 to Method 10. ISAR included only permanent employees when counting industrial safety accidents, while the new indicator TISA includes both contractors and permanent employees.

Note 3: Reactor Trip Rate was replaced by Reactor Automatic & Manual Trip Rate following the NPI Method 10 transition in 2024. The indicator change includes the change from Unplanned Automatic Scrams (UA7) to Unplanned Total Scrams (US7). Method

4 utilized UA7 metric which only included the automatic scram data. The new indicator, US7, which includes both automatic and manual scrams.

Note 4: The Nuclear Performance Index Method 10 is a WANO sponsored performance measure and is a weighted composite of ten WANO Performance Indicators related to safety and production performance reliability. In Q1 of 2024, Method 10 replaced Method 4: Unit Capability Factor (UCF) was replaced by Unit Capability Rate (UCR), Automatic Reactor Scrams (UA7) was replaced by Automatic and Manual Scrams (US7) and Industrial Safety Accident Rate (ISAR2) – replaced by Total Industrial Safety Accident Rate (TISA2). NPI is calculated using a 2-year rolling average for PN and a 3-year rolling average for DN.

Note 5: UCR replaced UCF due to NPI methodology change from Method 4 to Method 10 in Q1 of 2024. UCF will continue to be reported as UCF incorporates additional factors that impact production (i.e. Unbudgeted Planned Outages).

Note 6: Value for Money targets are indicative and will be updated for final cost allocations reflected in this Application.

Normalization methodologies are applied as described in Ex. F2-1-1, Section 3.2.1.

Chart 4 - Annual Operational and Financial Targets for Darlington

Benchmarking Indicators	WANO Max NPI	Best Quartile[1]	Median Quartile[1]	Third Quartile[1]	Darlington Annual Targets						
					2025	2026	2027	2028	2029	2030	2031
					Targets Only						
Safety											
Total Recordable Injury Frequency (#/200k hours worked)		0.95	1.48	2.21	0.20	0.20	0.20	0.20	0.20	0.20	0.20
Total Industrial Safety Accident Rate (#/200k hours worked)[2]	0.20	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Collective Radiation Exposure (person-rem per unit)	80.00	46.00	72.13	94.67	25.57	66.78	67.28	47.95	73.35	44.05	45.80
Airborne Tritium Emissions (Curies) per Unit		3,131	6,068	6,845	1,215	1,049	1,017	1,008	1,002	1,040	1,008
Fuel Reliability (microcuries per gram)	0.0005	0.000001	0.000094	0.000239	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005
Reactor Automatic and Manual Trip Rate (# per 7,000 hours)[3]	0.50	0.000	0.215	0.430	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Auxiliary Feedwater System Unavailability (#)	0.020	0.0000	0.0006	0.0021	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Emergency AC Power Unavailability (#)	0.025	0.0002	0.0004	0.0030	0.000	0.000	0.000	0.000	0.000	0.000	0.000
High Pressure Safety Injection Unavailability (#)	0.020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Reliability											
Rolling Average WANO NPI (Index)[4]		89.44	87.02	82.78	87.8	82.1	92.2	92.3	91.6	93.1	93.6
Forced Loss Rate (%)	1.00	1.05	1.41	2.29	3.6	3.5	2.9	2.2	2.0	2.0	2.0

Benchmarking Indicators	WANO Max NPI	Best Quartile[1]	Median Quartile[1]	Third Quartile[1]	Darlington Annual Targets						
					2025	2026	2027	2028	2029	2030	2031
					Targets Only						
Unit Capability Factor (%)[5]	92.0	90.46	87.43	86.59	94.2	76.0	62.9	88.6	83.5	88.6	88.7
Unit Capability Rate (%)[5]	98.0	98.68	98.17	97.35	95.3	95.3	95.8	96.6	96.8	96.9	96.8
Chemistry Performance Indicator (Index)	1.01	1.00	1.01	1.01	1.1	1.1	1.00	1.00	1.00	1.00	1.00
On-line Deficient Non-Critical Backlog (work orders/unit)		1.33	7.66	22.00	14.0	3.0	3	3	3	2	2
On-line Deficient Critical Backlog (work orders/unit)		0.00	0.00	0.50	0	0	0	0	0	0	0
On-Line Corrective Non-Critical Backlog (work orders/unit)		0.00	0.33	1.00	0	0	0	0	0	0	0
On-Line Corrective Critical Backlog (work orders/unit)		0.00	0.00	0.00	0	0	0	0	0	0	0
Value for Money											
Normalized Total Generating Cost per MWh – Updated Methodology ($/MWh)**[6]		29.51	34.09	41.78	34.72	42.26	51.58	41.14	42.21	39.14	34.68
Normalized Total Generating Cost per MWh – Original Methodology ($/MWh) **[6]		27.95	33.51	42.57	37.48	59.44	81.36	50.70	55.08	48.74	44.08
Total Generating Cost per MWh ($/MWh)**		33.44	39.66	49.23	72.18	84.90	106.86	67.80	74.02	66.71	62.23
Normalized Total Generating Cost per Unit –		257.91	284.30	328.93	240.44	299.75	342.47	292.13	300.11	280.07	250.36

Benchmarking Indicators	WANO Max NPI	Best Quartile[1]	Median Quartile[1]	Third Quartile[1]	Darlington Annual Targets						
					2025	2026	2027	2028	2029	2030	2031
					Targets Only						
Updated Methodology (M$ per Unit)**[6]											
Normalized Total Generating Cost per Unit – Original Methodology (M$ per Unit)**[6]		236.12	276.78	320.69	277.24	355.46	402.50	352.23	360.25	340.23	310.51
Total Generating Cost per Unit (M$ per Unit)**		283.01	313.31	358.44	507.52	482.67	499.36	452.42	463.87	447.38	421.28
Normalized Non-Fuel Operating Cost per MWh ($/MWh) **(6)		N/A	N/A	N/A	37.78	49.26	N/A	N/A	N/A	N/A	N/A
Non-Fuel Operating Cost per MWh ($/MWh) **		19.64	24.64	32.22	48.35	51.86	66.61	42.33	50.82	44.35	44.46
Fuel Cost per MWh ($/ MWh)		6.11	6.68	7.44	5.02	6.05	6.49	6.80	7.33	7.80	8.19
Normalized Capital Cost per MW DER (k$/MW) ***[6]		N/A	N/A	N/A	110.40	161.75	N/A	N/A	N/A	N/A	N/A
Capital Cost per MW DER (k$/MW) ***		33.87	60.01	107.30	150.71	174.73	179.72	141.84	113.24	111.21	73.84
Human Performance											
Human Performance Error Rate (# per 200k ISAR hours)		0.0000	0.0000	0.0410	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

** TGC/MWh and Non-Fuel Operating Cost per MWh exclude OPEB, Pension and Corporate Asset Service Fees to align with the industry standard.

*** Design Electrical Rating (DER)

Note 1: Indicates a 2-Year Rolling Average for Pickering and a 3-Year Rolling Average for Darlington.

Note 2: Industrial Safety Accident Rate (ISAR2) has been replaced by Total Industrial Safety Accident Rate (TISA2) in Q1 2024 to align with NPI methodology transition from Method 4 to Method 10. ISAR included only permanent employees when counting industrial safety accidents, while the new indicator TISA includes both contractors and permanent employees.

Note 3: Reactor Trip Rate was replaced by Reactor Automatic & Manual Trip Rate following the NPI Method 10 transition in 2024. The indicator change includes the change from Unplanned Automatic Scrams (UA7) to Unplanned Total Scrams (US7). Method

4 utilized UA7 metric which only included the automatic scram data. The new indicator, US7, which includes both automatic and manual scrams.

Note 4: The Nuclear Performance Index Method 10 is a WANO sponsored performance measure and is a weighted composite of ten WANO Performance Indicators related to safety and production performance reliability. In Q1 of 2024, Method 10 replaced Method 4: Unit Capability Factor (UCF) was replaced by Unit Capability Rate (UCR), Automatic Reactor Scrams (UA7) was replaced by Automatic and Manual Scrams (US7,) and Industrial Safety Accident Rate (ISAR2) – replaced by Total Industrial Safety Accident Rate (TISA2). NPI is calculated using a 2-year rolling average for PN and a 3-year rolling average for DN.

Note 5: UCR replaced UCF due to NPI methodology change from Method 4 to Method 10 in Q1 of 2024. UCF will continue to be reported as UCF incorporates additional factors that impact production (i.e. Unbudgeted Planned Outages).

Note 6: Value for Money targets are indicative and will be updated for final cost allocations reflected in this Application. Normalization methodologies are applied as described in Ex. F2-1-1, Section 3.2.1

The following summarizes the rationale for the targets set for each of the four cornerstones for the period 2027-2031, specifically:

- **Safety Cornerstone:** For the safety cornerstone, OPG is targeting either best quartile performance or maximum NPI points at both stations.
- **Reliability Cornerstone:** For the reliability cornerstone, OPG is targeting a post-refurbishment FLR of 12.0% at Pickering for the first year following return to service of Unit 5 in 2031. This is based on industry operating experience and is also impacted by the extended offline period of Pickering's units. Darlington's UCF fluctuate over the IR term. The higher FLR in earlier years reflects the expected initial increase after the units return to service post-refurbishment, with all units expected to transition to post-refurbishment normal operations by 2028 (Ex. E2-1-1, Section 3.3). The 2.0% FLR target for Darlington has been set to drive improvement from the recent performance. Online Deficient and Corrective Maintenance backlogs will remain a focus for continued improvements at both Pickering and Darlington. The online corrective non-critical maintenance backlog is expected to be in the top quartile throughout 2027-2031, with continuous improvement efforts being made for the on-line deficient non-critical backlogs.
- **Value for money:** As Pickering progresses toward the end of "first life" operation, the station is expected to improve to second quartile normalized TGC/MWh performance by 2026, reflecting improved reliability and reduced capital investment requirements. For Darlington, the TGC/MWh over the period 2027-2031 is expected to continue to be temporarily affected by higher project-related investments supporting continued preparation for Darlington second life operations and reduced generation resulting from

refurbishment outages up to 2026, and subsequently from the VBO in 2027, as well as emergent work associated with the Primary Moisture Separator Replacements and Turbine Rotors Replacement. Toward the end of the IR term, Darlington is expected to achieve second quartile normalized TGC/MWh performance.

- **Human Performance:** For the human performance cornerstone, OPG is targeting top quartile performance at both Darlington and Pickering stations due to continuous improvement efforts.

3.4 Gap Based Business Planning - Gap Closure and Resource Plan

The operational and financial targets established by the target setting process are the basis for site and support group business planning. As part of that process, fleetwide and site improvement initiatives are established to close performance gaps to targets over the business planning period. The fleetwide improvement initiatives, which are described in Section 3.4.2, are intended to improve efficiency, operational performance and cost effectiveness.

3.4.1 Prior Gap Closure Initiatives

In its EB-2020-0290 submission, OPG identified three Nuclear gap closure initiatives: (i) Right Work, Right Time, Right Value, (ii) Leaders Driving Business Results, and (iii) People Powering the Future. Attachment 1 provides details about these prior initiatives and benefits realized.

3.4.2 Current Fleetwide Improvement Initiatives

OPG's 2025-2031 Business Plan (Ex. A2-2-1, Attachment 1) sets out the resource requirements for Nuclear. OPG's operating cost profile in the 2025-2031 Business Plan is based on challenging but achievable OM&A targets necessary to position Darlington towards improving TGC performance during the IR term. Darlington's TGC is expected to achieve second quartile performance toward the end of the IR term.

In addition to managing improvements, OPG will make greater use of innovation, leveraging proven technologies in the nuclear industry to change how work programs are executed. This will be enabled by OPG's Digital Strategy (see Ex. D3-1-1). In order to maximize the value of these initiatives, OPG will focus on empowering leaders, progress projects that enable

effective monitoring of plant equipment, strengthening how work is planned and executed with an overall innovation mindset to help drive business efficiencies.

Consistent with the above, the key nuclear initiatives discussed below are designed to bring improvements across a range of areas broadly characterized as “our people, our plant and our future”. The initiatives will strengthen operational performance and cost effectiveness of the nuclear fleet, helping drive improvements needed to meet the 2025-2031 Business Plan commitments. The initiatives are also designed to mitigate risks to future performance and ensure a successful transition from a ten-unit, two station fleet to a four-unit, one station fleet until the first Pickering unit returns to service. Following successful execution of the DNNP, with Unit 1 becoming commercially available in 2030 (see Ex. D2-4-1), and the PRP, with the first unit becoming commercially available in 2031 (see Ex. D2-3-1), these initiatives would also mitigate risks and ensure those units’ successful transition to commercial operations.

3.4.2.1 Nuclear Specific Initiatives

Investments are integrated to ensure improvements are executed and sequenced appropriately. Initiatives focus on strengthening how OPG executes work programs by leveraging proven technology that is used in the nuclear industry.

The initiatives discussed below will help OPG to successfully transition to the PRP in 2026 and support other areas of planned growth opportunities to achieve the Nuclear business plan targets.

Improving Safety as a Core Value

Improving safety as a core value initiative focuses on developing a workforce that is committed to continuous improvement and Excellence standards as well as focused on maintaining a fail-safe mindset and elimination of at-risk behaviours. Key improvements and anticipated results for this initiative are:

- Workforce committed to own safe execution of work and ensure that people, plant, community and the environment are protected and shielded from hazards.

- Fail Safe initiative includes identifying and strengthening the defenses so that when an event does occur, the defenses in place ensure the event occurs safely. This involves a shift in focus on measuring defenses, not events, to build capacity with strong defenses.
- High levels of proficiency are essential to achieving consistent, sustainable, high performance and outcomes in individuals, teams and organizations. This is being achieved through assessing the proficiency of teams and developing improvement plans that cover the following elements:
    - Foundations – Ensure workers have the knowledge, skills, familiarity, understanding in executing work.
    - Challenges – awareness of plant status, environment, organizational and human performance.
    - Mitigation – understanding risk strategies, oversight and implementing Enterprise, Industry operating experience and lessons learned.

These initiatives support cost efficiencies as well as improved operational performance in areas of conventional safety, maintenance, outage performance, and equipment reliability. Anticipated results from Improving Safety as a core value initiative would be shown by sustaining performance in work protection, minimize or eliminate human performance consequential events (i.e., Event Free Day Resets), and industry best performance associated with conventional safety (i.e., Serious Injury Incident Rates).

Building Talent for Today & Tomorrow

The Building Talent for Today & Tomorrow initiative focuses on building and proactively maintaining a talent and leadership pipeline for the future through effective staff planning, succession planning, knowledge management and transition planning. Key improvements and anticipated results include:

- Leadership field presence, recognizing and engaging workforce in solutions for sustainable performance improvements. Fostering leadership intrusiveness, with a focus on enhancing team proficiency and providing feedback.

- Ensuring work programs are resourced appropriately in accordance with the 2025-2031 Business Plan while minimizing the organizational and operational impacts associated with transition to the PRP and Pickering and Darlington post-refurbishment operations.
- Drive continuous improvement and increased cross-functional effectiveness through peer challenge and behavioral shaping actions.
- Cultivate a high-performance culture that strives for excellence through industry learnings and benchmarking.
- Operations leading the station by demonstrating and enforcing excellence standards.

These initiatives are expected to result in enhanced employee engagement, strong succession planning and improving processes used to proactively address early signs of performance decline.

Leading Reliability of Plant Equipment

The Leading Reliability of Plant Equipment initiative focuses on the prevention and detection of vulnerabilities so actions can be taken to eliminate or mitigate events. Key improvement actions and anticipated results for this initiative include:

- Preventative Maintenance ("PM") reductions through sensor installations, optimizing maintenance strategies and plant reliability processes with a focus on sustainability, efficiency and cost-effectiveness.
- Simplify and optimize PM processes by implementing technology and data-driven solutions, improve equipment health monitoring and develop innovative equipment reliability tools while maintaining high standards of quality and performance and inform decision making.
- Empower system health teams to identify the key issues of focus to improve overall system health. Team members take ownership and accountability by creating innovative, practical solutions and implement improvement plans that drive Excellence in equipment reliability, raise awareness of issues and follow through to full resolution.

These initiatives are expected to result in improving and sustaining Forced Loss Rates, Equipment Reliability Consequential Events, Fuel Handling Equipment Reliability Index performance, Online Critical Preventive Maintenance Open 2nd Half of Grace and Online critical PM deferrals.

Strengthening How Work is Planned and Executed

The Strengthening How Work is Planned and Executed initiative focuses on excellence in maintenance, outage and project planning and ensure work programs are executed with a strong operational focus. Key improvement actions and anticipated results for this initiative include:

- Leverage lessons learned and Industry best practices to improve advanced planning and execution of maintenance, projects and major outages.
- Improve integrated technology to maximize effective maintenance tool time and PM strategies through use of high-performance diagnostic tools to avoid operations and maintenance costs and improve plant performance.
- Integrate resource balancing across project and maintenance functions to enable efficient online, outage and project planning and execution.

These initiatives are expected to result in improving or meeting online Maintenance backlogs, Work Management Index performance, planned outage durations and meeting planned targets.

Advancing Continuous Improvements to Support Growth

The Advancing Continuous Improvements to Support Growth initiative focuses on Excellence in Operations supporting future opportunities. Key improvement actions and anticipated results for this initiative include:

- Leading Operations and strengthening Indigenous relations and business partnership to develop new growth.
- Having a “Fit for Purpose” innovative mindset to drive efficiencies and plant reliability perspectives into our processes and core culture.

- Leadership and talent development through succession/transition planning, knowledge retention and industry benchmarking with focus on training programs that promote an organizational culture of continuous improvement.
- Strengthening external relationships with local communities and industry organizations in developing plans for future ready teams that support Pickering Units 1 and 4 safe store, the PRP and the DNNP.

These initiatives are expected to result in improving performance, enhance transition planning, succession planning and ready now leaders.

4.0 PICKERING OPTIMIZED SHUTDOWN

4.1 Overview

On August 14, 2020, the Province of Ontario issued a press release announcing its support of OPG's plan to pursue Optimization. The IESO's Annual Planning Outlook published in December 2020 also assumes Pickering shutdown in 2024/2025. Optimizing the shutdown of Pickering mitigates capacity uncertainties during the refurbishments of the Darlington and Bruce stations.

In EB-2020-0290, OPG provided an update on the Pickering Extended Operations[13] initiative and Pickering Optimization Shutdown aimed to safely optimize the shutdown of Pickering by operating all six units until September 2024, five of the six units through the end of 2024 and the remaining four units (Pickering Units 5-8) to the end of 2025.

On September 29, 2022, the Province issued a press release to support Pickering B Extension from December 2025 to September 30, 2026 that further mitigates capacity uncertainties to Darlington Refurbishment project completion in April 2026 and meet 2026 summer peak demand.

[13] The Pickering Extended Operations initiative was completed in 2023 within its budget of $307M, as detailed EB-2023-0336, Ex. H1-1-1, Section 5.6.2, pp. 20-22.

The Pickering B Extension Variance Account (now Pickering B Variance Account) was established pursuant to an amendment to O. Reg. 53/05 made in December 2022. The variance account records the difference between the revenues generated from the output of Pickering Units 5-8 during the period from January 1, 2026-September 30, 2026, and the sum of any forgone revenue related to forgone output from these units arising from activities undertaken in furtherance of their operation during the period from January 1, 2026-September 30, 2026 and the revenue requirement impact resulting from actual capital and non-capital costs incurred for such extension activities. As discussed in Ex. D2-3-1, O. Reg. 53/05 was further amended to allow OPG to record, in the now Pickering B Variance Account, costs that OPG is incurring for preserving resources and supporting infrastructure to enable potential refurbishment and subsequent operation of the units beyond September 30, 2026.

4.2 Work and Costs Required for Optimization

The work related to the Pickering Optimized Shutdown initiative demonstrated that it is feasible for Pickering to safely operate to the optimized shutdown dates of 2024 (for Units 1/4) and 2025 (for Units 5-8). Subsequent decision through the current 2022-2026 IR term resulted in a Pickering B (Units 5-8) extension to September 2026.

Optimization involves incremental activities to demonstrate to the CNSC the station's continued fitness of service to safely and reliably operate to the planned shutdown dates, and to make other necessary improvements in support of this plan. The estimated cost of this work, which has been incremental to normal operating costs, is over 2020-2026 period ("Enabling Costs"). The Picking Optimized Shutdown initiative has now been completed, under budget. Further details on the Pickering Optimized Shutdown work and Enabling Costs are described below.

4.2.1 Pickering Optimized Shutdown Work

In advance of recommending Optimization, OPG completed an initial technical assessment of the Pickering units' continued ability to operate to the Optimization's proposed shutdown dates. The initial technical assessments serve as the basis for the detailed scope for the Enabling Costs. The main elements of this scope of work were for: 1) the Periodic Safety Review ("PSR")

revision; 2) the Fuel Channel Life Cycle Management Plan ("FC-LCMP"), and 3) Component Condition Assessments.

Periodic Safety Review Revision

Between 2019 and 2023, OPG's plan to extend commercial operation of Pickering Units 5-8 to the end of 2026 required an update to the most recent comprehensive Pickering Periodic Safety Review (named PSR2) PSR2 assessment. The most recent comprehensive Pickering Periodic Safety Review had been completed in support of Pickering commercial life extension to 2024, as part of the Pickering 2018-2028 licence. OPG conducted an incremental review of the PSR2, named the PSR2-B, and reassessed the time-dependent elements of the PSR2. This addendum to the PSR assessed the period of 2024-2026 commercial operation for Pickering Units 5-8. The PSR2-B IIP was accepted by the CNSC in July 2023. By December 2024, the last PSR2-B IIP Assignments and Resolution Actions were completed and accepted as closed by the CNSC. OPG informed the CNSC in February 2025 that all PSR2-B commitments are closed and no further reporting was required.

Fuel Channel Life Cycle Management Plan ("FC-LCMP")

The major limiting component for operations is the life expectancy of the fuel channels. Technical assessments on the fuel channels' fitness-for-service continue through the FC-LCMP and ongoing inspections and include incremental fuel channel scope required to address known degradation to enable operation to the planned shutdown dates through to September 2026. The ongoing work program consists of analysis and work activities to assess fuel channel fitness-for-service for the planned operating durations and to develop methods for assuring that each Pickering unit can meet its extended service life target. This work program is being conducted under the Fuel Channel Life Management Phase V Project (Ex. F2-3-3) and builds on the Fuel Channel Life Management and Fuel Channel Life Extension projects.

Component Condition Assessments

While the technical fitness-for-service of other major components, separate from the fuel channels, is not considered life limiting, Component Condition Assessments were completed to validate their fitness-for-service to the planned shutdown dates in 2024 and 2026.

4.2.2 Enabling Costs

The costs associated with completing the above work are included within OPG's Nuclear Base, Outage and Project OM&A exhibits and associated tables, as summarized in Chart 5 below. The budgets established in EB-2020-0290[14] for the enabling costs were $50M.

Chart 5 – Optimization of Pickering Shutdown Costs ($M)*

Line No.	Cost Item	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 YTD[1]	Total Actual
1	Base OM&A	0.5	0.9	1.7	1.4	3.0	0.2	7.7
2	Project OM&A	0.3	1.7	4.9	3.0	0.2	0.0	10.1
3	Outage OM&A	0.1	1.9	1.8	7.2	11.8	1.1	23.9
4	Total Pickering Optimization	0.9	4.5	8.4	11.6	14.9	1.3	41.7

**Numbers may not add due to rounding*

[1]Year-to-date costs incurred as of September 30, 2025

Differences between forecast and actual Enabling Costs incurred to achieve Optimization have been recorded in the Capacity Refurbishment Variance Account. The variance account is discussed in Ex. H1-1-1, Section 5.6.

5.0 NEW NUCLEAR INITATIVES

5.1 Darlington New Nuclear and New Nuclear Development

In EB-2020-0290, OPG identified forecasted non-capital preliminary planning and preparation costs in 2020 and 2021 for a new on-grid small modular reactor facility at the Darlington new nuclear site (the Darlington New Nuclear Program ("DNNP")) to be recorded in the Nuclear Development Variance Account. This included costs for technology developer selection with

[14] EB-2020-0290, Ex. F2-1-1, Section 4.2.2.

the objective of arriving at the selection decision by the end of 2021. In the EB-2020-0290 Decision and Order, the OEB found that these costs were appropriate to be recorded in the Nuclear Development Variance Account. In the EB-2023-0336 Decision and Order,[15] the OEB agreed to the recovery of $108.3M for the amounts requested over 2020-2022 period. The actual costs incurred in 2020 ($13.1M), 2021 ($95.4M), and 2022 ($2.4M) are presented in Ex. F2-1-1, Table 1a, Line 7. These costs are not part of the DNNP. Further details about the DNNP are discussed at Ex. D2-4-1.

As highlighted in the Ontario government announcement in November 2024,[16] OPG continues to work with local communities to explore opportunities for new nuclear generation at the Wesleyville site. Historical and bridge year amounts, identified in Ex. F2-1-1, Table 1a, Line 9, primarily relate to preparation for potential new nuclear generation at OPG sites (Wesleyville, Nanticoke and Lambton). These costs are being recorded in the Nuclear Development Variance Account. No amounts related to potential new nuclear generation projects are included in the revenue requirement for OPG's nuclear facilities over the IR term.

5.2 Pickering Refurbishment Feasibility Study

As described in Ex. D2-3-4, Section 2.1.1, following the Province of Ontario's request for OPG to update its feasibility assessment for refurbishing Pickering Units 5-8 in 2022, OPG officially began the Feasibility Phase of the refurbishment. The Feasibility Phase was the initial step in assessing whether refurbishment of the Pickering Nuclear Generating Station is technically, economically, and operationally viable. During this phase, a comprehensive feasibility study was conducted, evaluating a range of options and identifying the most promising path forward. The project team undertook high-level technical assessments, examined the condition of key station components, and developed preliminary strategies for refurbishment.

As discussed in Ex. D2-3-4, key outputs that were driven by the feasibility report included a preliminary project scope, an order-of-magnitude cost estimate, and a high-level schedule.

[15] Decision and Order, EB-2023-0336, June 13, 2024, pp. 39-41.
[16] Province of Ontario, News Release: Ontario Generating More Energy to Meet Soaring Demand, November 27, 2024. <https://news.ontario.ca/en/release/1005403/ontario-generating-more-energy-to-meet-soaring-demand>

OPG conducted early engagement with stakeholders, including regulators, government, and Indigenous communities, to understand expectations and concerns. A preliminary risk assessment was also completed, identifying major technical and delivery risks, along with potential mitigation strategies. The actual costs incurred to support this study, 2022 ($0.2M), and 2023 ($17.8M), as presented in Ex. F2-1-1, Table 1a. The completion of this study, and its subsequent approvals, led to the Pickering Refurbishment Program, as discussed in Ex. D2-3-1. These costs are not part of the PRP.

LIST OF ATTACHMENTS

Attachment 1:	Prior Gap Closure Initiatives
Attachment 2:	OPG 2024 Nuclear Benchmarking Report
Attachment 3:	ScottMadden Evaluation of OPG Nuclear Benchmarking
Attachment 4:	OPG Nuclear Cost Performance Benchmarking – A Study of Factors Impacting TGC/MWH Performance with Normalizing Adjustments to Facilitate Closer Comparison (ScottMadden)
Attachment 5:	2025 Indeavor Nuclear Staffing Benchmarking Analysis
Attachment 6:	ScottMadden Evaluation of OPG Nuclear Benchmarking Retainer Letter
Attachment 7:	ScottMadden OPG Nuclear Cost Performance Benchmarking Retainer Letter
Attachment 8:	Indeavor Nuclear Staffing Benchmarking Analysis Retainer Letter

Note: Attachments may be marked “Confidential”, however, OPG has determined all Attachments to be non-confidential in their entirety.

ATTACHMENT 1
Prior Initiatives

Nuclear Operations continues to leverage industry working groups, benchmarking industry peers and utilizing next level industry tools to enable us to adopt industry best practices. Operating stations and supporting business units have established targets that reflect strong industry performance while leveraging Corporate Functional Area Manager accountability and intrusive oversight.

The following provides an update of the objectives, description of activities undertaken and benefits achieved of the three key fleet wide initiatives as identified in EB-2020-0290, Ex. F2-1-1, Section 3.4: (i) Right Work, Right Time, Right Value, (ii) Leaders Driving Business results, and (iii) People Powering the Future.

Right Work, Right Time, Right Value

Objective

The Right Work, Right Time, Right Value initiative focusses on improving plant reliability by improving maintenance productivity. Another key area of focus is on improving work management performance by transitioning to the use of digital work management tools and artificial intelligence in work management and outage planning processes.

Description

Key improvement actions for this initiative are:

- Expanding the “Fix it Now” maintenance team and optimizing assessment of minor maintenance. The benefit of the Fix it Now team is increased agility in executing priority work. This team is empowered with cross-functional members to tackle urgent issues more efficiently. Similarly, minor maintenance work is being optimized to ensure assessment is based on a graded approach, which improves efficiency and reduces the comprehensive requirements that are applied to complex work.
- Utilizing the Monitoring and Diagnostic Center (“M&D Center”) to develop predictive failure models and transitioning components of its time-based maintenance program to condition-

based maintenance. The objective of condition-based maintenance is to establish continuous equipment condition monitoring using high performance diagnostic tools that can combine the power of on-line process and equipment performance data acquisition with advanced diagnostic methodologies, including advanced pattern recognition technology (a form of artificial intelligence ("AI")), to avoid operations and maintenance costs and improve plant performance.

Benefits Realized

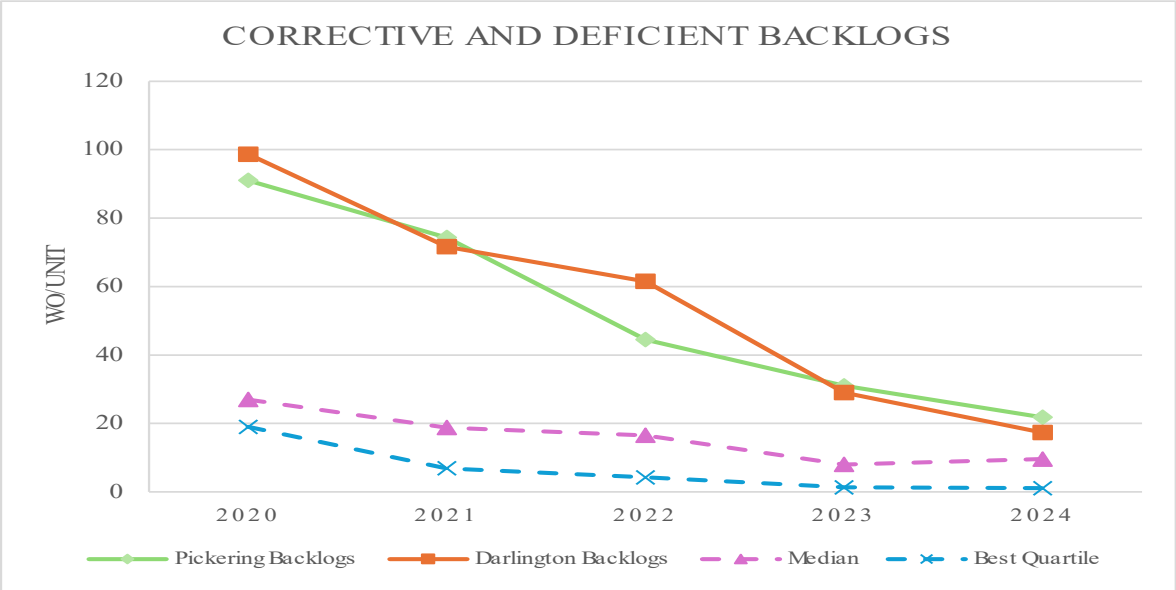
Fix it Now Centre of Excellence at Pickering and Darlington have been established which are industry best practices. The establishment of the Fix it Now Centre of Excellence has improved minor maintenance execution and has driven reductions in both targeted critical and deficient maintenance backlogs (see Figure 1).

As part of the continued evolution of the M&D Center, sensors and remote monitoring technologies are being installed on plant equipment, which will provide real time data and analysis to ensure maintenance is done promptly and resource utilization is maximized. This enables the prioritization of maintenance activities and optimal use of resources to ensure high plant reliability. OPG will continue to seek further opportunities to apply AI to support planning outage scope and the efficient execution of outage work. The following performance improvements have been realized:

- Corrective Critical backlogs at 0 for both stations. Corrective Non-critical and Deficient Critical backlogs are 0 at Darlington while < 1 WO per unit at Pickering. Deficient Non-critical backlogs show significant decline at both stations since 2020 (see Figure 1[1]);
- Critical PMs deferral at live 0 for both Pickering and Darlington;
- Reduction in number of PM's completed in 2nd half of grace;
- Maintenance and Work Management Index at industry best 100% for Pickering and Darlington.

[1] Figure 1 combines On-Line Corrective Non-Critical, On-Line Corrective Critical, On-Line Deficient Non-Critical and On-Line Deficient Critical Backlogs for ease of reading.

Figure 1



Leaders Driving Business Results

Objective

The Leaders Driving Business Results initiative focusses on managers driving business efficiencies through innovation. The initiative provides managers with information, tools and training to make sound risk based decisions that will improve the performance of their teams and support improvement in Safety, Financial, Project, and Operational excellence through readily available information.

Description

Key improvement actions for this initiative are:

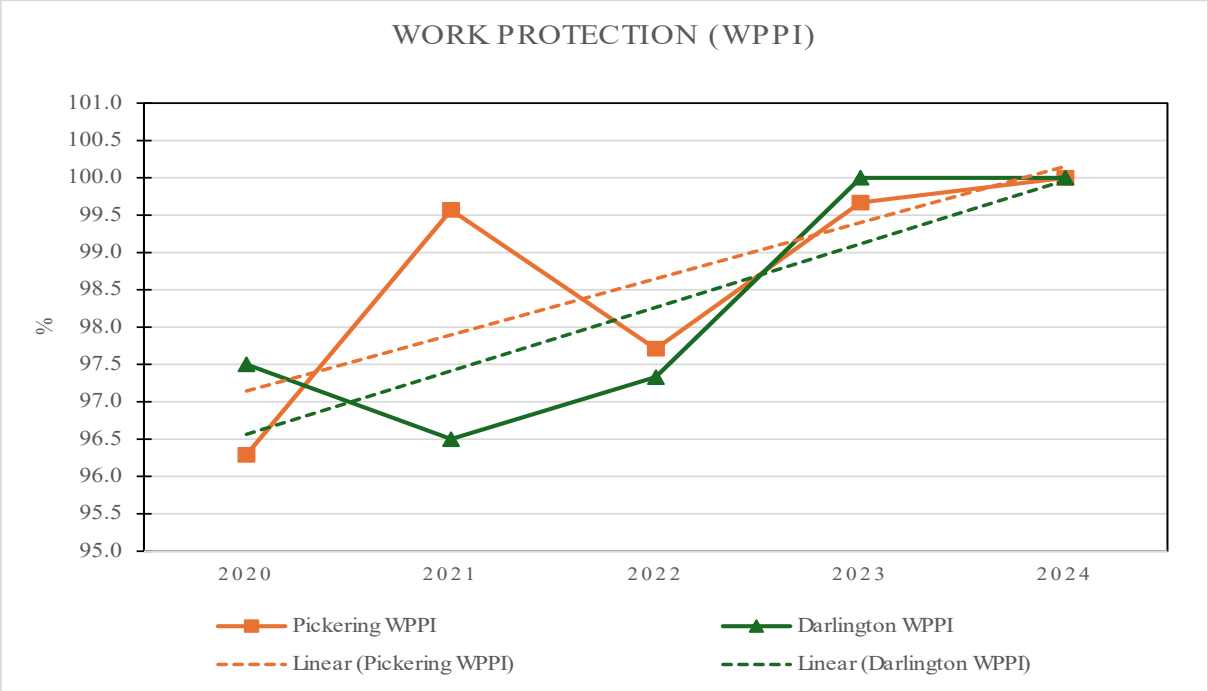
- Established automated centralized business data and reports providing managers with more efficient reporting and access to information to make better informed and more timely decisions. As an example, OPG has implemented a suite of online reporting dashboards providing managers with the ability to see up-to-date operational and cost information, including Performance Improvement, Work Protection, Business Unit Risk Dashboards as well as overtime trend data to better manage budgets. These dashboards also support building broader awareness of business acumen.

- Training and workshops to ensure that all managers have the required knowledge and skills to use these tools and manage their teams to drive and sustain innovation and performance improvement.

Benefits Realized

OPG created reports, along with training to support their understanding, simplifies and enables leaders to quickly grasp overall performance. These reports are used in station monthly Key Performance Indicator review meetings, Business Unit Risk meetings and Organizational Effectiveness Reflection sessions. Innovation and data analytics have shown significant gains and progress with available Power BI dashboards that include both Operational and Financial tools. Planned enhancements in OPG's safety culture are being achieved through improving work protection, executing work error free and strengthening defenses. This is accomplished through implementing industry defined excellence standards, use of employee advocates and employee-led innovations to improve safety, maintenance and effectiveness.

FIGURE 2



People Powering the Future

Objective

The People Powering the Future initiative focused on ensuring work programs were resourced appropriately while minimizing the organizational and financial impacts associated with the then planned Pickering commercial operations shutdown.

With the announcement in January 2024 where the government supported OPG to proceed with the Project Initiation Phase of Pickering Refurbishment (see Ex. D2-3-1), OPG has been working on its strategies to resource the business based on the work demands, transitioning the organization from Pickering end of commercial operations to Pickering Refurbishment and back to commercial operations within the upcoming IR term.

Description

In preparing for this transition, OPG has developed a workforce plan that redeploys skilled labour during this transition period to meet the demands of operations and projects across the business. As the organization makes these changes, it is important to ensure that the right individuals and skills are available to meet project and operational demands while addressing risks such as attrition and the retirement eligibility of OPG's workforce (discussed further in Ex. F4-3-1, Section 5.1). The workforce strategies will ensure operational and project excellence to maintain strong performance, while also securing the required resources to progress Pickering Refurbishment and Darlington post-refurbishment operational life.

Benefits Realized

Nuclear Operations is improving as a business through strategies to continuously improve and address emerging risks and opportunities. A focus on leadership development and behaviours, employee engagement strategies and high levels of proficiency will help to ensure the workforce can continue to meet demands of continued operational excellence and further, to ensure a sustainable future throughout the IR term and its impending workforce transitions. The focus on leadership development and workforce proficiency includes initiatives on knowledge retention and mentoring programs to strengthen leaders and coaching, and improved feedback to drive proficiency and maintain high safety standards. The continued

focus on workforce strategies also helps to secure a capable workforce that can adapt to OPG's future needs.

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 1 of 61

2024 Nuclear Benchmarking Report



Safety • Reliability • Value for Money • Human Performance



OPG Confidential – Internal Use Only
Controllership – Business Planning & Benchmarking

ONTARIO POWER GENERATION | Electrifying life

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 2 of 61

Table of Contents

1.0 EXECUTIVE SUMMARY 2

2.0 SAFETY 10

Methodology and Sources of Data 10
Total Recordable Injury Frequency (TRIF) 11
Rolling Average Industrial Safety Accident Rate (ISAR) 12
Rolling Average Collective Radiation Exposure (CRE) 14
Airborne Tritium Emissions 16
Fuel Reliability Index (FRI) 18
2-Year Unplanned Automatic Reactor Trips 20
3-Year Auxiliary Feedwater Safety System Performance (Unavailability) 22
3-Year Emergency AC Power Safety System Performance (Unavailability) 23
3-Year High Pressure Injection (ECI) Safety System Performance (Unavailability) 25

3.0 RELIABILITY 27

Methodology and Sources of Data 27
WANO Nuclear Performance Index (NPI) 28
Rolling Average Forced Loss Rate (FLR) 29
Rolling Average Unit Capability Factor (UCF) 31
Rolling Average Chemistry Performance Indicator (CPI) 32
On-Line Deficient & Corrective non-critical Backlog 34
On-Line Deficient & Corrective Critical Backlog 34

4.0 VALUE FOR MONEY 36

Methodology and Sources of Data 36
3-Year Total Generating Cost (TGC) per MWh 37
3-Year Non-Fuel Operating Cost per MWh 39
3-Year Fuel Cost per MWh 40
3-Year Capital Cost per MW DER (Design Electrical Rating) 42

5.0 HUMAN PERFORMANCE 44

Methodology and Sources of Data 44
18-Month Human Performance Error Rate 44

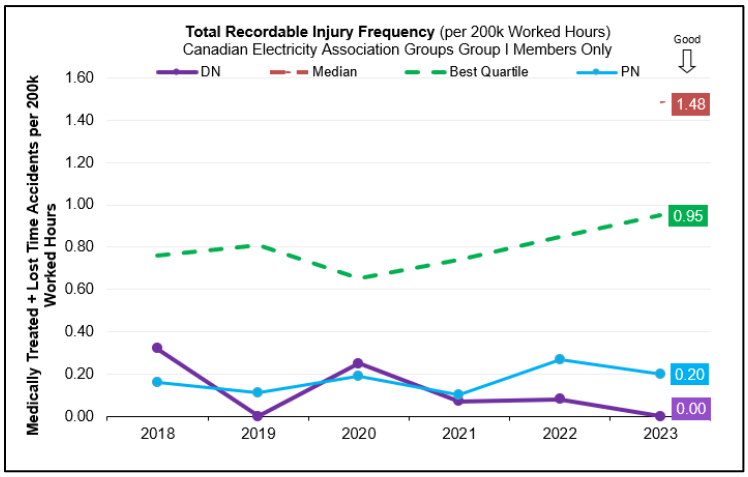
6.0 APPENDIX 45

Acronyms 45
Safety and Reliability Definitions 49
Value for Money Definitions 52
Human Performance Definitions 53
Industry Peer Groups 54
Panels/Members 56

In 2023, Ontario Power Generation (OPG) demonstrated favorable results compared to its peer in number of key areas.

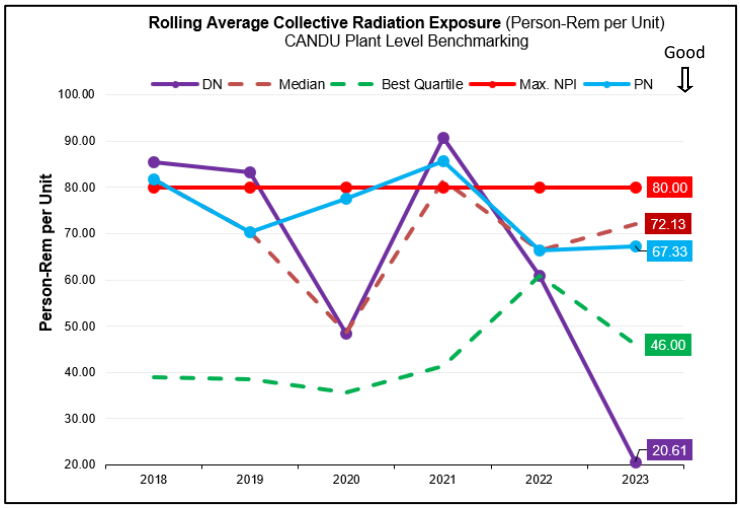
Safety

Total Recordable Injury Rate (TRIF)
Both Darlington Nuclear Generating Station (DNGS) and Pickering Nuclear Generating Station (PNGS) improved performance in 2023, contributing to OPG's best ever TRIF performance, and exceeding industry top quartile.



To further strengthen safety performance, OPG continues to build on its Fail-Safe strategy by building capacity & strengthening safety defences, implementing the Edison Electrical Institute Safety Classification & Learning (SCL) model to recognize and mitigate Serious Injuries & Fatalities (SIF) precursor conditions, as well as the integration of the Electronic Safe work Planning & Pre-Job Briefing (eSWP) platform to enhance sharing of safe work planning knowledge including the Energy Wheel to identify energy hazards.

Collective Radiation Exposure (CRE)
DNGS and PNGS continued to achieve maximum Nuclear Performance Index (NPI) in 2023. DNGS improved performance is due to the planned outage schedule in 2023 of zero outages. PNGS CRE slightly increased as a result of planned and unplanned outage scope.

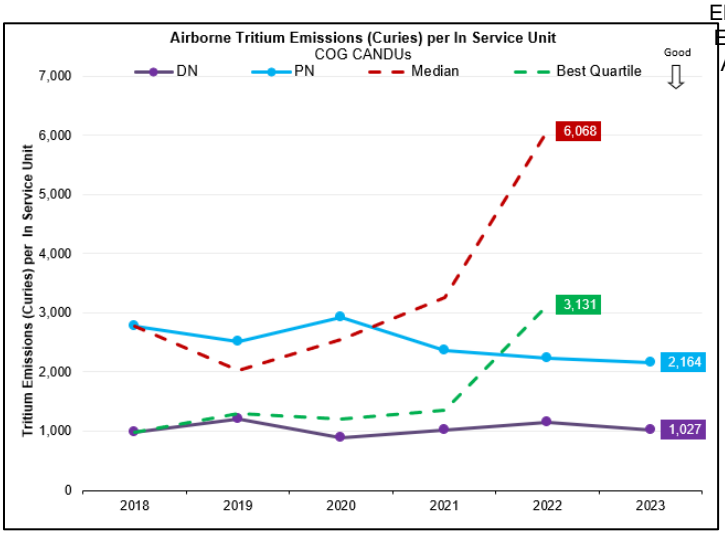


DNGS and PNGS have implemented source term controls including utilizing dose reducing Lanxess resin and improved shielding to reduce dose rates. PNGS is also continuing to focus on foreign material and chemistry heat transport purification management.

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 4 of 61

Airborne Tritium Emissions

PNGS and DNGS Airborne Tritium Emissions remain at a very small fraction of regulatory limits.

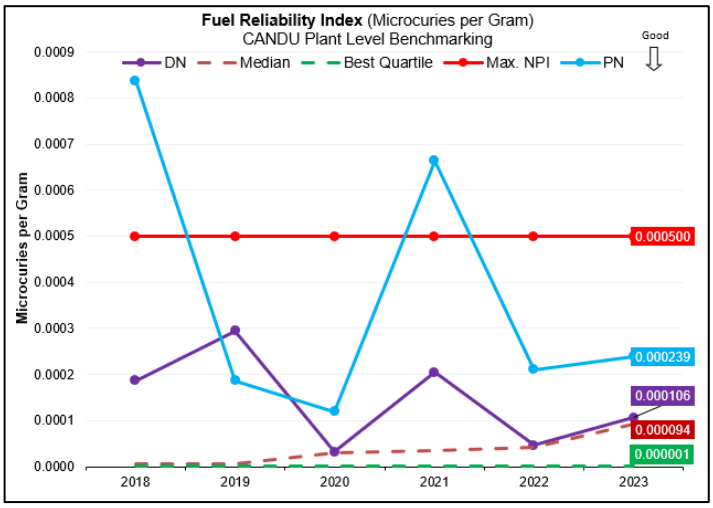


DNGS and PNGS achieved top quartile in 2023, largely driven by the increase of industry quartiles. This factor led to PNGS achieving top quartile in 2023 for the first time since 2005. DNGS continued best quartile performance is also attributable to tritium identification and reduction activities.

Both sites have continued tritium reduction activities driven by a High Impact Team (HIT), enhancing focus on tritium sources identification and enhanced management oversight. In addition, collaboration between both sites to exchange operating experience, innovation activities on tritium mitigation, and benchmark performance.

Fuel Reliability Index (FRI)

DNGS and PNGS continued to achieve maximum NPI points in 2023.



One fuel defect was observed for DNGS in 2023 in comparison to zero in 2022. Two fuel defects for PNGS were confirmed in 2023, similar to 2022.

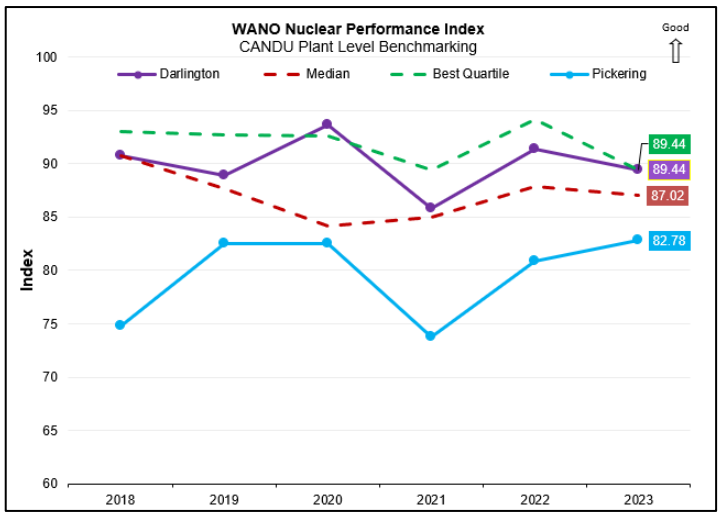
Continual efforts to enhance performance at both sites includes completing the fuel design manual and drawing update which strictly controls the manufacturing process as well as the fuel operating, fuel handling and fuel performance limits. PNGS is also improving surveillance methods and eliminating foreign materials from entering the Heat Transport System through improved Fuel Handling and Outage practices. DNGS continues to mitigate fuel debris failures by utilization of Foreign Material Exclusion practices.

The five other safety-related metrics at DNGS and PNGS were favourable and achieved green ratings in 2023. Both DNGS and PNGS achieved maximum World Association of Nuclear Operators (WANO) NPI results and best quartile performance for all NPI Safety sub-metrics.

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 5 of 61

Reliability

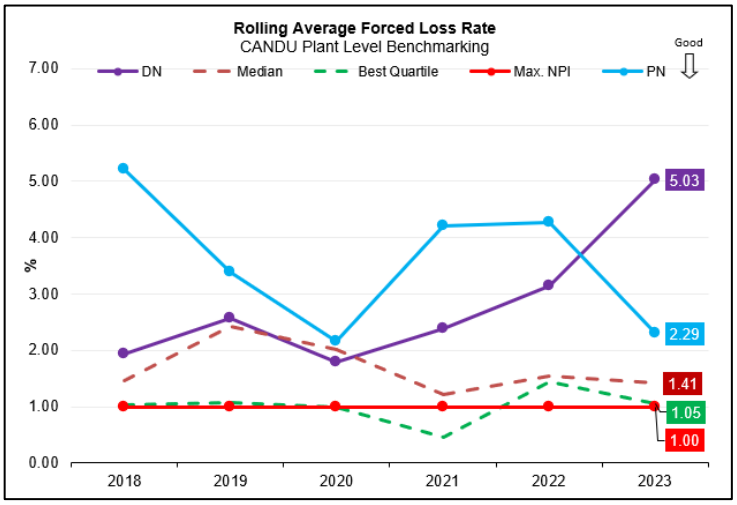
Nuclear Performance Index (NPI)



In 2023, DNGS performance continues to achieve best quartile due to excellent performance for all seven of the safety metrics.

PNGS performance improved in 2023 due to Unit Capability Factor (UCF) and Forced Loss Rate (FLR) improving performance. PNGS' third quartile performance also reflects the need for extended outages to accommodate fuel channel inspection programs, unbudgeted planned outages for non-routine maintenance work and unplanned outages due to external causes which impact UCF, Collective Radiation Exposure (CRE) and Chemistry Performance Index (CPI) Metrics.

Forced Loss Rate (FLR)



In 2023, FLR performance declined at DNGS and improved at PNGS.

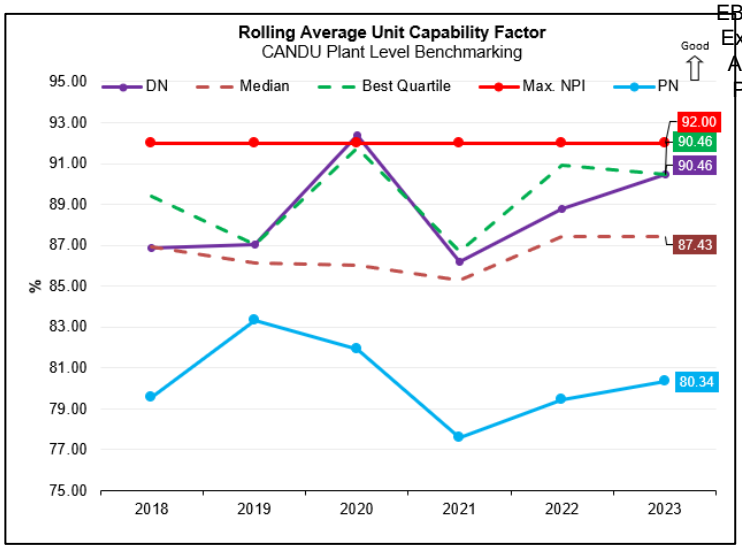
PNGS experienced six forced outages in 2023 compared to elevated FLR in 2021 which is no longer included in the rolling window. DNGS experienced one forced outage and was attributable to post refurbishment outage events on Unit 2.

Fuel handling contribution reduced in 2023 and remains a focus area to build sustainability. Focused initiatives including vulnerability identification and elimination, proficiency building and project execution at both stations to increase Turbine Generator Reliability, the highest fleet contributor. Fuel handling remains a fleet focus area to build sustainability.

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 6 of 61

Unit Capability Factor (UCF)

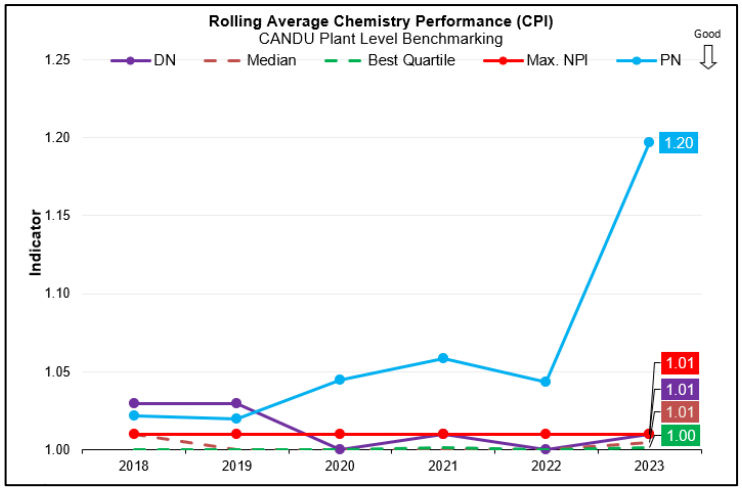
In 2023, DNGS improved to achieve best quartile and PNGS remained in fourth quartile. PNGS improved performance is attributable to improved FLR performance in 2023 compared to elevated FLR in 2021 which is no longer included in the rolling average. This was partially offset by increased planned outage days in 2023 in comparison to 2021. DNGS best quartile performance in 2023 is attributable to reduced planned outage days in 2023 compared to 2021, partially offset by forced outage events impacting post refurbishment for Unit 2.



Focused initiatives including vulnerability identification and elimination, proficiency building and project execution at both stations to increase Turbine Generator Reliability, the highest fleet contributor. Fuel handling contribution reduced in 2023 and remains a focus area to build sustainability.

Chemistry Performance Index (CPI)

PNGS decline in 2023 performance is attributed to condenser tube leaks and boiler level transient. Declined performance in 2019-2022 was primarily caused by start-up boiler sulfates due to turbine maintenance activities during outage, and condenser tube leak resulted in elevated boiler ions.



DNGS continues to achieve maximum Nuclear Performance Index (NPI). The slight decline in performance in 2023 compared to 2022 can be attributed to condenser tube leaks on Unit 2.

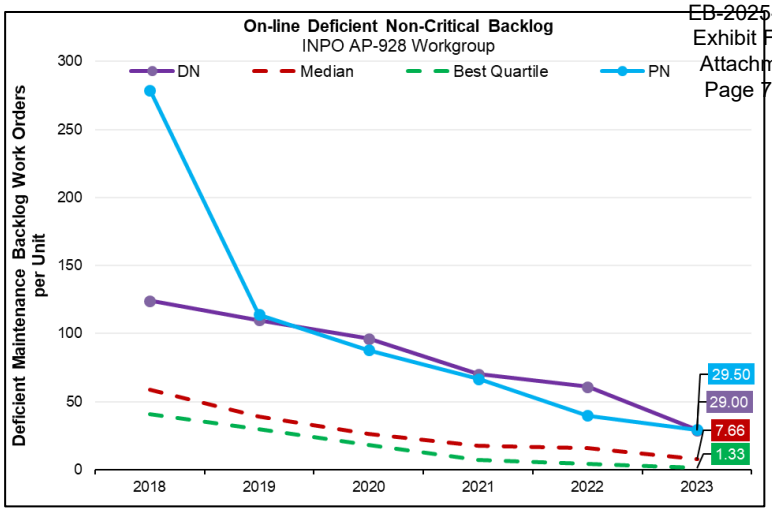
DNGS and PNGS continue to have a Chemistry Outage Single Point of Contact (SPOC) to provide improved coordination/planning such that system chemistry control is improved during outages/start-ups.

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 7 of 61

On-Line Deficient Non-Critical Backlog and Deficient Critical Backlog

The favourable trend for Backlog performance at PNGS continued into 2023, with significant improvements for On-line Deficient Non-Critical Backlogs (26% improvement) compared to 2022 results.

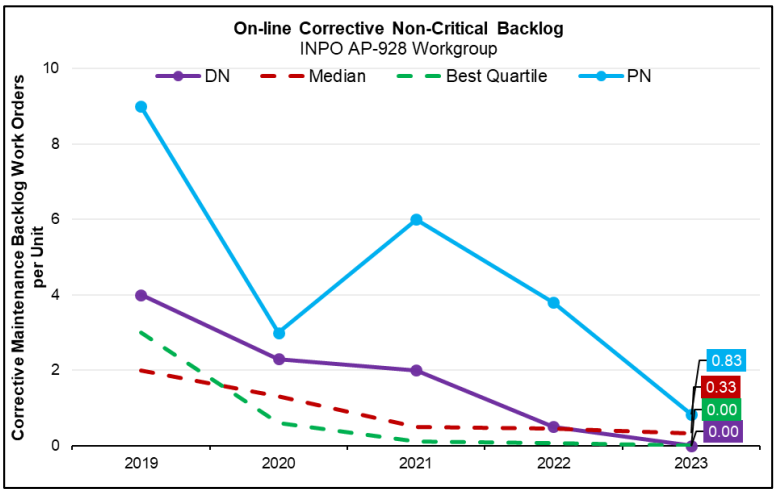
DNGS improved their On-line Deficient Non-Critical Backlog by 52% and Deficient Critical Backlog sustained a best quartile score of zero as a result of continued station focus, overall maintenance efficiency and improved schedule quality.



On-Line Corrective Non-Critical Backlog and Corrective Critical Backlog

PNGS On-line Corrective Non-Critical Backlog performance improved in 2023 due to decreases in the Corrective Non-Critical Backlogs.

DNGS remained in the best quartile for the Corrective Critical Backlogs and improved to best quartile for On-line Corrective Non-Critical Backlog performance.

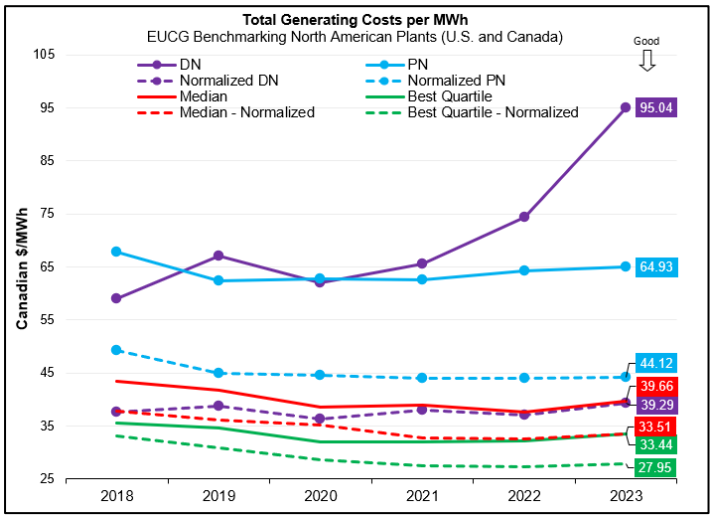


Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 8 of 61

Value for Money

TGC/MWh

In 2023, normalized Total Generating Cost per Megawatt-hour (TGC/MWh) performance remained in the third quartile for DNGS and the fourth quartile for PNGS after normalizing[1] for refurbishment, technology including outage duration and age-related impacts.

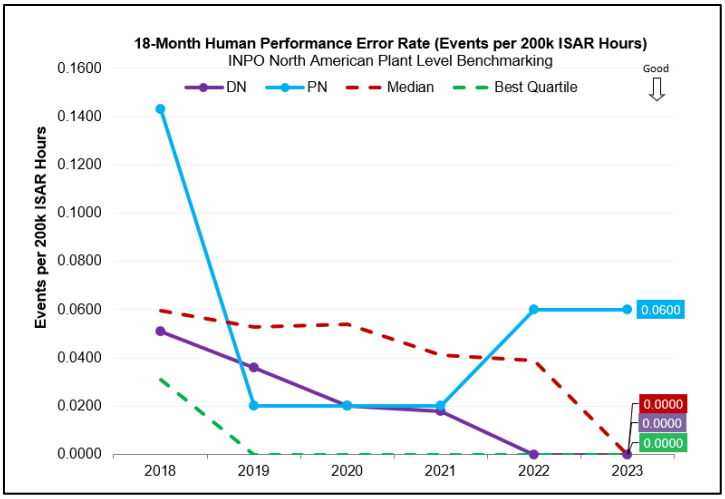


DNGS normalized performance was impacted by capital investment requirements for life post-refurbishment and reduced 3-year generation related to the refurbishment schedule while PNGS normalized performance reflects continued reduction in capital investment as the station approaches the end of commercial operations in 2026.

Human Performance

Human Performance Error Rate

DNGS maintained best quartile performance and did not experience any Site Event Free Day Reset (S-EFDR)'s in 2023.



PNGS experienced one S-EFDR which contributed to fourth quartile performance. The event causes were identified, and corrective actions implemented to address the gaps.

Human performance continues to be a focus across the fleet with actions taken to further improve performance by continuously improving the Observation & Coaching program as well as integration of Fail Safe strategies and trending processes to strengthen values and behaviours of Nuclear Professionals.

[1] See section 4.0 for more information about the TGC/MWh normalization methodology.

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 9 of 61

Benchmarking Results – Plant Level Summary

Table 1 provides a complete summary of 2023 performance compared to benchmark results.

Table 1: Plant Level Performance Summary

Metric	2023 Actuals					
	NPI Max	Best Quartile	Median	Third Quartile	Pickering	Darlington
Safety						
Total Recordable Injury Frequency (#/200k hours worked)		0.95	1.48	2.21	0.20	0.00
Rolling Average[2] Industrial Safety Accident Rate (#/200k hours worked)[1]	0.20	0.00	0.00	0.05	0.00	0.00
Rolling Average[2] Collective Radiation Exposure (Person-rem per unit)[1]	80.00	46.00	72.13	94.67	67.33	20.61
Airborne Tritium Emissions (Curies) per Unit [3]		3,131	6,068	6,845	2,164	1,027
Fuel Reliability (microcuries per gram)[1]	0.000500	0.000001	0.000094	0.000239	0.000239	0.000106
2-Year Reactor Trip Rate (# per 7,000 hours)[1]	0.500	0.000	0.215	0.430	0.247	0.430
3-Year Auxiliary Feedwater System Unavailability (#)[1]	0.0200	0.0000	0.0006	0.0021	0.0019	0.0000
3-Year Emergency AC Power Unavailability (#)[1]	0.0250	0.0002	0.0004	0.0030	0.0000	0.0000
3-Year High Pressure Safety Injection Unavailability (#)[1]	0.0200	0.00000	0.00000	0.00000	0.0000	0.0002
Reliability						
Rolling Average[2] WANO NPI (Index)[1]		89.44	87.02	82.78	82.78	89.44
Rolling Average[2] Forced Loss Rate (%)[1]	1.00	1.05	1.41	2.29	2.29	5.03
Rolling Average[2] Unit Capability Factor (%)[1]	92.00	90.46	87.43	86.59	80.34	90.46
Rolling Average[2] Chemistry Performance Indicator (Index)[1]	1.01	1.00	1.01	1.01	1.20	1.01
1-Year Online Deficient Critical Backlog (work orders per unit) [1]		0.00	0.00	0.50	0.67	0.00
1-Year Online Deficient Non-Critical Backlog (work orders per unit) [3]		1.33	7.66	22.00	29.50	29.00
1-Year Online Corrective Critical Backlog (work orders per unit) [1]		0.00	0.00	0.00	0.00	0.00
1-Year Online Corrective Non-Critical Backlog (work orders per unit) [3]		0.00	0.33	1.00	0.83	0.00
Value for Money						
3-Year Total Generating Costs per MWh ($ per Net MWh) [1]		33.44	39.66	49.23	64.93	95.04
Normalized 3-Year Total Generating Cost per MWh ($ per Net MWh)		27.95	33.51	42.57	44.12	39.29
3-Year Total Generating Cost per Unit (M $ per Unit)		283.01	313.31	358.44	230.73	627.40
Normalized 3-Year Total Generating Cost per Unit (M $ per Unit)		236.12	276.78	320.69	168.77	277.51
3-Year Non-Fuel Operating Costs per MWh ($ per Net MWh) [1]		19.64	24.64	32.22	58.31	62.76
3-Year Normalized Non-Fuel Operating Cost per Net MWh ($/MWh)		19.64	24.64	32.22	--	43.89
3-Year Fuel Costs per MWh ($ per Net MWh)[1]		6.11	6.68	7.44	3.79	4.05
3-Year Capital Costs per MW DER (k$ per MW)[1]		33.87	60.01	107.30	19.54	212.29
Normalized 3-Year Capital Cost per MW DER (k$ per MW)		33.87	60.01	107.30	--	106.57
Human Performance						
18-Month Human Performance Error Rate (# per 200k ISAR and contractor hours) [1]		0.0000	0.0000	0.0410	0.0600	0.0000

1. Best Quartile, Median and Third Quartile are from Q4 2023 best available information.

2. Indicates a 2-Year Rolling Average for Pickering and a 3-Year Rolling Average for Darlington.

3. Best Quartile, Median, Third Quartile are from the Q4 2022 which is the most current available benchmark for these metrics.

Legend

4th Quartile Performance	3rd Quartile Performance	2nd Quartile Performance	Maximum NPI points achieved or Best Quartile

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 10 of 61

Background

This report presents a comparison of OPG Nuclear's performance to that of nuclear industry peer groups. Benchmarking results are used during business planning to drive top-down target setting with business improvement as the objective.

Performance Indicators

Good performance indicators used for benchmarking are metrics with standard definitions, reliable data sources, and utilization across a representative portion of the industry. Good indicators allow for benchmarking to be repeated year after year in order to track performance and improvement. Additionally, when selecting an appropriate and relevant set of metrics, a balanced approach covering all key areas of the business is essential. In accordance with these criteria, key performance indicators have been selected for comparison to provide a balanced view of performance and for which consistent, comparable data is available. These indicators are defined in Section 6.0.

Each indicator reflects a particular duration of historical performance in accordance with peer group expectations. For example, Electric Utility Cost Group (EUCG) data for Value for Money metrics are based on three-year average performance, whereas WANO NPI safety and reliability metrics reflect multi-year rolling averages based on each station's outage cycle. For NPI metrics, Darlington and Pickering's results reflect a three-year and two-year outage cycle, respectively.[2]

Industry Peer Groups

Peer groups were selected based on performance indicators widely utilized within the nuclear industry. Overall, six different peer groups were used as illustrated in Table 2 of Section 6.0 and panel members are detailed in Tables 3 to 8 of Section 6.0.

Report Structure

Sections 2.0 to 5.0 of the report focus on safety, reliability, value for money and human performance areas.

The Major Operator Section (historically Section 6.0) was removed from this report, consistent with ScottMadden's recommendations with respect to streamlining the report and ensuring consistency with leading practices and value for stakeholders. The Major Operator section provided a fleet operator level summary across a few key metrics, primarily across North America, utilizing a simple average of the results (mean) from each of their units/plants. While the operator level summary can be informative, it is more appropriate to look at OPG's two nuclear facilities individually given that they are at different stages of their lifecycle, have different sized units and reflect different generations of CANDU technology. This view is aligned with ScottMadden's most recent evaluation OPG Nuclear Benchmarking. The detailed data in sections 2.0 to 5.0 of the report provides a more complete picture of OPG's performance.

Section 6.0 provides an appendix of supporting information, including common acronyms, definitions, peer group and panel composition details.

[2] The planned outage cycle for each unit at Pickering is transitioning from a 24-month to a 30-month outage cycle. Pickering continues to assume a 24-month rolling average for benchmarking to be consistent with WANO reporting expectations.

Methodology and Sources of Data

The majority of safety metrics were calculated using data from WANO. Data labelled as invalid by WANO were excluded from all calculations. Indicator values of zero are not plotted or included in calculations except in cases where zero is a valid result. Current data was obtained and consolidated with previous benchmarking data.

The WANO Nuclear Performance Index (NPI), a maximum score of 100 is possible. The WANO NPI is an operational performance indicator comprised of 10 metrics, 7 of which are analyzed in this section:

- Industrial Safety Accident Rate (ISAR) [Rolling Average]
- Collective Radiation Exposure (CRE) [Rolling Average]
- Fuel Reliability Index (FRI) [Annual]
- 2-Year Unplanned Automatic Reactor Trips
- 3-Year Auxiliary Feedwater Safety System Performance Unavailability
- 3-Year Emergency AC Power Safety System Performance Unavailability
- 3-Year High Pressure Safety Injection Unavailability

The remaining three WANO NPI metrics are included in the Reliability Section (Section 3.0).

Note: To benchmark performance, Max NPI is used to indicate best quartile performance for metrics that perform better than the Max NPI benchmark. If metric performance is not better than Max NPI, quartile benchmarks are used to benchmark performance.

In addition to the WANO NPI safety sub-indicators listed above, Total Recordable Injury Frequency and Airborne Tritium Emissions per In Service Unit are included in this section of the report.

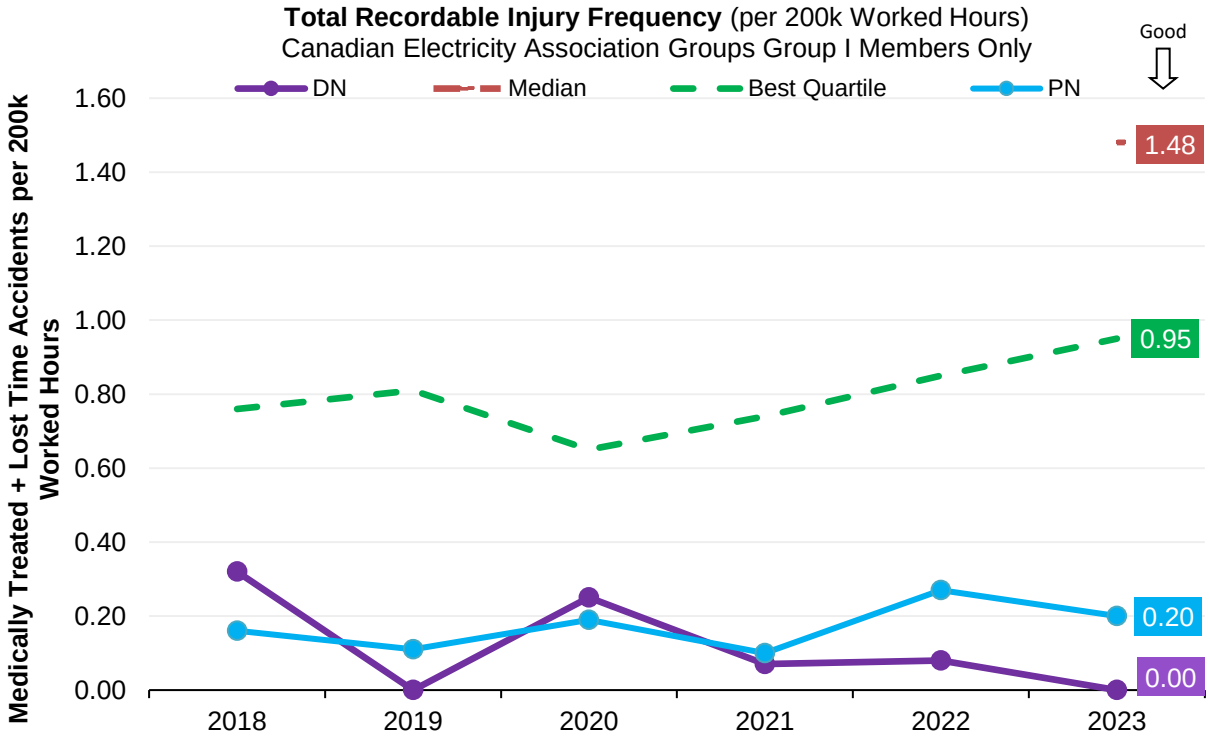
Total Recordable Injury Frequency (TRIF) was calculated using data from the Electricity Canada (EC). The peer group are members of Electricity Canada (EC) (Section 6.0, Table 6).

- OPG benchmarks against EC Group 1 peers (a subset of all EC members), which incorporates organizations with more than 1,500 employees, including most provincial utilities, leveraging EC's Occupational Health & Safety Statistics 2023 Report.

Airborne Tritium Emissions per In Service Unit data was collected from the CANDU Owners Group (COG). The peer group for this metric is all CANDUs who are a member of COG. There is a one-year lag for the industry values associated with this metric.

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 12 of 61

Total Recordable Injury Frequency (TRIF)



Note: Annual Value; median unavailable 2018-2022.

	2023 Value
DN	0.00
PN	0.20
Best Quartile	0.95
Median	1.48

Factors Contributing to Performance

- DNGS and PNGS improved performance in 2023 continued a long-standing pattern of excellent TRIF performance by exceeding the industry top quartile (top 25%) mark of 0.95 and top decile (top 10%) mark of 0.56, where DNGS reached 0.00 and PNGS achieved 0.20.
- Both DNGS and PNGS combined TRIF performance of 0.13 contributed to OPG's best TRIF performance of 0.16 in 2023 since the company's inception in 1999 and was the best performance in 2023 when compared to Electricity Canada's Group 1 companies with over 1,500 employees.

Initiatives to Improve and Sustain Favorable Performance Include:

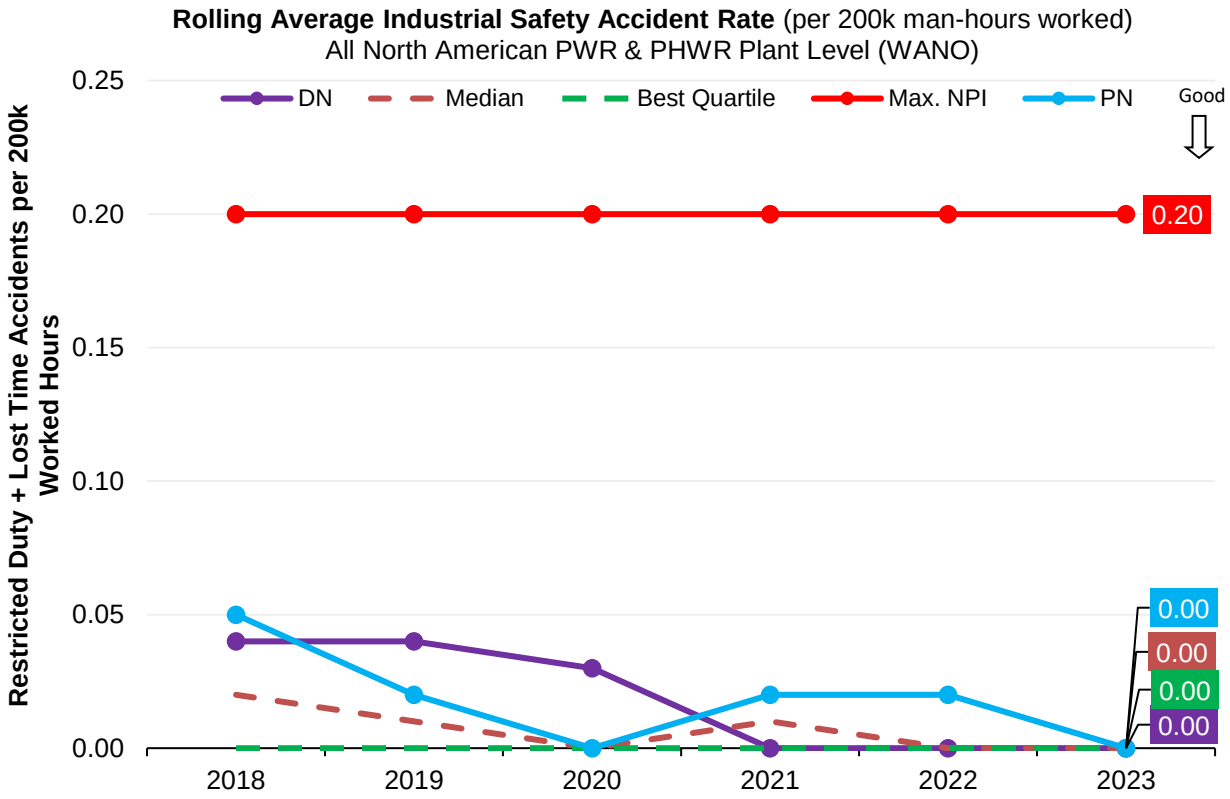
Implementation of the following initiatives are aimed at leading OPG to world-class safety performance:

- OPG continues to build upon its Fail-Safe Strategy to reduce the frequency of employee injuries by building capacity and strengthening safety defences.

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 13 of 61

- As part of the Fail-Safe Strategy, OPG is modernizing how it classifies safety events - through the implementation of the Edison Electrical Institute Safety Classification and Learning (SCL) model. The SCL model helps enable early recognition and mitigation of Significant Injuries & Fatalities (SIF) precursor conditions to learn from safety events and prevent recurrences. In addition, the SCL model identifies if barriers/controls were in place when the event occurred, providing learnings and insights on where OPG can make improvements.
- OPG has an ongoing initiative to modernize Pre Job-Briefs (PJBs) and Safe Work Plannings (SWPs) into a single integrated digital platform, the Electronic Safe Work Planning & Pre-Job Briefing (eSWP) platform. The eSWP will strengthen Fail-Safe defences and enhance the sharing of safe work planning knowledge. The eSWP platform will also feature The "Energy Wheel" tool, to aid in the identification of energy hazards that are often overlooked, and to support workers in implementing additional safety precautions for high-energy tasks that pose significant risks in the event of human error or equipment failure.
- Updates have been made to data systems to integrate and facilitate trending of safety events as well as the early identification of emerging safety risks.
- OPG continues to incorporate and implement external benchmarking learnings to achieve industry best practice.

Rolling Average Industrial Safety Accident Rate (ISAR) * +



* *Sub-indicator for WANO NPI*

\+ *2 Year Avg PNGS, 3 Year Avg DNGS – Unit 2 (U1 & U4 in Refurbishment. Unit 3 in-service Q2, not online for 3 years)*

	2023 Value
DN	0.00
PN	0.00
Best Quartile	0.00
Median	0.00

Factors Contributing to Performance

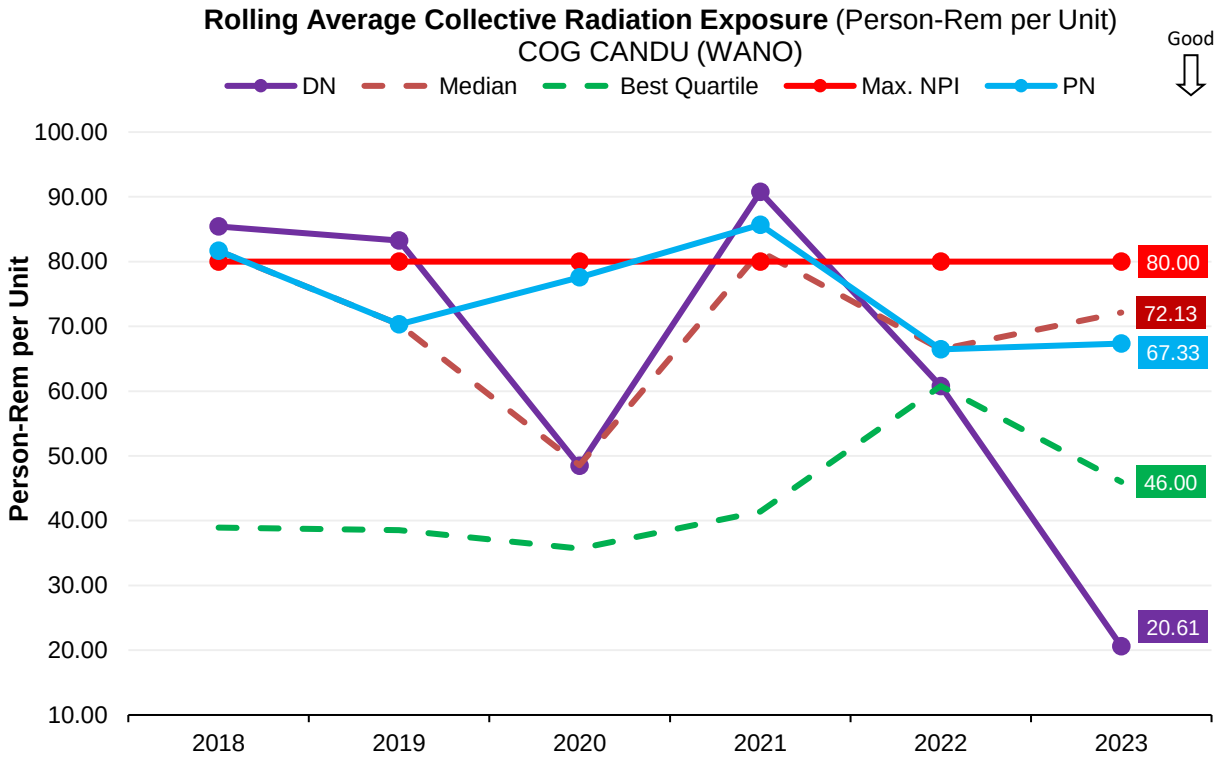
- DNGS and PNGS continued to achieve maximum Nuclear Performance Index (NPI) points.
- DNGS achieved best quartile performance with zero ISAR events during the last 3-year rolling average reporting period.
- PNGS achieved best quartile performance with zero ISAR events during the last 2-year rolling average reporting period.

Initiatives to Improve and Sustain Favourable Performance Include:

- OPG continues to prioritize the implementation of the Fail-Safe health and safety program, which focuses on high-energy work, sequential control measures, event learning, and various strategies:
    - Modernization of safety metrics to incorporate leading indicators for early intervention includes the use of Quality of Safety Practices (QSP) which monitors high and low energy conventional safety risks to identify vulnerability and opportunities to increase capacity by implementing controls.
    - Implementation of Electronic Safe Work Planning (eSWP) which aims to assess the quality of direct controls addressing high-energy hazards within safe work plans.
    - Adoption of the Edison Electrical Institute Safety Classification and Learning (SCL) model to better identify more learning opportunities through safety classifications which will allow for better benchmarking within the industry.
    - Enhancing the oversight program with a graded approach that monitors performance for prevention and early intervention by increasing oversight to address behaviors and/or program deficiencies through Observation and Coaching (O&C's), metrics, audits/assessments, benchmarking, and events.

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 15 of 61

Rolling Average Collective Radiation Exposure (CRE) * +



* *Sub-indicator for WANO NPI*

\+ *2 Year Avg PNGS, 3 Year Avg DNGS – Unit 2 (U1 & U4 in Refurbishment. Unit 3 in-service Q2, not online for 3 years)*

	2023 Value
DN	20.61
PN	67.33
Best Quartile	46.00
Median	72.13

Factors Contributing to Performance

- DNGS and PNGS continued to achieve maximum Nuclear Performance Index (NPI) points.
- DNGS performance improved in 2023, as a result of:
  - Zero planned outages scheduled in 2023.
  - 2022 CRE calculated for Unit 4 prior to refurbishment (Unit 1 & 3 were in refurbishment and Unit 2 was only online for 2 years) and 2023 CRE calculated for Unit 2 post-refurbishment (Units 1, 3 and 4 were in refurbishment) as this metric is a rolling average.
  - Two forced unit outages occurred but did not have significant impact to collective dose. Outage scope involved repairs on a primary heat transport pressurizer valve, moderator cover gas system repairs, tritium immobilization system glovebox repair, and a rupture disk repair.
  - Online and major project dose remained consistent compared to previous years.

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 16 of 61

- PNGS performance in 2023 was slightly higher compared to 2022. This was a result of additional planned unbudgeted and forced outages.
    - In 2023 there were three planned outages, two planned unbudgeted outages and six forced outages compared to three planned outages, one planned unbudgeted outage and five forced outages in 2022.
    - Work programs for the planned maintenance outages which contributed to dose included fuel channel components periodic inspection program, boiler inspection programs and a first in a while evolution of Boiler Secondary Side Chemical Clean which was performed on Unit 8.
    - The two planned unbudgeted outages were taken to address fueling machine vault air conditioner unit repairs and the six forced outages were taken to address emergent conditions.

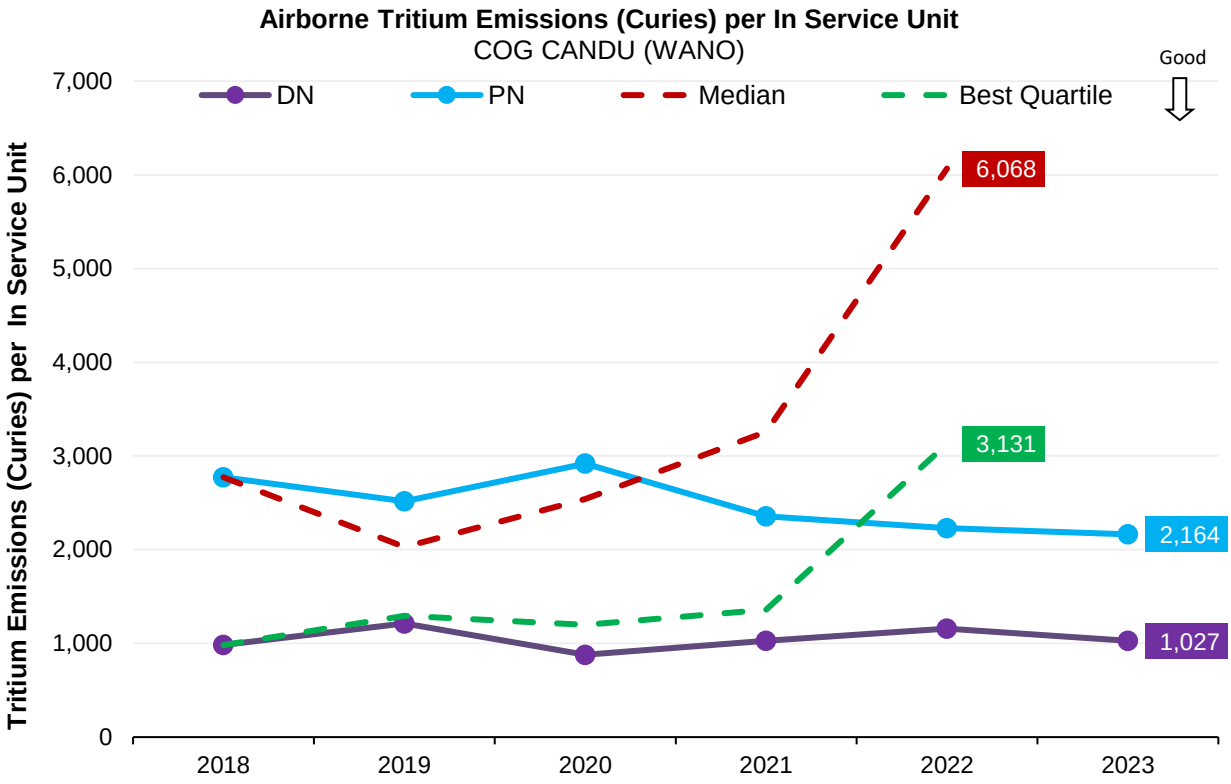
Initiatives to Improve and Sustain Favourable Performance Include:

- DNGS has placed emphasis on these initiatives and practices to reduce exposures**:**
    - Implementation of source term controls such as post-refurbishment source term monitoring and characterization program, dose reducing Lanxess resin in purification systems, permanent isolation of containment equipment D_2O circulation supply lines, development and testing of ultrasonic technology for hot spot and crud removals.
    - Upcoming deployment of the Rapid Delivery Machine (RDM) for automated fuel channel inspections during unit outages to eliminate personnel on the reactor maintenance platform and minimize collective dose.
    - Modification of piping and lines containing build up of crud and hot spots to facilitate installation of magnetic shielding to reduce ambient dose rates inside containment during outages.

- PNGS continues to place concerted effort on improving performance by utilizing the following practices:
    - Reactor face dose rate surveys performed during 2023 Planned Outages showed that dose rates were slightly lower than the previous outages with between a 5 – 10% reduction.
    - Implementation of specialized source term reduction agents (i.e., Lanxess resin, fueling machine filter pore size reduction)
    - Continued focus on foreign material management and chemistry heat transport purification management.
    - ALARA (as low as reasonably achievable) initiatives, such as improved shielding, source term reduction initiatives and work methods improvements and efficiencies, contribute to improvements in dose performance.

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 17 of 61

Airborne Tritium Emissions



Notes:

- *Annual Value*
- *Median and Best Quartiles are plotted until 2022 as the 2023 results were unavailable at the time of benchmarking (one-year lag).*
- *Darlington values exclude Tritium Removal Facility (TRF) and associated West Annex emissions (consistent with COG benchmark results).*
- *Unit 1, Unit 3 and Unit 4 refurbishment periods, and the Retube Waste Processing Building (RWPB).*

	2023 Value
DN	1,027
PN	2,164
Best Quartile	3,131
Median	6,068

Factors Contributing to Performance

- DNGS and PNGS Airbourne Tritium Emissions remain at a very small fraction of regulatory limits
- DNGS and PNGS achieved top quartile in 2023, largely driven by the increase of industry quartile which reflects an additional plant being included in the peer group.
- Both sites have continued tritium reduction activities driven by a High Impact Team (HIT) which focuses on day-to-day tritium reduction activities such as heavy water leaks and repairs, drier performance, continued management oversight and communication of priorities, utilized enhanced monitoring system station wide to provide real-time tritium monitoring capability.

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 18 of 61

- DNGS continues to achieve best quartile performance. This was mainly attributed to efforts by the station to focus on tritium identification and reduction activities such as prioritized repairs to leaking equipment and driers, utilized enhanced monitoring system station wide to provide real-time tritium monitoring capability and continued management oversight and communication of priorities.

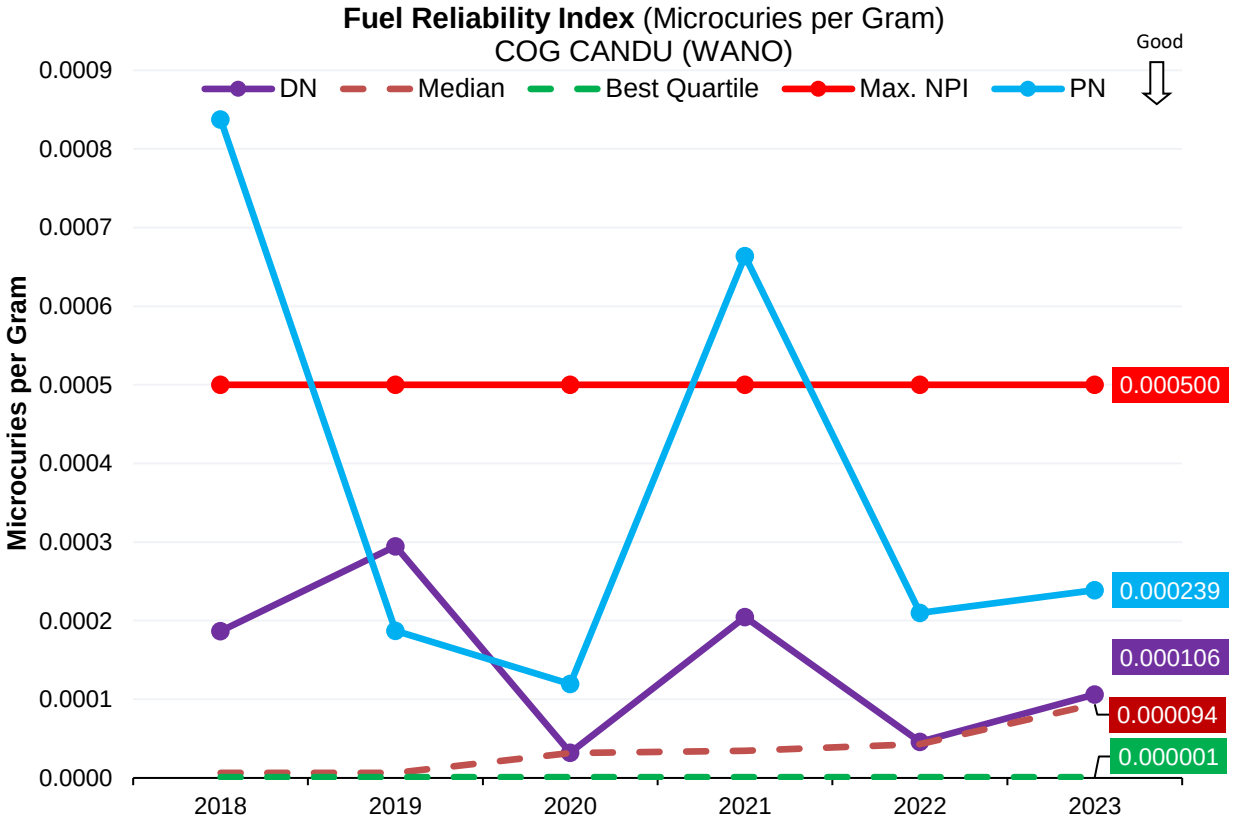
- PNGS achieved industry top quartile performance in 2023 for the first time since 2005. This was mainly attributable to the declining industry performance in 2022. Improved performance can also be attributed to efforts by a High Impact Team in place to drive station tritium reduction activities such as a focused effort on reducing drier downtime, and prioritizing repairs and equipment leaks clean up, thus minimizing airborne impact.

Initiatives to Improve and Sustain Favourable Performance Include:

- Ongoing dedicated teams at both sites to enhance focus on tritium sources identification and elimination, including drier performance, heavy water leaks and repair.
- Enhanced management oversight and communication of priorities to focus tritium reduction activities daily at the Integrated Station Brief (ISB) meetings.
- Collaboration to exchange operating experience and innovation activities on tritium mitigation, and benchmark performance.
- Source term reduction on heat transport and moderator water.
- Tritium Oversight Committee in place at DNGS to develop longer term actions, provide oversight, and proactively schedule preventive maintenance activities.
- Tritium Prevention Procedure training for Operators to increase awareness on tritium reduction.
- Ongoing participation in COG environmental benchmarking of participating CANDU stations to determine best environmental practices.

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 19 of 61

Fuel Reliability Index (FRI) *



* *Sub-indicator for WANO NPI*
Note: 2023 Most Recent Operating Quarter
Note: DNGS – Unit 2 (U1 & U4 in Refurbishment. Unit 3 in-service Q2, not online for 3 years)

	2023 Value
DN	0.000106
PN	0.000239
Best Quartile	0.000001
Median	0.000094

Factors Contributing to Performance

- DNGS and PNGS continued to achieve maximum Nuclear Performance Index (NPI) points.
- One fuel defect was observed and discharged at DNGS in 2023, compared to zero in 2022.
- Two fuel defects were observed at PNGS in 2023, similar to 2022. One was discharged and the second remained in-core at the end of 2023. OPG is working to remove the remaining defect at the earliest possibility.

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 20 of 61

Initiatives to Improve and Sustain Favourable Performance Include:

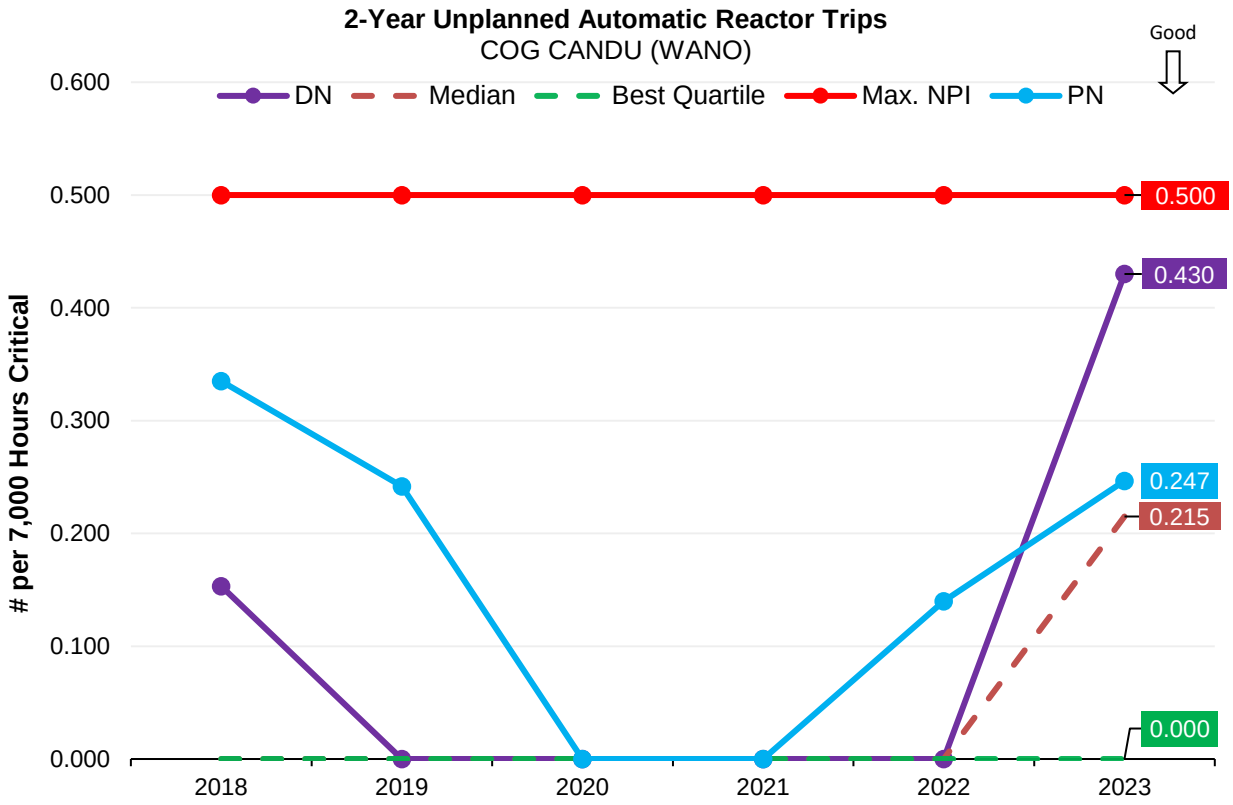
- Both sites completed the fuel design manual and drawing update process. These documents strictly control the manufacturing process, fuel operating limits, fuel handling limits and the fuel performance limits. OPG continues to source fuel with tighter manufacturing tolerances at both sites, thereby eliminating certain modes of fuel defecting following fuelling runs.

- DNGS improvement initiatives include:
    - Foreign Material Exclusion practices continue to mitigate fuel debris fretting failures as shown by the low number of fuel defects following the DNGS reactor refurbishment activities.

- PNGS improvement initiatives include:
    - Increasing scope of Primary Heat Transport System (PHTS) grab sampling and analysis when defects are in-core, continues to assist in earlier detection.
    - Improving the methods of surveillance and elimination of the possibility of foreign materials entrance into the HTS due to Fuel Handling and Outage practices continues to mitigate entrance of micro-debris.
    - Improving and sustaining awareness of impact of foreign material in the PHTS on fuel performance.
    - Improving capability in Units 5 to 8 of detecting the defected fuel bundles during the discharge from the fuelling machines continues to assist in re-directing failed fuel to the inspection area.

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 21 of 61

2-Year Unplanned Automatic Reactor Trips *



* *Sub-indicator for WANO NPI*
Note: DNGS – Unit 2 (U1 & U4 in Refurbishment. Unit 3 in-service Q2, not online for 3 years)

	2023 Value
DN	0.430
PN	0.247
Best Quartile	0.000
Median	0.215

Factors Contributing to Performance

- DNGS and PNGS continue to achieve maximum Nuclear Performance Index (NPI) points.
- DNGS performance was impacted by the following unplanned automatic reactor trip:
  - Unit 2: Shutdown System (SDS) 1 trip occurred due to failure of a hand controller causing a control valve to open and resulting in pressurizer steam loss. The cause of failure of the hand controller was a lack of maintenance, and less than adequate risk perception of the potential failure.
- PNGS performance was impacted by the following unplanned automatic reactor trip:
  - Unit 8: An automatic reactor trip on SDS1 and SDS2 occurred. SDS1 tripped on Heat Transport High Temperature (HTHT) trip parameter, while SDS2 tripped on the same trip parameter on channel G, followed by O (LBL) trip parameter on channel J. The direct cause of this event is high output failure of a boiler level transmitter, although the internal mechanism that caused the level transmitter to fail is unknown.

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 22 of 61

Initiatives to Improve and Sustain Favourable Performance Include:

The following are being implemented in both PNGS and DNGS:

- On-going performance monitoring and improvement activities by Station Operations, Engineering, and Maintenance organizations.

- Operating Experience (OPEX) from each event has been shared at PNGS, DNGS and at external summits. To improve human performance, technical procedures have been revised. To improve equipment reliability, where possible, like-for-like parts replacement has taken place. System health teams are involved in obsolescence issues.

- OPEX and lessons learned from the continuous exchange of information among Canadian utilities are incorporated into the OPG governance and governance support documents.

- OPG methods and approaches in Operations, Engineering, and Maintenance are compared with other utility and the latest international standards through CANDU Owners Group (COG) projects. Under the COG sponsorship, OPG participates in the COG task teams for alignment of practices and staying current with best industry practices.

- Internal and external audits as well as inspections and self-assessments are performed to verify compliance and recommend future improvement opportunities.

- Training and qualification requirements are established and reviewed to be up-to-date to execute the job tasks at all levels of Operations, Maintenance and Engineering.

DNGS planned actions:

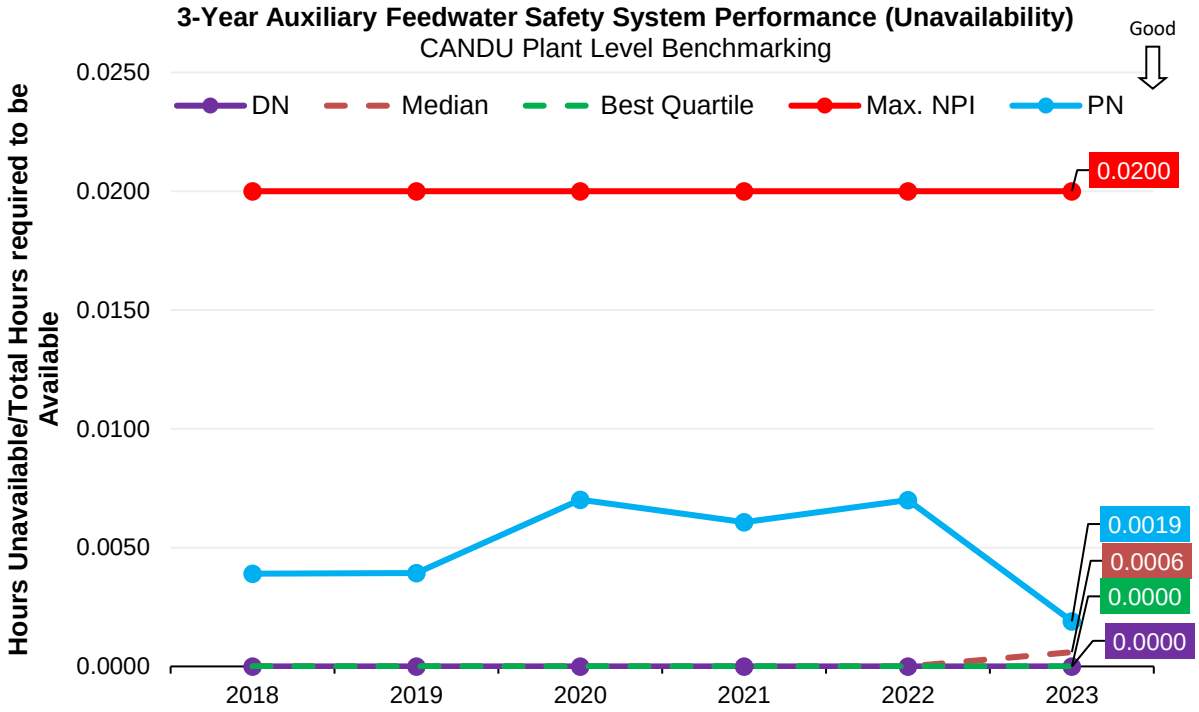
- Significant Issue Response (SIR) team was initiated with a mandate of determining the cause of control valve drifting fully open over a period of 6 minutes. Systematic Approach to Technical Problem Solving (SATPS) was initiated and a Troubleshooting plan was developed in attempts to replicate the scenario which caused the event. The cause was determined and the hand controller was replaced with new model.
- Continuous actions, such as, Engineering Technical Surveillance Program, are being implemented at DNGS to ensure the best performance through Safety Related System Tests.

The following actions were identified at PNGS:

- Track extent of condition review of this type of Rosemount transmitters and confirm maintenance strategy aligns with the consequence of failure.
- Review forensic analysis results and address any failure modes not already covered.
- Add risk associated with aged boiler level control (BLC) level and flow transmitters to the risk register.
- Propose BLC upgrade Engineering Change Request (ECR) to Site Screening committee.
- Revise BLC level transmitter criticality.
- Implement regular replacement Preventive Maintenance (PM) for BLC level and flow transmitters.

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 23 of 61

3-Year Auxiliary Feedwater Safety System Performance (Unavailability)*



* *Sub-indicator for WANO NPI*
Note: DNGS – Unit 2 (U1 & U4 in Refurbishment. Unit 3 in-service Q2, not online for 3 years)

	2023 Value
DN	0.0000
PN	0.0019
Best Quartile	0.0000
Median	0.0006

Factors Contributing to Performance

- DNGS and PNGS continue to achieve maximum Nuclear Performance Index (NPI) points.
- Factors contributing to performance for DNGS include:
    - Identifying critical work on the plant reliability list.
    - Scheduling work using Integrated Planning Group and Cycle Plan processes.
    - Adhering to the cycle planning.
    - Following the System Performance Monitoring Plan.
    - Adhering to the Health Report 10-Year Improvement Plan.

- Factors contributing to performance for PNGS include:
    - System performance improvement due to preventative maintenance and test procedures
    - Unit 4: During execution of the safety related system, the Auxiliary Boiler Feedwater Pump (ABFP) control valve fails to maintain pump discharge pressure between 5.2 - 5.8 MPag, which leads to system impairment (System Does Not Meet Design Intent (SDNMDI)). Adjusted ABFP controller found setpoint to be higher to allow the control valve to control the pressure at 5.5 MPag.

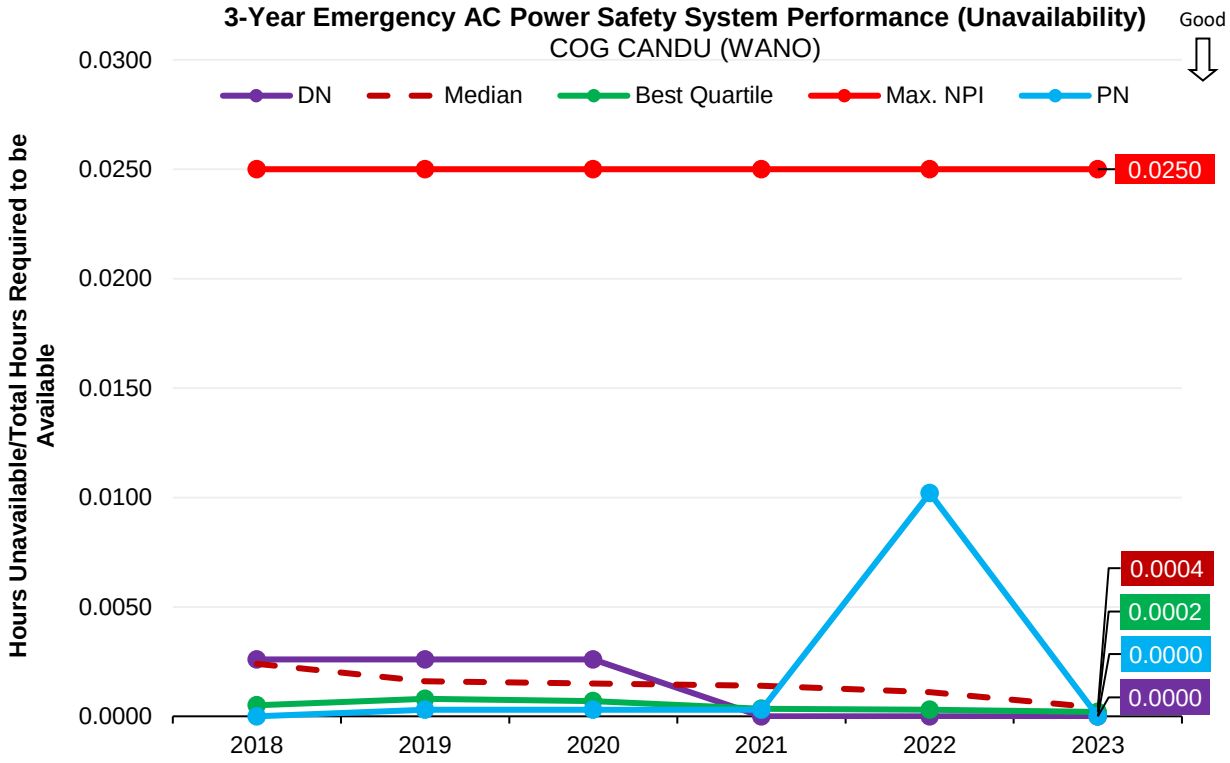
Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 24 of 61

Initiatives to Improve and Sustain Favourable Performance Include:

- DNGS design changes to the Auxiliary Boiler Feed (ABF) system include:
  - Installing gland injection cooling on pump seals to resolve mechanical seal O-ring failure.
  - Replacement of reverse rotation device for main and ABF pumps.

- The following was implemented at PNGS to improve the ABF system performance:
  - Performing an evaluation of repeat failures of Units 1 and 4 ABFP discharge pressure control valves.

3-Year Emergency AC Power Safety System Performance (Unavailability) *



* *Sub-indicator for WANO NPI*
Note: DNGS – Unit 2 (U1 & U4 in Refurbishment. Unit 3 in-service Q2, not online for 3 years)

	2023 Value
DN	0.0000
PN	0.0000
Best Quartile	0.0002
Median	0.0004

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 25 of 61

Factors Contributing to Performance:

- DNGS and PNGS continue to achieve maximum Nuclear Performance Index (NPI) points.
- DNGS Emergency AC Power system achieved the best quartile performance of zero unavailability by performing the following:
    - Identifying critical work on the plant reliability list.
    - Scheduling work using Integrated Planning Group and Cycle Plan processes.
    - Adhering to the 10-year Outage Maintenance Strategy for the Standby Generators (SG) and Health Report Improvement Plan.
    - Following the System Performance Monitoring Plan.
    - Adhering to the Health Report 10-Year Improvement Plan.

- PNGS Emergency AC Power system achieved best quartile performance of by performing the following:
    - In Q1-2023, there was an overlapping of the failure of Gas Producer Lube Oil Low Pressure of one standby generator (SG), test performed on the second SG, and planned maintenance outage of the third SG. This resulted in unavailability of all three redundant standby generators (SGs) as it impacted quarterly and year-to-date performance despite overall SGs performance unavailability of zero.
    - Corrective and routine outage maintenance.

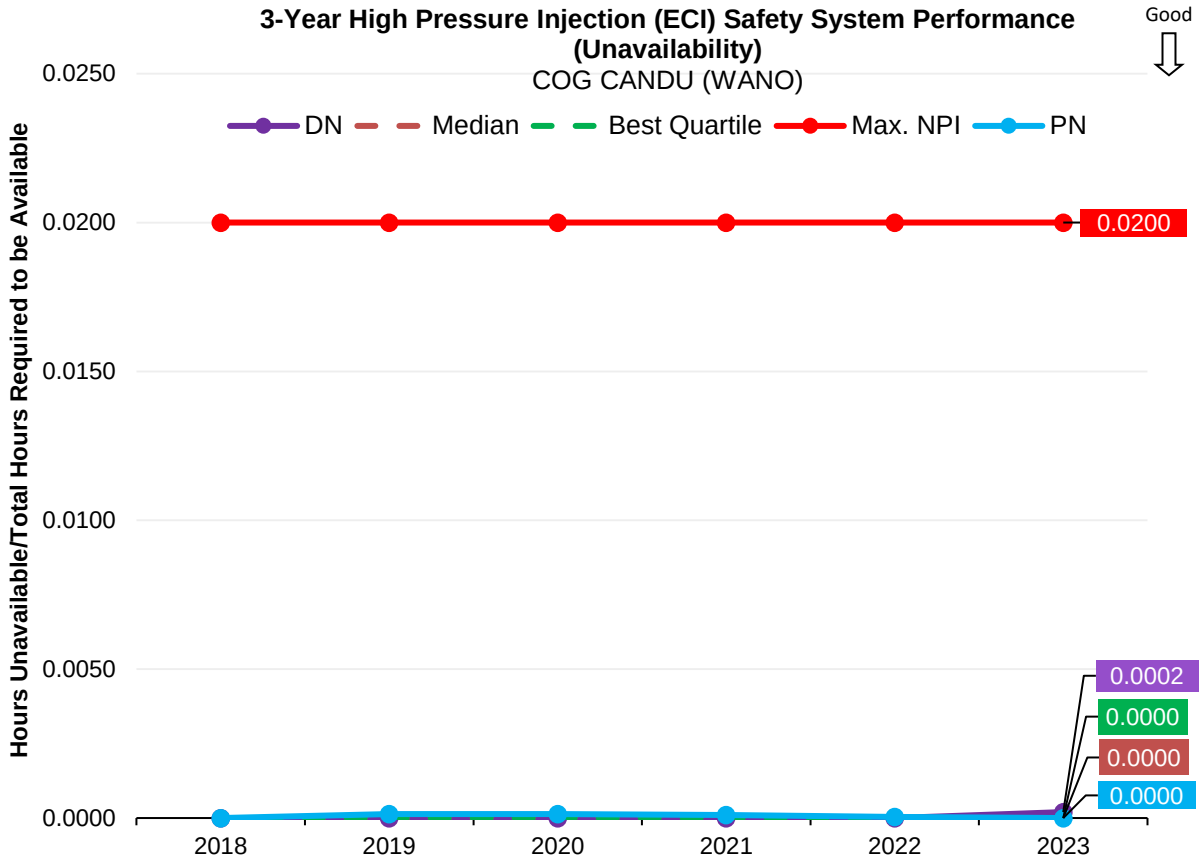
Initiatives to Improve and Sustain Favourable Performance Include:

- DNGS planned actions:
    - SGs Control System upgrades includes small updates to software and hardware to resolve aging/part obsolescence issue on the controls circuits.
    - A 10-year project is in progress on the SG protective relays to replace all the old electro-mechanical relays with modern digital versions.

- PNGS planned actions:
    - Performance Engineering will take actions to ensure timely review/implementation of the corrective and routine maintenance.
    - Cracked power turbine casings will be repaired or replaced.

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 26 of 61

3-Year High Pressure Injection (ECI) Safety System Performance (Unavailability) *



* *Sub-indicator for WANO NPI*
Note: DNGS – Unit 2 (U1 & U4 in Refurbishment. Unit 3 in-service Q2, not online for 3 years)

	2023 Value
DN	0.0002
PN	0.0000
Best Quartile	0.0000
Median	0.0000

Factors Contributing to Performance:

- DNGS and PNGS continue to achieve maximum Nuclear Performance Index (NPI) points.
- DNGS High Pressure Safety Injection (HPSI) unavailability was 0.0002. The factor contributing to performance includes:
    - Unit 0: The loss of 4.16 kV Emergency Power Supply (EPS) buses leads to Level 2 impairment of Emergency Cooling Injection (ECI) system, which affected all units due to both Post-Accident Water Cooling System (PAWCS) heat exchanger flow paths being unavailable.

- PNGS continued with the best High Pressure Safety Injection (HPSI) quartile performance of zero unavailability.

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 27 of 61

Initiatives to Improve and Sustain Favourable Performance Include:

- DNGS HPSI related activities include the following:
  - Review the relay logic and determine if closing circuit breaker 0-53290-101CB3 in the TEST mode with a ground fault trip signal present trip of EPS E0-53290-BU101 and BU103 buses supply breakers.
  - Units 1-4 injection valve internals were overhauled.
  - Completion of equipment reliability improvement work is driven via the 52-week cycle plan and Plant Reliability List (PRL) initiatives.
  - Performing preventive maintenance on schedule to reduce component failures and unplanned unavailability hours.
  - Scheduling maintenance work which could cause equipment unavailability as such that it maximizes system availability.
  - Overhaul or replacement of critical components increases the equipment reliability (i.e., ECI Hydraulic Power Unit (HPU)/ECI Accumulator Control Module (AMCA)).

- PNGS HPSI related activities include the following:
  - Placing an additional Calandria face cooling fan which returns ECI moderator level indications back in line with SDS2/process indications.
  - H_2O injection valve diagnostic test.
  - Ultrasonic flow measurements performed on the cooling water supply to the moderator room air conditioning units (ACUs).
  - Ongoing voltage check and routine calibration of logic instrumentation.

Methodology and Sources of Data

The majority of reliability metrics were calculated using data from WANO. Any data labelled as invalid by WANO was excluded from all calculations. Indicator values of zero are not plotted or included in calculations except in cases where zero is a valid result. Complete data for the review period was obtained and averages are as provided by WANO.

For the WANO Nuclear Performance Index (NPI), a maximum score of 100 is possible. The WANO NPI is an operational performance indicator comprised of 10 metrics, three of which are analyzed in this section:

- Forced Loss Rate (FLR) [Rolling Average]
- Unit Capability Factor (UCF) [Rolling Average]
- Chemistry Performance Indicator (CPI) [Rolling Average]

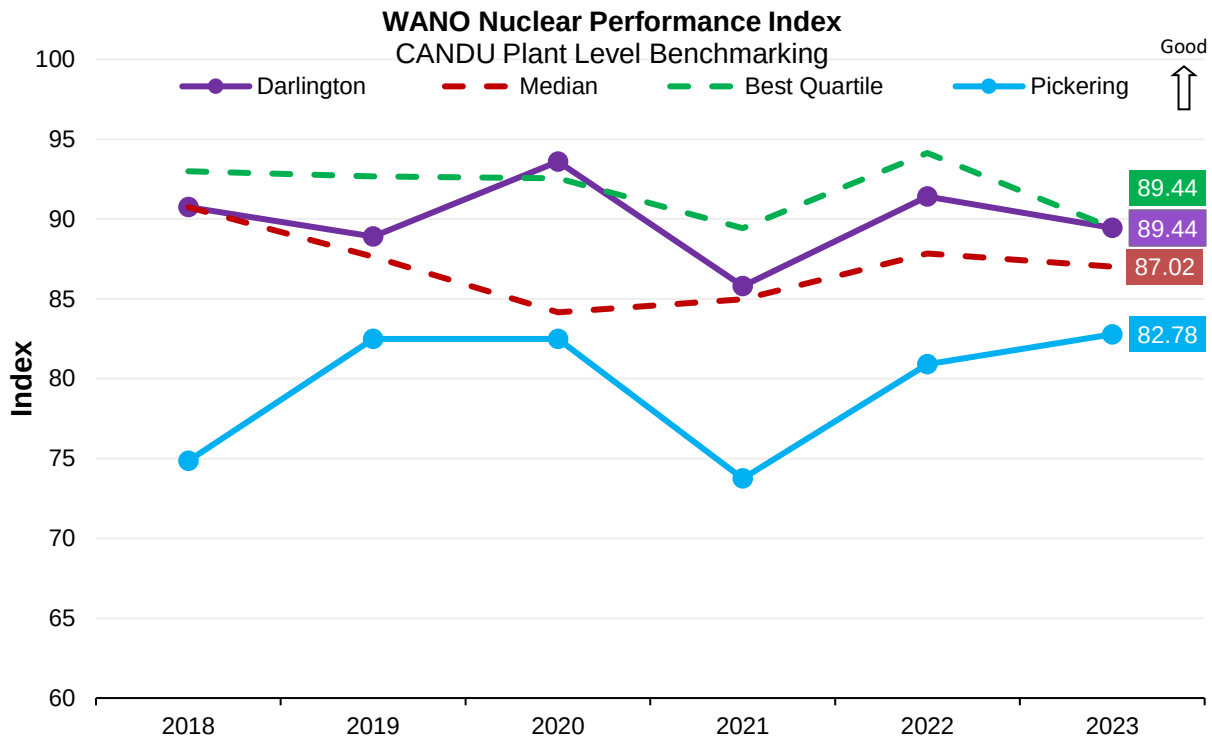
The other seven WANO NPI components are shown in the Safety Section (Section 2.0).

Note: To benchmark performance, Max NPI is used to indicate best quartile performance for metrics that perform better than the Max NPI benchmark. If metric performance is not better than Max NPI, benchmark quartiles are utilized to indicate quartile performance.

Backlog metrics for On-line Deficient and Corrective Maintenance are also included within this section and the data comes from an industry sponsored Institute of Nuclear Power Operators (INPO) AP-928 subcommittee. Data points benchmarked on backlogs are annual, not a rolling average. All data is self-reported.

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 29 of 61

WANO Nuclear Performance Index (NPI) +



+ *2 Year Avg PNGS, 3 Year Avg DNGS – Unit 2 (U1 & U4 in Refurbishment. Unit 3 in-service Q2, not online for 3 years)*

	2023 Value
DN	89.44
PN	82.78
Best Quartile	89.44
Median	87.02

Factors Contributing to Performance:

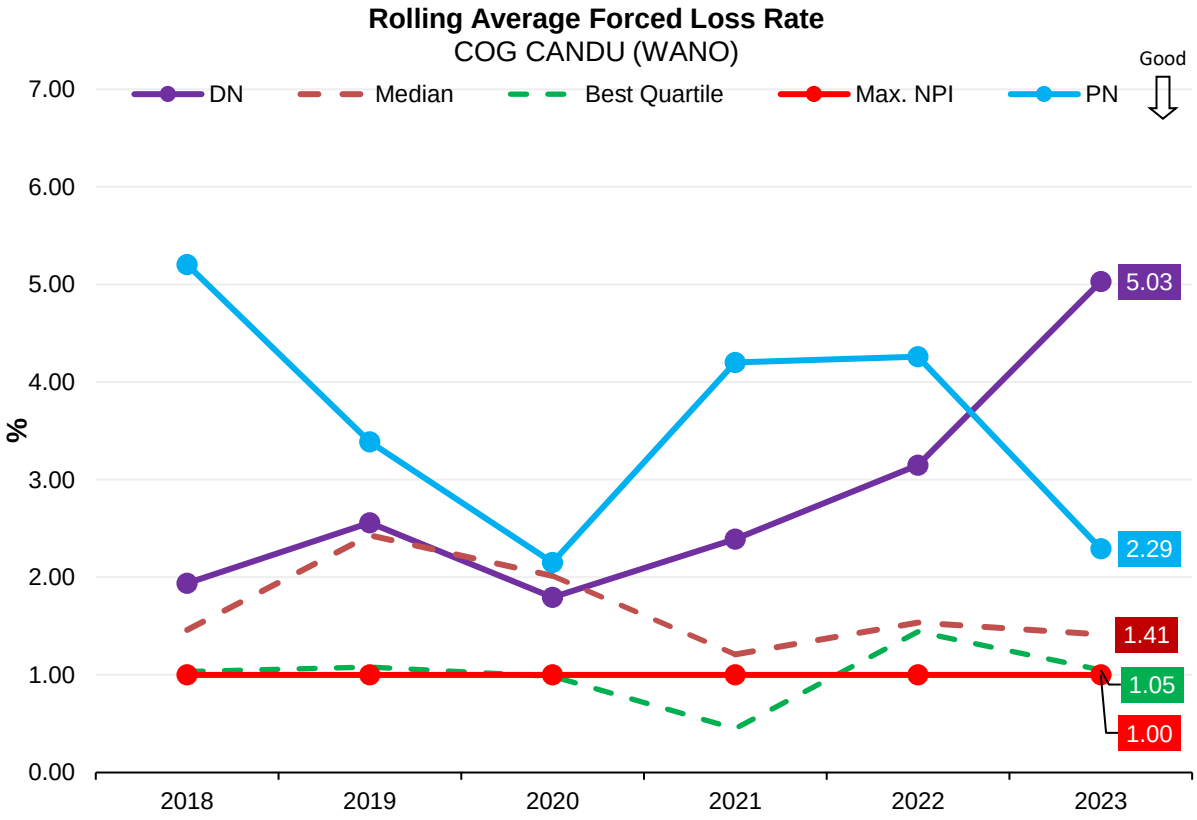
- PNGS performance has improved by approximately two points primarily due to improved Unit Capability Factor (UCF) and Forced Loss Rate (FLR) performance with only brief forced outages in 2023, resulting in a sustained third quartile position from 2022.
  - UCF and FLR have the most significant weighting within NPI calculation.
  - Excellent performance for Reactor Trip Rate (RTR), High Pressure Safety Injection Unavailability (HPSI), Emergency AC Power Unavailability (EACP), Auxiliary Boiler Feedwater Unavailability (ABF), and Industrial Safety Accident Rate (ISAR) combined with good performance on Fuel Reliability Index (FRI), Collective Radiation Exposure (CRE), Chemistry Performance Indicator (CPI) was partially offset by the Unit Capability Factor (UCF) fourth quartile performance. Unit Capability Factor, Collective Radiation Exposure and Chemistry Performance Index metrics were impacted by the need for extended outages to accommodate fuel channel inspection programs, unbudgeted planned outages for non-routine maintenance work and unplanned outages due to external causes, which impacts Unit Capability Factor, Collective Radiation Exposure and Chemistry Performance Index metrics.

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 30 of 61

- DNGS achieved best quartile performance.
  - NPI slightly lower performance compared to previous years was attributed to continued excellent performance for all seven of the safety metrics offset by decline in FLR performance attributed to Unit 2 forced outage events compared to elevated FLR in 2021 which is no longer included in the rolling window.

Further details on factors contributing to performance and initiatives to improve and sustain favourable performance are discussed within each respective NPI sub-metric in this report.

Rolling Average Forced Loss Rate (FLR) * +



* *Sub-indicator for WANO NPI*

+ *2 Year Avg PNGS, 3 Year Avg DNGS – Unit 2 (U1 & U4 in Refurbishment. Unit 3 in-service Q2, not online for 3 years)*

	2023 Value
DN	5.03
PN	2.29
Best Quartile	1.05
Median	1.41

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 31 of 61

Factors Contributing to Performance

- PNGS improved performance is attributable to improved FLR in 2023 compared to elevated FLR in 2021 which is no longer included in the rolling window. In 2023, there were six forced outages related to Turbine, Boiler Feedwater, Main Output, and Human Performance, and three forced outages related to Generator, Shutdown Systems and Human Performance in 2022.

- DNGS decline in performance is attributable to forced outage events impacting post-refurbishment Unit 2 on Turbines and Main Power Output (2022) and Primary Heat Transport (2023). As the metric is a rolling average, in 2023 only Unit 2 results are included (Units 1, 3 and 4 were in refurbishment). Similarly in 2022, only Unit 4 results were included (Unit 1 & 3 were in refurbishment and Unit 2 was only online for 2 years) Unit 2 FLR decreased in 2023 compared to 2022.

Initiatives to Improve and Sustain Favourable Performance Include:

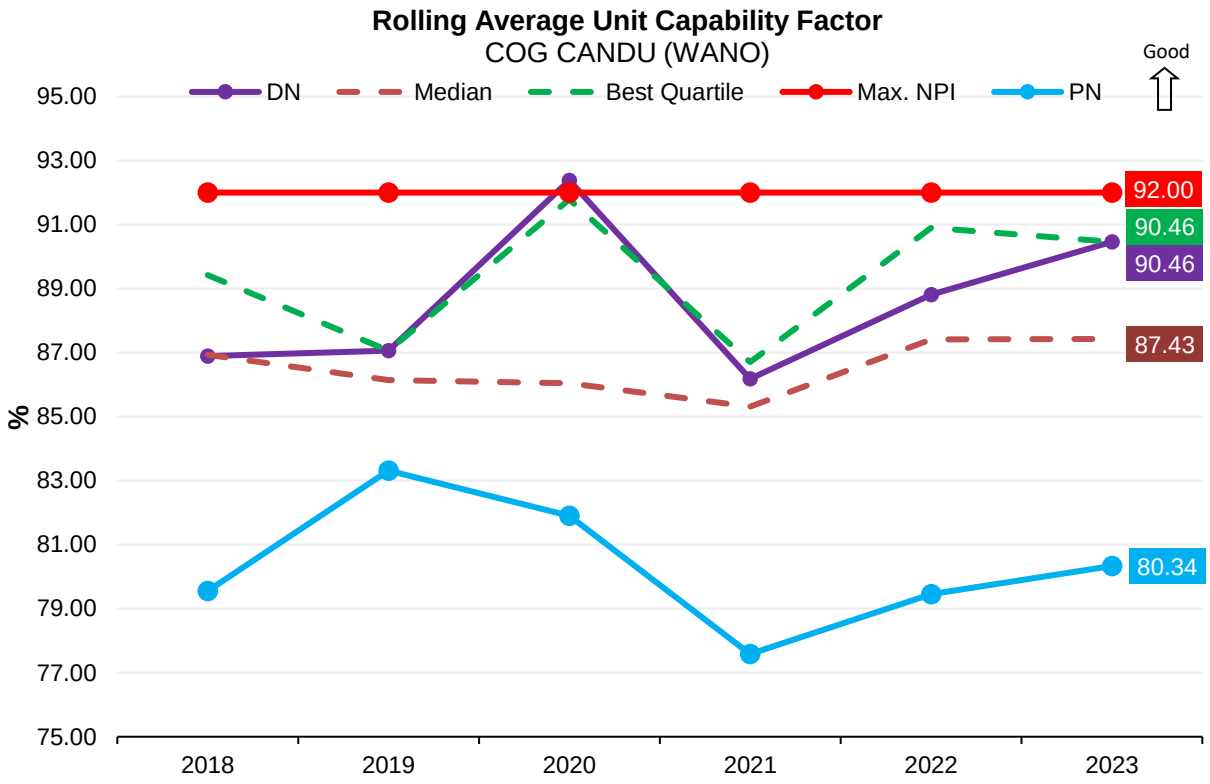
- Focused actions, including vulnerability identification and elimination, project execution, and building proficiency at both the fleet and site level have been implemented for Turbine Generator Reliability, the highest fleet contributor.

- Fuel Handling contribution reduced in 2023 and remains a fleet focus area to build sustainability. Focused actions on proactive risk identification and elimination as well as work management are in place at both the fleet and site level.

- Internal peer teams, industry benchmarking, fleet assessments against industry best practice, enhanced participation in industry working groups are in place to manage this risk going forward.

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 32 of 61

Rolling Average Unit Capability Factor (UCF) * +



* *Sub-indicator for WANO NPI*

\+ *2 Year Avg PNGS, 3 Year Avg DNGS – Unit 2 (U1 & U4 in Refurbishment. Unit 3 in-service Q2, not online for 3 years)*

	2023 Value
DN	90.46
PN	80.34
Best Quartile	90.46
Median	87.43

Factors Contributing to Performance:

- PNGS improved performance is attributable to improved FLR in 2023 compared to elevated FLR in 2021 which is no longer included in the rolling window, partially offset by increased planned outage days in 2023 compared to 2021 and by increased FLR in 2023 compared to 2022. Unit 7 achieved Industry Best Quartile in 2023. Unit 4 and Unit 6 achieved Industry Best Quartile in 2022.

- DNGS improved and achieved Industry Best Quartile. As the metric is a rolling average, only Unit 2 results are included (Units 1, 3 and 4 were in refurbishment). DNGS improved performance is attributable to reduced planned outage days in 2023 partially offset by forced outage events impacting post-refurbishment Unit 2. 2022 results were measured against Unit 4 performance prior to entering refurbishment (Unit 1 & 3 were in refurbishment and Unit 2 was only online for 2 years).

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 33 of 61

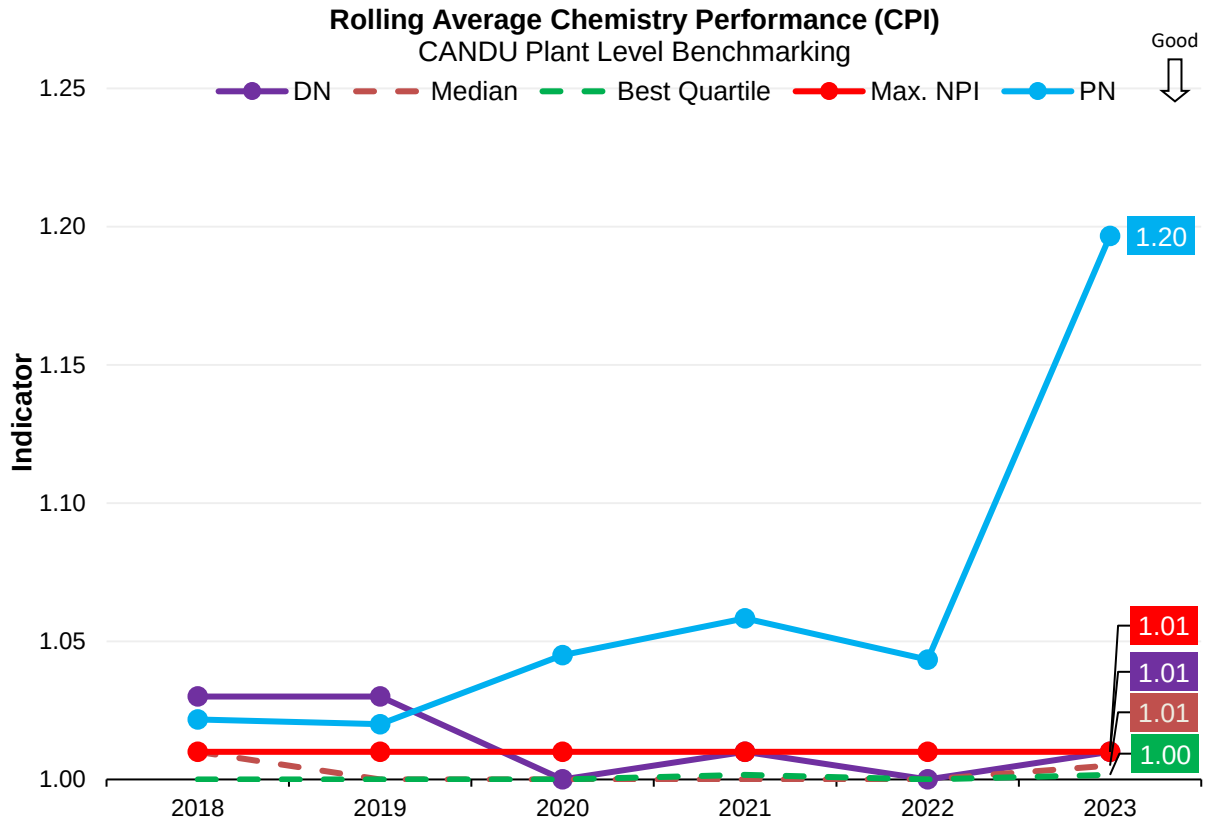
Initiatives to Improve and Sustain Favourable Performance Include:

- Focused actions, including vulnerability identification and elimination, project execution, and building proficiency at both the fleet and site level have been implemented for Turbine Generator Reliability, the highest fleet contributor.

- Fuel Handling contribution reduced in 2023 and remains a fleet focus area to build sustainability. Focused actions proactive risk identification and elimination and work management implementations are in place at both the fleet and site level.

- Internal peer teams, industry benchmarking, fleet assessments against industry best practice, enhanced participation in industry working groups are in place to manage this risk going forward.

Rolling Average Chemistry Performance Indicator (CPI) *+



* *Sub-indicator for WANO NPI*

+ *2 Year Avg PNGS, 3 Year Avg DNGS –U nit 2 (U1 & U4 in Refurbishment. Unit 3 in-service Q2, not online for 3 years)*

	2023 Value
DN	1.01
PN	1.20
Best Quartile	1.00
Median	1.01

Factors Contributing to Performance

The decline in performance at PNGS from 2019 to 2023 can be attributed to the following:

- Post Unit 5 (2019) and Unit 7 (2021) start-up boiler sulfates due to turbine maintenance activities during their respective outages.
- Unit 4 condenser tube leak resulted in chronic elevated boiler ions for ~9 months (2021).
- Unit 8 condenser tube leak resulted in elevated boiler ions for ~2 weeks (2021).
- Unit 8 multiple condenser tube leaks resulted in elevated boiler ions (2023).
- Forced outage on Unit 8 resulting from condenser tube leak (2023).
- Forced outage on Unit 8 resulting from boiler level transient (2023).

DNGS continues to receive maximum Nuclear Performance Index (NPI) points. The decline in performance in 2023 from 2022 can be attributed to the following:

- Condenser tube leak on Unit 2 (2023).

Initiatives to Improve and Sustain Favourable Performance Include:

Both sites have an ongoing Chemistry Outage SPOC to provide improved coordination/planning such that system chemistry control has improved during outages/start-ups.

PNGS:

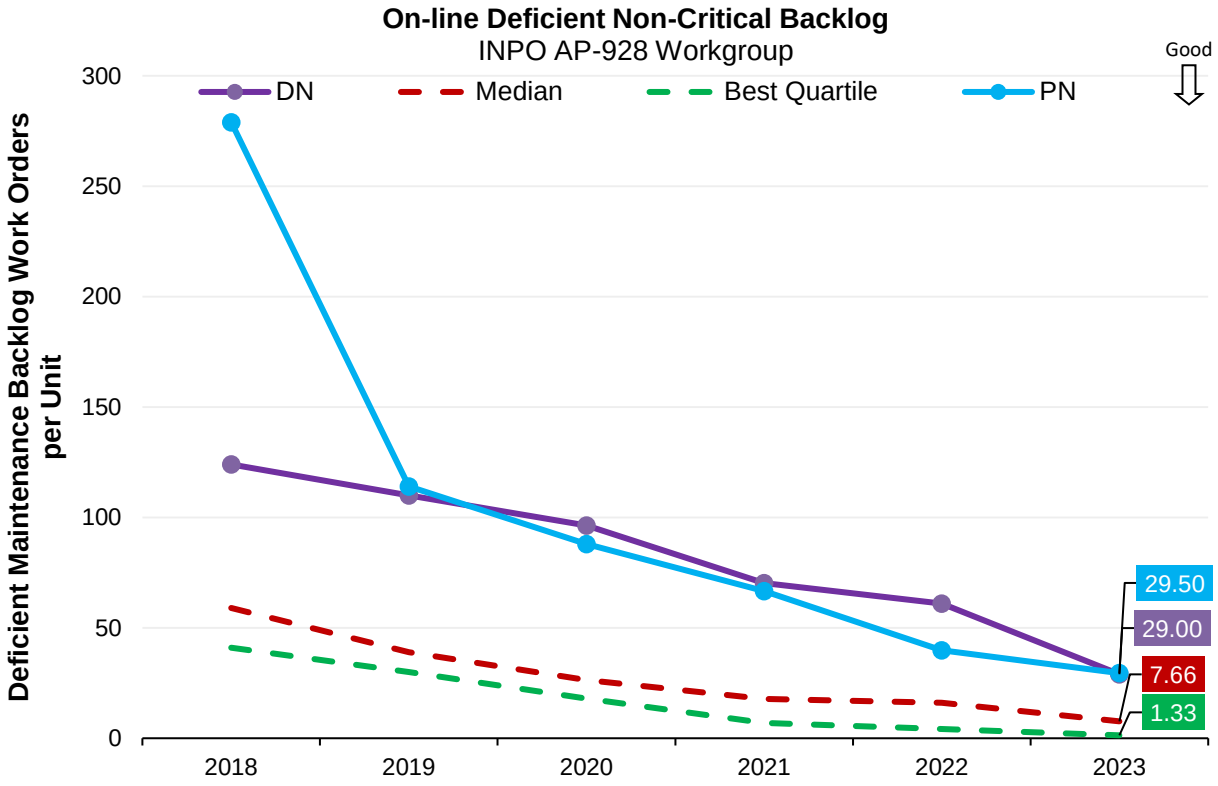
- Assess retubing plugged and stake tubes to regain thermal efficiency.
- Improve turbine vendor quality management program and oversight.
- Improve planning and execution of chemistry start-up activities through integration of Chemistry, Outage, and Operations.

DNGS:

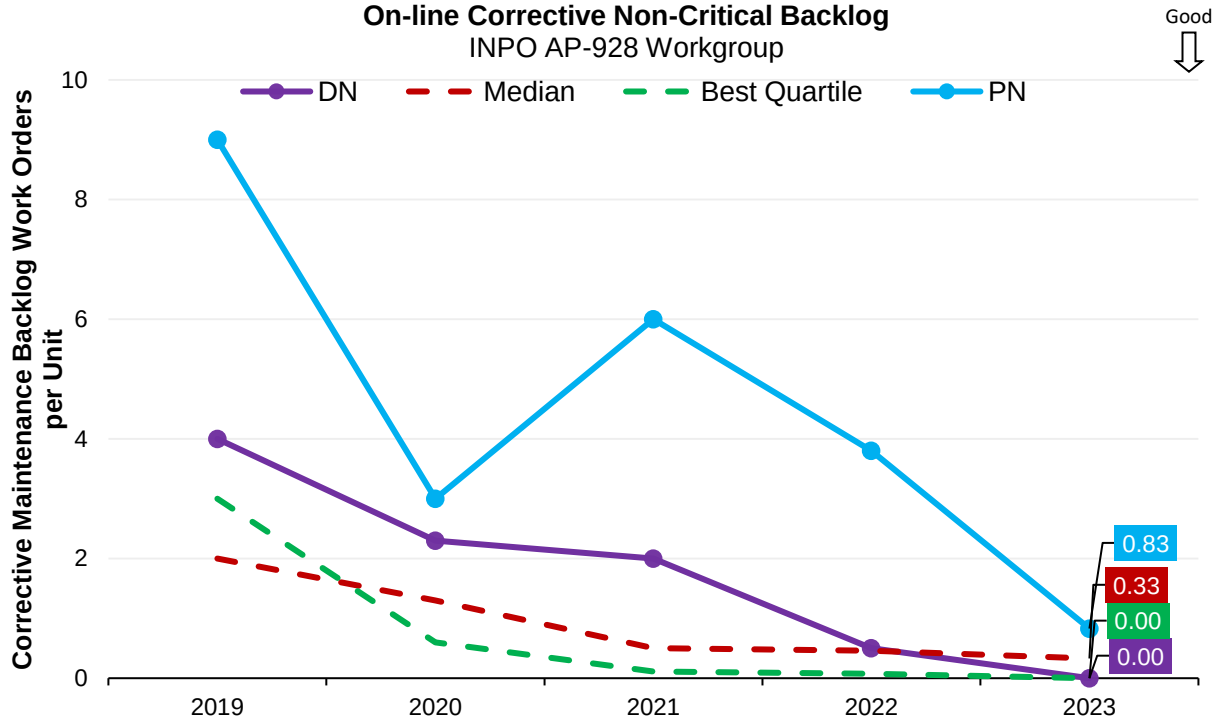
- Improve integration into Outage meetings to optimize boiler chemistry (i.e. minimize duration where boilers are drained, improvements in Boiler Water Lancing activities etc.).
- Implemented a revised chemistry control strategy using continuous boiler blowdowns to manage secondary side chemistry control leading until Unit start-up to remove boiler ions.
- Revise the condenser tube leak response procedure and guidance to include previous operating experience and pre-decision-making logic during leak searching activities.
- Install permanent sodium hotwell analyzers for early detection of condenser tube leaks, to assist in isolating the correct Waterbox and minimize time out of specification.
- Improve reliability of condenser equipment including Condenser Tube Cleaning System (CTCS) through piping and valve replacements and increase inspections to assess condenser tube health to prevent and mitigation condenser tube leaks.

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 35 of 61

On-Line Deficient & Corrective Non-Critical Backlog
On-Line Deficient & Corrective Critical Backlog



Note: Annual



Note: Annual

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 36 of 61

	2023 On-Line Deficient Non-Critical Backlog	2023 On-Line Deficient Critical Backlog	2023 On-Line Corrective Non-Critical Backlog	2023 On-Line Corrective Critical Backlog
DN	29.00	0.00	0.00	0.00
PN	29.50	0.67	0.83	0.00
Best Quartile	1.33	0.00	0.00	0.00
Median	7.66	0.00	0.33	0.00

Factors Contributing to Performance

- PNGS and DNGS continue to meet industry best quartile for Corrective Critical Backlog.
- Both sites experienced performance improvement On-line Deficient Non-Critical Backlog, PNGS 26%, and DNGS 52%.
- PNGS performance improved for On-line Deficient Critical Backlog and On-line Corrective Non-Critical Backlog.
- Factors contributing to performance:
    - Continuing to work down the backlog priorities through Fix It Now (FIN) and Work Management (WM) process.
    - Action to implement sustainable FIN process for Live Zero backlog, long lead part and grace period enhancements.
    - Provide oversight/support on DNGS Refurb Backlog to ensure targets are met.
    - Frequently performed cross functional backlog review of all current Online Backlog work orders for quality of coding.

- Not all station backlog targets were set to industry best quartile for 2023.
- DNGS continues to leverage the Minor Maintenance Tool.
- PNGS initiated Cross Functional Backlog Recovery Team

Initiatives to Improve and Sustain Favourable Performance Include:

- Continued review of opportunities to execute online work during unit shutdowns and specific unit configurations.
- Continued scrutiny over work orders that are introduced into the backlog.
- Monitor and track actions as well as metrics via weekly Integrated Station Briefing meetings, bi-weekly Senior Work Management meetings, and monthly Station Excellence meetings.

Note: Factors Contributing to Performance and Initiatives to Improve and Sustain Favorable Performance are relevant to all backlogs.

Methodology and Sources of Data

The Electric Utility Cost Group (EUCG) database is the source for cost benchmarking data. Data was collected for three-year rolling averages for all financial metrics. All data submitted to and subsequently extracted from EUCG by OPG is presented in Canadian dollars.

EUCG automatically applies a purchasing power parity (PPP) factor to adjust all values across national borders. The primary function of the PPP value is to adjust for currency exchange rate fluctuations, but it also adjusts for additional cross-border factors, which may impact purchasing power of companies in different jurisdictions. As a result, cost variations between plants are limited, as much as possible, to real differences and not due to advantages of utilizing one currency over another.

The benchmarking panel utilized for value for money metrics is made up of all North American (U.S. & Canada) plants reporting to EUCG. Bruce Power is the only other CANDU technology plant reporting within that panel. The remaining plants are Boiling Water Reactors or Pressurized Water Reactors making it challenging to compare performance across plants with technology differences. As a result, beginning with 2017 results, both PNGS and DNGS TGC/MWh and TGC/Unit performance has been normalized for CANDU technology (including outage duration) and age-related impacts.

Darlington's TGC/MWh, TGC/Unit, Non-Fuel Operating Costs (NFOC)/MWh and Capital Cost/MW DER performance have also been normalized for refurbishment. The refurbishment normalization methodology allows OPG to adjust the distribution of actual operating and capital costs to reflect Darlington's number of operating units rather than a four-unit site. OPG is performing a mid-life refurbishment at Darlington, which involves bringing units offline for the replacement of certain life-limiting components. It is necessary to normalize these metrics during refurbishment to allow for comparisons to prior site performance and industry peers, given reduced generation and no corresponding decline in fixed costs.

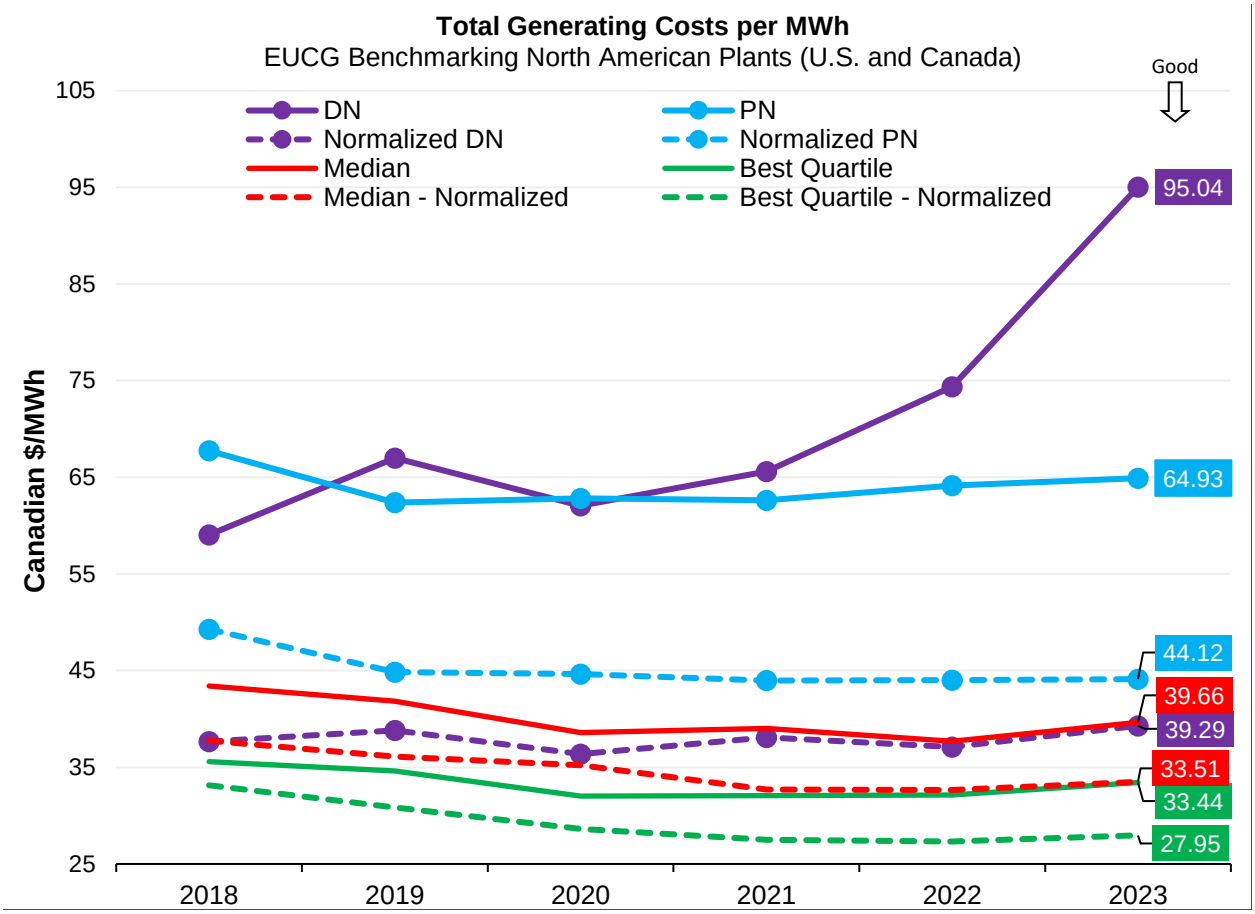
OPG engaged ScottMadden Management Consultants (ScottMadden) to develop the normalization methodologies[3]. The combined normalization allows for a more comparable assessment of performance between peers.

Total Generating Cost per MWh is the sum of Non-Fuel Operating Cost (NFOC), Fuel Cost and Capital Cost measured on a per MWh basis for benchmarking purposes.
Given the differences between OPG's nuclear generating stations and most North American plants with respect to non-fuel operating costs, fuel and capital costs, it is difficult to compare plants using non-fuel operating cost, fuel cost or capital cost metrics separately.

[3] Two ScottMadden normalization reports provide details on the normalization methodologies: 1) *OPG Nuclear Cost Performance Benchmarking A Study of Factors Impacting TGC/MWh Performance with Normalizing Adjustments to Facilitate Closer Comparison* and 2) *OPG Nuclear Cost Performance Benchmarking Methodology to Adjust for Refurbishment and Validation of Implementation*

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 38 of 61

3-Year Total Generating Cost (TGC) per MWh



** DNGS – Unit 2, Unit 4 in Refurbishment until Q3 2024, Unit 3 in-service Q2 2024 (U1 in Refurbishment)*

	2023 Non-Normalized Value	2023 Normalized Value
DN	95.04	39.29
PN	64.93	44.12
Best Quartile	33.44	27.95
Median	39.66	33.51

Factors Contributing to Performance

- DNGS normalized performance declined in 2023 compared to 2022 due to reduced 3-year generation related to the Refurbishment outage schedule with the equivalent of two units being in refurbishment outages the full year in 2023 (Unit 1 full year, Unit 4 offline in Q3 and Unit 3 in-service Q2) compared to one unit for 9 months in 2020 (Unit 2 in-service Q2 and Unit 3 offline in Q3) increasing spending on sustaining investments to ensure long term reliability, and higher OM&A costs in 2023 from increased unionized compensation as a result of the Ontario Superior court decision finding Bill 124 of limiting annual wage increases to one percent for a 3-year period unconstitutional, partially offset by lower fuel & OM&A costs due to refurbishment schedule.

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 39 of 61

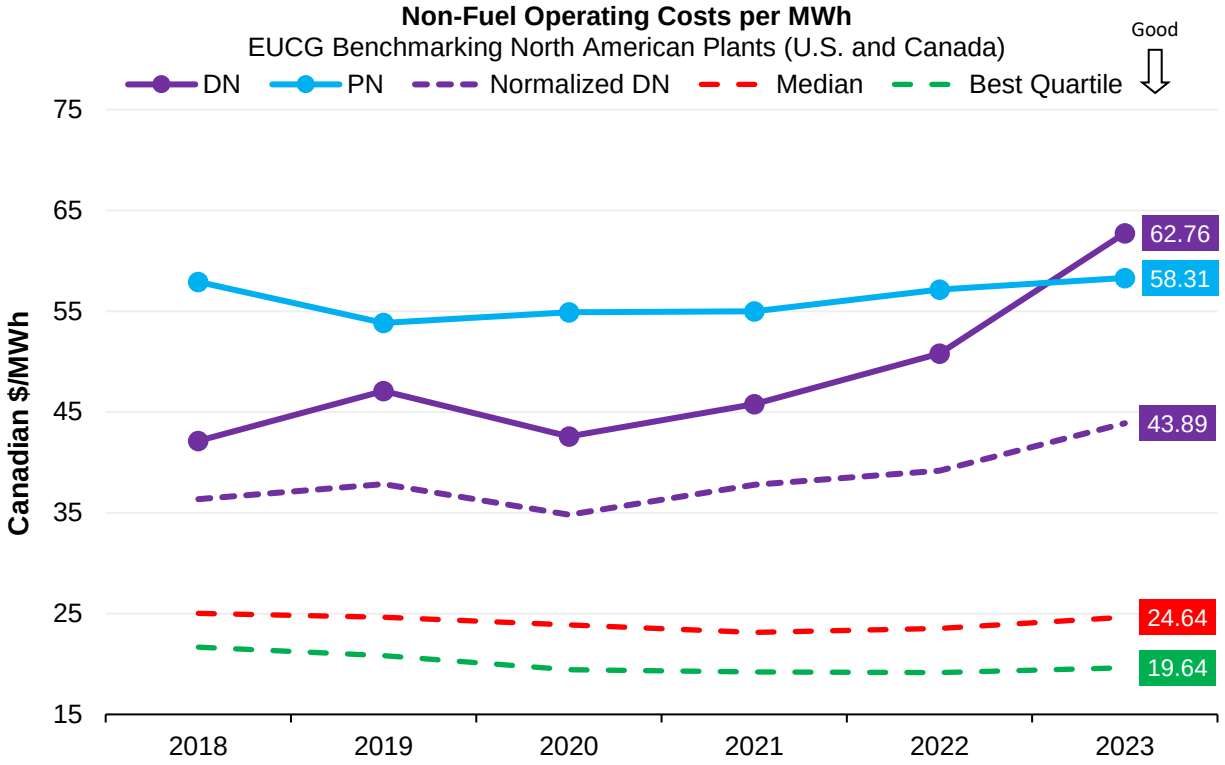
- DNGS non-normalized performance declined in 2023 compared to 2022 due to reduced 3-year generation related to the Refurbishment outage schedule (as per above), higher OM&A costs in 2023 from increased unionized compensation as a result of the Bill 124 court ruling (as per above), and increased capital investment requirements for life post-refurbishment, partially offset by lower fuel costs due to refurbishment schedule.
- PNGS normalized and non-normalized performance is similar to 2022, reflecting reduced capital spending while maintaining reliable operations in the period leading up to the end of commercial operations, partially offset by higher OM&A costs from increased unionized compensation as a result of the Bill 124 court ruling (as per above).
- PNGS units are the smallest in the peer group at 540 MW/unit compared to the peer average of 1,026 MW, a factor for which results have not been normalized.

Initiatives to Improve and Sustain Favourable Performance Include:

- Maximizing generation: See initiatives to improve and sustain favourable performance for Reliability Metrics UCF and FLR.
- Continue to utilize opportunities to reduce operating costs through strategic initiatives, excellence plans, technology deployment and resource planning.
- Employing a portfolio and asset management approach to assess, prioritize and deliver all nuclear operations projects which are developed to meet regulatory commitments (e.g., from the Canadian Nuclear Safety Commission), increase system or unit reliability, address system obsolescence, or optimize station generation.

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 40 of 61

3-Year Non-Fuel Operating Cost per MWh



** DNGS – Unit 2, Unit 4 until Q3, Unit 3 in-service Q2 (U1 in Refurbishment)*

	2023 Non-Normalized Value	2023 Normalized Value
DN	62.76	43.89
PN	58.30	-
Best Quartile	19.64	19.64
Median	24.64	24.64

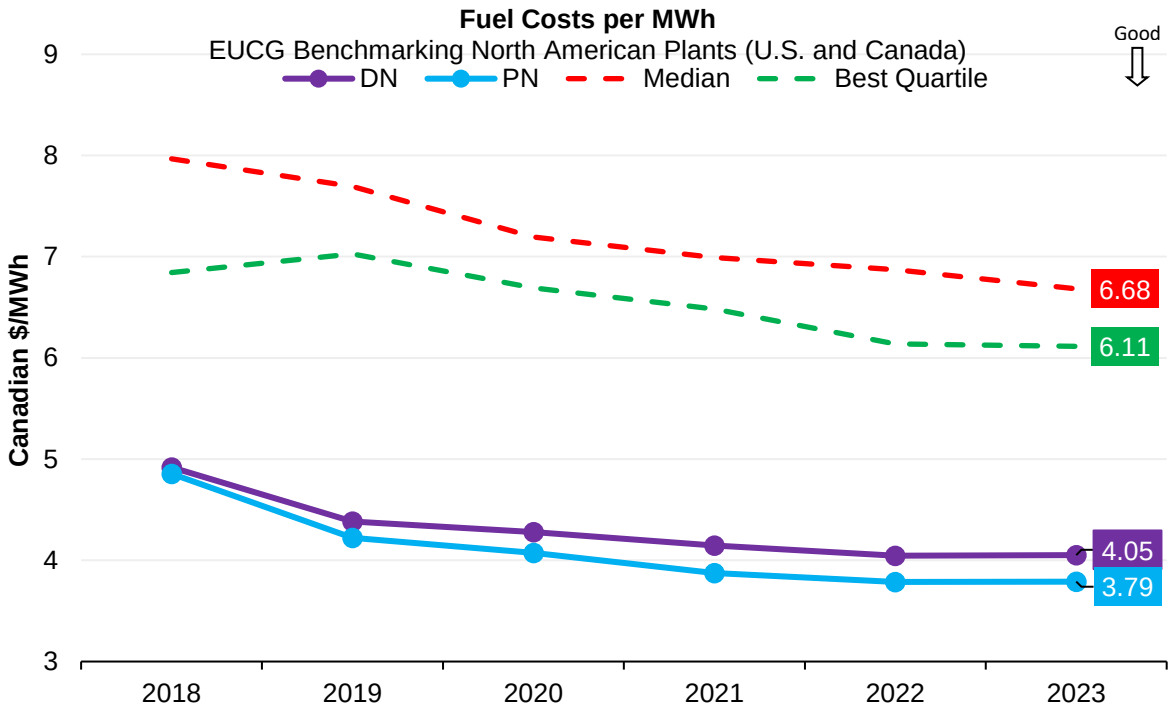
Factors Contributing to Performance

- DNGS normalized and non-normalized performance declined primarily due to reduced 3-year generation related to the Refurbishment outages schedule with the equivalent of two units being in refurbishment outages the full year in 2023 (Unit 1 full year, Unit 4 offline in Q3 and Unit 3 in-service Q2) compared to one unit for 9 months in 2020 (Unit 2 in-service Q2 and Unit 3 offline in Q3) and higher OM&A costs in 2023 from increased unionized compensation as a result of the Ontario Superior court decision finding Bill 124 of limiting annual wage increases to one percent for a 3-year period unconstitutional.
- PNGS non-normalized performance reflects higher OM&A costs in 2023 from increased unionized compensation as a result of the Bill 124 court ruling (as per above).
- PNGS units are the smallest in the peer group at 540 MW/unit compared to the peer average of 1,026 MW, a factor for which results have not been normalized.

Initiatives to Improve and Sustain Favourable Performance – refer to TGC/MWh.

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 41 of 61

3-Year Fuel Cost per MWh



** DNGS – Unit 2, Unit 4 until Q3, Unit 3 in-service Q2 (U1 in Refurbishment)*

	2023 Value
DN	4.05
PN	3.79
Best Quartile	6.11
Median	6.68

Factors Contributing to Performance

- Fuel costs are lower for OPG than most North American Pressurized Water Reactors or Boiling Water Reactors (PWR/BWR) reactors as CANDUs do not require enriched uranium like PWRs and BWRs.
    - Raw uranium is processed directly into uranium dioxide to make fuel pellets, without the additional cost and process complexity of enriching the fuel as required in light water reactors.
    - CANDU reactors are also the most efficient reactors in using uranium, requiring less uranium than PWRs and BWRs for each megawatt hour of electricity.
    - These two factors provide a significant advantage for OPG and other CANDUs in this cost category.

- Regular entry into the uranium market has allowed OPG to reduce uranium input costs year over year for the past several years. Historical multi-year contracts signed between 2015 and 2021, and for which deliveries were made in 2021, 2022 and 2023, have allowed OPG to take deliveries of uranium on a both fixed price and market price basis during a period of historically low uranium spot market prices (2015-2021) not seen since 2005 and earlier.

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 42 of 61

- In 2017, the uranium spot market price reached its cyclical low point and has continued an increasing trend up to the present, and this trend is projected to continue. Over the coming years, as historical uranium contracts are completed and new contracts are entered into, the effect of the more recent increasing uranium price trend is expected to place upward pressure on the 3-year rolling average fuel cost per MWh. A slight increase in fuel costs at PNGS from 2022 to 2023 can be attributed to this uranium price trend and by general escalation in fuel conversion and fuel fabrication costs.

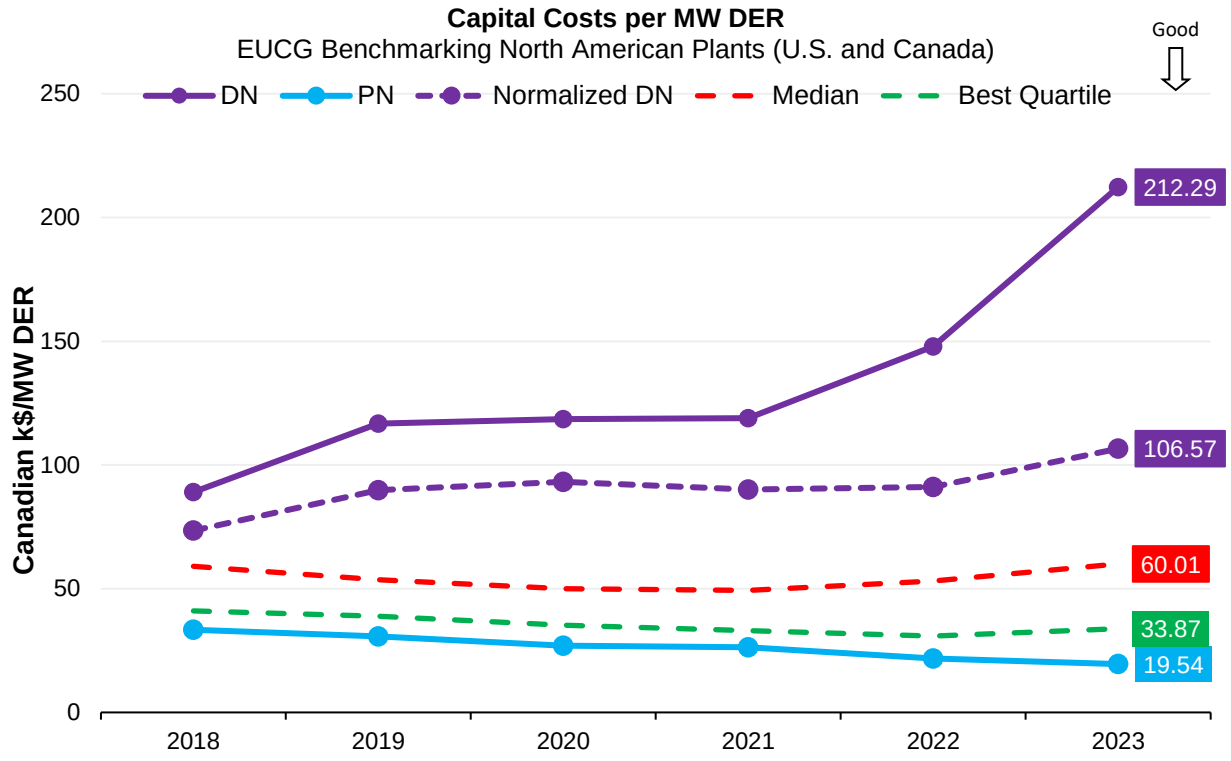
Initiatives to Improve and Sustain Favourable Performance

- Certain factors are expected to place upward cost pressures on nuclear fuel supply chains over the next several years, including:
    - Resurgence in global demand for nuclear power due to carbon emissions targets of world governments, leading to increased global demand for uranium, conversion, and enrichment services.
    - Uranium supply constrained by many years of under-investment in new mine development due to low prices, as well as constrained Western conversion and enrichment capacities.
    - Global conflicts, including the war in Ukraine, leading to a bifurcation of global nuclear fuel supply chains, along with legislative actions such as the recent U.S. ban on the import of Russian nuclear fuel products.

- OPG will continue to seek improvements in contract pricing for its nuclear fuel supply to sustain favorable comparative fuel costs, while also ensuring a resilient and robust nuclear fuel supply chain, given recent and ongoing geopolitical and economic events

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 43 of 61

3-Year Capital Cost per MW DER (Design Electrical Rating)



** DNGS – Unit 2, Unit 4 until Q3, Unit 3 in-service Q2 (U1 in Refurbishment)*

	2023 Non-Normalized Value	2023 Normalized Value
DN	212.29	106.57
PN	19.54	-
Best Quartile	33.87	33.87
Median	60.01	60.01

Factors Contributing to Performance

- PNGS is performing in the first quartile with a slight improvement in 2023 and the improvement over the trend period. This reflects reductions in spending while maintaining reliable operations in the period leading up to the end of commercial operations, which is consistent with spending trends observed at other nuclear facilities approaching their end of commercial operations.

- DNGS performance in 2023 showed an increase on a normalized basis as compared to 2022, as the station remained in the third quartile. The large increase in the absolute DNGS Capital Cost per MW in 2023 is mainly due to the reduction in available MW as two units were in refurbishment outages throughout the majority of the 3-year period as well as increased spending on sustaining investments to ensure long term reliability. The change over the trend period reflects increased spending on life extension, performance improvements, sustaining investments, information technology and capital spares to support operations before, during and after Darlington refurbishment.

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 44 of 61

- Historically, DNGS capital expenditures were better than the industry median. Once the decision to refurbish Darlington and extend end of life was made, OPG began an extensive program to replace obsolete and/or life-expired plant equipment to support performance and reliability of Darlington's unit's post-refurbishment.

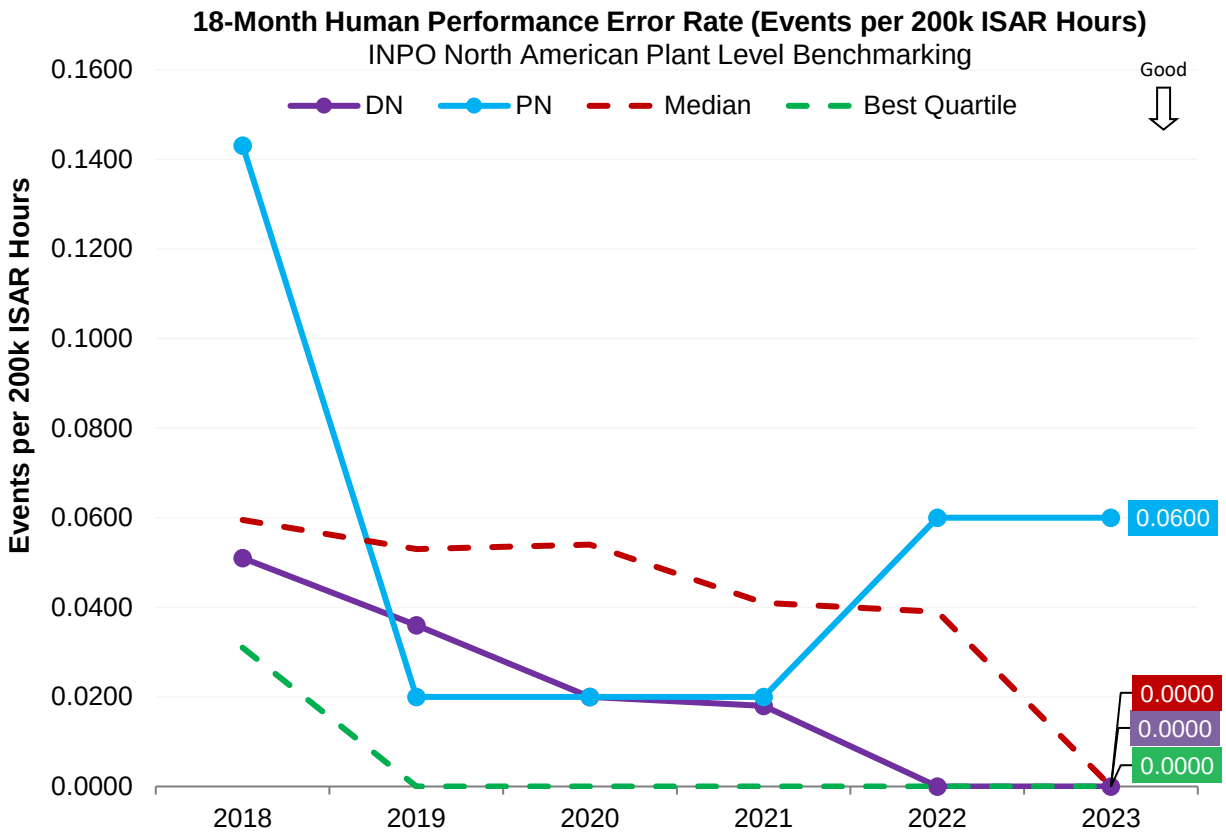
Initiatives to Improve and Sustain Favourable Performance Include:

- Employing a portfolio and asset management approach to assess, prioritize, and deliver all nuclear operations projects which are developed to meet regulatory commitments (i.e. from the Canadian Nuclear Safety Commission), increase system or unit reliability, address system obsolescence, or optimize station generation.

Methodology and Sources of Data

The Human Performance Error Rate metric is used to benchmark the performance of OPG's Nuclear fleet against other INPO utilities in the area of Human Performance.

18-Month Human Performance Error Rate



	2023 Value
DN	0.0000
PN	0.0600
Best Quartile	0.0000
Median	0.0000

Factors Contributing to Performance

- DNGS maintained best quartile performance and did not experience any Site Event Free Day Reset (S-EFDR)s in 2023 or in 2022.
- PNGS experienced one S-EFDR event in Q4 2023. Event causes were identified, and corrective actions implemented to address the gaps. All actions have been completed.

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 46 of 61

Initiatives to Improve and Sustain Favourable Performance Include:

- Continuing to build upon Fail Safe Strategies across the fleet through Pre-Job Briefs (PJB) and Observation & Coaching programs
- Trigger training continued to be deployed
- Supervisors continued to complete Coaching to Enhance Performance training, also with expected completion in Q1 2024.
- Revision and enhancement of Holiday and Outage planning to include more proactive activities, such as the HU Safety Light, becoming Yellow in anticipated higher risk periods.
- Continued focus on the Stop When Unsure campaign as part of the Observation and Coaching improvement plan.
- Further engagement with the TPI (Trending, Prevention, and Intervention) program to provide additional oversight on identified trends.
- Utilization of Validation of Trend (VOT) process to proactively identify and verify emerging trends adverse to safety and quality

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 47 of 61

Acronyms

Acronym	Meaning
ABF	Auxiliary Boiler Feed
ABFP	Auxiliary Boiler Feedwater Pump
AC	Alternating Current
ACU	Air Conditioning Units
ALARA	As Low as Reasonably Achievable
BLC	Boiler Level Control
BWR	Boiling Water Reactor
CANDU	CANada Deuterium Uranium (type of PHWR)
CC	Corrective Critical
CM	Corrective Maintenance
CN	Corrective Non-Critical
CNSC	Canadian Nuclear Safety Commission
COG	CANDU Owners Group
CPI	Chemistry Performance Index
CRE	Collective Radiation Exposure
CTCS	Condenser Tube Cleaning System
D2O	Heavy Water
DC	Deficient Critical
DER	Design Electrical Rating
DM	Deficient Maintenance
DN	Deficient Non-Critical
DNGS	Darlington Nuclear Generating Station
EACP	Emergency AC Power
EC	Electricity Canada
ECI	Emergency Coolant Injection
ECR	Engineering Change Request
EPS	Emergency Power Supply
eSWP	Electronic Safe Work Plans
EUCG	Electric Utility Cost Group
FIN	Fix It Now
FLR	Forced Loss Rate
FRI	Fuel Reliability Index
GWH	Gigawatt Hours
HIT	High Impact Team
HPER	Human Performance Error Rate
HPSI	High Pressure Safety Injection
HPU	Hydraulic Power Unit

Acronym	Meaning
HTHT	Heat Transport High Temperature
HTS	Heat Transport System
HU	Human Performance
INPO	Institute of Nuclear Power Operators
ISAR	Industrial Safety Accident Rate
ISB	Integrated Station Brief
LBL	Low Boiler Level
MW	Mega-Watt
NFOC	Non-Fuel Operating Cost
NPI	Nuclear Performance Index
O&C	Observation & Coaching
OM&A	Operating, Maintenance & Administrative
OPEX	Operating Experience
OPG	Ontario Power Generation
PAWCS	Post-Accident Water Cooling System
PJB	Pre Job-Brief
PNGS	Pickering Nuclear Generating Station
PHTS	Primary Heat Transport System
PHWR	Pressurized Heavy Water Reactor
PM	Preventive Maintenance
PPP	Purchasing Power Parity
PRL	Plant Reliability List
PWR	Pressurized Water Reactor
QSP	Quality of Safety Practices
RDM	Rapid Delivery Machine
RTR	Reactor Trip Rate
RWPB	Retube Waste Processing Building
SATPS	Systematic Approach to Technical Problem Solving
SCL	Safety Classification and Learning
SDS	Shutdown System
SPNMDI	System Does Not Meet Design Intent
S-EFDR	Site event free day resets
SG	Standby Generators
SIF	Significant Injuries and Fatalities
SIR	Significant Issue Response
SPOC	Single Point of Contact
TGC	Total Generating Costs
TGC/MWH	Total Generating Costs per Mega-Watt Hour
TPI	Trending, Prevention, and Intervention

Acronym	Meaning
TRIF	Total Recordable Injury Rate
TRF	Tritium Removal Facility
UCF	Unit Capability Factor
VOT	Validation of Trend
WANO	World Association of Nuclear Operators
WM	Work Management

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 50 of 61

Safety and Reliability Definitions

The following definitions are summaries extracted from industry peer group databases.

Total Recordable Injury Frequency (TRIF)
The number of fatalities, lost time injuries, medical treatment injuries and restricted work injuries per 200,000 hours worked.

Industrial Safety Accident Rate (ISAR)
Number of accidents for all utility personnel (permanently or temporarily) assigned to the station, that result in one or more days away from work (excluding the day of the accident) or one or more days of restricted work (excluding the day of the accident), or fatalities, per 200,000 man-hours worked. The selection of 200,000 man-hours worked or 1,000,000 man-hours worked for the indicator will be made by the country collecting the data, and international data will be displayed using both scales. Contractor personnel are not included for this indicator.

Collective Radiation Exposure (CRE)
Total external and internal whole-body exposure determined by a dose control device (e.g., electronic personal dosimeter, dose recording device, etc.) and internal exposure calculations. All measured exposure should be reported for station personnel, contractors, and those personnel visiting the site or station on official utility business.
Visitors, for purposes of this indicator, include only those monitored visitors who are visiting the site or station on official utility business.

Airborne Tritium Emissions per Unit
Tritium emissions to air.

Fuel Reliability Index (FRI)
Inferred from fission product activities present in the reactor coolant. Due to design differences, this indicator is calculated differently for different reactor types. For PHWR's, the indicator is defined as the steady-state primary coolant iodine-131 activity (Becquerels/gram or Microcuries/gram), corrected for the tramp uranium contribution and power level, and normalized to a common purification rate.

Unplanned automatic reactor trips (SCRAMS)
Number of unplanned automatic reactor trips (reactor protection system logic actuations) that occur per 7,000 hours of critical operation. The indicator is further defined as follows:

- Unplanned means that the trip was not an anticipated part of a planned test.
- Trip means the automatic shutdown of the reactor by a rapid insertion of negative reactivity (e.g., by control rods, liquid injection shutdown system, etc.) that is caused by actuation of the reactor protection system. The trip signal may have resulted from exceeding a set point or may have been spurious.
- Automatic means that the initial signal that caused actuation of the reactor protection system logic was provided from one of the sensors' monitoring plant parameters and conditions, rather than the manual trip switches or, in certain cases described in the clarifying notes, manual turbine trip switches (or pushbuttons) provided in the main control room.

- Critical means that, during the steady-state condition of the reactor prior to the trip, the effective multiplication factor (k_{eff}) was essentially equal to one.
- The value of 7,000 hours is representative of the critical hours of operation during a year for most plants and provides an indicator value that typically approximates the actual number of scrams occurring during the year.

Safety System Performance Indicators include the following:

- Auxiliary boiler feedwater system
- Emergency AC power
- High pressure emergency coolant injection system

These systems were selected for the safety system performance indicator based on their importance in preventing reactor core damage or extended plant outage. They include the principal systems needed for maintaining reactor coolant inventory following a loss of coolant, for decay heat removal following a reactor trip or loss of main feedwater, and for providing emergency AC power following a loss of plant off-site power. (Gas cooled reactors have an additional decay heat removal system instead of the coolant inventory maintenance system).

Nuclear Performance Index (NPI) Method 4
INPO sponsored performance measure and is a weighted composite of 10 WANO Performance Indicators related to safety and production performance reliability.

Forced Loss Rate (FLR)
Ratio of all unplanned forced energy losses during a given period of time to the reference energy generation minus energy generation losses corresponding to planned outages and any unplanned outage extensions of planned outages, during the same period, expressed as a percentage.

Unplanned Energy Losses
Either unplanned forced energy losses (unplanned energy generation losses not resulting from an outage extension) or unplanned outage extension of planned outage energy losses.

Unplanned Forced Energy Loss
Energy that was not produced because of unplanned shutdowns or unplanned load reductions due to causes under plant management control when the unit is considered to be at the disposal of the grid dispatcher. Causes of forced energy losses are considered to be unplanned if they are not scheduled at least four weeks in advance. Causes considered to be under plant management control are further defined in the clarifying notes.

Unplanned Outage Extension Energy Loss
Energy that was not produced because of an extension of a planned outage beyond the original planned end date due to originally scheduled work not being completed, or because newly scheduled work was added (planned and scheduled) to the outage less than four weeks before the scheduled end of the planned outage.

Planned Outage Energy Losses
Corresponding to outages or power reductions which were planned and scheduled at least four weeks in advance (see clarifying notes for exceptions).

Reference Energy Generation
Energy that could be produced if the unit were operated continuously at full power under reference ambient conditions throughout the given period. Reference ambient conditions are environmental conditions representative of the annual mean (or typical) ambient conditions for the unit.

Unit Capability Factor (UCF)
Ratio of the available energy generation over a given time period to the reference energy generation over the same time period, expressed as a percentage. Both of these energy generation terms are determined relative to reference ambient conditions.

Available Energy Generation
Energy that could have been produced under reference ambient conditions considering only limitations within control of plant management, i.e., plant equipment and personnel performance, and work control.

Reference Energy Generation
Energy that could be produced if the unit were operated continuously at full power under reference ambient conditions.

Reference Ambient Conditions
Environmental conditions representative of the annual mean (or typical) ambient conditions for the unit.

Chemistry Performance Indicator (CPI)
CPI compares the concentration of selected impurities and corrosion products to corresponding limiting values. Each parameter is divided by its limiting value, and the sum of these ratios is normalized to 1.0. If an impurity concentration is equal to or better than the limiting value, the limiting value is used as the concentration. This prevents increased concentrations of one parameter from being masked by better performance in another. As a result, if a plant is at or below the limiting value for all parameters, its indicator value would be 1.0, the lowest chemistry indicator value attainable under the indicator definition.

The following is used to determine each unit's chemistry indicator value for PHWRs:

- *Inconel-600 or Monel tubes
  - Steam generator blowdown chloride
  - Steam generator blowdown sulfate
  - Steam generator blowdown sodium
  - Final feedwater iron
  - Final feedwater copper
  - Final feedwater dissolved oxygen

- Incoloy-800 tubes
  - Steam generator blowdown chloride
  - Steam generator blowdown sulfate
  - Steam generator blowdown sodium
  - Final feedwater iron
  - Final feedwater dissolved oxygen

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 53 of 61

Online Deficient Maintenance (DM) Backlog
Average number of active on-line maintenance work orders per operating unit classified as Deficient Critical (DC) or Deficient Non-Critical (DN) that can be worked on without requiring the unit shutdown. This metric identifies deficiencies or degradation of plant equipment components that need to be remedied, but which do not represent a loss of functionality of the component or system.

Online Corrective Maintenance (CM) Backlog
Average number of active on-line maintenance work orders per operating unit classified as Corrective Critical (CC) or Corrective Non-Critical (CN) that can be worked on without requiring the unit shutdown. This metric identifies deficiencies or degradation of components that need to be remedied and represents a loss of functionality of a major component or system.

On-line Maintenance
Performed with the main generator connected to the grid.

Value for Money Definitions

The following definition summaries are taken from the January 2022 EUCG Nuclear Committee Data Definitions and Nuclear Integrated Information Database.

Capital Costs
All costs associated with improvements and modifications made during the reporting year. These costs should include design and installation costs in addition to equipment costs. Other miscellaneous capital additions such as facilities, computer equipment, moveable equipment, and vehicles should also be included. These costs should be fully burdened with indirect costs, but exclude AFUDC (interest and depreciation), spent fuel storage costs and/or reimbursements, capital write-off expenditures, taxes (except Payroll), and COVID response costs.

Nuclear Fuel Costs
Total cost associated with a load of fuel in the reactor which is burned up in a given year. Fuel burn costs should NOT include spent fuel storage costs or fuel impairment.

Fuel impairment is the write-down of the value of the Nuclear fuel and thus reduces the amortization or fuel expense, occurs in plants either announcing shutdown or are in a pending shutdown.

Net Generation
Gross electrical output of the unit measured at the output terminals of the turbine-generator minus the normal station service loads during the hours of the reporting period, expressed in Gigawatt hours (GWh).

Design Electrical Rating (DER)
Nominal net electrical output of a unit specified by the utility and used for plant design (DER net expressed in MWe). Design Electrical Rating should be the value that the unit was certified/designed to produce when constructed. The value would change if a power uprate was completed. After a power uprate, the value should be the certified or design value resulting from the uprate.

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 54 of 61

Operating Costs (Non-Fuel Operating Costs - NFOC)
All costs associated with normal operations, maintenance, and outage periods that occur within the current EUCG data reporting year. These costs should be fully burdened and reflect the total operating costs for labour, materials & equipment, outside services and other costs, but exclude depreciation, interest, taxes (except Payroll), COVID response costs, spent fuel storage costs and/or reimbursements, capital write-off expenditures, and new plant expenditures

New Plant Expenditures
All costs for supporting new nuclear generation and licensing efforts

Total Generating Costs (TGC)
Sum of operating costs, fuel costs and capital costs

Total Generating Costs (TGC) per MWh
Sum of operating costs, fuel costs and capital costs divided by Net Generation

Total Generating Costs (TGC) per Unit
Sum of operating costs, fuel costs and capital costs divided by Number of Units at Station

Non-Fuel Operating Costs (NFOC) per MWh
Operating costs divided by Net Generation

Fuel Costs per MWh
Nuclear Fuel costs divided by Net Generation

Capital Cost per MW DER
Capital costs divided by Design Electrical Rating (DER)

Human Performance Definitions
The following definition summary is taken from the Institute of Nuclear Power Operations (INPO) database.

Human Performance Error Rate (HPER)
Represents the number of site level human performance events in an 18-month period per 200,000 Industrial Safety Accident Rate (ISAR) hours worked (including on site supplemental personnel).

Formula = {(# of S-EFDRs) / (Total ISAR Hours + Total Contractor Hours)} x 200,000 Hours *(Calculated as an 18-month rolling average)*

Non-utility Personnel
Includes contractor, supplemental personnel assigned to perform work activities on site or at other buildings that directly support station operation. This includes personnel who deliver and receive equipment, deliver fuel oil, remove trash and radioactive waste, and provide building and grounds maintenance within the owner-controlled areas or facilities that support the station.

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 55 of 61

Event
An initiating action (error) by an individual or group of individuals (event resulting from an active error) or an initiating action (not an error) by an individual or group of individuals during an activity conducted as planned (event resulting from a flawed defense or latent organizational weakness). They may be related to Nuclear Safety, Radiological Safety, Industrial Safety, Facility Operations or considered to be a Regulatory Event reportable to a regulator or governing agency. OPG Nuclear's criteria for defining station event free day resets have been developed based on INPO guidelines.

Industry Peer Groups

All data provided by the peer groups (WANO, INPO, EC, and EUCG) is confidential. A redacted version of this report, which removes individual plant and unit names, is available from Nuclear Business Planning and Benchmarking should there be a requirement to publicly release this report.

Table 2: Industry Peer Groups

	COG CANDUs (WANO)	All North American PWR and PHWRs (WANO)	INPO AP-928 Workgroup	INPO	EC	EUCG North American Plants (US and Canada)
Safety						
Total Recordable Injury Frequency					X	
Rolling Average Industrial Safety Accident Rate*+		X				
Rolling Average Collective Radiation Exposure*+	X					
Airborne Tritium Emissions (Curies) per Unit	X					
Fuel Reliability Index*	X					
2-Year Reactor Trip Rate*	X					
3-Year Auxiliary Feedwater System Unavailability*	X					
3-Year Emergency AC Power Unavailability*	X					
3-Year High Pressure Safety Injection Unavailability*	X					
Reliability						
Rolling Average WANO NPI +	X					
Rolling Average Forced Loss Rate*+	X					
Rolling Average Unit Capability Factor*+	X					
Rolling Average Chemistry Performance Indicator*+	X					
1-Year On-line Deficient Maintenance Backlog			X			
1-Year On-line Deficient Critical Backlog			X			
1-Year On-line Corrective Maintenance Backlog			X			
1-Year On-line Corrective Critical Backlog			X			
Value for Money						
3-Year Total Generating Costs / MWh						X
3-Year Non-Fuel Operating Costs (OM&A) / MWh						X
3-Year Fuel Costs / MWh						X
3-Year Capital Costs / MW DER						X
Human Performance						
18-Month Human Performance Error Rate				X		

** Sub-indicator of WANO NPI*

+ Rolling 2 Year Average PNGS ; Rolling 3 Year Average DNGS

Safety and Reliability Peer Groups

Primary source of benchmarking data for operational performance (Safety and Reliability) indicators is the World Association of Nuclear Operators (WANO). Eleven out of the twenty benchmarking metrics have been compared to the COG CANDU (WANO) panel. Industrial Safety Accident Rate (ISAR) is compared to the All North American PWR and PHWR (WANO) panel.

All WANO performance indicators are presented at the unit and plant levels except the Industrial Safety Accident Rate (ISAR) and Emergency AC Power Unavailability which are only measured at the plant level.

Different peer groups were used for 5 specialized operating metrics which are not tracked through WANO:

- *Total Recordable Injury Frequency*: Electricity Canada panel was utilized. OPG benchmarks against EC Group 1 peers (a subset of all EC members), which incorporates organizations with more that 1,500 employees, including most provincial utilities.

- *On-line Deficient Maintenance Backlog, On-line Deficient Critical Backlog, On-line Corrective Maintenance Backlog, On-line Corrective Critical Backlog:* Institute of Nuclear Power Operations (INPO) AP-928 working group was utilized.

Value for Money Peer Group

For financial performance comparisons, data compiled by the Electric Utility Cost Group (EUCG) was utilized. EUCG is a nuclear industry operating group and the recognized source for cost benchmark information. EUCG cost indicators are presented at the plant level and compared on a net megawatt hour generated basis and on a per megawatt (MW) design electrical rating (DER) basis. The only CANDU operators reporting data to EUCG were OPG and Bruce Power which is not a sufficiently large panel to provide a basis for comparison; hence, the data sets were not limited to a CANDU specific panel. Should more CANDU operators choose to join EUCG in the future, comparisons to a CANDU specific panel will be reconsidered.

Human Performance Peer Group

For human performance comparisons, data was obtained from INPO.

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 57 of 61

Panels/Members

Table 3: WANO Panel

Operator	Plant
Ameren Missouri	Callaway
American Electric Power Co.	Cook
Arizona Public Service Co.	Palo Verde
Bruce Power	Bruce A Bruce B
Dominion Energy	Millstone North Anna Surry V.C. Summer
Duke Energy	Catawba Harris Mcguire Oconee Robinson
Entergy Nuclear	Waterford
Constellation Energy	Braidwood Byron Calvert Cliffs R.E. Ginna
FirstEnergy Nuclear Operating Co.	Beaver Valley Davis-Besse
Florida Power & Light Co.	St. Lucie Turkey Point
International CANDU	Cernavoda Embalse Qinshan 3 Wolsong A Wolsong B
Luminant Generation	Comanche Peak
New Brunswick Power	Point Lepreau
NextEra Energy Resources	Point Beach Seabrook
Northern States Power Company	Prairie Island
Ontario Power Generation	Darlington Pickering
Pacific Gas & Electric Co.	Diablo Canyon
Public Service Enterprise Group Nuclear	Salem
Southern Nuclear Operating Co.	Farley Vogtle
STP Nuclear Operating Co.	South Texas
Tennessee Valley Authority	Sequoyah Watts Bar
Wolf Creek Nuclear Operating Corp.	Wolf Creek

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
8 of 61

Table 4: EUCG Panel

Operator	Plant
AmerenUE	Callaway
American Electric Power Co. Inc.	Cook
Arizona Public Service Co.	Palo Verde
Bruce Power	Bruce
Dominion Generation	Millstone North Anna Surry V.C. Summer
DTE Energy	Fermi
Duke Energy	Brunswick Catawba Harris Mcguire Oconee Robinson
Energy Northwest	Columbia
Entergy Nuclear	Arkansas Nuclear One Grand Gulf Indian Point River Bend Waterford
Constellation Energy	Braidwood Byron Calvert Cliffs Clinton Dresden Fitzpatrick Lasalle Limerick Nine Mile Peach Bottom Quad Cities R.E. Ginna

Operator	Plant
FirstEnergy Nuclear Operating Co.	Beaver Valley Davis-Besse Perry
Florida Power & Light Co.	St Lucie Turkey Point
Luminant Generation	Comanche Peak
Nebraska Public Power District	Cooper
NextEra Energy Resources	Point Beach Seabrook
Northern States Power Company	Monticello Prairie Island
Ontario Power Generation	Darlington Pickering
Pacific Gas & Co.	Diablo Canyon
Public Service Enterprise Group Nuclear	Hope Creek Salem
Southern Nuclear Operating Co.	Farley Hatch Vogtle
STP Nuclear Operating Co.	South Texas
Talen Energy	Susquehanna
Tennessee Valley Authority	Browns Ferry Sequoyah Watts Bar
Wolf Creek Nuclear Operations Corp.	Wolf Creek

Filed: 2025-12-12
EB-2025-0297
Exhibit F2-1-1
Attachment 2
Page 59 of 61

Table 5: COG CANDUs

Operator	Plant
Bruce Power	Bruce A Bruce B
China (CNNP)	Qinshan 3
NASA	Embalse
Korea (KHNP)	Wolsong A Wolsong B
New Brunswick Power	Point Lepreau
OPG	Darlington Pickering
Romania	Cernavoda

Table 6: Electricity Canada Members

Companies
Alectra Inc.
Algonquin Power
AltaLink
ATCO Electric (Alberta Power Ltd.)
Atura Power
BC Hydro
Canada Power Holdings
Capital Power
City of Medicine Hat
City of Red Deer
Elexicon
ENMAX
EPCOR
Evolugen
FortisAlberta
FortisBC
FortisOntario
Heartland Generation
Hydro One
Hydro Ottawa
Hydro-Québec

Companies
IESO
London Hydro
Manitoba Hydro
Maritime Electric
New Brunswick Power
Newfoundland and Labrador Hydro
Newfoundland Power
Northwest Territories Power Corporation
Nova Scotia Power/Emera
Oakville Enterprises Corporation
Ontario Power Generation
Qulliq Energy Corporation
Rio Tinto
Saint John Energy
Saskatoon Light & Power
SaskPower
TC Energy
Toronto Hydro
TransAlta
Utilities Kingston
Yukon Energy

Table 7: INPO Members for On-Line Maintenance Backlogs

Plant	
Arkansas Nuclear One (ANO)	Millstone
Beaver Valley	Monticello
Braidwood	Nine Mile Point
Browns Ferry	North Anna
Brunswick	Oconee
Byron	Oyster Creek
Callaway	Palo Verde
Calvert Cliffs	Peach Bottom
Catawba	Perry
Clinton	Pilgrim
Columbia Gen	Point Beach
Comanche Peak	Prairie Island
Cook	Quad Cities
Cooper	River Bend
Davis-Besse	Robinson
Diablo Canyon	Salem
Dresden	Seabrook
Duane Arnold	Sequoyah
Farley	South Texas
Fermi 2	St. Lucie
Fitzpatrick	Summer
Ginna	Surry
Grand Gulf	Susquehanna
Harris	Turkey Point
Hatch	Vogtle
Hope Creek	Waterford
LaSalle	Watts Bar
Limerick	Wolf Creek
McGuire	

Table 8: INPO Members for Human Performance Error Rate

Plant	
Arkansas Nuclear One (ANO)	Millstone
Beaver Valley	Monticello
Braidwood	Nine Mile Point
Browns Ferry	North Anna
Brunswick	Oconee
Byron	Oyster Creek
Callaway	Palo Verde
Calvert Cliffs	Peach Bottom
Catawba	Perry
Clinton	Pilgrim
Columbia Gen	Point Beach
Comanche Peak	Prairie Island
Cook	Quad Cities
Cooper	River Bend
Davis-Besse	Robinson
Diablo Canyon	Salem
Dresden	Seabrook
Duane Arnold	Sequoyah
Farley	South Texas
Fermi 2	St. Lucie
Fitzpatrick	Summer
Ginna	Surry
Grand Gulf	Susquehanna
Harris	Turkey Point
Hatch	Vogtle
Hope Creek	Waterford
LaSalle	Watts Bar
Limerick	Wolf Creek
McGuire	

ScottMadden Evaluation of 2024 OPG Nuclear Benchmarking

Smart. Focused. Done Right.®

scottmadden
MANAGEMENT CONSULTANTS

TABLE OF CONTENTS

1. Executive Summary 2
2. Background 3
3. Objectives and Scope 3
4. Changes in Comparative Peer Panels 4
5. Changes in Comparative Benchmark Metrics 4
6. Validation of Data Calculations and Reporting 5
7. Use of Benchmarks in the Business Planning Process 6
8. Changes in Report Format and Presentation 6

1. EXECUTIVE SUMMARY

The benchmarking methods evaluated were those recently performed by OPG in support of its 2025-2031 planning cycle. The scope of our review encompassed the identification of key performance metrics used for comparison, the selection of companies to be included in the peer panels, the preparation of supporting analyses and data displays, and the utilization of benchmarks in the business planning cycle. The purpose of this review was to evaluate the Company's nuclear benchmarking methods and approach.

ScottMadden's analysis determined that OPG's existing benchmarking methods align with previous guidance and industry leading practices. Our review did not identify any concerns with the calculations or data presentations in the benchmarking report. OPG's selection of benchmarking metrics offers a comprehensive perspective on the Company's nuclear performance, and the choice of comparator companies accurately represents its industry peers. Furthermore, the 2024 report is more concise than the 2020 report. This modification improved the clarity of the document and increased the efficiency of its production, without compromising the quality of the performance information it provides. Finally, ScottMadden's review of OPG's Nuclear Business Planning Procedure indicates that this governance approach remains consistent with industry leading practices.

Changes in Comparative Peer Panels

There have been no substantive changes to the peer panels for comparison in the benchmarking report since ScottMadden's evaluation of the 2020 report, and these panels remain valid industry comparisons for OPG. The choice of companies for comparison appropriately reflects their industry peers.

Changes in Comparative Benchmark Metrics

We compared the metrics currently used by OPG to those used by OPG in the 2020 report. We also compared the metrics currently used by OPG to those currently used by other nuclear operators to benchmark their operational and financial performance.

Our review identified no differences between the 2020 and 2024 benchmarking reports in the metrics used to measure performance. The 2024 report presents the data related to backlogs under the reliability cornerstone in a slightly different, yet clear and appropriate, manner, which we support. ScottMadden also supports the inclusion of normalizing adjustments to some value for money metrics, which are presented in conjunction with unadjusted (i.e., non-normalized) versions of those cost metrics. Our review also indicated that OPG's metrics are appropriate when compared to those employed by other nuclear operators. It is our opinion that OPG's suite of benchmarked metrics provides a sufficiently robust view of the Company's nuclear performance.

Validation of Data Calculations and Reporting

We conducted a data validation exercise to ensure benchmarking data contained in the 2024 report was assessed, calculated, and reported accurately. Our evaluation found no issues with OPG's assessments, calculations, or presentations of data in the benchmarking report.

Use of Benchmarks in the Business Planning Process

ScottMadden reviewed OPG's Nuclear Business Planning Procedure. We found that this governance remains aligned with industry leading practice and ScottMadden's previous guidance.

Smart. Focused. Done Right.®
scottmadden MANAGEMENT CONSULTANTS
Copyright © 2025 by ScottMadden, Inc. All rights reserved.

Changes in Report Format and Presentation

We compared the 2020 and 2024 benchmarking reports for consistency in report format and presentation. It is ScottMadden's view that any changes from 2020 to 2024 yielded improvements in the associated clarity and conciseness of the report and the overall purpose of the benchmarking analysis.

2. BACKGROUND

In 2009, OPG retained ScottMadden to assist in formally benchmarking its nuclear financial and non-financial performance with industry peers. This initiative was undertaken consistent with shareholder mandate and pursuant to direction from the Ontario Energy Board (OEB). Since this time, nuclear benchmarking has been a standard part of OPG's annual business planning process. OPG has continued to publish annual benchmarking results, comparing OPG to the nuclear industry in terms of financial and non-financial performance metrics. Results are then used to inform target setting for business planning purposes.

OPG previously retained ScottMadden for a similar review of its benchmarking methods. That review of the 2020 benchmarking report determined that OPG's benchmarking and target-setting processes remained consistent with industry leading practices and supportive of the direction from the OEB. The 2020 review did not find any issues in the content of the report. The review did recommend that OPG focus on site-level comparisons of performance for Pickering and Darlington rather than operator-level comparisons in the future, and OPG implemented these changes. OPG has continued to file a review by ScottMadden regarding OPG's nuclear benchmarking methodologies with its cost-based applications, consistent with OEB direction described in prior decisions.

In an effort to ensure OPG's benchmarking and target setting processes are still responsive to the direction from the Ontario Energy Board (OEB), OPG retained ScottMadden, as an independent evaluator, to examine the current methods used by OPG to benchmark the Company's operational and financial performance against its peer companies in the industry.

3. OBJECTIVES AND SCOPE

Objectives

The purpose of this evaluation is to confirm that the Company's benchmarking methods and approach remain responsive to the original direction from the OEB.

Scope

The benchmarking methods evaluated were those recently performed by OPG in support of its 2025-2031 planning cycle. The scope of our review includes the following:

- Identification of key performance metrics used for comparison
- Selection of companies to be included in the peer panels
- Preparation of supporting analyses and displays of data
- Use of benchmarks in the business planning cycle

Smart. Focused. Done Right.®
scottmadden MANAGEMENT CONSULTANTS
Copyright © 2025 by ScottMadden, Inc. All rights reserved.

The scope of the review compared the 2024 OPG Nuclear Benchmarking Report to the 2020 OPG Nuclear Benchmarking Report, which was reviewed by ScottMadden in 2020. The two documents were compared in terms of (1) use of appropriate peer companies for comparison, (2) use of industry standard metrics, (3) accuracy of assessments, calculations, and presentations of data, (4) application of the performance benchmarks to inform and guide management during the Company's business planning process, and (5) consistency in format and presentation.

This evaluation also validated the application of the normalization adjustments included by OPG for value for money metrics, which reflected methodologies presented in separate documents prepared by ScottMadden for OPG:

- "OPG Nuclear Cost Performance Benchmarking: A Study of Factors Impacting TGC / MWh Performance with Normalizing Adjustments to Facilitate Closer Comparison"
- "OPG Nuclear Cost Performance Benchmarking: Methodology to Adjust for Refurbishment and Validation of Implementation"[1]

4. CHANGES IN COMPARATIVE PEER PANELS

Approach

To evaluate changes in comparative peer panels, ScottMadden reviewed summary tables as well as individual metrics to determine which peer groups were used for which metrics. This exercise was performed at the plant and unit level.

Key Changes and Justification

There have been no substantive changes to the peer panels for comparison in the benchmarking report since ScottMadden's evaluation of the 2020 report.

ScottMadden's Evaluation

The peer panels for comparison remain valid industry comparisons for OPG, and OPG's choice of companies for comparison appropriately reflects its industry peers.

5. CHANGES IN COMPARATIVE BENCHMARK METRICS

Approach

We compared the metrics currently used by OPG to those used by OPG in 2020. We also reviewed the metrics used by OPG, drawing on our experience with other nuclear operators, to determine their suitability for benchmarking operational and financial performance.

[1] ScottMadden outlined the methodology for Refurbishment normalization for 2017 and subsequently validated the OPG calculations to ensure the methodology was applied correctly. Subsequently, ScottMadden has validated that the approach of OPG remained consistent with the methodology and assumed that OPG had also continued to accurately perform the calculations consistent with OPG's current corporate cost allocation methodology and organizational structure.

Smart. Focused. Done Right.®
scottmadden MANAGEMENT CONSULTANTS
Copyright © 2025 by ScottMadden, Inc. All rights reserved.

Key Changes and Justification

Our review identified no differences between the 2020 and 2024 benchmarking reports in the metrics used to measure performance. However, there is a difference in the presentation of online deficient and corrective maintenance backlogs from the 2020 report to the 2024 report. Specifically, the 2020 report only included the current performance year and the benchmark in the performance chart and described the trend in the subsequent observations. The 2024 report includes the current performance year and the prior five years of performance with benchmarks, creating a visual representation of the trend. The trend and other observations are then addressed in the subsequent "Factors Contributing to Performance" and "Initiatives to Improve and Sustain Favorable Performance." ScottMadden supports these enhancements in visual representation and performance commentary.

ScottMadden also supports OPG continuing to include normalizing adjustments to some value for money metrics, which are presented in conjunction with unadjusted (i.e., non-normalized) versions of those cost metrics.

Lastly, ScottMadden found that the metrics used for each cornerstone area (e.g., reliability) in this benchmarking report provide excellent coverage of overall nuclear performance in comparison to the broader industry. They represent key metrics that are well-known and commonly used for executive-level benchmarks in nuclear power generation.

ScottMadden's Evaluation

We compared the metrics currently used by OPG to those used by OPG in the 2020 report. We also reviewed the metrics used by OPG, drawing on our experience with other nuclear operators, and found they were suitable for benchmarking operational and financial performance.

It is our opinion that OPG's suite of benchmarked metrics provides a sufficiently robust view of the Company's nuclear performance.

6. VALIDATION OF DATA CALCULATIONS AND REPORTING

Approach

We conducted a data validation exercise to ensure benchmarking data contained in the 2024 report was assessed, calculated, and reported accurately. Data capture for the benchmarking report occurs in three principal steps:

1. Receipt of the data from the reporting agencies (e.g., WANO, INPO, COG, EUCG, etc.) and posting of this data to OPG-consolidated spreadsheets
2. Custom calculations of the data as needed (e.g., development of two- or three-year rolling averages if not directly reported as such)
3. Development of tables and charts comparing OPG performance to that of associated peer panels

ScottMadden independently validated steps 2 and 3 for available data. We were unable to directly validate step 1 insofar as ScottMadden is not a member utility and does not have direct access to the underlying reports provided by these organizations. Membership rules restrict distribution to third parties.

Smart. Focused. Done Right.®
scottmadden MANAGEMENT CONSULTANTS
Copyright © 2025 by ScottMadden, Inc. All rights reserved.

In validating step 2, OPG data and associated calculations were examined in detail. Data and calculations for other comparators were examined and validated in aggregate. Aggregate discrepancies could then be followed up by examining the calculation detail to identify the source of the discrepancy, though none were found during this review.

ScottMadden's Evaluation

Our evaluation found no issues with OPG's assessments, calculations, or presentations of data in the benchmarking report.

7. USE OF BENCHMARKS IN THE BUSINESS PLANNING PROCESS

Approach

ScottMadden reviewed OPG's Nuclear Business Planning Procedure (N-PROC-AS-0080 R007) and Nuclear Benchmarking Report Instruction Guide against previous ScottMadden guidance and current industry leading practice.

Summary of Business Planning Process

OPG's nuclear business planning framework consists of five phases: (1) Performance Review, (2) Setting Strategic Direction, (3) Gap Closure Planning, (4) Developing Detailed Business Plan, and (5) Performance Reporting. Throughout this business planning cycle, nuclear performance is compared against the targets from the last business plan, new targets are set, and fleet-wide improvement initiatives to address performance gaps are formulated. Based on the approved strategic direction, generation, cost, and staffing plans are developed. Finally, performance is reported and monitored.

ScottMadden's Evaluation

We found that OPG's Nuclear Business Planning Procedure remains aligned with industry leading practice and ScottMadden's previous guidance.

8. CHANGES IN REPORT FORMAT AND PRESENTATION

Approach

We compared the 2020 and 2024 benchmarking reports for consistency in report format and presentation.

Key Changes and Their Justification

Changes to the 2024 report, compared with the 2020 report, include:

- The same content and flow, with the exception of the elimination of the Major Operator Summary, which is consistent with a prior recommendation from ScottMadden
- Various improvements to clarity and conciseness of the report (e.g., the Executive Summary in the 2024 report addresses performance cornerstones, like Reliability, rather than each individual metric.

Smart. Focused. Done Right.®
scottmadden MANAGEMENT CONSULTANTS
Copyright © 2025 by ScottMadden, Inc. All rights reserved.

ScottMadden's Evaluation

It is ScottMadden's view that any changes from 2020 to 2024 were appropriate to the overall purpose of the benchmarking analysis. The 2024 report is more concise than the 2020 report. This modification improved the clarity of the document and increased the efficiency of its production, without compromising the quality of the performance information provided.

Copyright © 2025 by ScottMadden, Inc. All rights reserved.

OPG Nuclear Cost Performance Benchmarking

A Study of Factors Impacting TGC / MWh Performance with Normalizing Adjustments to Facilitate Closer Comparison

Smart. Focused. Done Right.®

scottmadden
MANAGEMENT CONSULTANTS

TABLE OF CONTENTS

1. Background 2
Context 2
Current TGC/MWh Performance 3
2. About The ScottMadden Approach 3
Scope and Objectives 3
Assumptions and Qualifications 4
3. Executive Summary 5
4. Adjusting for Inflation 7
5. Econometric Analysis 7
About The Data 7
Predictive Model for Total Generating Costs 8
6. Nuclear Outages Analysis 10
About The Data 11
MWh Adjustment Calculation to Account for Planned Outages 11

Copyright © 2025 by ScottMadden, Inc. All rights reserved.

1. BACKGROUND

Context

Ontario Power Generation (OPG) is Ontario's largest electricity generator, producing nearly half of the province's electricity. OPG operates a diverse portfolio of generation assets, including nuclear, hydroelectric, biomass, natural gas, and solar facilities. OPG is committed to meeting Ontario's growing electricity demands reliably and cost-effectively, while minimizing environmental impacts by reducing greenhouse gas and carbon emissions.

Pickering Nuclear Generating Station (PNGS) is one of the two nuclear stations operated by OPG. PNGS has six operating units (two additional units ended commercial operations in 1997), with a net output of 3,094 megawatts (MW), providing about 14 percent of Ontario's electricity needs. The site has been operational since 1971. As of 2023, OPG has extended the operation of PNGS until 2026 and is planning to refurbish units 5, 6, 7, and 8.

Darlington Nuclear Generating Station (DNGS) is OPG's other nuclear station, a four-unit facility with a net output of 3,512 MW, contributing approximately 20 percent of Ontario's electricity needs since the early 1990s. OPG has completed a major mid-life refurbishment of three of the four reactors (units 1, 2, and 3), which involved the replacement of certain life-limiting components. The project began in October 2016 with Unit 2, which returned to service in June 2020, followed by Unit 3, which completed refurbishment in July 2023, and Unit 1, which completed refurbishment in November 2024. Refurbishment of Unit 4 is ongoing, having started in July 2023 and scheduled for completion in the fourth quarter of 2026.

OPG tracks and benchmarks the performance of PNGS and DNGS against industry peers under its nuclear cornerstones of Safety, Reliability, Human Performance, and Value for Money. Value for Money is measured relative to an Electric Utility Cost Group (EUCG) panel of nuclear plants in North America across four metrics, with the headline metric being Total Generating Cost (TGC) per Megawatt-Hour (MWh). Given nuclear power's importance to current operations and plans for future generation capacity, OPG wants to ensure that the cost performance of its operating nuclear plants continues to deliver good value for money. Thus, OPG requested that ScottMadden update the past study of nuclear cost performance using the most current benchmarking data, which is inclusive through 2023.

ScottMadden previously compared Pickering's and Darlington's TGC/MWh to the same measurement of cost performance for other nuclear operators. These past studies facilitated comparisons of OPG plants to others by making various adjustments to baseline comparisons:

- Adjustments to total generating cost (TGC) to normalize for Refurbishment at Darlington, as it is a multi-year mega-project
- Adjustments to total generating cost (TGC) to normalize for technology type (CANDU, BWR, or PWR) and average unit age in months, as these plant characteristics influence cost performance but cannot be impacted by how the plant is managed
- Adjustments to MWhs to address differences in outage length.

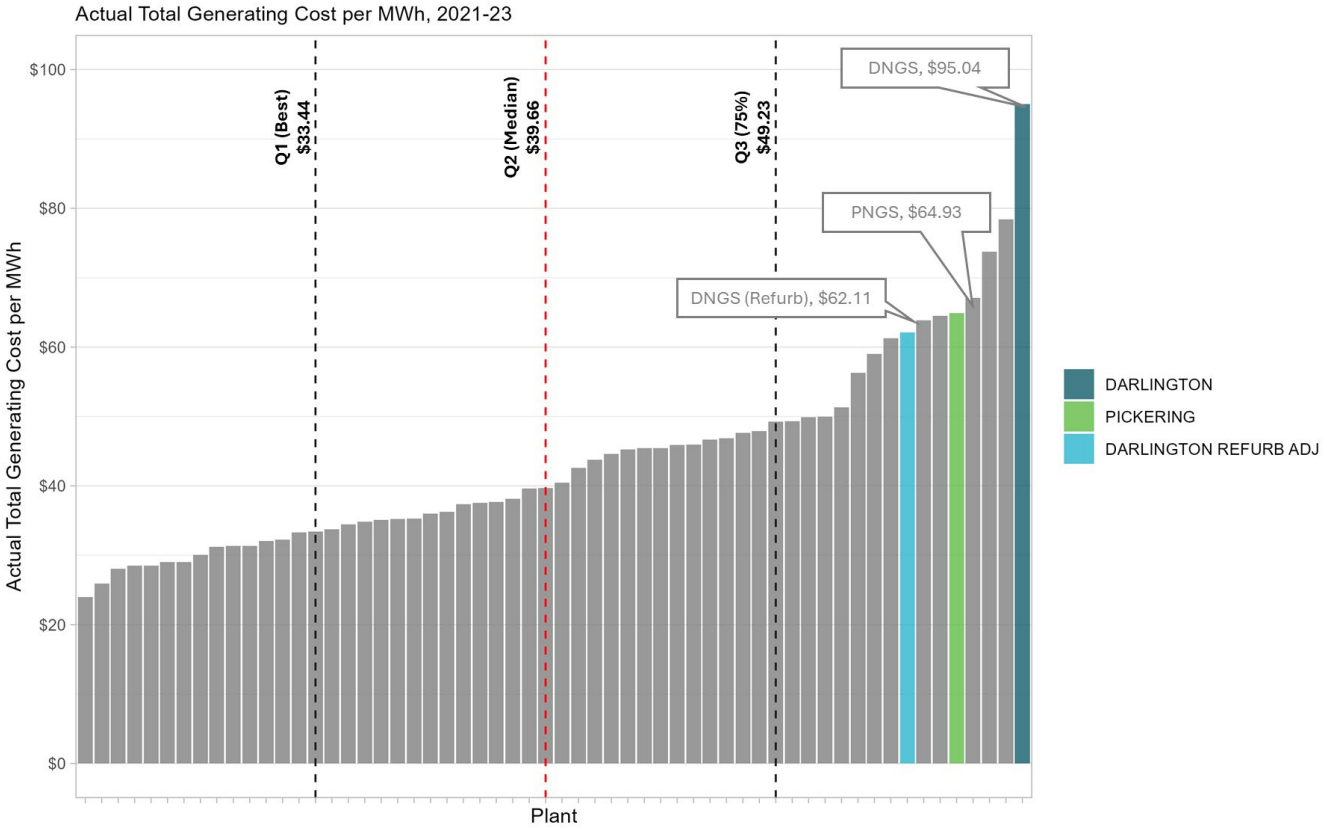
Past ScottMadden studies were considered and re-assessed with current data in this examination, which continued to focus on understanding the cost impacts of factors outside the direct control of OPG plant management.

Smart. Focused. Done Right.®
scottmadden MANAGEMENT CONSULTANTS
Copyright © 2025 by ScottMadden, Inc. All rights reserved.

Current TGC/MWh Performance

Using the EUCG data provided by OPG, TGC/MWh performance for the most recent three-year time period (2021-2023) for PNGS and DNGS appears in the fourth quartile relative to the other sites. However, TGC/MWh performance for DNGS must be adjusted to account for the ongoing Refurbishment, using the established methodology provided under a separate study. The result of the adjustment was a relative improvement in TGC/MWh performance for DNGS as illustrated below.

TGC/MWh performance 2021-'23 for EUCG Panel with DNGS Adjusted for Refurbishment



2. ABOUT THE SCOTTMADDEN APPROACH

Scope and Objectives

Consistent with past examination, this study focused on two primary areas of analysis:

- **Econometric** – analysis of site characteristics to understand and quantify the impact on total generating cost (TGC)
- **Nuclear Planned Outages** – analysis of planned outages to determine impacts on energy production (MWh) and establish a basis for normalizing plant production figures. Rather than collecting data via a survey instrument, as was done previously, ScottMadden used actual

Smart. Focused. Done Right.®
Copyright © 2025 by ScottMadden, Inc. All rights reserved.
scottmadden MANAGEMENT CONSULTANTS

outage hours, number of units, and plant capacity based on extensive data from the Electric Utility Cost Group (EUCG)

The objectives of this investigation were to:

1. Determine whether and to what extent relatively static plant characteristics of a nuclear site influence TGC/MWh performance
2. Quantify and adjust for these characteristics to produce normalized TGC/MWh values that account for plant characteristics that have a significant impact on TGC/MWh performance

We analyzed eighteen years of nuclear plant data (from 2006 to 2023) and 1026 data points per variable to understand and quantify, where possible, relationships between the data and TGC/MWh performance.

Assumptions and Qualifications

In performing this study and preparing this document, ScottMadden assumes that all data provided by OPG and external sources are complete and accurate, including Electric Utility Cost Group (EUCG) data, with plant information blinded, that was provided by OPG.

This ScottMadden report is also subject to the following qualifications:

- ScottMadden does not imply the performance of any additional, specific research beyond what is described in this document.
- ScottMadden does not express an opinion in this document on the effectiveness of management practices at OPG or the appropriateness of any of OPG's costs, outage durations, or other performance characteristics.
- The ScottMadden methodology was prepared for the benefit of OPG and is limited to the subject matter expressly stated in this document; no additional ScottMadden opinion is implied or may be inferred.

Smart. Focused. Done Right.®
Copyright © 2025 by ScottMadden, Inc. All rights reserved.
scottmadden MANAGEMENT CONSULTANTS

3. EXECUTIVE SUMMARY

ScottMadden focused on two major areas of analysis: 1) econometric analysis and 2) analysis of planned outages.

Econometric Analysis: We used Multiple Linear Regression (MLR) to quantify the relationships between reactor type, site capacity, unit age, and other variables in many combinations (the independent variables) and the EUCG data for TGC (the dependent variable). We developed a robust predictive model for TGC through this analysis of the current dataset. This model explains ~77% of the variability in TGC across the dataset using three variables (reactor type, site capacity, and unit age). The model indicates:

- Relative to BWR plants, CANDU technology increases predicted TGC by over ~C$539[1] million per year
- Relative to BWR plants, PWR technology increases predicted TGC by over ~C$17 million per year
- Each MW of site capacity increases predicted TGC by ~C$291 thousand per year
- Each month of average unit age increases predicted TGC by ~C$77 thousand per year

Once ScottMadden established a mathematically sound quantification of the impact of these site characteristics on TGC, we applied this adjustment method for all sites in the EUCG dataset. However, to be conservative and ensure adjustments were easy to understand, we only performed adjustments for reactor type and unit age, but not for site capacity.[2]

Special Consideration for TGC Adjustments to Plants Undergoing Refurbishment: Our econometric analysis relied on unadjusted (other than for inflation) TGC data. In the case of DNGS, this included costs attributable to unit(s) in Refurbishment. OPG also calculates an adjustment for Refurbishment based on the previously established methodology. To avoid the possibility of making an adjustment for DNGS that is overly influenced by Refurbishment costs, we reduced the DNGS adjustments associated with the econometric model. Specifically, we applied the refurbishment adjustment on a year-by-year basis and proportionally reduced the econometric model adjustments for DNGS by the corresponding annual factors. For example, in 2023 refurbishment costs accounted for 42.9% (~C$684MM / ~C$1,593MM) of total generating costs, so the econometric model technology adjustment ~C$539MM is scaled to the 57.1% (1 – 0.429) of costs not associated with refurbishment in that year. Similarly, the adjustment for average unit age at DNGS is reduced using the same annual

[1] All C$ values in this document are in 2023 dollars, unless otherwise indicated

[2] We do not adjust costs for differences in site capacity, despite this being a significant driver of cost, since this would also have required a complex adjustment to generation. Adjusting for site capacity would follow the logic of other adjustments to cost. In this model, that would mean adjusting costs by ~C$291k per MW per year for each site by a multiple of (median capacity in MW across all sites minus the capacity of the specific site in MW). However, such an adjustment for site capacity would also require that we adjust the MWhs produced by the site in kind. This adjustment would require determination of, for example, the capacity factor to use when determining the change in MWh, further complicating the adjustment and magnifying differences across sites in certain periods. ScottMadden thus felt it more conservative and intuitive to adjust only for technology and age of equipment. The median site capacity in the dataset was 1,819 MW, while PNGS and DNGS have 3,100 MW and 3,512 MW of site capacity, respectively. Higher site capacities are related to higher costs, raising TGC/MWh, but higher site capacities also allow for greater MWh of generation, lowering TGC/MWh. The amount of additional MWh of generation produced depends on how consistently the plant operates and at what percentage of capacity.

Smart. Focused. Done Right.®
scottmadden MANAGEMENT CONSULTANTS
Copyright © 2025 by ScottMadden, Inc. All rights reserved.

proportions. The mechanics of these adjustments are outlined in the figure below. This reduction in the adjustments driven by the econometric model is a change from our prior study. We believe this approach is more conservative (i.e., by reducing the size of the adjustment) given the increased relative magnitude of the adjustment associated with the CANDU reactor type.[3]

Darlington TGC Adjustments Based on Econometric Analysis and Refurbishment Costs

Calculation of Refurbishment Adjustments for Darlington

1. Total Generating Cost (2021-2023) — $ 4,470,192

	Base
2021 TGC	$1,467,101
2022 TGC	$1,409,975
2023 TGC	$1,593,117

2. Apply Refurb Adjustment to TGC — $ 1,549,050

	Base
2021 Adjustment	$279,356
2022 Adjustment	$585,817
2023 Adjustment	$683,877

3. Total Refurb Adjusted Generating Cost (2021-2023) — $ 2,921,142

4. Model Adjustment for Technology — $ (1,006,947)

	Base	Proportion	Inf Factor	Modified Adj
2021 Adjustment	-$539,468	81.0%	90%	-$395,203
2022 Adjustment	-$539,468	58.5%	96%	-$303,854
2023 Adjustment	-$539,468	57.1%	100%	-$307,891

5. Model Adjustment for Age — $ (52,729)

	Base	Proportion	Inf Factor	Age	Modified Adj
2021 Adjustment	-$77.26	81.0%	90%	355	-$20,092
2022 Adjustment	-$77.26	58.5%	96%	367	-$15,970
2023 Adjustment	-$77.26	57.1%	100%	378	-$16,667

6. Model Adjusted Generating Cost (2021-2023) — $ 1,861,466

The result of these adjustments only on TGC/MWh performance for the most recent three-year time period (2021-2023) for PNGS and DNGS is summarized below:

- Pickering's relative performance improves to 33rd out of the 57 sites in the EUCG panel or third quartile, approaching the median
- After accounting for Refurbishment, Darlington's relative performance is 34th out of the 57 sites in the EUCG panel, or third quartile, close to the median.

Nuclear Outages Analysis: ScottMadden sought to normalize energy generation to help isolate the impact of other factors on TGC/MWh, enabling a better comparison of cost performance. We used outage data provided by OPG from EUCG and focused the analysis on planned outages to avoid any potential adjustment for unplanned outages. The approach for this normalization is as follows:

[3] The adjustment for the CANDU reactor type in the prior study was $283,946,104 in 2017 C$. Adjusting for inflation to 2023 C$ would yield an equivalent 2023 adjustment of $343,290,840; however, the adjustment in our econometric model in 2023 C$ is $539,468,076.

Smart. Focused. Done Right.®
scottmadden MANAGEMENT CONSULTANTS
Copyright © 2025 by ScottMadden, Inc. All rights reserved.

1. Calculate the 18-year average planned outages as a percentage of time online for each plant from 2006-2023
2. Identify the plant with the lowest average percentage of planned outages
3. Using the lowest average planned outage percentage as the benchmark, we adjust MWh for each plant/year to match the benchmark rate, adding MWh when outages are longer and subtracting when outages are shorter

This method was applied to all plants in the EUCG dataset to normalize MWh generation based on a common standard for planned outage duration. The result of these adjustments to TGC and MWh on TGC/MWh performance for the most recent three-year time period (2021-2023) for PNGS and DNGS is summarized below:

- Pickering's relative performance improves further to 28th out of the 57 sites in the EUCG panel in the second quartile
- After accounting for Refurbishment, Darlington's relative performance remains 34th out of the 57 sites in the EUCG panel and remains third quartile

4. ADJUSTING FOR INFLATION

Before performing cost analysis, ScottMadden adjusted dollar values for inflation to ensure that we could establish mathematical relationships that persisted across the eighteen-year dataset. Specifically, we adjusted Total Generating Costs (TGC) from 2006 to 2023 for inflation using the Gross Domestic Product Implicit Price Index Final Domestic Demand (GDP-IPI FDD) in Canada from Statistics Canada, converting all TGC values to 2023 dollars. This index was used in the prior study, and it is commonly used by the OEB for rate-setting matters.[4]

5. ECONOMETRIC ANALYSIS

About The Data

The data used for this analysis contains:

- 57 nuclear sites and 1026 total data points (one / site / year)
- Three reactor types:
  - PWRs – 34 sites
  - BWRs – 20 sites
  - CANDUs – 3 sites
- Nuclear sites with a median capacity of 1,819 MW and median unit capacity of 956 MW
- Primarily sites with either one or two units (51 of 57), but:
  - Three sites (two PWRs and one BWR) with three units
  - One site with four units (CANDU – Darlington)
  - One site with six units (CANDU – Pickering)
  - One site with eight units (CANDU – Bruce)

[4] GDP-IPI FDD is an inflation factor that is commonly-used and frequently referenced by the OEB in multiple documents.

Smart. Focused. Done Right.®
Copyright © 2025 by ScottMadden, Inc. All rights reserved.
scottmadden MANAGEMENT CONSULTANTS

It is worth noting that there are three CANDU plants (Bruce, Pickering, and Darlington) in the EUCG data and the technology differs in important ways from the PWR and BWR plants. For example, CANDU plants

- Have greater numbers of smaller capacity units but generally larger total site capacities
- Have different online and outage maintenance requirements but can be refueled online
- Operate in Canada and are subject to a different regulatory and market environment than PWRs and BWRs operating in the US

Predictive Model for Total Generating Costs

ScottMadden used the data described above to analyze how certain site characteristics influence nuclear site costs. We focused the analysis on site characteristics that are outside the operational control of management, and are likely to have a meaningful influence on costs:

- Reactor type – CANDU, PWR, or BWR
- Site capacity – total site capacity across all operating units (MW)
- Number of units – total number of operating units at the site
- Unit size – average capacity of the units at the site (MW)
- Unit age – average age of the units at the site (months)

Specifically, ScottMadden used Multiple Linear Regression (MLR) to quantify the relationships between various combinations of the above site characteristics (the independent variables) and site costs (TGC). Consistent with the previous study, *OPG Nuclear Cost Performance Benchmarking – A Study of Factors Impacting TGC / MWh Performance with Normalizing Adjustments to Facilitate Closer Comparison*, we were able to develop a powerful predictive model, and this model explains ~77% of the variability in TGC with reactor type, site capacity, and average unit age (months). The model indicates:

- Relative to BWR technology, CANDU and PWR technology increases TGC
- Greater site capacity increases TGC
- Higher average unit age increases TGC

The specific, mathematical model for site costs in thousands of Canadian dollars (C$k) is: $f(TGC\ per\ year) = (539{,}468 * (CANDU)) + (17{,}310 * (PWR)) + (291 * (site\ capacity)) + (77 * (unit\ age)) + 134{,}235$. Each coefficient in the formula is the estimated change in TGC corresponding to one unit change in that associated variable when all other variables are held constant. Specifically:

- If the CANDU value is 1, indicating it is a CANDU reactor, predicted TGC would increase by C$539,468k (2023); If 0, it will remain unchanged
- If the PWR value is 1, indicating it is a PWR reactor, predicted TGC would increase by C$17,310k (2023); If 0, it will remain unchanged
- For each MW of site capacity, predicted TGC would increase by C$291k (2023)
- For each month of average unit age, predicted TGC would increase by C$77k (2023)

Put more simply, with all other variables held constant:

Smart. Focused. Done Right.®
Copyright © 2025 by ScottMadden, Inc. All rights reserved.
scottmadden MANAGEMENT CONSULTANTS

- CANDU technology increases predicted TGC by just over ~C$539 million per year relative to BWR technology
- PWR technology increases predicted TGC by just over ~C$17 million per year relative to BWR technology
- Each MW of site capacity increases predicted TGC by ~C$291 thousand per year
- Each month of average unit age increases predicted TGC by ~C$77 thousand per year

Once we established a mathematically-sound quantification of the impact these site characteristics have on TGC, we adjusted for all sites in the EUCG data set to account for these factors. However, we only perform adjustments for reactor type and unit age, using the process below.[5]

- Reactor Type – if the reactor is a:
  - BWR, we assign no adjustment value
  - PWR, we assign a decrease adjustment value of ~(C$17M per year)
  - CANDU, we assign a decrease adjustment value of ~(C$539M per year)
- We assign a decrease adjustment value equal to the actual number of unit-age months multiplied by ~C$77k
- Inflation – For any year other than 2023, we use the appropriate GDP-IPI FDD value to inflate or deflate the cost adjustment to a value for that specific year

We do not adjust costs for differences in site capacity, despite this being a significant driver of cost, since this would also have required a complex adjustment to generation.[6]

To adjust cost for a given year, we use the GDP-IPI FDD to modify the adjustment value to the appropriate year (e.g., to adjust TGC in 2021, we take the TGC impact from the model above, which is in 2023 dollars, modify it to 2021 dollars, and adjust the value for 2021).

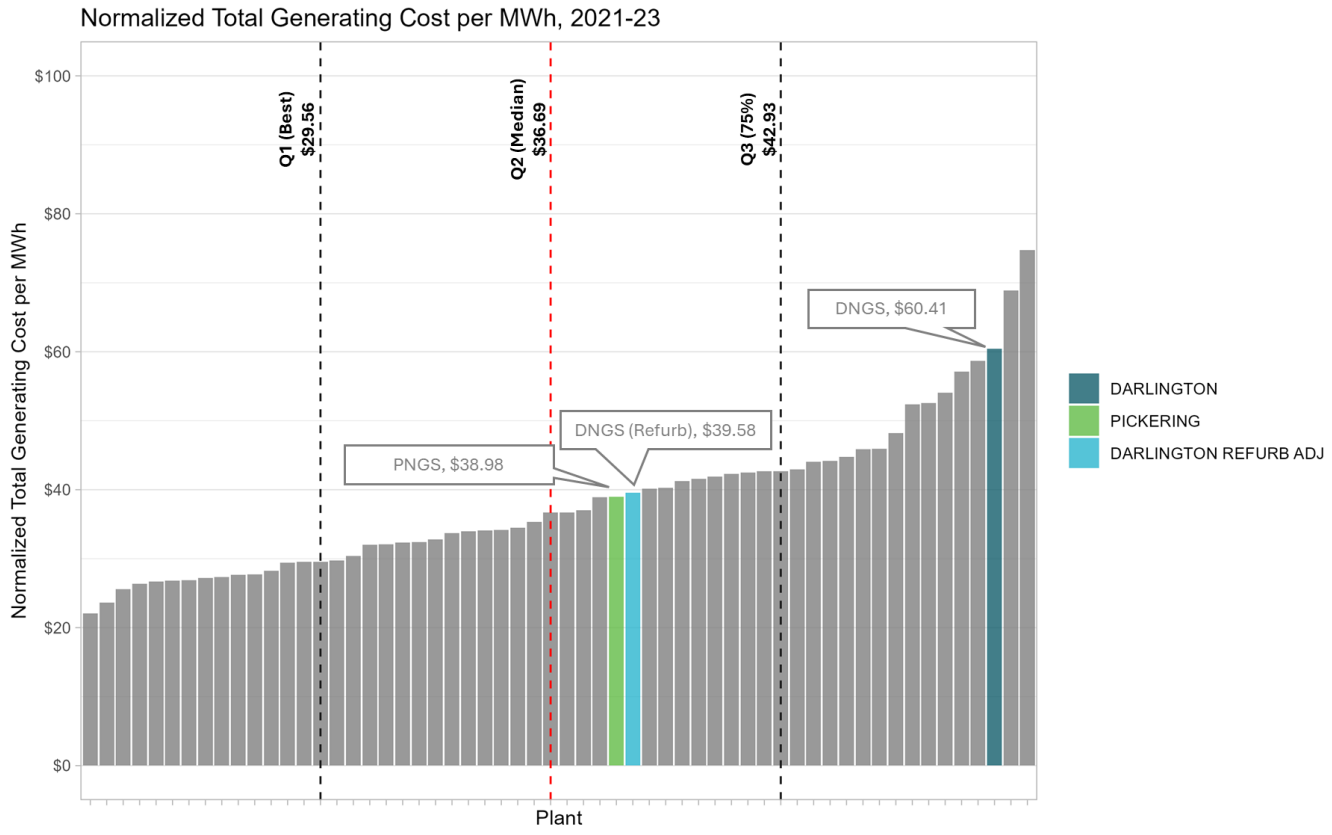
Then, to account for the refurbishment at DNGS, we converted and removed C$279,356k in 2021 and C$585,817k in 2022, and removed C$683,877k in 2023. To avoid double-counting the adjustment values, that is to avoid applying full adjustment amounts for a partial cost due to the refurbishment, we calculated the total refurbishment adjustment as a proportion of the total generating costs for each year. We then applied the proportion not attributable to refurbishment for each year to the economic adjustments outlined above for DNGS.

Finally, we divided the adjusted TGC by actual MWh of generation to get the updated comparison shown in the chart below.

[5] Precise adjustment values were C$(-539,468,076) / yr for CANDU, C$(17,309,809) / yr for PWR and C$(-77,257) / month of unit age
[6] See supra note 2

Smart. Focused. Done Right.®
Copyright © 2025 by ScottMadden, Inc. All rights reserved.
scottmadden MANAGEMENT CONSULTANTS

TGC/MWh performance 2021-'23 for EUCG Panel with All Sites Adjusted Based on Econometric Analysis and DNGS Also Adjusted for Refurbishment



As a result of these adjustments:

- Pickering's relative performance improves to 33rd out of the 57 sites in the EUCG panel or third quartile, approaching the median
- Darlington's relative performance, without accounting for Refurbishment, improves to 55th out of the 57 sites in the EUCG panel. After accounting for Refurbishment, Darlington's relative performance is 34th out of the 57 sites in the EUCG panel, in the third quartile.

6. NUCLEAR OUTAGES ANALYSIS

All reactor types have planned maintenance outages on either 18, 24, 30, or 36-month cycles. Planned maintenance outages for PWRs and BWRs are incorporated into refueling cycles and occur every 18 or 24 months. Planned maintenance outages for CANDU reactors occur every 24, 30, or 36 months. Work to significantly extend the operating life of a plant (life-extension activities) is also approached differently across technologies. For PWR and BWR plants, it is more common to complete this work as part of planned refueling and maintenance outages over a series of multiple outages to minimize time in outage. The scope for this work also differs from one plant to the next due to differences in plant design, market construct, and other factors. Comparable life-extension activities for CANDU plants largely occur during long-duration refurbishment outages where multiple, major plant components are replaced, though some related work can also be incorporated into more frequently recurring planned maintenance outages.

Smart. Focused. Done Right.®
scottmadden MANAGEMENT CONSULTANTS
Copyright © 2025 by ScottMadden, Inc. All rights reserved.

Due to the higher variability and lower frequency of life-extension activities that occur across reactor technologies and operators, ScottMadden focused only on quantifying and adjusting for the impact of recurring, planned outages on power generation. We analyzed an extensive data set to arrive at an adjustment that normalizes across plants for planned outage durations, as described below.

About The Data

ScottMadden analyzed EUCG data to account for variations in planned outages, which can significantly impact a plant's energy production (MWh). In this study, ScottMadden analyzed plant level data over an eighteen-year period (2006–2023) to understand the impact of planned outages on MWh over a sustained period. The dataset used for this analysis includes:

- Outage Hours – The number of planned outage hours reported for each plant in each year
- Plant Capacity – The full-load plant capacity reported for each unit in each year, reported in MWe

MWh Adjustment Calculation to Account for Planned Outages

ScottMadden conducted an analysis to normalize MWh generation across the dataset by adjusting for planned outage hours. This involved calculating the expected generation by adding MWh when outages are longer and subtracting when outages are shorter than the benchmark, effectively estimating each plant's potential output if it had experienced benchmarked industry outage rates. This approach can be summarized as follows:

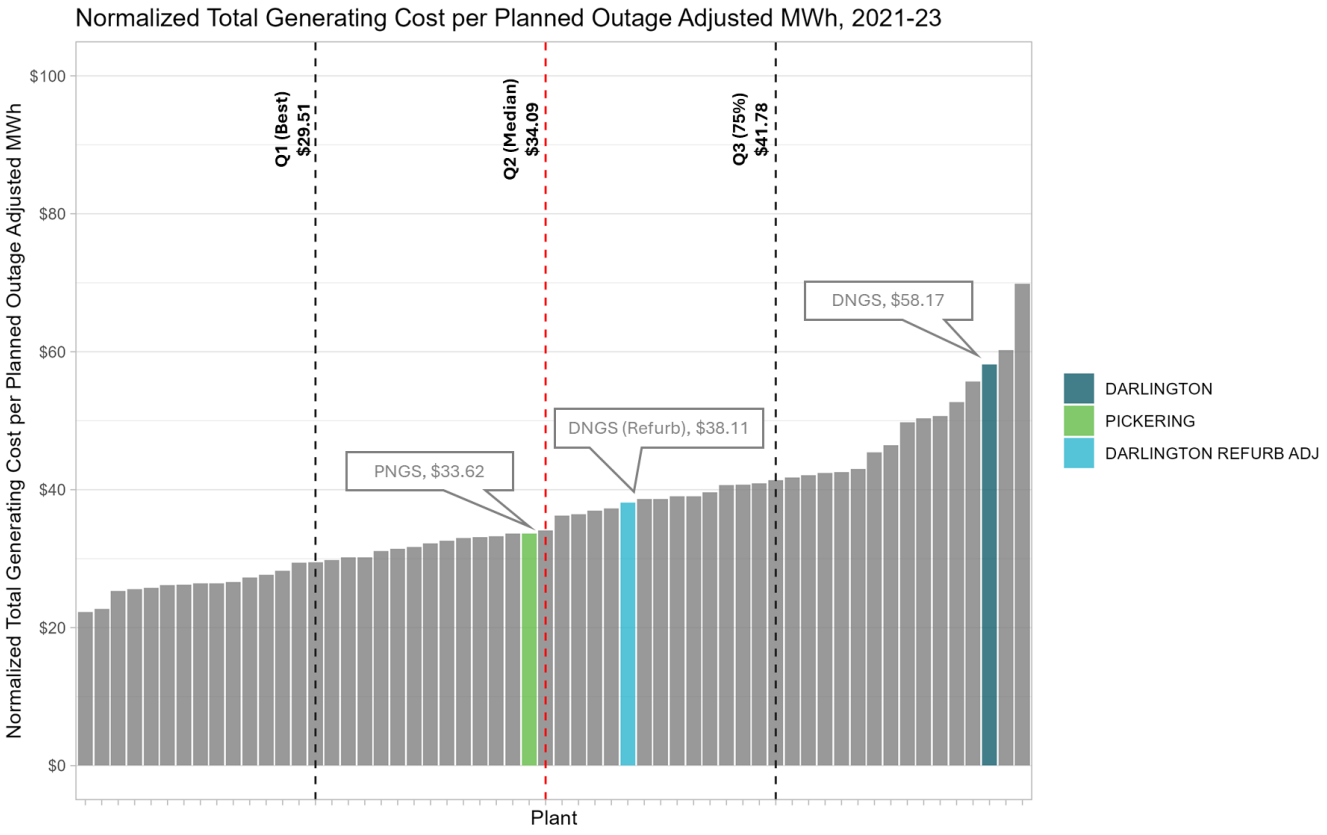
1. **Calculate Average Planned Outage Percentage** (Each Plant From 2006-2023)
   - Total Outage Hours ÷ Number of Units ÷ 8760 (hours in a year)
2. **Identify the Most Efficient Plant** (i.e., Lowest Average Planned Outage % From 2006-2023)
   - Lowest planned outage % serves as benchmark for optimal efficiency
   - This value may be used on a go-forward basis
3. **Determine Adjustment Factor** (Per Plant, Per Year)
   - Plant Planned Outage % - Benchmark Planned Outage %
4. **Calculate Planned Outage Difference** (i.e., Additional or fewer MWh to match benchmark)
   - Adjustment Factor × Reference Energy Generation (Capacity x 8760 hours per year)
5. **Compute Adjusted Generation** (i.e., Adjusted total MWh for benchmark planned outage)
   - Actual Generation + Planned Outage Difference

ScottMadden adjusted the MWh values for all 57 sites from 2006-2023, as described above, to account for the impact of differences in planned outage durations across technology types and outage frequencies. In addition, the Darlington Refurbishment accounted for significant time in planned outage, but this outage time was captured in the reported unit capacity each year, so no further capacity adjustments were needed.

The chart below shows the adjusted TGC values from the econometric analysis divided by the adjusted MWh values from the nuclear outage analysis.

Smart. Focused. Done Right.®
scottmadden MANAGEMENT CONSULTANTS
Copyright © 2025 by ScottMadden, Inc. All rights reserved.

TGC/MWh performance 2021-'23 for EUCG Panel with All Sites Adjusted Based on Econometric Analysis and Outage Analysis and DNGS Also Adjusted for Refurbishment



As a result of these adjustments:

- Pickering's relative performance improves further to 28th out of the 57 sites in the EUCG panel to the second quartile
- Darlington's relative performance without accounting for Refurbishment is 55th out of the 57 sites in the EUCG panel; after accounting for Refurbishment, Darlington's relative performance remains 34th out of the 57 sites in the EUCG panel and remains third quartile

Smart. Focused. Done Right.®
Copyright © 2025 by ScottMadden, Inc. All rights reserved.
scottmadden MANAGEMENT CONSULTANTS

INDEAVOR

November 2025

Ontario Power Generation (OPG) - Nuclear Staff Benchmarking

Report Contents

- Executive Summary
- Background and Data Methodology
  - Methodology Overview – OPG
  - Methodology Overview – Benchmark
  - Methodology Overview – Exclusions
- PWR Data Normalization Process
- Benchmark Data

INDEAVOR

Executive Summary

INDEAVOR

Executive Summary

- OPG engaged Indeavor, a company with workforce analytics expertise in the energy sector, to conduct a nuclear staffing benchmark.
- The benchmark methodology began with staffing data from 2-unit United States (U.S.) Pressurized Water Reactor (PWR) sites, selected for their technical comparability to Canada Deuterium Uranium (CANDU) reactors. This data was scaled to reflect operations at OPG's fleet. Non-comparable functions, such as Purchased Services and CANDU-specific activities, were excluded due to the lack of detailed data from benchmarked peers.
- OPG's 2024 staffing headcount is 4,458, which is 9.3% below the benchmark of 4,913.
- Operations and Facilities remain the largest variance categories, consistent with prior benchmarks: −206 in Operations and +171 in Facilities.

INDEAVOR

Data Methodology

INDEAVOR

Methodology Overview – OPG

- OPG reviewed EUCG (Electric Utility Cost Group) staffing data for 2024, and allocated staffing headcount to corresponding Indeavor functions.
  - Indeavor function allocations were determined using a mix of EUCG account mappings, department level information, job titles, business unit classification.
  - To establish a consistent benchmark, any data that was determined to not be comparative was excluded from the analysis.*
- These functional headcount allocations were reviewed and validated by Indeavor for use to compare against the benchmark.

**Exclusion list and rationale provided on slide 8*

INDEAVOR

Methodology Overview – Benchmark

- Surveys were sent out to comparable 2-unit PWR (Pressurized Water Reactor) sites who agreed to participate in the study; sites from across the United States self-reported their staffing data and submitted it to Indeavor for analysis.
- The survey data was normalized to ensure the benchmark was comparative with OPG data.*
- The normalized data was then rounded to the nearest whole number to eliminate any fractional headcounts.

Benchmark normalization methodology described in the next section.

INDEAVOR

Benchmarking Methodology – Exclusions

To ensure that both OPG staffing and Benchmark staffing numbers were in alignment and reflect an accurate headcount comparison, some data sets were excluded.

Function	PWR Benchmark	OPG	Rationale
Capital Staffing	Excluded	Excluded	Staffing tied to capital projects/one-time initiatives/refurbishments was not included because it is not representative of the operations.
Outage Execution Activities	Not provided	Excluded	Not representative of the operations.
Nuclear Waste and Decommissioning	Not provided	Excluded	Not applicable for PWR sites.
Security and Security Support	Excluded	Excluded	Excluded to remain compliant with OPG security policy.
Purchased Services (Managed Tasks)	Not provided	Excluded	Excluded due to the lack of detailed data from benchmarked peers.*
CANDU Specific Activities	Not applicable	Excluded	Full detail discussed within PWR normalization section of report.

Excluding Purchased Services is a methodological change from previous studies. Without the ability to interview benchmark sites and fully analyze PWR contract staffing, the data was excluded from both data sets.

INDEAVOR

PWR Data Normalization

INDEAVOR

PWR Data Survey Participants

NEXTera ENERGY	DUKE ENERGY	entergy	TVA
3 Sites Provided	**2 Sites Provided**	**1 Site Provided**	**3 Sites Provided**
EUCG Account Level	***Indeavor Functional Level***	***Indeavor Functional Level***	***EUCG Account Level***

- To generate the comparable benchmark, surveys were sent to PWR nuclear operating centers within the US to request their current staffing levels. Sites self reported staffing data in one of 2 formats.
  - EUCG Account Level Data [A]
  - Indeavor Function Data [B]

- PWR Staffing Survey data was then normalized to be able to provide an accurate comparison with OPG staffing.

A, B – Full list in Appendix

INDEAVOR

PWR Data Normalization

Once the survey data was received, it was normalized as follows:

1. Data was normalized as needed to ensure it was consistent across participants
   - Data provided at the EUCG Account level was normalized using historical ratios to split the EUCG account groups into the respective Indeavor functions. [C]
   - Data provided at the Indeavor Functional level was left at the level provided.
   - With the survey data at the same level, each function was averaged across the data set to create the baseline data for the benchmark.
2. To establish a benchmark, any data that was not consistent between PWR and OPG data sets was excluded from the analysis.*
3. Included survey data was then adjusted to account for process and technological differences between CANDU and PWR. The listed functions are unique to CANDU reactor designs and have no comparable equivalent with PWR reactor designs:
   - Fuel Handling
   - Heavy Water Handling
   - Spent Fuel/Radwaste
   - Tritium Removal Facility
   - Feeder and Fuel Channel Support
4. The data was then adjusted to account for the difference between 35 hour and 40 hour work weeks. This adjustment accounts for any staffing differences due to the yearly variance of the same position worked at 40 hours in the U.S. and 35 hours in Canada.
5. To scale staffing for reactor count differences between 2-Unit and 4-Unit sites, the work week normalized staffing data was scaled to account for 2 additional reactor units at Pickering B and Darlington. Data was also adjusted to include staffing for cross-tied operations for Units 2 & 3 at Pickering A.
6. The normalized fractional headcounts were rounded up to the nearest whole number, as less than one person cannot be staffed.

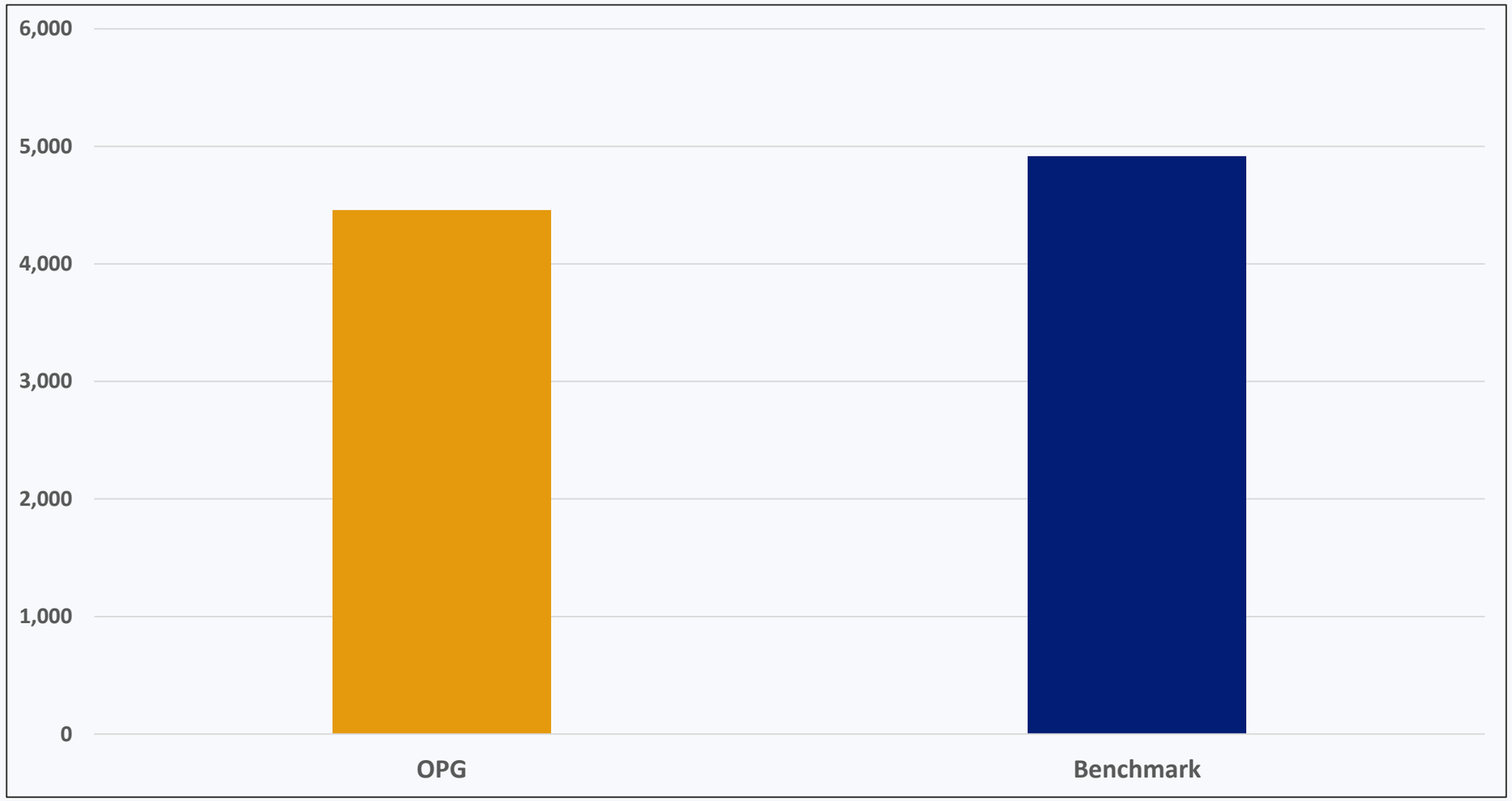
C – Full list in Appendix
** Exclusion list provided on slide 8*

INDEAVOR

Benchmark Data

INDEAVOR

Site Headcount – Total



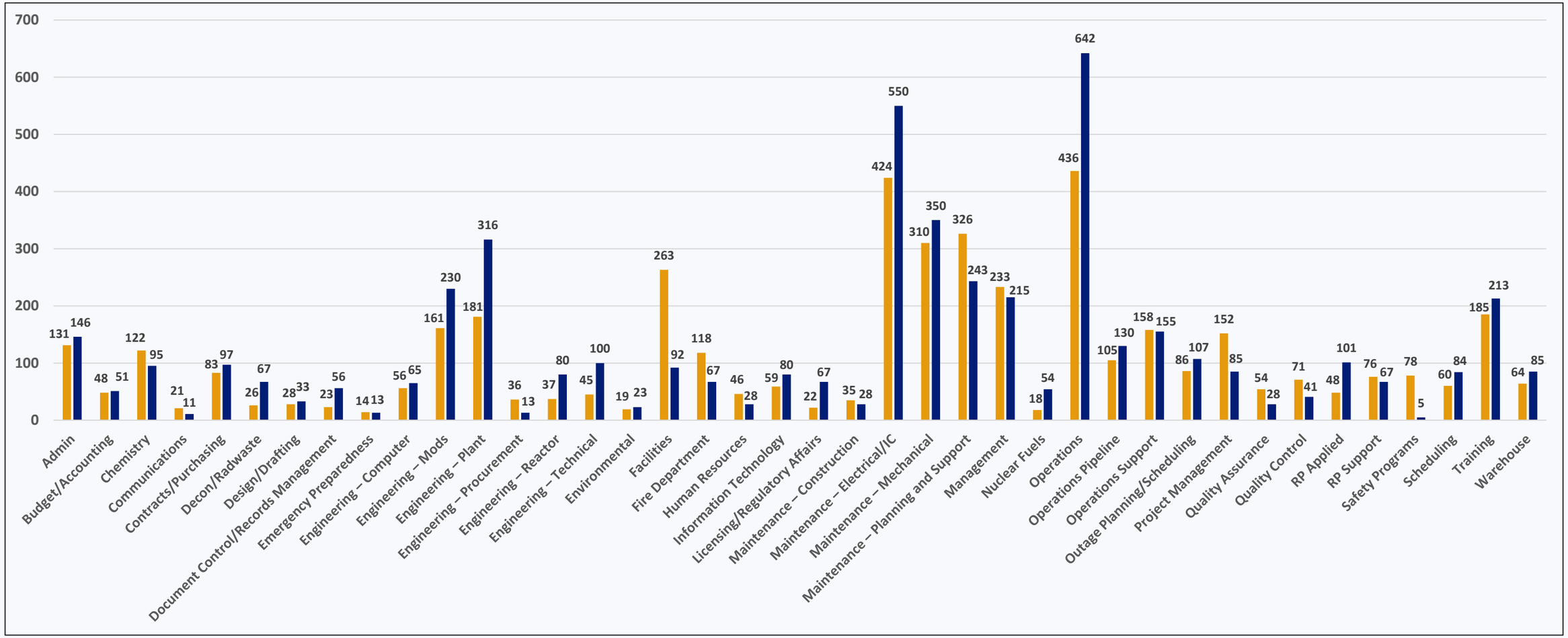
OPG Headcount is 455 (-9.3%) below benchmark

OPG

Benchmark

INDEAVOR

Site Headcount – Indeavor Functions



OPG

Benchmark

INDEAVOR

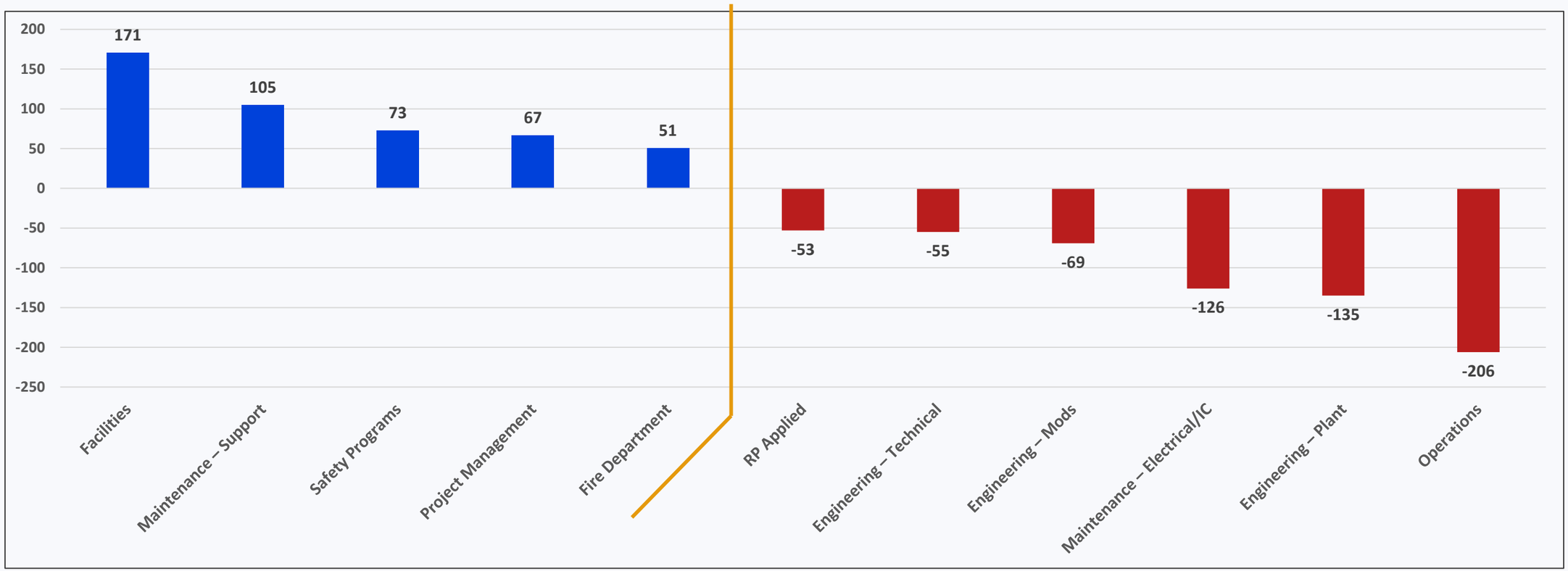
Variance Analysis



INDEAVOR

Headcount Variance by Function – Highlights

5 Functions were above *the benchmark by more than 50 headcount;*
6 Functions were below *the benchmark by more than 50 headcount.*



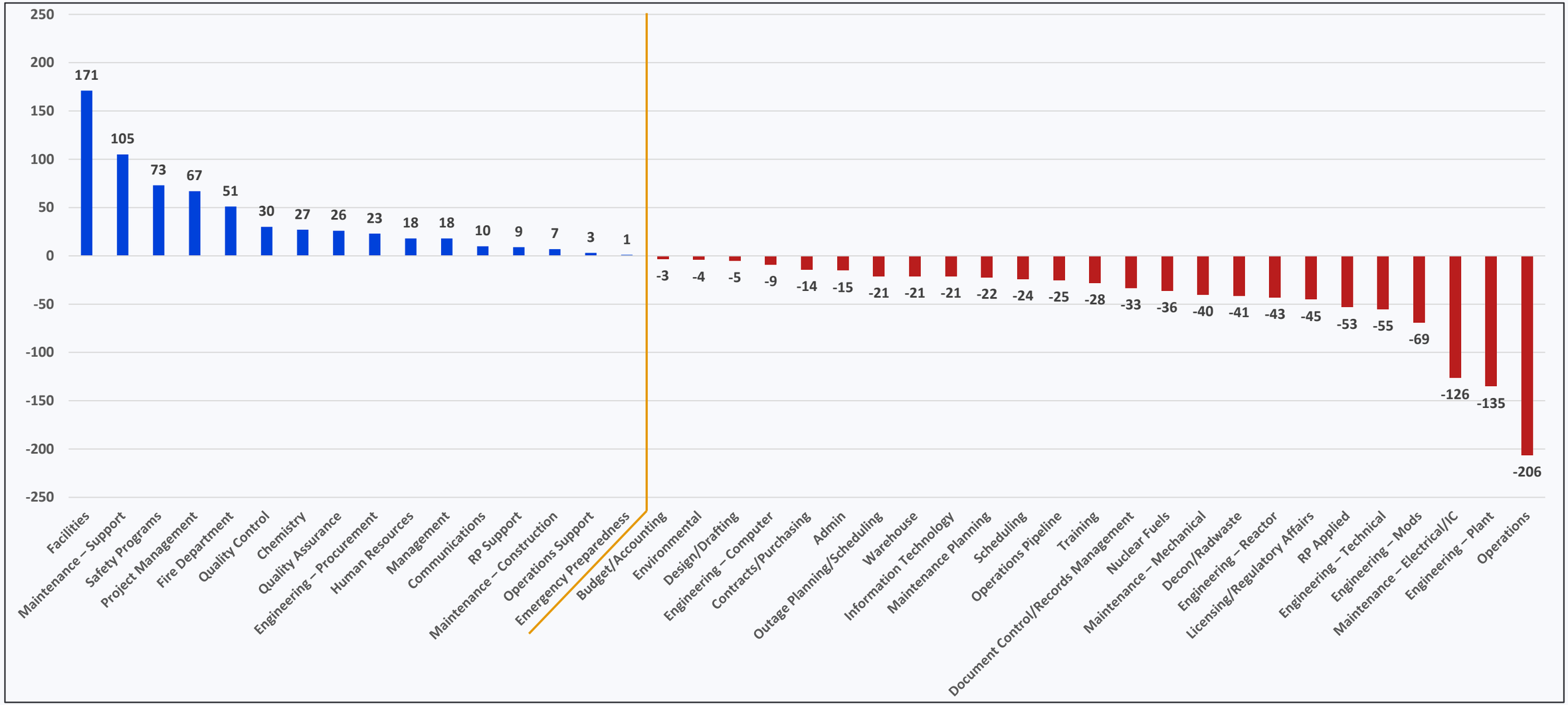
Above Benchmark

Below Benchmark

The 11 functions shown represent 64% of the total headcount variance across all functions.

INDEAVOR

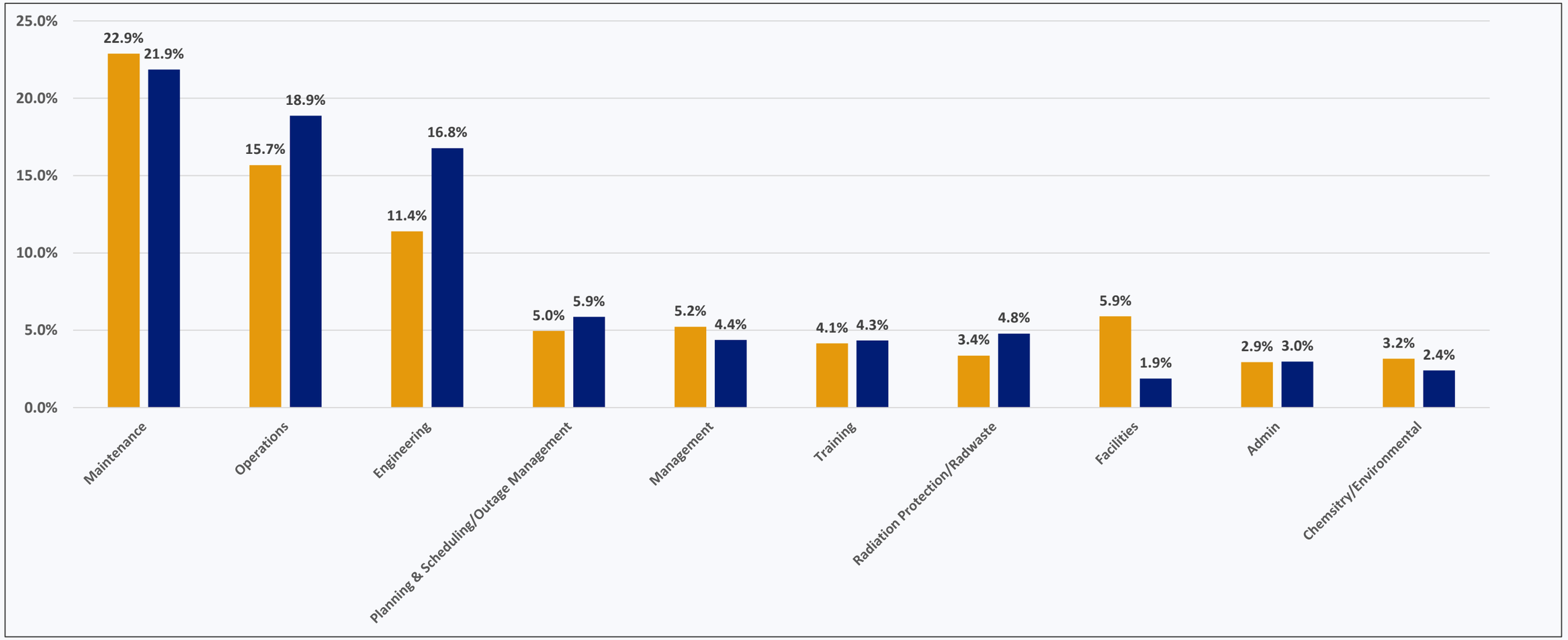
Headcount Variance by Function



Above Benchmark Below Benchmark

INDEAVOR

Overall EUCG Account % of Total Staffing



OPG

Benchmark

**Only the top 10 EUCG accounts are shown for visualization purposes. Ranked by the average of OPG and benchmark % of total staffing.*

Average breakdown of functions not shown is 1.3%

INDEAVOR

Appendix

INDEAVOR

Appendix – A

EUCG Code	EUCG Account
AD01*	Admin
ENGTOT	Engineering
LP01	Security
LP03	Corrective Action Program and OE
LP02	Quality Assurance/Quality Control
LP04	Safety and Health
LP05	Licensing
LP06	Emergency Preparedness
LP07	Dedicated Fire Responders
MS01	Materials Management & Warehousing
MS02	Contracts & Purchasing
MS03	Procurement Engineering
NFTOT	Fuel Management
OP01	Operations
OP02	Chemistry/Environmental
OP03	Radiation Protection/Radwaste
SS01	Information Technology
SS02	Business Services
SS03	Records Management and Procedures
SS04	Human Resources
SS05	Housekeeping and Facilities Management
SS06	Communications and Community Relations
SS07	Nuclear Officers, Executives, Management Assistance and Industry Associations
TRTOT	Training - Develop and Conduct
WM01	Planning & Scheduling/Outage Management
WM02	Maintenance
WM05*	Project Management

**AD01 and WM05 are not official EUCG account codes, they are used only for data analysis purposes*

INDEAVOR

Appendix – B

Indeavor Function	
Admin	Maintenance – Construction
Budget/Accounting	Maintenance – Electrical/IC
Chemistry	Maintenance – Mechanical
Communications	Maintenance – Planning and Support
Contracts/Purchasing	Management
Decon/Radwaste	Nuclear Fuels
Design/Drafting	Operations
Document Control/Records Management	Operations Pipeline
Emergency Preparedness	Operations Support
Engineering – Computer	Outage Planning/Scheduling
Engineering – Mods	Project Management
Engineering – Plant	Quality Assurance
Engineering – Procurement	Quality Control
Engineering – Reactor	RP Applied
Engineering – Technical	RP Support
Environmental	Safety Programs
Facilities	Scheduling
Fire Department	Training
Human Resources	Warehouse
Information Technology	
Licensing/Regulatory Affairs	

INDEAVOR

Appendix – C

EUCG Function	Indeavor Function	FTE Ratio
Admin	Admin	1.00
Engineering	Design/Drafting	0.03
Engineering	Engineering – Computer	0.09
Engineering	Engineering – Mods	0.31
Engineering	Engineering – Plant	0.39
Engineering	Engineering – Reactor	0.09
Engineering	Engineering – Technical	0.10
Security	Security Support	1.00
Corrective Action Program and OE	Corrective Action Program and OE	1.00
Quality Assurance/Quality Control	Quality Assurance	0.37
Quality Assurance/Quality Control	Quality Control	0.63
Safety and Health	Emergency Preparedness	0.23
Safety and Health	Safety Programs	0.77
Licensing	Licensing/Regulatory Affairs	1.00
Dedicated Fire Responders	Fire Department	1.00
Materials Management & Warehousing	Warehouse	1.00
Contracts & Purchasing	Contracts/Purchasing	1.00
Procurement Engineering	Engineering – Procurement	1.00
Fuel Management	Nuclear Fuels	1.00
Operations	Operations	0.61
Operations	Operations Support	0.19
Operations	Operations Pipeline	0.20
Chemistry/Environmental	Chemistry	0.89
Chemistry/Environmental	Environmental	0.11
Radiation Protection/Radwaste	Decon/Radwaste	0.21
Radiation Protection/Radwaste	RP Applied	0.34
Radiation Protection/Radwaste	RP Support	0.44
Business Services	Budget/Accounting	1.00
Records Management and Procedures	Document Control/Records Management	1.00
Human Resources	Human Resources	1.00
Housekeeping and Facilities Management	Facilities	1.00
Communications and Community Relations	Communications	1.00
Nuclear Officers, Executives, Management Assistance and Industry Associations	Management	0.98
Nuclear Officers, Executives, Management Assistance and Industry Associations	Management Support	0.02
Training - Develop and Conduct	Training	1.00
Planning & Scheduling/Outage Management	Maintenance Planning	0.34
Planning & Scheduling/Outage Management	Outage Planning/Scheduling	0.37
Planning & Scheduling/Outage Management	Scheduling	0.29
Maintenance	Maintenance – Construction	0.02
Maintenance	Maintenance – Electrical/IC	0.46
Maintenance	Maintenance – Mechanical	0.33
Maintenance	Maintenance – Support	0.19
Project Management	Project Management	1.00

INDEAVOR

TORYS LLP

79 Wellington St. W., 30th Floor
Box 270, TD South Tower
Toronto, Ontario M5K 1N2 Canada
P. 416.865.0040 | F. 416.865.7380
www.torys.com

Charles Keizer
ckeizer@torys.com
P. 416-865-7510

BY EMAIL

CONFIDENTIAL — PRIVILEGED

February 10, 2025

Scott Madden Management Consultants
3495 Piedmont Road, NE
Building Ten, Suite 805
Atlanta, GA 30305-8800

Attention: Marc Miller, Partner

Re: Retainer Letter Agreement – Ontario Power Generation – Nuclear Benchmarking and Business Planning Processes

Dear Mr. Miller,

We represent Ontario Power Generation ("OPG") in connection with payment amount and other proceedings (collectively, "Proceedings") before the Ontario Energy Board (the "Board").

We confirm that, on behalf of and to assist us in providing legal advice to OPG in connection with certain Proceedings, Torys LLP ("Torys") has engaged ScottMadden (the "Consultant" or "you") effective as of the date hereof ("Effective Date") to provide consulting services as described in this letter. By signing back a copy of this letter, the Consultant agrees that this letter contains the agreed-upon terms and conditions of its retainer with Torys effective on the Effective Date, subject to amendment by written agreement between the parties (the "Retainer Agreement").

1. **No Conflict**

The Consultant does not have any conflict of interest or other constraints on its ability to provide expert advice in connection with this Retainer Agreement. You confirm that you are free to provide your services to Torys in connection with Torys' representation of OPG in the Proceedings. You agree that during this engagement you will not provide, directly or indirectly, any services to any other party in connection with the matters at issue in the Proceedings.

2. Consultant Expertise

The Consultant has been selected to provide consulting services to Torys in connection with the Proceedings, namely by undertaking an independent review of nuclear cost performance benchmarking. The sponsors of the work of the Consultant and the persons who have the relevant expertise will be Marc Miller, one of your consultants as he determines, and staff from your research organization as needed (the "Sponsors").

3. Scope of Services and Work Product

The Consultant will:

(a) Analyze OPG's nuclear benchmarking by (i) reviewing key performance metrics used for comparison; (ii) reviewing companies included in the peer panels; (iii) preparing supporting analysis and displays; (iv) reviewing the use of benchmarks in the business planning cycle; and (v) reviewing and comparing OPG's current 2024 benchmarking report to the Consultant's most recent assessment of the same report and the Consultant's 2021 improvement recommendations (the "Study");

(b) if requested by Torys, produce a report detailing the Study's methodology, analysis performed, and the ensuing findings and recommendations (the "Report"), which may be filed with the Board in the Proceedings; and

(c) if requested by Torys, provide support during the hearing of the Proceedings and testify before the Board in the Proceedings, in connection with the scope of the services provided hereunder ("Application Support" and, together with the Study and the Report, the "Services").

Assuming a February 10, 2025 start date, the Study will be completed by February 24, 2025, and the Report, if requested, will be completed by March 31, 2025

4. Fees and Invoices

The Consultant acknowledges that the price for the Consultant to perform the Study and to deliver a written Report, if requested, shall not exceed [redacted] (not including HST) based on actual time spent by the team working to provide the Services, plus travel and living expenses which are billed as incurred with no mark-up, and administrative support costs (billed at 1% of professional fees), without prior written approval from Torys.

The Consultant's fee for its Services (including Application Support, if requested by Torys) shall be charged at the following hourly rates:

Partner Director Manager Director of Research Clean Tech Manager Senior Associate	[redacted]	Associate Benchmarking Manager Senior Analyst Survey Manager Analyst/Research Analyst	[redacted]

Any disbursements for additional incidentals incurred by the Consultant in relation to this Retainer Agreement must be pre-approved by Torys or OPG in writing. Torys reserves the right to deduct any applicable non-resident withholding taxes from any amounts owing to the Consultant under this Retainer Agreement and remit such amounts to the applicable taxation authority.

The Consultant shall direct all invoices relating to Services performed by it under this Retainer Agreement to Torys, to the attention of:

Charles Keizer
Torys LLP
79 Wellington St. W., 30th Floor
Box 270, TD South Tower
Toronto, Ontario M5K 1N2
ckeizer@torys.com

with a copy to OPG, to the attention of:

Peter Cuff
Assistant General Counsel, Law Division
Ontario Power Generation
700 University Avenue, H18 E27.1
Toronto, ON M5G 1X6
peter.cuff@opg.com

Invoices shall include at least the following information:

(a) identification of the billing period to which the account relates;

(b) an itemized summary of the services that have been undertaken by you, including a brief description thereof, the date on which the services were rendered, the time spent on the services, the individual who performed the services, and the billing rate of such individual; and

(c) an itemized and brief description of all expenses incurred during the billing period, with copies of supporting invoices.

Torys will send your invoice to OPG for its approval and if OPG does not approve your invoice, Torys will send it back to you for revision. Once OPG approves the invoice, Torys will submit the invoice to OPG's payment system. OPG pays invoices once per month (on the 25th of each month) and, for payment to be made on the 25th of a particular month, the invoice must have been approved in OPG's payment system by the 25th of the prior month. Once Torys receives the payment from OPG, Torys will send payment to you.

5. **Confidentiality**

All work performed by the Consultant in connection with this Retainer Agreement, including all findings, opinions and conclusions the Consultant reaches in relation to this Retainer Agreement, and any communications relating thereto, are strictly privileged and confidential and shall not be disclosed to any other person or party without the prior written consent of Torys or OPG. The Consultant agrees to designate all written communications and material accordingly. The Consultant further agrees to notify Torys in the event that the Consultant receives a request to

disclose information relating to this matter, and agrees to cooperate with Torys, to the fullest extent permitted by law, to prevent or limit the disclosure of such material or otherwise preserve the privileged and confidential status of such material.

The Consultant agrees to hold in confidence: (a) all information provided to the Consultant, and (b) the Consultant's opinions to Torys and to OPG as they relate to the information, whether the information or opinions are documentary or oral (collectively, the "Confidential Information"). The Consultant will not disclose the Confidential Information to any person unless Torys or OPG authorizes you in writing to do so. All documents given to the Consultant in connection with this Retainer Agreement remain the property of Torys or of OPG, and are held in trust by the Consultant as agent. The Consultant agrees to return these documents on request. During the engagement, the Confidential Information shall be segregated from other OPG data (including on electronic information systems) and shall not be accessible to individuals other than the Consultant, Torys, and OPG employees requiring access).

The Consultant will not refer to Torys or to OPG, directly or indirectly, in connection with the promotion of its services, without obtaining the prior written consent of Torys or OPG, as the case may be.

6. Intellectual Property

Nothing in this Retainer Agreement shall be deemed to transfer, license, assign, permit the use of, or otherwise convey an interest in whole or in part to the Consultant of any intellectual property belonging to OPG or any of its representatives or any third party whose intellectual property is in OPG's custody or control, and the use by the Consultant of any such intellectual property shall be subject to the prior written approval of OPG.

Torys and OPG shall at all times have full rights and title to all works prepared, generated or created by the Consultant pursuant to this Retainer Agreement, including without limitation any reports, presentations, status updates, or other documents created by the Consultant, and any related works, modifications or additions thereto (the "Work Product"), and may at all times take possession of or use any completed or partially completed Work Product, notwithstanding any provision, express or implied, to the contrary. Without limiting the generality of the foregoing, OPG shall own all intellectual property rights in all Work Product, and the Consultant hereby waives and assigns to OPG any such rights, and agrees to give OPG and its representatives all assistance as may be reasonably required to perfect such rights including, without limitation, obtaining waiver of moral rights from any of the Consultant's employees, partners or other representatives.

Anything contained in this agreement to the contrary notwithstanding, nothing in this Retainer Agreement shall prevent Consultant from utilizing any general know-how, ideas, techniques, concepts, methods, processes, or other knowledge applied in performing the Services, on behalf of itself or its future customers. Consultant may (i) perform the same or similar services for others, and (ii) retain one copy of deliverables produced in connection with the Services hereunder for the sole purpose of documenting the conduct of its work and its exercise of due professional care in connection with the Services, provided that any of OPG's confidential information is treated in accordance with the confidentiality requirements of this Retainer Agreement.

7. Controlled Nuclear Information

The Consultant has been made aware of certain Canadian federal requirements relating to the import and export of controlled nuclear information, and recognizes that it is an offence for any person to export controlled nuclear information from Canada without an export permit issued for the purpose by the Canadian Nuclear Safety Commission. The Consultant agrees not to remove or cause to be removed from Canada any controlled nuclear information during the performance of the Services, and will promptly raise the issue with OPG where the Consultant is in doubt as to whether information to be removed from Canada as part of the Services may be – or contain – controlled nuclear information.

8. Termination

Torys may terminate this Retainer Agreement at any time on written notice to the Consultant. Torys will pay, or will cause OPG to pay, for work performed up to the date of the notice of termination. Upon the termination or expiration of this Retainer Agreement, the Consultant shall return to Torys and delete any and all electronic copies the Consultant may have of all documents and materials in its possession relating to the Services or this Retainer Agreement, including all Confidential Information (defined above) and Work Product, whether completed or not.

9. Liability and Indemnification

The Consultant shall be liable for and shall indemnify and hold harmless OPG and Torys from all claims, demands, actions, penalties, damages, losses, judgments and settlements, liabilities, costs, expenses, including legal fees and other related costs and expenses arising out of, related to, or incident to, the Consultant or any of its representatives' performance of the Services under this Retainer Agreement, including, without limitation:

a) any breach, violation or non-performance by the Consultant or any of its representatives of any terms, conditions, warranties, obligations or covenants contained in this Retainer Agreement;

b) any breach or violation by the Consultant or any of its representatives of any applicable laws; and

c) any actions, omissions, negligence or wilful misconduct of the Consultant or any of its representatives.

10. Intellectual Property Protection

The Consultant expressly warrants that the manufacture, delivery, sale or use of the Consultant's Services will not infringe any Canadian or foreign patents, trademarks, copyrights, industrial design or other intellectual property rights and the Consultant shall indemnify and save OPG harmless from all claims, judgments and decrees that may be entered against OPG or its representatives and against all damage, liability, costs and expenses (including legal fees and other attendant costs and expenses**)** OPG incurs by reason of any infringement or claim thereof.

11. Limitation of Liability

Except for breach of confidentiality obligations, gross negligence, wilful misconduct, fraud, breach of applicable laws, breach of privacy laws, and the Consultant's obligation to indemnify under

section 10 (Intellectual Property Protection), the Consultant's total liability for any claim arising out of the performance of the Services, regardless of the form of claim, will in no event exceed total fees paid to Consultant hereunder and under no circumstances will either party be liable for any damages in respect of any incidental, punitive, special, indirect or consequential loss, even if that party had been advised of the possibility of such damages including, but not limited to, loss of profits, loss of revenues, failure to realize expected savings, loss of data, loss of business opportunity, or similar losses of any kind.

12. **Insurance**

(a) Unless otherwise specified in this Retainer Agreement, the Consultant shall, during the term of this Retainer Agreement, and at its own expense, maintain and keep in full force and effect:

i. commercial general liability insurance on an occurrence basis having a minimum inclusive coverage limit, including personal injury and property damage, of not less than one million dollars ($1,000,000.00) per occurrence, which shall be extended to cover contractual liability, products and completed operations liability, owners/contractors protective liability and must also contain a cross liability clause and a severability of interest clause, and must name OPG and its affiliates as additional insureds; and

ii. errors and omissions insurance (professional liability) in the amount of not less than two million dollars ($2,000,000.00).

(b) All insurance coverages and limits required to be maintained by the Consultant shall be primary to any insurance maintained by OPG, which shall be excess and non-contributory. Prior to the commencement of the delivery of the Services, the Consultant shall deliver to OPG a certificate of insurance which evidences the Consultant's compliance with this Section, including the provision of a thirty (30) day prior written notice of cancellation, non-renewal or adverse material change, to OPG. The Consultant agrees that the insurance described herein does in no way limit the Consultant's liability pursuant to the indemnity provisions of this Retainer Agreement.

13. **Independence**

By entering into this Retainer Agreement, the Consultant acknowledges and agrees that the Sponsors have received a copy of Rule 13A of the Board's *Rules of Practice and Procedure* concerning expert evidence, and agree to accept the responsibilities that are or may be imposed on them by that rule with respect to testimony before the Board. A copy of the rule and the relevant form are attached as Schedules 'A' and 'B' hereto.

14. **Entire Agreement**

This Retainer Agreement, together with all Schedules attached hereto and any agreements and other documents to be delivered pursuant to this Retainer Agreement, constitute the complete agreement between Torys and the Consultant or their respective agents with respect to the subject matter hereof and supersedes any and all prior agreements and understandings. This Retainer Agreement may be amended only in a writing that refers to this Retainer Agreement and is signed by both parties.

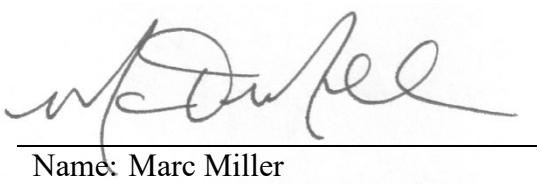
Sincerely,

TORYS LLP

Charles Keizer
Partner

Agreed and Accepted by:

ScottMadden Management Consultants

By: 

Name: Marc Miller
Title: Partner

SCHEDULE 'A'

Rule 13A of the Board's Rules of Practice and Procedure

13A. Expert Evidence

13A.01 A party may engage, and two or more parties may jointly engage, one or more experts to give evidence in a proceeding on issues that are relevant to the expert's area of expertise.

13A.02 An expert shall assist the Board impartially by giving evidence that is fair and objective.

13A.03 An expert's evidence shall, at a minimum, include the following:

(a) the expert's name, business name and address, and general area of expertise;

(b) the expert's qualifications, including the expert's relevant educational and professional experience in respect of each issue in the proceeding to which the expert's evidence relates;

(c) the instructions provided to the expert in relation to the proceeding and, where applicable, to each issue in the proceeding to which the expert's evidence relates;

(d) the specific information upon which the expert's evidence is based, including a description of any factual assumptions made and research conducted, and a list of the documents relied on by the expert in preparing the evidence;

(e) in the case of evidence that is provided in response to another expert's evidence, a summary of the points of agreement and disagreement with the other expert's evidence; and

(f) an acknowledgement of the expert's duty to the Board in **Form A** to these Rules, signed by the expert.

13A.04 In a proceeding where two or more parties have engaged experts, the Board may require two or more of the experts to:

(a) in advance of the hearing, confer with each other for the purposes of, among others, narrowing issues, identifying the points on which their views differ and are in agreement, and preparing a joint written statement to be admissible as evidence at the hearing; and

(b) at the hearing, appear together as a concurrent expert panel for the purposes of, among others, answering questions from the Board and others as permitted by the Board, and providing comments on the views of another expert on the same panel.

13A.05 The activities referred to in **Rule 13A.04** shall be conducted in accordance with such directions as may be given by the Board, including as to:

(a) scope and timing;

(b) the involvement of any expert engaged by the Board;

(c) the costs associated with the conduct of the activities;

(d) the attendance or non-attendance of counsel for the parties, or of other persons, in respect of the activities referred to in paragraph (a) of **Rule 13A.04**; and

(e) any issues in relation to confidentiality.

13A.06 A party that engages an expert shall ensure that the expert is made aware of, and has agreed to accept, the responsibilities that are or may be imposed on the expert as set out in this **Rule 13A** and **Form A**.

SCHEDULE 'B'

FORM A

Proceeding: .....

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is .....(*name)*. I live at ..... (*city)*, in the ..... (*province/state*) of .....

2. I have been engaged by or on behalf of..... (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) to provide opinion evidence that is fair, objective and non-partisan;
   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and
   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date.....

_____

Signature

TORYS LLP

79 Wellington St. W., 30th Floor
Box 270, TD South Tower
Toronto, Ontario M5K 1N2 Canada
P. 416.865.0040 | F. 416.865.7380
www.torys.com

Charles Keizer
ckeizer@torys.com
P. 416-865-7510

BY EMAIL

CONFIDENTIAL — PRIVILEGED

October 1, 2024

ScottMadden, Inc.
3495 Piedmont Road, NE
Building Ten, Suite 805
Atlanta, GA 30305-8800

Attention: Marc Miller, Partner

Re: Retainer Letter Agreement – Ontario Power Generation – Total Generating Cost Normalization for Strategic Hiring in Nuclear

Dear Mr. Miller,

We represent Ontario Power Generation ("OPG") in connection with payment amount and other proceedings (collectively, "Proceedings") before the Ontario Energy Board (the "Board").

We confirm that, on behalf of and to assist us in providing legal advice to OPG in connection with certain Proceedings, Torys LLP ("Torys") has engaged ScottMadden, Inc. (the "Consultant" or "you") effective as of the date hereof ("Effective Date") to provide consulting services as described in this letter. By signing back a copy of this letter, the Consultant agrees that this letter contains the agreed-upon terms and conditions of its retainer with Torys effective on the Effective Date, subject to amendment by written agreement between the parties (the "Retainer Agreement").

1. **No Conflict**

The Consultant does not have any conflict of interest or other constraints on its ability to provide expert advice in connection with this Retainer Agreement. You confirm that you are free to provide your services to Torys in connection with Torys' representation of OPG in the Proceedings. You agree that during this engagement you will not provide, directly or indirectly, any services to any other party in connection with the matters at issue in the Proceedings.

2. Consultant Expertise

The Consultant has been selected to provide consulting services to Torys in connection with the Proceedings, namely by undertaking an independent review of nuclear cost performance benchmarking. The sponsors of the work of the Consultant and the persons who have the relevant expertise will be Marc Miller, one of your senior consultants as he determines, your benchmarking manager and staff from your research organization as needed (the "Sponsors").

3. Scope of Services and Work Product

The Consultant will:

(a) Conduct a new, holistic study of nuclear cost performance by (i) developing a complete and current data set for analysis and benchmarking, (ii) finalizing metrics to assess cost performance; and (iii) determining cost metric normalizations and peer group changes to account for non-controllable factors and facilitate more reasonable benchmark comparisons (the "Study");

(b) if requested by Torys, produce a report detailing the Study's methodology, analysis performed and the ensuing findings and recommendations (the "Report"), which may be filed with the Board in the Proceedings; and

(c) if requested by Torys, provide support during the hearing of the Proceedings and testify before the Board in the Proceedings, in connection with the scope of the services provided hereunder ("Application Support" and, together with the Study and the Report, the "Services").

Assuming an October 1, 2024 start date, the Study will be completed by December 10, 2024 and the Report, if requested, will be completed by January 6, 2025.

4. Fees and Invoices

The Consultant acknowledges that the price for the Consultant to perform the Study and to deliver a written Report, if requested, shall not exceed [redacted] (not including HST) based on actual time spent by the team working to provide the Services, plus travel and living expenses which are billed as incurred with no mark-up, and administrative support costs (billed at 1% of professional fees), without prior written approval from Torys.

The Consultant's fee for its Services (including Application Support, if requested by Torys) shall be charged at the following hourly rates:

Partner Director Manager Director of Research Clean Tech Manager Senior Associate	[redacted]	Associate Benchmarking Manager Senior Analyst Survey Manager Analyst/Research Analyst	[redacted]

Any disbursements for additional incidentals incurred by the Consultant in relation to this Retainer Agreement must be pre-approved by Torys or OPG in writing. Torys reserves the right to deduct

any applicable non-resident withholding taxes from any amounts owing to the Consultant under this Retainer Agreement and remit such amounts to the applicable taxation authority.

The Consultant shall direct all invoices relating to Services performed by it under this Retainer Agreement to Torys, to the attention of:

Charles Keizer
Torys LLP
79 Wellington St. W., 30th Floor
Box 270, TD South Tower
Toronto, Ontario M5K 1N2
ckeizer@torys.com

with a copy to OPG, to the attention of:

Peter Cuff
Assistant General Counsel, Law Division
Ontario Power Generation
700 University Avenue, H18 E27.1
Toronto, ON M5G 1X6
peter.cuff@opg.com

Invoices shall include at least the following information:

(a) identification of the billing period to which the account relates;

(b) an itemized summary of the services that have been undertaken by you, including a brief description thereof, the date on which the services were rendered, the time spent on the services, the individual who performed the services, and the billing rate of such individual; and

(c) an itemized and brief description of all expenses incurred during the billing period, with copies of supporting invoices.

Torys will send your invoice to OPG for its approval and if OPG does not approve your invoice, Torys will send it back to you for revision. Once OPG approves the invoice, Torys will submit the invoice to OPG's payment system. OPG pays invoices once per month (on the 25th of each month) and, for payment to be made on the 25th of a particular month, the invoice must have been approved in OPG's payment system by the 25th of the prior month. Once Torys receives the payment from OPG, Torys will send payment to you.

5. Confidentiality

All work performed by the Consultant in connection with this Retainer Agreement, including all findings, opinions and conclusions the Consultant reaches in relation to this Retainer Agreement, and any communications relating thereto, are strictly privileged and confidential and shall not be disclosed to any other person or party without the prior written consent of Torys or OPG. The Consultant agrees to designate all written communications and material accordingly. The Consultant further agrees to notify Torys in the event that the Consultant receives a request to disclose information relating to this matter, and agrees to cooperate with Torys, to the fullest

extent permitted by law, to prevent or limit the disclosure of such material or otherwise preserve the privileged and confidential status of such material.

The Consultant agrees to hold in confidence: (a) all information provided to the Consultant, and (b) the Consultant's opinions to Torys and to OPG as they relate to the information, whether the information or opinions are documentary or oral (collectively, the "Confidential Information"). The Consultant will not disclose the Confidential Information to any person unless Torys or OPG authorizes you in writing to do so. All documents given to the Consultant in connection with this Retainer Agreement remain the property of Torys or of OPG, and are held in trust by the Consultant as agent. The Consultant agrees to return these documents on request. During the engagement, the Confidential Information shall be segregated from other OPG data (including on electronic information systems) and shall not be accessible to individuals other than the Consultant, Torys, and OPG employees requiring access).

The Consultant will not refer to Torys or to OPG, directly or indirectly, in connection with the promotion of its services, without obtaining the prior written consent of Torys or OPG, as the case may be.

6. Intellectual Property

Nothing in this Retainer Agreement shall be deemed to transfer, license, assign, permit the use of, or otherwise convey an interest in whole or in part to the Consultant of any intellectual property belonging to OPG or any of its representatives or any third party whose intellectual property is in OPG's custody or control, and the use by the Consultant of any such intellectual property shall be subject to the prior written approval of OPG.

Torys and OPG shall at all times have full rights and title to all works prepared, generated or created by the Consultant pursuant to this Retainer Agreement, including without limitation any reports, presentations, status updates, or other documents created by the Consultant, and any related works, modifications or additions thereto (the "Work Product"), and may at all times take possession of or use any completed or partially completed Work Product, notwithstanding any provision, express or implied, to the contrary. Without limiting the generality of the foregoing, OPG shall own all intellectual property rights in all Work Product, and the Consultant hereby waives and assigns to OPG any such rights, and agrees to give OPG and its representatives all assistance as may be reasonably required to perfect such rights including, without limitation, obtaining waiver of moral rights from any of the Consultant's employees, partners or other representatives.

Anything contained in this agreement to the contrary notwithstanding, nothing in this Retainer Agreement shall prevent Consultant from utilizing any general know-how, ideas, techniques, concepts, methods, processes, or other knowledge applied in performing the Services, on behalf of itself or its future customers. Consultant may (i) perform the same or similar services for others, and (ii) retain one copy of deliverables produced in connection with the Services hereunder for the sole purpose of documenting the conduct of its work and its exercise of due professional care in connection with the Services, provided that any of OPG's confidential information is treated in accordance with the confidentiality requirements of this Retainer Agreement.

7. Controlled Nuclear Information

The Consultant has been made aware of certain Canadian federal requirements relating to the import and export of controlled nuclear information, and recognizes that it is an offence for any person to export controlled nuclear information from Canada without an export permit issued for the purpose by the Canadian Nuclear Safety Commission. The Consultant agrees not to remove or cause to be removed from Canada any controlled nuclear information during the performance of the Services, and will promptly raise the issue with OPG where the Consultant is in doubt as to whether information to be removed from Canada as part of the Services may be – or contain – controlled nuclear information.

8. Termination

Torys may terminate this Retainer Agreement at any time on written notice to the Consultant. Torys will pay, or will cause OPG to pay, for work performed up to the date of the notice of termination. Upon the termination or expiration of this Retainer Agreement, the Consultant shall return to Torys and delete any and all electronic copies the Consultant may have of all documents and materials in its possession relating to the Services or this Retainer Agreement, including all Confidential Information (defined above) and Work Product, whether completed or not.

9. Liability and Indemnification

The Consultant shall be liable for and shall indemnify and hold harmless OPG and Torys from all claims, demands, actions, penalties, damages, losses, judgments and settlements, liabilities, costs, expenses, including legal fees and other related costs and expenses arising out of, related to, or incident to, the Consultant or any of its representatives' performance of the Services under this Retainer Agreement, including, without limitation:

a) any breach, violation or non-performance by the Consultant or any of its representatives of any terms, conditions, warranties, obligations or covenants contained in this Retainer Agreement;

b) any breach or violation by the Consultant or any of its representatives of any applicable laws; and

c) any actions, omissions, negligence or wilful misconduct of the Consultant or any of its representatives.

10. Intellectual Property Protection

The Consultant expressly warrants that the manufacture, delivery, sale or use of the Consultant's Services will not infringe any Canadian or foreign patents, trademarks, copyrights, industrial design or other intellectual property rights and the Consultant shall indemnify and save OPG harmless from all claims, judgments and decrees that may be entered against OPG or its representatives and against all damage, liability, costs and expenses (including legal fees and other attendant costs and expenses**)** OPG incurs by reason of any infringement or claim thereof.

11. Limitation of Liability

Except for breach of confidentiality obligations, gross negligence, wilful misconduct, fraud, breach of applicable laws, breach of privacy laws, and the Consultant's obligation to indemnify under section 10 (Intellectual Property Protection), the Consultant's total liability for any claim arising

out of the performance of the Services, regardless of the form of claim, will in no event exceed total fees paid to Consultant hereunder and under no circumstances will either party be liable for any damages in respect of any incidental, punitive, special, indirect or consequential loss, even if that party had been advised of the possibility of such damages including, but not limited to, loss of profits, loss of revenues, failure to realize expected savings, loss of data, loss of business opportunity, or similar losses of any kind.

12. **Insurance**

(a) Unless otherwise specified in this Retainer Agreement, the Consultant shall, during the term of this Retainer Agreement, and at its own expense, maintain and keep in full force and effect:

i. commercial general liability insurance on an occurrence basis having a minimum inclusive coverage limit, including personal injury and property damage, of not less than one million dollars ($1,000,000.00) per occurrence, which shall be extended to cover contractual liability, products and completed operations liability, owners/contractors protective liability and must also contain a cross liability clause and a severability of interest clause, and must name OPG and its affiliates as additional insureds; and

ii. errors and omissions insurance (professional liability) in the amount of not less than two million dollars ($2,000,000.00).

(b) All insurance coverages and limits required to be maintained by the Consultant shall be primary to any insurance maintained by OPG, which shall be excess and non-contributory. Prior to the commencement of the delivery of the Services, the Consultant shall deliver to OPG a certificate of insurance which evidences the Consultant's compliance with this Section, including the provision of a thirty (30) day prior written notice of cancellation, non-renewal or adverse material change, to OPG. The Consultant agrees that the insurance described herein does in no way limit the Consultant's liability pursuant to the indemnity provisions of this Retainer Agreement.

13. **Independence**

By entering into this Retainer Agreement, the Consultant acknowledges and agrees that the Sponsors have received a copy of Rule 13A of the Board's *Rules of Practice and Procedure* concerning expert evidence, and agree to accept the responsibilities that are or may be imposed on them by that rule with respect to testimony before the Board. A copy of the rule and the relevant form are attached as Schedules 'A' and 'B' hereto.

14. **Entire Agreement**

This Retainer Agreement, together with all Schedules attached hereto and any agreements and other documents to be delivered pursuant to this Retainer Agreement, constitute the complete agreement between Torys and the Consultant or their respective agents with respect to the subject matter hereof and supersedes any and all prior agreements and understandings. This Retainer Agreement may be amended only in a writing that refers to this Retainer Agreement and is signed by both parties.

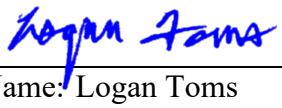
Sincerely,

TORYS LLP

Charles Keizer
Partner

Agreed and Accepted by:

ScottMadden, Inc.

By: 

Name: Logan Toms
Title: Partner, Finance and Risk

SCHEDULE 'A'

Rule 13A of the Board's Rules of Practice and Procedure

13A. Expert Evidence

13A.01 A party may engage, and two or more parties may jointly engage, one or more experts to give evidence in a proceeding on issues that are relevant to the expert's area of expertise.

13A.02 An expert shall assist the Board impartially by giving evidence that is fair and objective.

13A.03 An expert's evidence shall, at a minimum, include the following:

(a) the expert's name, business name and address, and general area of expertise;

(b) the expert's qualifications, including the expert's relevant educational and professional experience in respect of each issue in the proceeding to which the expert's evidence relates;

(c) the instructions provided to the expert in relation to the proceeding and, where applicable, to each issue in the proceeding to which the expert's evidence relates;

(d) the specific information upon which the expert's evidence is based, including a description of any factual assumptions made and research conducted, and a list of the documents relied on by the expert in preparing the evidence;

(e) in the case of evidence that is provided in response to another expert's evidence, a summary of the points of agreement and disagreement with the other expert's evidence; and

(f) an acknowledgement of the expert's duty to the Board in **Form A** to these Rules, signed by the expert.

13A.04 In a proceeding where two or more parties have engaged experts, the Board may require two or more of the experts to:

(a) in advance of the hearing, confer with each other for the purposes of, among others, narrowing issues, identifying the points on which their views differ and are in agreement, and preparing a joint written statement to be admissible as evidence at the hearing; and

(b) at the hearing, appear together as a concurrent expert panel for the purposes of, among others, answering questions from the Board and others as permitted by the Board, and providing comments on the views of another expert on the same panel.

13A.05 The activities referred to in **Rule 13A.04** shall be conducted in accordance with such directions as may be given by the Board, including as to:

(a) scope and timing;

(b) the involvement of any expert engaged by the Board;

(c) the costs associated with the conduct of the activities;

(d) the attendance or non-attendance of counsel for the parties, or of other persons, in respect of the activities referred to in paragraph (a) of **Rule 13A.04**; and

(e) any issues in relation to confidentiality.

13A.06 A party that engages an expert shall ensure that the expert is made aware of, and has agreed to accept, the responsibilities that are or may be imposed on the expert as set out in this **Rule 13A** and **Form A**.

SCHEDULE 'B'

FORM A

Proceeding: .....

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is .....(*name)*. I live at ..... (*city)*, in the ..... (*province/state*) of .....

2. I have been engaged by or on behalf of..... (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) to provide opinion evidence that is fair, objective and non-partisan;
   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and
   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date.....

_____

Signature

TORYS LLP

79 Wellington St. W., 30th Floor
Box 270, TD South Tower
Toronto, Ontario M5K 1N2 Canada
P. 416.865.0040 | F. 416.865.7380
www.torys.com

Charles Keizer
ckeizer@torys.com
P. 416-865-7510

BY EMAIL

CONFIDENTIAL — PRIVILEGED

February 13, 2025

Brad Jones
Senior Vice President of Revenue, Indeavor
834 E. Washington Ave Suite 257
Madison, WI 53703

Attention: Brad Jones, Senior Vice President of Revenue

Re: Retainer Letter Agreement – Ontario Power Generation – Nuclear Benchmarking

Dear Mr. Jones,

We represent Ontario Power Generation ("OPG") in connection with payment amount and other proceedings (collectively, "Proceedings") before the Ontario Energy Board (the "Board").

We confirm that, on behalf of and to assist us in providing legal advice to OPG in connection with certain Proceedings, Torys LLP ("Torys") has engaged Indeavor (the "Consultant" or "you") effective as of the date hereof ("Effective Date") to provide consulting services as described in this letter. By signing back a copy of this letter, the Consultant agrees that this letter contains the agreed-upon terms and conditions of its retainer with Torys effective on the Effective Date, subject to amendment by written agreement between the parties (the "Retainer Agreement").

1. **No Conflict**

The Consultant does not have any conflict of interest or other constraints on its ability to provide expert advice in connection with this Retainer Agreement. You confirm that you are free to provide your services to Torys in connection with Torys' representation of OPG in the Proceedings. You agree that during this engagement you will not provide, directly or indirectly, any services to any other party in connection with the matters at issue in the Proceedings.

2. **Consultant Expertise**

The Consultant has been selected to provide consulting services to Torys in connection with the Proceedings, namely by undertaking an independent review of nuclear staffing benchmarking. The sponsors of the work of the Consultant and the persons who have the relevant expertise will be Dan Scholz, Lakshya Gupta, Andrew Mering, Tim Lines, and staff from your research organization as needed (the "Sponsors").

3. **Scope of Services and Work Product**

The Consultant will:

(a) Analyze OPG's nuclear staffing levels by comparing them to industry benchmarks (the "Study");

(b) if requested by Torys, produce a report detailing the Study's methodology, analysis performed, and any findings and recommendations (the "Report"), which may be filed with the Board in the Proceedings; and

(c) if requested by Torys, provide support during the hearing of the Proceedings and testify before the Board in the Proceedings, in connection with the scope of the services provided hereunder ("Application Support" and, together with the Study and the Report, the "Services").

Assuming a March 31, 2025 start date, the Consultant will undertake reasonable efforts to complete the Study by May 15, 2025 and to complete the Report, if requested, by May 30, 2025.

4. **Fees and Invoices**

The Consultant acknowledges that the price for the Consultant to perform the Study and to deliver a written Report, if requested, shall not exceed [redacted] (not including HST) based on actual time spent by the team working to provide the Services, plus travel and living expenses which are billed as incurred with no mark-up, and administrative support costs (billed at 1% of professional fees), without prior written approval from Torys.

The Consultant's fee for its Services shall be charged in accordance as follows:

Services (per section 3)	**Fees**
Study	[redacted] USD
Report	[redacted] USD
Application Support	Hourly Rate (as outlined in the table below)

Two separate invoices will be issued for the Study. The first invoice for the [redacted] will be issued after the Consultant has collected all the data for the Study, and the second invoice [redacted] will be issued after the Consultant has analyzed all the data for the Study.

Name	**Title/Role**	**Location**	**Hourly Rate (USD)**
Dan Scholz	Project Manager	Chattanooga, TN	[redacted]
Lakshya Gupta	Labor Expert	Long Beach, CA	
Andrew Mering	Nuclear Ops Expert	Madison, WI	
Tim Lines	Analyst	Minneapolis, MN	
Name	**Title/Role**	**Location**	**Hourly Rate (USD)**

Any disbursements for additional incidentals incurred by the Consultant in relation to this Retainer Agreement must be pre-approved by Torys or OPG in writing. Torys reserves the right to deduct any applicable non-resident withholding taxes from any amounts owing to the Consultant under this Retainer Agreement and remit such amounts to the applicable taxation authority.

The Consultant shall direct all invoices relating to Services performed by it under this Retainer Agreement to Torys, to the attention of:

Charles Keizer
Torys LLP
79 Wellington St. W., 30th Floor
Box 270, TD South Tower
Toronto, Ontario M5K 1N2
ckeizer@torys.com

with a copy to OPG, to the attention of:

Peter Cuff
Assistant General Counsel, Law Division
Ontario Power Generation
700 University Avenue, H18 E27.1
Toronto, ON M5G 1X6
peter.cuff@opg.com

Invoices shall include at least the following information:

(a) identification of the billing period to which the account relates;

(b) an itemized summary of the services that have been undertaken by you, including a brief description thereof, the date on which the services were rendered, the time spent on the services, the individual who performed the services, and the billing rate of such individual; and

(c) an itemized and brief description of all expenses incurred during the billing period, with copies of supporting invoices.

Torys will send your invoice to OPG for its approval and if OPG does not approve your invoice, Torys will send it back to you for revision. Once OPG approves the invoice, Torys will submit the invoice to OPG's payment system. OPG pays invoices once per month (on the 25th of each month) and, for payment to be made on the 25th of a particular month, the invoice must have been approved in OPG's payment system by the 25th of the prior month. Once Torys receives the payment from OPG, Torys will send payment to you.

5. **Confidentiality**

All work performed by the Consultant in connection with this Retainer Agreement, including all findings, opinions and conclusions the Consultant reaches in relation to this Retainer Agreement, and any communications relating thereto, are strictly privileged and confidential and shall not be disclosed to any other person or party without the prior written consent of Torys or OPG. The Consultant agrees to designate all written communications and material accordingly. The Consultant further agrees to notify Torys in the event that the Consultant receives a request to disclose information relating to this matter, and agrees to cooperate with Torys, to the fullest extent permitted by law, to prevent or limit the disclosure of such material or otherwise preserve the privileged and confidential status of such material.

The Consultant agrees to hold in confidence: (a) all information provided to the Consultant, and (b) the Consultant's opinions to Torys and to OPG as they relate to the information, whether the information or opinions are documentary or oral (collectively, the "Confidential Information"). The Consultant will not disclose the Confidential Information to any person unless Torys or OPG authorizes you in writing to do so. All documents given to the Consultant in connection with this Retainer Agreement remain the property of Torys or of OPG, and are held in trust by the Consultant as agent. The Consultant agrees to return these documents on request. During the engagement, the Confidential Information shall be segregated from other OPG data (including on electronic information systems) and shall not be accessible to individuals other than the Consultant, Torys, and OPG employees requiring access).

The Consultant will not refer to Torys or to OPG, directly or indirectly, in connection with the promotion of its services, without obtaining the prior written consent of Torys or OPG, as the case may be.

6. Intellectual Property

Nothing in this Retainer Agreement shall be deemed to transfer, license, assign, permit the use of, or otherwise convey an interest in whole or in part to the Consultant of any intellectual property belonging to OPG or any of its representatives or any third party whose intellectual property is in OPG's custody or control, and the use by the Consultant of any such intellectual property shall be subject to the prior written approval of OPG.

Torys and OPG shall at all times have full rights and title to all works prepared, generated or created by the Consultant pursuant to this Retainer Agreement, including without limitation any reports, presentations, status updates, or other documents created by the Consultant, and any related works, modifications or additions thereto (the "Work Product"), and may at all times take possession of or use any completed or partially completed Work Product, notwithstanding any provision, express or implied, to the contrary. Without limiting the generality of the foregoing, OPG shall own all intellectual property rights in all Work Product, and the Consultant hereby waives and assigns to OPG any such rights, and agrees to give OPG and its representatives all assistance as may be reasonably required to perfect such rights including, without limitation, obtaining waiver of moral rights from any of the Consultant's employees, partners or other representatives.

Anything contained in this agreement to the contrary notwithstanding, nothing in this Retainer Agreement shall prevent Consultant from utilizing any general know-how, ideas, techniques, concepts, methods, processes, or other knowledge applied in performing the Services, on behalf of itself or its future customers. Consultant may (i) perform the same or similar services for others, and (ii) retain one copy of deliverables produced in connection with the Services hereunder for the sole purpose of documenting the conduct of its work and its exercise of due professional care in connection with the Services, provided that any of OPG's confidential information is treated in accordance with the confidentiality requirements of this Retainer Agreement.

7. Intellectual Property Protection

The Consultant expressly warrants that the manufacture, delivery, sale or use of the Consultant's Services will not infringe any Canadian or foreign patents, trademarks, copyrights, industrial design or other intellectual property rights and the Consultant shall indemnify and save OPG harmless from all claims, judgments and decrees that may be entered against OPG or its

representatives and against all damage, liability, costs and expenses (including legal fees and other attendant costs and expenses**)** OPG incurs by reason of any infringement or claim thereof.

8. Controlled Nuclear Information

The Consultant has been made aware of certain Canadian federal requirements relating to the import and export of controlled nuclear information, and recognizes that it is an offence for any person to export controlled nuclear information from Canada without an export permit issued for the purpose by the Canadian Nuclear Safety Commission. The Consultant agrees not to remove or cause to be removed from Canada any controlled nuclear information during the performance of the Services, and will promptly raise the issue with OPG where the Consultant is in doubt as to whether information to be removed from Canada as part of the Services may be – or contain – controlled nuclear information.

9. Termination

Torys may terminate this Retainer Agreement at any time on written notice to the Consultant. Torys will pay, or will cause OPG to pay, for work performed up to the date of the notice of termination. Upon the termination or expiration of this Retainer Agreement, the Consultant shall return to Torys and delete any and all electronic copies the Consultant may have of all documents and materials in its possession relating to the Services or this Retainer Agreement, including all Confidential Information (defined above) and Work Product, whether completed or not.

10. Liability and Indemnification

The Consultant shall be liable for and shall indemnify and hold harmless OPG and Torys from all claims, demands, actions, penalties, damages, losses, judgments and settlements, liabilities, costs, expenses, including legal fees and other related costs and expenses arising out of, related to, or incident to, the Consultant or any of its representatives' performance of the Services under this Retainer Agreement, including, without limitation:

a) any breach, violation or non-performance by the Consultant or any of its representatives of any terms, conditions, warranties, obligations or covenants contained in this Retainer Agreement;

b) any breach or violation by the Consultant or any of its representatives of any applicable laws; and

c) any actions, omissions, negligence or wilful misconduct of the Consultant or any of its representatives.

11. Limitation of Liability

Except for breach of confidentiality obligations, gross negligence, wilful misconduct, fraud, breach of applicable laws, breach of privacy laws, and the Consultant's obligation to indemnify under section 10 (Intellectual Property Protection), the Consultant's total liability for any claim arising out of the performance of the Services, regardless of the form of claim, will in no event exceed total fees paid to Consultant hereunder and under no circumstances will either party be liable for any damages in respect of any incidental, punitive, special, indirect or consequential loss, even if that party had been advised of the possibility of such damages including, but not limited to, loss

of profits, loss of revenues, failure to realize expected savings, loss of data, loss of business opportunity, or similar losses of any kind.

12. **Insurance**

(a) Unless otherwise specified in this Retainer Agreement, the Consultant shall, during the term of this Retainer Agreement, and at its own expense, maintain and keep in full force and effect:

i. commercial general liability insurance on an occurrence basis having a minimum inclusive coverage limit, including personal injury and property damage, of not less than one million dollars ($1,000,000.00) per occurrence, which shall be extended to cover contractual liability, products and completed operations liability, owners/contractors protective liability and must also contain a cross liability clause and a severability of interest clause, and must name OPG and its affiliates as additional insureds; and

ii. errors and omissions insurance (professional liability) in the amount of not less than two million dollars ($2,000,000.00).

(b) All insurance coverages and limits required to be maintained by the Consultant shall be primary to any insurance maintained by OPG, which shall be excess and non-contributory. Prior to the commencement of the delivery of the Services, the Consultant shall deliver to OPG a certificate of insurance which evidences the Consultant's compliance with this Section, including the provision of a thirty (30) day prior written notice of cancellation, non-renewal or adverse material change, to OPG. The Consultant agrees that the insurance described herein does in no way limit the Consultant's liability pursuant to the indemnity provisions of this Retainer Agreement.

13. **Independence**

By entering into this Retainer Agreement, the Consultant acknowledges and agrees that the Sponsors have received a copy of Rule 13A of the Board's *Rules of Practice and Procedure* concerning expert evidence, and agree to accept the responsibilities that are or may be imposed on them by that rule with respect to testimony before the Board. A copy of the rule and the relevant form are attached as Schedules 'A' and 'B' hereto.

14. **Responsibility Statement**

The Consultant agrees that the Services provided for herein will be performed in a timely, competent, professional manner in accordance with recognized professional consulting standards for similar services to be performed by a leading consulting advisory firm, and that adequate qualified personnel will be assigned for that purpose. If, during the performance of the Services or prior to the Board's issuance of final, non-appealable order(s) disposing of all relevant relief sought in the Application, such Services prove to be faulty or defective by reason of a failure to meet such standards, the Consultant agrees that upon prompt written notification from Torys, such faulty or defective portion of the Services will be redone at no cost to Torys or OPG, up to a maximum amount equivalent to the cost of the Services rendered under this Retainer Agreement, or, at Torys' request, the Consultant will refund an amount equal to the amount paid for the faulty or defective portion of the Services.

15. **Entire Agreement**

This Retainer Agreement, together with all Schedules attached hereto and any agreements and other documents to be delivered pursuant to this Retainer Agreement, constitute the complete agreement between Torys and the Consultant or their respective agents with respect to the subject matter hereof and supersedes any and all prior agreements and understandings. This Retainer Agreement may be amended only in a writing that refers to this Retainer Agreement and is signed by both parties.

16. **Governing Law**

This Retainer Agreement shall be construed and otherwise governed pursuant to the laws of the Province of Ontario and the federal laws of Canada applicable therein.

Sincerely,

TORYS LLP



Charles Keizer
Partner

Agreed and Accepted by:

Indeavor

By: Bradley Jones
box SIGN 187KXVW4-4Q3Q7LLX
Name: Brad Jones
Title: SVP of Revenue, Indeavor

SCHEDULE 'A'

Rule 13A of the Board's Rules of Practice and Procedure

13A. Expert Evidence

13A.01 Where a party intends to engage one or more experts to give evidence in a proceeding on issues that are relevant to the expert's area of expertise, Rule 13 applies to that evidence.

13A.02 An expert shall assist the OEB impartially by giving evidence that is fair and objective.

13A.03 An expert's evidence shall, at a minimum, include the following:

(a) the expert's name, business name and address, and general area of expertise;

(b) the expert's qualifications, including the expert's relevant educational and professional experience in respect of each issue in the proceeding to which the expert's evidence relates;

(c) the instructions provided to the expert in relation to the proceeding and, where applicable, to each issue in the proceeding to which the expert's evidence relates;

(d) the specific information upon which the expert's evidence is based, including a description of any factual assumptions made and research conducted, and a list of the documents relied on by the expert in preparing the evidence;

(e) in the case of evidence that is provided in response to another expert's evidence, a summary of the points of agreement and disagreement with the other expert's evidence; and

(f) an acknowledgement of the expert's duty to the OEB in **Form A** to these Rules, signed by the expert.

13A.04 In a proceeding where two or more parties have engaged experts, the OEB may require two or more of the experts to:

(a) in advance of the hearing, confer with each other for the purposes of, among others, narrowing issues, identifying the points on which their views differ and are in agreement, and preparing a joint written statement to be admissible as evidence at the hearing; and

(b) at the hearing, appear together as a concurrent expert panel for the purposes of, among others, answering questions from the OEB and others as permitted by the OEB, and providing comments on the views of another expert on the same panel.

13A.05 The activities referred to in **Rule 13A.04** shall be conducted in accordance with such directions as may be given by the Board, including as to:

(a) scope and timing;

(b) the involvement of any expert engaged by the OEB;

(c) the costs associated with the conduct of the activities;

(d) the attendance or non-attendance of counsel for the parties, or of other persons, in respect of the activities referred to in paragraph (a) of **Rule 13A.04**; and

(e) any issues in relation to confidentiality.

13A.06 A party that engages an expert shall ensure that the expert is made aware of, and has agreed to accept, the responsibilities that are or may be imposed on the expert as set out in this **Rule 13A** and **Form A**.

SCHEDULE 'B'

FORM A

Proceeding: .....

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Daniel J. Scholz (*name*). I live at Signal Mtn. (*city*), in the State (*province/state*) of Tennessee

2. I have been engaged by or on behalf of Tory's (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) to provide opinion evidence that is fair, objective and non-partisan;
   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and
   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date Apr 8, 2025

Dan Scholz

boxSIGN 197PX6ZV-4Q3Q7LLX

Signature

NEWS RELEASE

Ontario Supports Plan to Safely Extend the Life of the Pickering Nuclear Generating Station

Updated schedule keeps high quality jobs in Durham region longer

August 14, 2020

Energy, Northern Development and Mines

PICKERING - The Ontario government is supporting a plan by Ontario Power Generation (OPG) to safely extend the life of the Pickering Nuclear Generating Station. The updated schedule will provide electricity consumers with emission-free, low-cost energy and allow 4,500 high-quality jobs to remain in Durham region longer.

Under its proposed plan, Ontario Power Generation (OPG) will keep Pickering's units 1 and 4 operating until the end of 2024 and units 5 to 8 operating until the end of 2025, allowing for the safe, sequential shutdown of all units while maximizing the economic benefits of the generation station in the community.

"The safe operation of Ontario's nuclear assets is our top priority," said Greg Rickford, Minister of Energy, Northern Development and Mines. "I'm pleased that OPG (Ontario Power Generation) has developed an innovative proposal that will provide Ontarians with emission-free, low cost energy, and keep highly-skilled Ontarians working in their communities longer."

OPG (Ontario Power Generation) informed the government that ongoing testing demonstrates the plant is safe to operate beyond its previously scheduled shutdown date of 2024 and the continued improved performance at the plant provides value to electricity consumers. In December 2019, Pickering was given an exemplary performance rating from the World Association of Nuclear Operators.

"Our extensive analysis has shown that we can safely and reliably operate Pickering until the end of 2025 and provide a solid benefit to the ratepayer," said Ken Hartwick, OPG (Ontario Power Generation) President and CEO. "I want to recognize every one of the Pickering staff for their commitment to safety and for their role in

improving performance year over year. The station's performance is better than ever and Ontario electricity users will continue to benefit from clean and stable baseload power for several more years."

OPG (Ontario Power Generation) requires approval from the Canadian Nuclear Safety Commission (CNSC) for its revised schedule. The final decision regarding the safe operating life of the Pickering site will be made by the CNSC (Canadian Nuclear Safety Commission), which employs a rigorous and transparent process, including public hearings for decisions on licensing of major nuclear facilities.

Supporting OPG's (Ontario Power Generation's) efforts to optimize the Pickering Nuclear Generating Station's shutdown schedule is part of the government's plan to maintain a reliable and affordable energy system while keeping good jobs in local communities.

Quick Facts

- OPG (Ontario Power Generation) employs approximately 4,500 staff to support ongoing operation at its Pickering Nuclear Generating Station. In total, there are about 7,500 jobs across Ontario related to the Pickering Nuclear Generating Station.
- The Pickering Nuclear Generating Station currently provides enough power to meet the needs of a city of 1.5 million people.
- Under this proposal, all nuclear generation at Pickering would end in 2025.
- The plan was developed using data and analysis from the Independent Electricity System Operator (IESO) on capacity needs and was incorporated into its Annual Planning Outlook.

Additional Resources

- Learn more about Pickering Nuclear Generating Station

Related Topics

Business and economy

Information about Ontario’s economy and how to do business here. Includes economic development opportunities, research funding, tax credits for business and the Ontario Budget. Learn more

Environment and energy

Learn more about how Ontario protects and restores wildlife and the environment. Includes information on conservation and the electricity system. Learn more

Government

Learn about the government services available to you and how government works. Learn more

Jobs and employment

Find resources and supports for job seekers and employers. Learn more

Media Contacts

Alex Puddifant
Minister's Office
647-201-8821
alex.puddifant@ontario.ca

Natasha Demetriades
Communications Branch
416-327-3855
natasha.demetriades@ontario.ca

© King's Printer for Ontario, 2012-2025

NEWS RELEASE

Ontario Supports Plan to Safely Continue Operating the Pickering Nuclear Generating Station

Ontario Power Generation will also provide the province with an updated refurbishment feasibility assessment

September 29, 2022

Energy

PICKERING - The Ontario government is supporting Ontario Power Generation's (OPG) continued safe operation of the Pickering Nuclear Generating Station. At the Ontario government's request, OPG reviewed their operational plans and concluded that the facility could continue to safely generate electricity.

"Keeping Pickering safely operating will provide clean, low-cost, and reliable electricity to support the incredible economic growth and new jobs we're seeing, while building a healthier Ontario for everyone," said Todd Smith, Minister of Energy. "Nuclear power has been the safe and reliable backbone of Ontario's electricity system since the 1970s and our government is working to secure that legacy for the future. Our leadership on Small Modular Reactors and consideration of a refurbishment of Pickering Nuclear Generating Station are critical steps on that path."

Maintaining operations of Pickering Nuclear Generation Station will also protect good-paying jobs for thousands of workers in the region and across the province. OPG employs approximately 4,500 staff to support ongoing operation at its Pickering Nuclear Generating Station. In total, there are about 7,500 jobs across Ontario related to the Pickering Nuclear Generating Station.

Further operation of Pickering Nuclear Generating Station beyond September 2026 would require a complete refurbishment. The last feasibility study was conducted between 2006 and 2009. With significant economic growth and increasing electrification of industry and transportation, Ontario has asked OPG to update its feasibility assessment for refurbishing Pickering "B" units at the Nuclear Generating Station, based on the latest information, as a prudent due diligence measure to

support future electricity planning decisions. Refurbishment of Pickering Nuclear Generating Station could result in an additional 30 years of reliable, clean and zero-emissions electricity from the facility.

“Pickering Nuclear Generating Station has never been stronger in terms of both safety and performance,” said Ken Hartwick, OPG President and CEO. “Due to ongoing investments and the efforts of highly skilled and dedicated employees, Pickering can continue to safely and reliably produce the clean electricity Ontarians need.”

Keeping Pickering Nuclear Generating Station operational would ensure Ontario has reliable, clean, and low-cost energy while reducing CO_2 emissions by 2.1 megatonnes in 2026. This represents an approximate 20 per cent reduction in projected emissions from the electricity sector in that year, which is the equivalent of taking up to 643,000 cars off the road annually. It would also increase North America’s supply of Cobalt-60, a medical isotope used in cancer treatments and medical equipment sterilization, by about 10 to 20 per cent.

OPG requires approval from the Canadian Nuclear Safety Commission (CNSC) for its revised schedule. The CNSC, which employs a rigorous and transparent decision-making process, will make the final decision regarding Pickering’s safe operating life. OPG will continue to ensure the safety of the Pickering facility through rigorous monitoring, inspections, and testing.

Quick Facts

- Under OPG’s plan, electricity generation at Pickering Nuclear Generating Station would end in 2026 instead of 2025. Pickering “A” units 1 and 4 would operate until 2024, and Pickering “B” units 5 through 8 would operate until September 2026.
- Pickering “A” units 1 through 4 came online between 1971 and 1973, and were voluntarily removed from service in 1997. Units 1 and 4 were refurbished and returned to operation in November 2005 and September 2003, respectively. Pickering “B” units 5 through 8 began operating in the 1983-86 period.
- The Pickering Nuclear Generating Station currently provides enough power to meet the needs of a city of 1.5 million people.
- All units at both Darlington and Bruce Nuclear Generating Stations, Ontario’s other two nuclear facilities, are either scheduled for or have completed refurbishment.

Quotes

> "Pickering Nuclear Generating Station has been at the centre of Ontario's nuclear fleet for decades, safely providing clean, zero-emissions electricity to power our growing province. I'm pleased our government is continuing to study the future of nuclear power in Pickering, an industry which continues to support good-paying and highly skilled jobs here in Durham."
>
> **- Peter Bethlenfalvy**
> **MPP for Pickering-Uxbridge**

Additional Resources

Learn more about Pickering Nuclear Generating Station

Related Topics

Business and economy

Information about Ontario's economy and how to do business here. Includes economic development opportunities, research funding, tax credits for business and the Ontario Budget. Learn more

Environment and energy

Learn more about how Ontario protects and restores wildlife and the environment. Includes information on conservation and the electricity system. Learn more

Media Contacts

Palmer Lockridge
Minister's Office
palmer.lockridge@ontario.ca

Natasha Demetriades
Communications Branch
natasha.demetriades@ontario.ca
416-327-3855

© King's Printer for Ontario, 2012-2025

Numbers may not add due to rounding.

Updated: 2026-03-10
EB-2025-0297
Exhibit F2
Tab 1
Schedule 1
Table 1a

Table 1a
Operating Costs Summary - OPG Nuclear Facilities ($M)

Line No.	Cost Item	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	OM&A:												
1	**OPG Nuclear Facilities Base OM&A**	1,313.9	1,316.0	1,305.7	1,418.9	1,433.5	1,303.0	1,210.2	840.4	850.7	898.4	916.8	1,225.4
2	**OPG Nuclear Facilities Project OM&A**	99.5	111.6	89.5	141.1	107.9	75.6	73.3	76.1	82.4	84.0	84.8	83.2
3	**OPG Nuclear Facilities Outage OM&A**	293.9	382.8	265.0	318.1	358.1	127.0	209.4	223.7	112.7	219.1	121.6	142.2
4	**Pickering Cyclical Maintenance OM&A**	0.0	0.0	0.0	0.0	0.0	0.0	25.0	168.4	160.9	168.9	169.9	106.6
5	**Subtotal OPG Nuclear Facilities OM&A**	1,707.3	1,810.4	1,660.2	1,878.1	1,899.5	1,505.6	1,517.8	1,308.6	1,206.7	1,370.4	1,293.2	1,557.4
6	**Darlington Refurbishment OM&A**	19.0	35.6	22.3	39.0	59.7	10.5	1.8	0.0	0.0	0.0	0.0	0.0
7	**Darlington New Nuclear OM&A**[1,3]	13.1	95.4	2.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**DNNP Operational Readiness**	0.0	0.0	0.0	1.1	2.3	17.3	0.0	0.0	0.0	0.0	0.0	0.0
9	**Other New Nuclear OM&A**[2,3]	0.0	0.0	0.0	7.6	15.1	62.1	136.4	0.0	0.0	0.0	0.0	0.0
10	**Pickering Refurbishment Feasibility Study**[3]	0.0	0.0	0.2	17.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	**Pickering Refurbishment OM&A**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100.3	94.1	84.9	52.7	46.5
12	**Allocation of Corporate Costs**	352.7	359.7	366.2	406.3	400.8	411.5	416.1	417.5	412.1	432.7	444.7	471.6
13	**Allocation of Centrally Held Costs**	215.0	209.3	76.3	(18.5)	104.7	(48.1)	(47.2)	(35.4)	(30.8)	(60.1)	(33.3)	(21.6)
14	**Asset Service Fees**	55.6	65.0	71.1	74.3	77.1	85.6	93.3	72.7	73.9	89.5	99.0	99.4
15	**Subtotal Other OM&A**	655.3	765.1	538.5	527.6	659.8	538.9	600.3	555.1	549.3	547.0	563.1	596.0
16	**Total OPG Nuclear Facilities OM&A**	2,362.6	2,575.5	2,198.7	2,405.7	2,559.3	2,044.5	2,118.2	1,863.7	1,756.0	1,917.4	1,856.3	2,153.5
17	**OPG Nuclear Facilities Fuel Costs**	234.9	232.0	222.5	218.4	211.8	255.1	239.2	150.9	221.7	223.6	261.2	306.1
	Other Operating Cost Items:												
18	**Depreciation and Amortization**	448.6	504.8	626.6	685.6	753.7	540.3	617.7	663.3	708.5	730.3	779.8	992.6
19	**Income Tax**	158.6	(20.2)	81.0	83.5	(59.9)	181.1	30.4	(16.6)	(16.6)	(16.6)	(16.6)	(16.6)
20	**Property Tax**	11.1	11.6	11.8	12.1	12.6	12.2	13.5	14.0	14.2	14.5	14.8	15.0
21	**Total OPG Nuclear Facilities Operating Costs**	3,215.8	3,303.7	3,140.6	3,405.4	3,477.5	3,033.1	3,018.9	2,675.2	2,683.8	2,869.1	2,895.5	3,450.6

Notes:

1 For amounts in 2020 to 2022 refer to EB-2023-0336, Ex. H1-1-1, Table 20, line 2.

2 Actual and budget amounts in the Other New Nuclear OM&A category primarily relate to impact assessment preparation for potential new nuclear generation at OPG strategic sites. No amounts related to new nuclear generation projects is included in the revenue requirement for OPG's nuclear facilities.

3 Refer to Ex. F2-1-1, Section 5.0

Numbers may not add due to rounding.

Updated: 2026-03-10
EB-2025-0297
Exhibit F2
Tab 1
Schedule 1
Table 1b

Table 1b
Operating Costs Summary - DNNP Facilities ($M)

Line No.	Cost Item	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	OM&A:						
1	**DNNP Facilities Base OM&A**	3.9	4.3	5.0	5.3	34.4	119.0
2	**DNNP Facilities Outage OM&A**	0.0	0.0	0.0	0.0	0.1	48.6
3	**DNNP Operational Readiness**	28.8	45.9	46.3	40.0	40.2	0.0
4	**Subtotal DNNP Facilities OM&A**	32.7	50.2	51.3	45.3	74.7	167.6
5	**Allocation of Corporate Costs**	23.0	28.6	31.5	29.4	30.6	32.4
6	**Allocation of Centrally Held Costs**	(3.7)	(3.7)	(4.1)	(3.6)	5.2	14.2
7	**Asset Service Fees**[1]	2.5	1.9	1.4	(0.3)	8.2	45.0
8	**Subtotal Other OM&A**	21.8	26.8	28.8	25.5	44.1	91.7
9	**Total OM&A**	54.5	77.0	80.1	70.8	118.7	259.3
10	**Nuclear Fuel Service Fee**[2]	0.0	9.1	13.8	12.7	18.1	49.8
	Other Operating Cost Items:						
11	**Depreciation and Amortization**	0.0	0.0	0.0	0.0	22.6	109.7
12	**Income Tax**	0.0	0.0	0.0	0.0	0.0	0.0
13	**Property Tax**	0.0	0.0	0.0	0.0	0.8	3.7
14	**Total DNNP Facilities Operating Costs**	54.5	86.1	93.9	83.5	160.2	422.5

Notes:
1 Refer to Ex. C1-1-2, Section 4.5
2 Refer to Ex. F3-2-1, Table 3, line 10.

Numbers may not add due to rounding.

Filed: 2025-12-12
EB-2025-0297
Exhibit F2
Tab 1
Schedule 1
Table 2a

Table 2a (Two Pages)
Staff Summary - Regular and Non-Regular (FTEs) - OPG Nuclear Facilities

Line No.	Group	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	OPG Nuclear Facilities OM&A:												
1	**Regular Staff**	4,379.4	4,038.8	3,652.6	3,793.0	4,096.2	4,278.7	3,967.1	3,100.9	3,083.6	3,100.7	3,102.4	3,714.9
	Non-Regular Staff												
2	Term and Extended Temporary	584.7	766.7	887.0	927.0	599.2	202.2	174.7	0.0	0.0	0.0	0.0	0.0
3	Temporary	766.7	812.6	577.6	582.7	525.5	258.9	322.4	161.0	141.6	195.4	146.2	147.7
4	EPSCA	76.7	94.2	99.3	88.2	100.0	54.2	25.4	22.0	21.6	21.6	21.0	20.0
5	**Total Non-Regular Staff**	1,428.1	1,673.5	1,563.9	1,597.9	1,224.7	515.3	522.6	183.0	163.2	217.0	167.3	167.7
6	**Subtotal OPG Nuclear Facilities OM&A**	5,807.5	5,712.3	5,216.5	5,390.9	5,320.9	4,794.0	4,489.7	3,283.9	3,246.8	3,317.7	3,269.7	3,882.6
	OPG Nuclear Facilities Capital:												
7	**Regular Staff**	221.8	179.3	190.9	202.0	249.7	378.9	440.7	469.0	459.8	459.5	472.0	477.4
	Non-Regular Staff												
8	Term and Extended Temporary	5.2	11.7	20.0	25.7	25.1	29.0	17.0	0.0	0.0	0.0	0.0	0.0
9	Temporary	51.1	32.0	18.8	2.0	7.0	65.6	94.1	59.0	57.5	40.2	38.5	35.5
10	EPSCA	26.0	32.7	45.5	47.1	42.6	43.8	28.2	22.4	17.8	7.8	7.0	7.0
11	**Total Non-Regular Staff**	82.2	76.4	84.3	74.7	74.7	138.4	139.3	81.4	75.3	48.0	45.5	42.5
12	**Subtotal OPG Nuclear Facilities Capital**	304.0	255.6	275.2	276.7	324.3	517.3	580.0	550.4	535.2	507.5	517.5	519.9
	Darlington Refurbishment Program:												
13	**Regular Staff**	432.5	394.0	404.0	446.7	499.9	486.5	55.8	0.0	0.0	0.0	0.0	0.0
	Non-Regular Staff												
14	Term and Extended Temporary	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Temporary	117.0	83.3	69.7	67.2	69.2	50.8	21.6	0.0	0.0	0.0	0.0	0.0
16	EPSCA	128.6	224.2	252.2	295.1	271.1	188.9	29.3	0.0	0.0	0.0	0.0	0.0
17	**Total Non-Regular Staff**	245.6	307.4	321.9	362.3	340.4	239.7	50.9	0.0	0.0	0.0	0.0	0.0
18	**Subtotal Darlington Refurbishment**	678.2	701.5	725.9	809.0	840.3	726.2	106.7	0.0	0.0	0.0	0.0	0.0
	Pickering Refurbishment Program:												
19	**Regular Staff**	0.0	0.0	0.0	7.6	159.5	835.8	1,177.1	2,299.6	2,323.7	2,350.0	2,309.5	1,670.5
	Non-Regular Staff												
20	Term and Extended Temporary	0.0	0.0	0.0	0.0	0.8	0.0	21.3	7.0	7.0	7.0	0.0	0.0
21	Temporary	0.0	0.0	0.0	0.1	10.3	7.0	128.5	30.7	14.9	14.9	21.9	22.3
22	EPSCA	0.0	0.0	0.0	0.1	3.2	31.0	109.7	350.2	473.4	419.0	335.0	252.9
23	**Total Non-Regular Staff**	0.0	0.0	0.0	0.1	14.3	38.0	259.4	387.9	495.2	440.9	356.9	275.2

24	**Subtotal Pickering Refurbishment Program**	0.0	0.0	0.0	7.8	173.8	873.8	1,436.5	2,687.5	2,819.0	2,790.8	2,666.5	1,945.6
	DNNP Facilities Capital:												
25	**Regular Staff**	0.0	0.0	73.9	107.0	139.7	201.0	0.0	0.0	0.0	0.0	0.0	0.0
	Non-Regular Staff												
26	Temporary	0.0	0.0	5.4	9.1	10.4	18.0	0.0	0.0	0.0	0.0	0.0	0.0
27	EPSCA	0.0	0.0	0.0	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	**Total Non-Regular Staff**	0.0	0.0	5.4	9.3	10.4	18.0	0.0	0.0	0.0	0.0	0.0	0.0
29	**Subtotal DNNP Facilities Capital**	0.0	0.0	79.3	116.3	150.1	219.0	0.0	0.0	0.0	0.0	0.0	0.0
	Darlington & Other New Nuclear OM&A:												
30	**Regular Staff**	5.9	44.3	4.8	21.9	27.2	50.6	95.1	0.0	0.0	0.0	0.0	0.0
	Non-Regular Staff												
31	Temporary	0.6	2.0	2.6	0.6	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
32	EPSCA	0.0	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33	**Total Non-Regular Staff**	0.6	2.2	2.7	0.6	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	**Subtotal Darlington & Other New Nuclear**	6.5	46.5	7.5	22.5	28.5	50.6	95.1	0.0	0.0	0.0	0.0	0.0
	Nuclear Provision:												
35	**Regular Staff**	332.4	344.0	359.6	400.5	537.9	938.9	794.7	725.1	696.9	603.9	609.0	610.7
	Non-Regular Staff												
36	Term and Extended Temporary	8.3	16.1	20.2	33.0	31.1	9.0	2.3	0.0	0.0	0.0	0.0	0.0
37	Temporary	45.7	51.3	49.6	48.7	48.1	38.5	42.2	31.0	29.3	24.0	24.0	24.0
38	EPSCA	3.0	4.4	4.1	4.0	10.2	3.3	2.3	2.3	2.2	2.0	2.0	2.0
39	**Total Non-Regular Staff**	57.0	71.9	73.9	85.6	89.4	50.8	46.7	33.3	31.5	26.0	26.0	26.0
40	**Subtotal Nuclear Provision**	389.4	416.0	433.4	486.1	627.3	989.7	841.5	758.4	728.4	629.9	635.0	636.7
	OPG Nuclear Non-Energy Direct:												
41	**Regular Staff**	17.7	20.3	45.1	41.8	40.1	35.5	35.9	39.0	39.0	39.0	39.0	39.0
	Non-Regular Staff												
42	Term and Extended Temporary	0.7	0.4	0.9	2.9	1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
43	Temporary	1.1	0.8	0.6	1.9	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
44	EPSCA	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	**Total Non-Regular Staff**	1.8	1.2	1.5	4.8	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
46	**Subtotal OPG Nuclear Non-Energy Direct**	19.5	21.5	46.6	46.6	42.1	35.5	35.9	39.0	39.0	39.0	39.0	39.0
47	**Total OPG Nuclear Facilities**	7,205.1	7,153.4	6,784.4	7,155.9	7,507.3	8,206.1	7,585.4	7,319.2	7,368.4	7,284.9	7,127.7	7,023.8

Numbers may not add due to rounding.

Table 2b

Regular and Non-Regular (FTEs) - DNNP Facilities

Line No.	Group	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	DNNP Facilities OM&A:						
1	**Regular Staff**	89.9	141.6	144.2	121.0	197.2	237.9
	Non-Regular Staff						
2	Term and Extended Temporary	0.0	0.0	0.0	0.0	0.0	0.0
3	Temporary	6.4	3.3	2.4	1.4	3.4	0.6
4	EPSCA	0.0	0.0	0.0	0.0	0.0	0.0
5	**Total Non-Regular Staff**	6.4	3.3	2.4	1.4	3.4	0.6
6	**Subtotal DNNP Facilities OM&A Staff**	96.4	144.9	146.6	122.5	200.6	238.5
	DNNP Facilities Capital:						
7	**Regular Staff**	189.0	215.0	207.5	185.4	55.1	0.0
	Non-Regular Staff						
8	Term and Extended Temporary	0.0	0.0	0.0	0.0	0.0	0.0
9	Temporary	11.0	10.0	9.0	5.7	1.1	0.0
10	EPSCA	0.0	0.0	0.0	0.0	0.0	0.0
11	**Total Non-Regular Staff**	11.0	10.0	9.0	5.7	1.1	0.0
12	**Subtotal DNNP Facilities Capital**	200.0	225.0	216.5	191.1	56.2	0.0
13	**Total DNNP Facilities OM&A and Capital**	296.4	369.9	363.1	313.6	256.8	238.5

NUCLEAR BASE AND DNNP OPERATIONAL READINESS OM&A COSTS

1.0 PURPOSE

This evidence presents Base OM&A expenses for OPG's nuclear facilities and the Darlington New Nuclear Program ("DNNP") facilities, and DNNP Operational Readiness OM&A costs for the historical period, bridge year, and IR term.

2.0 OVERVIEW

OPG Nuclear Facilities Base OM&A

The OPG nuclear facilities Base OM&A expenses for 2020-2031 are provided in Ex. F2-2-1, Table 1a. This Application seeks approval of OPG Nuclear facilities Base OM&A expenses of $840.4M in 2027, $850.7M in 2028, $898.4M in 2029, $916.8M in 2030, and $1,225.4M in 2031. Compared to the 2022-2026 period, Base OM&A expenses over the IR term are approximately 30% lower.

The 2025-2031 Business Plan recognizes the changes in workforce needs as OPG shifts from an organization that was planning for a significant downsizing to one entering a period of significant investment. During the IR term, Pickering Units 5-8 will be undergoing a refurbishment with Unit 5 return to service planned for May 2031. As such, the Base OM&A expenses over the IR term leading up to, during, and beyond the four unit refurbishment outage, represent a reduction relative to the 2025 and 2026 bridge years due to the refurbishment outage after September 2026. The Base OM&A expenses remain stable for most of the IR term, with an increase in costs in 2031 mainly due to the Pickering Unit 5 return to service.

During the period from 2022-2024, the Company shifted from planning for Pickering shutdown by the end of 2025 to enabling extended operations to September 2026 and beginning to plan for refurbishing Pickering Units 5-8 thereafter. This shift required a responsive workforce plan to meet these changing business needs, while anticipating an increased risk of attrition over

the remaining life of the station. As of 2022, Nuclear Operations OM&A funded Full-Time Equivalents ("FTEs") were beginning to attrite to levels lower than those planned in EB-2020-0290, particular in the PWU-represented Term Employee[1] categories, which if left unaddressed, would have led to inadequate staffing levels to meet operational needs. With the implementation of responsive workforce strategies, by 2023, FTE levels aligned more closely to the original planned resourcing requirements identified in EB-2020-0290. By 2024, FTEs had increased to levels necessary for the extension of Pickering operations to 2026, to maintain site continuity through the planned Pickering refurbishment outage, and to meet ongoing operational and regulatory requirements. A further discussion of OPG's workforce strategies can be found at Ex. F4-3-1, Section 5.

The Nuclear Operations OM&A funded FTE levels over the 2025 and 2026 bridge years support meeting operational needs leading up to the refurbishment outage, while considering anticipated attrition over the remaining life of the station. This period is followed by a forecast reduction of 27.5% in FTEs in 2027 over 2025, as the resources are redeployed to support refurbishment and other areas of the business (Ex. F2-1-1, Table 2a). Staffing levels are then expected to remain stable through 2030 during the refurbishment outage, and then increase in 2031 due to the Pickering Unit 5 return to service. As a result of the refurbishment outage, OPG also expects a reduction to non-regular FTEs over the IR term as compared to the 2025 and 2026 bridge years.

Like other parts of the organization, OPG nuclear facilities Base OM&A expenses have experienced elevated inflationary cost increases since EB-2020-0290, including higher labour cost escalation reflecting bargaining process outcomes, including as a result of the repeal of the *Protecting a Sustainable Public Sector for Future Generations Act, 2019* ("Bill 124"), as discussed in Ex. F4-3-1, Section 6.2.

OPG's plan for both the station and support organizations demonstrates a continued focus on workforce planning and resourcing, cost controls and work reduction or elimination through

[1] Term employee is a Classification of PWU-represented employee who could be hired instead of regular staff in circumstances where employees were likely to be laid off as a result of the planned shutdown of Pickering.

streamlining workflows. OPG continues to implement various fleet-wide and site-specific initiatives for its nuclear business aimed at driving continuous improvement and achieving cost efficiencies (Ex. F2-1-1, Section 3.4).

DNNP Facilities OM&A

The DNNP facilities Base OM&A expenses for 2026-2031 are provided in Ex. F2-1-1, Table 1b. This Application seeks approval of DNNP facilities Base OM&A expenses of $4.3M in 2027, $5.0M in 2028, $5.3M in 2029, $34.4M in 2030, and $119.0M in 2031.

The requested Base OM&A funding for both Operations & Project Support organizations and the station primarily reflects the planned costs for DNNP Unit 1 beginning operations in late October 2030. These planned amounts reflect the anticipated staffing structure for the station based on a minimum complement strategy, leveraging the BWRX-300 plant design to optimize the workforce required to operate and maintain the plant. The design aspects supporting DNNP's more efficient operating and maintenance costs include: passive fail-safe systems with minimal control room and field actions required, plant design simplification through the elimination of systems and components in comparison to traditional Boiling Water Reactors, and where possible, minimizing the variability in training, procedures, and parts. The design facilitates automation of operation, testing and monitoring of plant systems and components.

The planned staffing structure also reflects that staff will be trained and qualified on a wider scope of tasks, leveraging broadened job classifications negotiated for PWU-represented roles. The streamlined operating model also reflects the greater resourcing flexibility negotiated with the union in support of maintenance outages for DNNP operations. Finally, the operating model will benefit from an integrated modern suite of technology that will efficiently address DNNP facilities' needs (Ex. D3-1-1).

The planned base OM&A expenses for the DNNP facilities also include allocations for Operations and Project Support functional groups, aligned with OPG's cost allocation methodology (Ex. F3-1-4).

Under OPG's cost allocation methodology, Operations & Project Support costs can be attributed to the DNNP facilities in three ways, as further detailed in the Elenchus Research Associates report (Ex. F3-4-1, Attachment 1):

1. Direct assignment of specific resources to the DNNP facilities;
2. Direct assignment of specific resources to the nuclear business as a whole, the costs of which are in turn allocated amongst the nuclear facilities including to the DNNP facilities using a cost driver; and
3. Allocation of costs across OPG's business, which are typically allocated to the individual OPG operating facilities, including the DNNP facilities, using an applicable cost driver.

DNNP Operational Readiness OM&A

In advance of DNNP facilities operations, resources will be leveraged to ensure readiness to safely, reliably and effectively operate these first-of-a-kind units once they are online (Section 4.0). DNNP Operational Readiness OM&A expenses over the IR term are provided in Ex. F2-1-1, Table 1b. This Application seeks OEB approval for DNNP Operational Readiness OM&A expenses of $45.9M for 2027, $46.3M for 2028, $40.0M for 2029, $40.2M for 2030, and $0.0M for 2031.

3.0 BASE OM&A BACKGROUND

Base OM&A funds the operations and maintenance of the nuclear stations, in support of:

- the safe operation of the plants;
- the ongoing production of electricity from the operating nuclear units;
- improving the reliability of the nuclear assets; and
- ensuring compliance with applicable legislation and nuclear regulatory requirements.

3.1 Base OM&A Description by Function and Resource Type

The Base OM&A costs for OPG nuclear facilities and DNNP facilities over the IR term are presented by Nuclear Station and Operations and Project Support in Ex. F2-2-1, Table 1a and 1b. The Nuclear Station and Operations and Project Support functions are described in Attachment 1 to this exhibit. Exhibit F2-2-1, Table 1a breaks out the Capacity Refurbishment Variance Account eligible nuclear facilities Base OM&A expenses, consisting of the Fuel Channel Life Extension Project, Pickering Extended Operations, and Optimization of Pickering Shutdown Enabling Costs (Ex. F2-1-1).[2]

Details of station Base OM&A costs by function and the allocation of Operations and Project Support costs between Pickering, Darlington and DNNP facilities for 2027-2031, are provided in Ex. F2-2-1, Tables 10-14. For OPG nuclear facilities, the majority of station base OM&A costs during the IR term are in the Operations and Maintenance functions, reflecting the significance of these core activities to ongoing station performance. As shown in Ex. F2-2-1, Table 1a, within Operations and Project Support, the majority of costs are Enterprise Engineering and Integrated Fleet Management, primarily for ensuring plant safety, reliability and training. In 2031, the majority of DNNP facilities station Base OM&A costs are in the Operations and Maintenance functions, reflecting the significance of these core activities to ongoing station performance, and within Operations and Project Support the majority of costs are in Enterprise Engineering and Integrated Fleet Management, primarily for ensuring plant safety, reliability and training.

In addition to the operational functions described in Attachment 1, OPG nuclear facilities Base OM&A also funds the following:

- The cost of staffing resources supporting the execution of planned outages, with the exception of Advanced Inspection and Maintenance (formerly Inspection and Reactor Innovation). The cost of Advanced Inspection and Maintenance staff involved in the execution of planned outages is charged directly to outage OM&A.

[2] See Ex. H1-1-1 for discussion of the Capacity Refurbishment Variance Account.

- All costs for forced outages, planned derates and forced derates. Forced outages can require significant effort and materials to address the cause of the outage and return a unit to operation. As forced outages are unplanned events for which no budget is provided, other base OM&A work must be deferred to accommodate them (see Ex. F2-4-1 for further details on outage costing).
- An inventory obsolescence provision to account for potential losses from inventory that may become obsolete, unsellable, or unusable in the future.

Base OM&A cost information for nuclear facilities and DNNP facilities are presented by standard OPG resource types in Ex. F2-2-1, Table 2a and 2b. OPG labour (regular and non-regular) is the most significant contributor to Base OM&A costs representing approximately 70.5% for OPG's nuclear facilities and 58.1% for DNNP facilities.

The resource types are as follows:

1. **Labour:** The salary and benefits cost of OPG full-time regular staff consisting of management, Society of United Professionals and Power Workers' Union employees. Base OM&A labour costs are derived using standard labour rates for job families within Nuclear. In addition to base salary and statutory benefits (e.g., Employment Insurance, Canada Pension Plan), these standard labour rates include a component for pension and other post-employment benefits earned by employees for current service (discussed in Ex. F4-3-2) as well as a component for current employee health, dental and other benefits provided during employment.
2. **Non-Regular Labour**: The salary and any applicable benefits cost of OPG non-regular staff consisting of Power Workers' Union Term Employee, Society of United Professionals Extended Temporary Employee, and other employees hired for a fixed period of time with a start and end date.
3. **Overtime:** The cost of incremental pay for work outside of core hours, for example during forced outages or urgent repairs.
4. **Augmented Staff:** Costs for external personnel providing specialized expertise (e.g., engineering) to supplement internal capability and/or to fill temporary vacancies.

5. **Materials:** The costs of all consumables, replacement parts, and associated transportation service costs supporting station operations (e.g., ongoing maintenance and repair work).
6. **Licence Fees:** The cost of licensing-related fees primarily paid to the Canadian Nuclear Safety Commission ("CNSC").
7. **Other Purchased Services:** The costs of specialized external services, including construction and maintenance services, laundry services, and specialized technical services (e.g., nuclear safety analysis, research and development, and specialized testing services). A discussion of the trend in Other Purchased Services over the period 2027-2031 is provided below.
8. **Other:** Costs for miscellaneous items such as variable low and intermediate level waste expenses, travel, and inventory obsolescence provision.

Leading into 2024, OPG has increasingly relied on the use of Term Employees and other non-regular labour for Base OM&A work, within collective agreement provisions, to effectively manage staffing resources required in contemplation of the then planned Pickering shutdown. In 2024, OPG made a decision to hire a number of Term Employees to regular positions within operations and maintenance in the face of increased attrition and a tightening labour market supply for these skillsets (Ex. F4-3-1, Section 5.1.1). Over the IR term, use of non-regular staff is planned to further decrease as the Company redeploys resources from the Darlington Refurbishment Program and Pickering to support its base work programs over this period. A breakout of total FTEs for OPG nuclear facilities and DNNP facilities is provided in Ex. F2-1-1, Table 2a and 2b, respectively, which separately identifies FTEs funded by OM&A, capital, refurbishment, nuclear non energy direct and provision.[3]

Incremental short-term labour resources, including overtime, non-regular labour, augmented staff and Other Purchased Services, are used as appropriate to operate the nuclear facilities safely, reliably and efficiently. Three primary factors have traditionally driven the use of incremental short-term labour resources in Nuclear: 1) to meet peak work requirements, 2) to maintain coverage for key staff positions in accordance with licensing requirements, and 3) to complete priority work impacted by short term or staff shortages due to factors such as

[3] "Provision" refers to OPG's accrued liabilities for nuclear decommissioning and waste management (Ex. C2-1-1).

temporary vacancies, permissible leaves, and vacations. The selection of incremental labour resource type to employ is an ongoing resource optimization and balancing process and depends on the specific circumstances driving the need for incremental resources. For example, OPG uses Base OM&A overtime to maintain coverage of key positions (e.g., authorized nuclear operators) and provide backup for these staff if absent, to maintain minimum staff complement on each shift.

For OPG nuclear facilities Base OM&A, the need for short term resources, including Other Purchased Services, remains stable from 2027-2030 before increasing (Ex. F2-2-1, Table 2a) with the return of Pickering Unit 5 to service in 2031. For DNNP facilities base OM&A, incremental short-term labour resources costs are immaterial over the IR term, with Unit 1 commercial in service planned in October 2030 (Ex. F2-2-1, Table 2b).

3.2 Major Objectives and Focus Areas

The 2025-2031 Business Plan identifies specific objectives, focus areas and planned costs to drive productivity and efficiency. These initiatives are expected to position Darlington's Total Generating Cost within second quartile of industry performance toward the end of the Business Plan period, while maintaining continued safe and reliable operations (Ex. F2-1-1).

In order to meet planned OM&A costs, fleet-wide initiatives have been implemented for the Nuclear business, as discussed in Ex. F2-1-1, Section 3.4.2.1. These initiatives are designed to help achieve the 2025-2031 Business Plan targets (Ex. F2-1-1, Section 3.3), and over the IR term, will be executed by Base OM&A resources (for Darlington) and both Base OM&A and Pickering Cyclical Maintenance OM&A resources (for Pickering), who will carry out ongoing inspection, maintenance and regulatory compliance activities, and ensure operational readiness for return to service at Pickering.[4]

[4] Engineering, maintenance, security, and nuclear operators.

3.3 Ongoing Station Support and Compliance Activities During Pickering Refurbishment

Separate from the workforce requirements for the Pickering Refurbishment, there is ongoing work necessary to maintain Pickering Units 5-8 and the associated infrastructure during the four unit refurbishment outage, while ensuring compliance with Licence requirements and readiness to return the unit to service. The Licence incorporates a comprehensive review of station operations and includes compliance requirements with regulatory standards, such as protecting the health and safety of the public and the environment, maintaining national security and adhering to international obligations. The Licence conditions continue to apply to Pickering throughout the entire refurbishment outage. These conditions require OPG to maintain applicable resources across a range of key support functions across the following areas: Enterprise Engineering, Integrated Fleet Management, Environment, Health & Safety, and Other Support. Base OM&A funding for such work over the IR term is inclusive of the following:

- **Enterprise Engineering**: The equipment and systems at the station, whether in active refurbishment or awaiting refurbishment, will require monitoring, oversight and troubleshooting along with ongoing execution of aging management programs. Such systems on all four units will cover areas such as nuclear and conventional safety functions, security, water supply systems, radiation protection, electrical supplies including battery banks, will remain in-service during the refurbishment outage.

  Within the Licence, there are CNSC regulations and other requirements, including the Ontario Building Code, Ontario Fire Code, *Environmental Protection Act*, American Society of Mechanical Engineers Pressure Boundary Code (“ASME”) and many standards within the Canadian Standards Association framework, that must continue to be adhered to during the refurbishment outage. For example, the ASME code requires that safety relief valves for systems and components installed to prevent over pressure events continue to be replaced and tested on a routine basis to ensure high quality protection, which requires engineering oversight.

The work required to meet regulations set out in the Licence and to support upkeep of the equipment requires both Station and Central engineering support.

For example, most digital control computer and control systems, chemistry technical support systems, periodic inspection programs, environmental qualification and pressure boundary programs will remain active when the units are de-fueled and de-watered, thereby requiring proper testing and maintenance for safety and regulatory compliance. Nuclear operational safety requirements include maintaining and developing codes and tools for Irradiated Fuel Bay stored fuel, implementing modifications and fuel management studies to support fresh core operation, and ongoing compliance activities with the CNSC. Other activities include fish diversion system maintenance and wildlife count reporting, and groundwater contamination testing.

Furthermore, OPG will also continue membership in Conexus (formerly CANDU Owners Group) with respect to Pickering. Maintaining Conexus membership throughout the refurbishment outage period benefits OPG and supports “second life” operations by maintaining OPG’s involvement in research and development areas of focus.

- **Integrated Fleet Management:** This organization carries out a number of central functions including security, fleet maintenance, fleet operations including human performance and stakeholder relations. These functions are integral to meeting ongoing site requirements during the refurbishment outage.

Site security programs must continue, including the emergency preparedness program, patrols of the protected area, performance monitoring, reporting requirements to the CNSC, fire protection, and administration of material safety and other permits.

Fleet maintenance is required to support systems such as service water, instrument and service air and heating, ventilation and air conditioning, which must be performed in accordance with OPG maintenance program governance and federal and provincial

requirements. Fleet maintenance also supports on going programs such as hoisting and rigging, foreign material exclusion, equipment calibration and control.

Fleet operations provides program governance and oversight for the maintenance program and is the primary interface to external agencies including the World Association of Nuclear Operators ("WANO") and the CNSC. This also includes ownership, oversight and support of the corporate work protection program which is required to ensure compliance with OHSA and other corporate requirements.

Furthermore, OPG will also continue membership in WANO with respect to Pickering. Maintaining WANO membership is fundamental to OPG's role as a nuclear fleet operator focused on ensuring excellence in operational nuclear safety.

- **Other Support:** The Licence and CSA Standard N286-12 require independent assessments of all 46 programs applicable to OPG Nuclear Management System. The nuclear oversight function will continue to complete audits and assessments on these programs to assess all activities affecting Pickering. These audits and assessments will continue to identify opportunities for improvement supporting safe, reliable maintenance of the facility. The nuclear regulatory affairs function will continue to interface with the CNSC in relation to the ongoing Licence requirements independent of the PRP.

3.4 OPG Nuclear Facilities Base OM&A Trends

The decrease in IR term Base OM&A expenses compared to the previous five-year period reflects the transition of Pickering Units 5-8 to refurbishment, with all four units planned to come offline in September 2026. It also reflects the permanent shutdown of Pickering Units 1 and 4 in the fourth quarter of 2024. The planned return to service of Unit 5 in May 2031 results in a restoration of substantial Base OM&A funding for part of that year. This funding reflects the substantial fixed costs involved in operating any one unit at the station. In line with these factors, Pickering's Base OM&A expenses decrease from an average of approximately $420M over the 2022-2026 period to an average of under $20M over the 2027-2030 period before

partially restoring to over $250M in 2031. These figures are inclusive of labour and other cost escalation impacts over time.

Darlington's Base OM&A expenses are forecasted to have a generally stable trend, reflecting ongoing station operations with the last unit, Unit 4, expect to return from refurbishment by April 2026. Excluding the impact of higher materials requirements beginning in 2027, associated with the return to four-unit operations, Darlington's Base OM&A expenses are forecast to increase by approximately 2.75% per year over the 2024-2031 period reflecting labour and other cost escalation. Planned Darlington Base OM&A expenses average just over $425M over the IR term.

Planned Base OM&A expenses for Operations & Project Support groups average approximately $440M per year over the 2027-2030 period, compared to $550M during the 2022-2026 period. This approximately 20% decrease reflects the transition of Pickering Units 5-8 to refurbishment. Similar to the Pickering station Base OM&A expenses, the costs are forecast to restore to approximately $520M in 2031. The figures above are inclusive of labour and other cost escalation impacts.

An explanation of period-over-period variances in base OM&A is provided in Ex. F2-2-2.

3.5 DNNP Facilities Base OM&A Trends

DNNP facilities Base OM&A costs are forecasted to be generally stable leading up to the commercial in-service date of October 2030, with modest amounts of costs attributed from Operations and Project Support Functional groups under OPG's cost allocation methodology during this period. Costs then increase as the first unit that goes into service in October 2030 and then has its first full year of operation in 2031.

An explanation of period-over-period variances in Base OM&A is provided in Ex. F2-2-2.

4.0 DNNP OPERATIONAL READINESS BACKGROUND

DNNP Operational Readiness includes activities required for ensuring readiness to safely, reliably and effectively operate Unit 1 once commercially in-service. These activities will cover comprehensive planning efforts such as developing operational processes and procedures, establishing work management functions for scheduling routine and outage maintenance, planning for emergency management and fire protection, implementing plant maintenance protocols, implementing comprehensive employee training programs tailored to the operation and maintenance requirements of the units, creating a specialized workforce with technology-specific expertise, defining oversight systems and establishing operational targets.

DNNP Operational Readiness also includes the training of the staff who will operate Unit 1 once it is commercially in-service, with the initial hiring cohort planned to occur in late 2026. Once staff completes training, they will support Operational Readiness activities and/or transition to commissioning as required by the DNNP project schedule. Commissioning is a DNNP capital funded workstream. Additional cohorts will be hired closer to Unit 1 commercial in-service to ensure that the planning and commissioning needs of the unit are met.

4.1 Operational Readiness OM&A Trends

DNNP Operational Readiness OM&A is forecasted to increase year-over-year by 59.5% in 2027, 0.9% in 2028, decrease by 13.7% in 2029, increase by 0.7% in 2030, and decrease 100.0% in 2031. Costs over the IR term vary as OPG prepares operational readiness for Unit 1 of the DNNP. The increase in 2027 compared to 2025-2026 is driven by the hiring and training of future operational staff and support required to plan the operations and management of the first unit. The decrease in 2029 is driven by staff transitioning from supporting operational readiness to commissioning. The decrease in 2031 is driven by Unit 1 becoming operational in October 2030.

LIST OF ATTACHMENTS

Attachment 1: Nuclear Operations Function Descriptions

NUCLEAR OPERATIONS FUNCTION DESCRIPTIONS

Since the OEB's Decision and Order in EB-2020-0290, there have been several changes to the structure of Nuclear operations.[1] For purpose of presentation of Base OM&A costs in Ex. F2-1-1, Table 1a and 1b and Ex. F2-2-1, Tables 3 to 14, Nuclear Operations functions has been segmented into Nuclear Stations, and Operations and Project Support, with the above changes applied to actuals and restated OEB-approved as if effective in 2020, unless otherwise noted below.

The following provides details on the operational functions within Nuclear Stations and Operations and Project Support.

1.0 OPERATIONAL FUNCTIONS WITHIN THE GENERATING STATIONS

At each of the generating stations (Darlington, Pickering and, as applicable in the future, DNNP facilities), operational functions are broken down into three main components: Operations and Maintenance, Work Management, and Site and Support Services, as described below. Darlington also operates the Tritium Removal Facility ("TRF")**.**

- Operations and Maintenance is comprised of:
  - Operations, which operates the plant on a 24-hour basis. The CNSC approves the operations organizational structure, including mandating a minimum shift complement to address foreseeable emergency response requirements.
  - Maintenance, which performs:
    - Maintenance activities, which includes all activities directly related to the preventive, elective, and corrective maintenance of structures, systems, or components to address material condition issues, maintain equipment reliability, and optimize equipment life, and,
    - Fuel Handling, which includes all activities in support of refuelling the reactor during unit operation; maintenance of the fuelling machines and related

[1] These changes are summarized in Ex. A1-3-1, Attachment 1, along with the normalization of historic Nuclear OM&A categories.

systems; support of outage activities requiring the fuelling machine or related systems; and management of new fuel storage.

- Work Management includes:
  - Work Control, which ensures that corrective, elective, and preventive maintenance is planned effectively and efficiently.
  - Outage Planning, which develops specific milestones for scope definition, long lead materials, schedule development, and pre-requisite work.

- Site and Support Services includes:
  - Chemistry, which includes the operation of the chemistry lab and assistance in managing plant chemistry.
  - Common Services (Pickering), which operates and maintains station and site support systems for the Pickering station, specifically management of heavy water and operation of facilities such as heavy water upgraders, station containment systems and radioactive waste management.
  - Site Vice President's office.
  - Interface with World Association of Nuclear Operators ("WANO") and other external parties.
  - Radiation Safety, which is accountable for radiation protection programming and services including assistance with radiation protection during plant operation and maintenance activities, and administration of the program for keeping radiation As Low As Reasonably Achievable ("ALARA").
  - Performance Improvement, which has oversight of Nuclear's corrective action program, nuclear safety culture, and a self-assessment program that conducts research and collects information to resolve a performance gap or to identify opportunities to achieved industry excellence in specific program areas.

- Tritium Removal Facility
  - Located at Darlington, the TRF provides tritium removal services to all OPG nuclear stations and third party customers (see Ex. G2-1-1).

2.0 OPERATIONAL FUNCTIONS WITHIN OPERATIONS AND PROJECT SUPPORT

Operations and Project Support is accountable for providing specialized services to the stations, as well as establishing the common procedural framework within which the stations operate.

For the purpose of presentation of Base OM&A in Ex. F2-2-1, Tables 1a and 1b and Ex. F2-2-1, Tables 3 to 14, Operations and Project Support has been segmented into the functional groups shown below. The following are the key functions within each group:

Enterprise Engineering is accountable for the following:

- Components Engineering provides specialized technical support for nuclear station components and equipment, major nuclear plant equipment (including life cycle plans for steam generators and fuel channels), engineering programs, selected systems (such as real-time process computers and security), chemistry, human factors engineering, plant information systems, and administration of the nuclear research and development program. This is a central function.
- Design Engineering provides design services such as, preparation of modifications; parts procurement support; and expert-level support on nuclear industry codes and standards for the nuclear stations and Nuclear Sustainability Services. This is a design function.
- Engineering Strategy provides strategic support to Enterprise Engineering long range planning, develops international relationships and provides strategic advice on matters relating to reactor technology, represents OPG Nuclear with international nuclear industry bodies and oversees Nuclear Projects executed by Enterprise Engineering. Engineering Strategy also oversees the strategy for data-driven decision making in all areas of Enterprise Operations, through a dedicated Data Analytics team (formerly part of the Generation Strategy & Innovation group) provides insights into operations areas through the application of analytics on a broad range of available data, manage data governance, collaborate on architecture development, and will include the operation of the Monitoring & Diagnostics Centre. This is a central function.

- Nuclear Safety provides oversight of technical support provided to the stations by the Reactor Safety Engineering Departments, and specialized services in the areas of Fuel, Nuclear Safety Analysis and Probabilistic Risk Assessment. This is a central function.
- Station Engineering is responsible for specifying engineering requirements, concurrence to schedule and acceptance of engineering products and services provided to support safe operation of the plant. It also ensures the Safety Operating Envelope and the Design and Licensing Basis for the plant are maintained by exercising prescriptive authority for the definition of operating and outage scope of work associated with these basis documents. This is a station function.
- Advanced Inspection and Maintenance (formerly Inspection and Reactor Innovation) ("AIM") is accountable for providing inspection and maintenance services to supplement those carried out by station staff, where the nature of the skills or equipment required makes the work more effectively managed as a centralized function. The direct costs associated with the provision of inspection and maintenance services during outages are included in outage OM&A costs (Ex. F2-4-1). AIM indirect costs such as administration are included in base OM&A as are the provision of inspection and maintenance services during normal (i.e. non-outage) operation. Machine dynamics and performance testing services. This is a central function.

Integrated Fleet Management has three main functions:

- Generation Strategy & Innovation, which drives improvement across the Nuclear fleet by developing, implementing and monitoring nuclear-wide programs and procedures for the nuclear stations in the areas of Operations, Maintenance, Performance Improvement Support and Human Performance. It is also responsible for nuclear fleet-wide asset management and generation planning, to ensure a strategic and streamlined approach to determining future investments considering cost, risk and performance. Enterprise Innovation is also part of this organization, developing and implementing value-based fleet initiatives and improvements.

- Security services for nuclear sites and facilities (and across OPG) and ensures compliance with all CNSC security requirements. Emergency Preparedness and Fire Protection services are also included within this division.
- Nuclear Training has the role of training personnel to safely operate, maintain and improve performance of the Pickering and Darlington nuclear stations. The most effective way to ensure public safety and a reliable source of electricity to the grid for public safety and national security, is to ensure that the personnel that operate, maintain and engineer these commercial nuclear power plants have been trained, evaluated and qualified to consistently high standards. The group is responsible for all Training Analysis, Design, Development, Implementation and Evaluation activities associated with Nuclear Training that leads to working rights (qualifications). It is also responsible for all Nuclear Plant Access Training (regular and contractor staff) and the Training Information Management System for all of the OPG Nuclear Fleet.

<u>Environment and Health & Safety (formerly in Support Services) ("EHS") is accountable for the following:</u>

- The Environment, Health & Safety ("EHS") organization develops and maintains EHS managed systems, programs and initiatives that support all employees in the company. The group provides expertise and operational support to OPG operations, facilities, projects and functions to meet EHS compliance obligations. It acts to minimize EHS risks and impacts, and advises on management of environmental issues, health and safety hazards, and prevention of workplace injuries in support of a strong safety culture. The group reports on OPG's environmental and health & safety performance, and performance and seeks opportunities for EHS to promote leadership and innovation. Finally, it provides assessment and specialist support in the areas of aquatic and terrestrial biology, contaminated land and groundwater, radiological management, air and water emissions, waste and spills management, safe work planning, permits and approvals, impact assessments, regulations, licenses, orders to comply, climate change related impacts and legislative monitoring.

<u>Enterprise Projects</u> includes Nuclear Projects as well as the Enterprise Project Management Office and Commercial Management & Project Assurance.

- Nuclear Projects, which is responsible for the planning, developing and execution of all nuclear projects (other than the Darlington Refurbishment Program).
- Enterprise Project Management Office, which is responsible for oversight of the processes, tools and project expertise necessary to deliver successful projects; serves as a source for best practices, training programs and an organizational focus for improving project performance across all portfolios.
- Commercial Management & Project Assurance, which is responsible for commercial relationships to support effective management of contracts during the post award, execution and close out phases, including Nuclear Extended Services Master Services Agreements and Engineering contracts.

Project work (in contrast to base OM&A work) is discussed in Ex. D2-1-1. While the Projects function is primarily funded by project OM&A and capital (Ex. F2-3-1 and Ex. D2-1-1, respectively), a limited amount of operational support to the stations is funded by base OM&A.

Other Support is an aggregate of a number of smaller functions including centralized or fleet-wide costs for services required to manage the Nuclear business that are not directly attributable to any one plant or support organization.

- Nuclear Oversight accountable for independent internal audits to evaluate compliance with regulatory, provincial and federal requirements and performance to industry standards of excellence and examinations of plant functional areas or various plant activities to evaluate the effectiveness of work practices and/or management controls.
- Nuclear Regulatory Affairs and Stakeholder Relations accountable for obtaining required CNSC approvals in a timely manner, ensuring that OPG complies with its licenses, regulatory requirements and commitments, and managing regulatory issues while maintaining good working relations with the CNSC.
- Renewable Generation Operations functions providing support for the Nuclear fleet, such as Energy Markets, with costs shown in Nuclear base OM&A actuals and plan.

- Costs include executive officers, inventory adjustments and, as applicable, Hydro One share awards expenses. Costs also include the limited amount of base OM&A in Nuclear Sustainability Services.

Low and Intermediate Level Waste includes low and intermediate level waste storage and disposal variable expenses for the Nuclear stations (Ex. C2-1-1).

Numbers may not add due to rounding.

Table 1a
Base OM&A - OPG Nuclear Facilities ($M)

Line No.	Function	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	OPG Nuclear Facilities[1]												
1	Darlington NGS	324.5	334.9	337.6	340.3	361.4	371.9	373.3	409.0	405.9	432.3	437.4	447.6
2	Pickering NGS	459.4	460.3	450.0	521.3	468.8	370.8	305.7	8.1	15.5	22.3	24.6	255.6
3	**Total OPG Nuclear Facilities**	783.9	795.2	787.7	861.6	830.2	742.7	679.0	417.1	421.4	454.5	462.1	703.3
	Operations and Project Support[1,2]												
4	Enterprise Engineering	217.2	209.3	215.7	242.5	253.0	239.4	217.8	164.0	164.8	173.9	177.0	217.6
5	Integrated Fleet Management	188.2	178.9	173.6	188.5	221.9	203.3	200.3	165.8	169.5	176.1	183.1	205.2
6	Environment, Health & Safety	18.0	21.9	16.0	13.9	13.5	11.8	14.3	14.0	14.3	13.7	14.6	15.6
7	Enterprise Projects	15.5	16.9	17.7	16.1	16.4	13.2	9.5	6.4	6.9	6.5	6.4	7.0
8	Other Support	68.7	72.1	67.4	81.5	84.1	82.9	79.6	69.5	70.3	71.2	70.9	72.7
9	Low and Intermediate Level Waste	6.9	6.7	16.3	12.3	11.5	9.2	9.7	3.6	3.4	2.6	2.7	4.1
10	**Total Operations and Project Support**	514.4	505.8	506.6	554.8	600.4	559.8	531.2	423.3	429.2	443.9	454.7	522.2
	CRVA Eligible Costs												
11	Fuel Channel Life Extension Project	7.8	8.7	9.7	1.1	(0.1)	0.4	0.0	0.0	0.0	0.0	0.0	0.0
12	Pickering Extended Operations	7.2	5.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Optimization of Pickering Shutdown	0.5	0.9	1.7	1.4	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	**Total CRVA Eligible Costs**	15.6	15.0	11.4	2.5	2.8	0.4	0.0	0.0	0.0	0.0	0.0	0.0
15	**Total Base OM&A**	1,313.9	1,316.0	1,305.7	1,418.9	1,433.5	1,303.0	1,210.2	840.4	850.7	898.4	916.8	1,225.4

Notes:

1 The figures presented here for 2020 Actuals have been restated for Nuclear organizational changes and transfers from Corporate Support ((See Ex. A1-4-1 Attachment 2 and Ex. F2-2-1, Attachment 1).

2 Operations and Project Support has been allocated between Darlington NGS and Pickering NGS:

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Darlington NGS	235.4	241.7	229.9	241.2	278.9	287.3	282.6	299.2	303.9	312.8	313.4	318.1
Pickering NGS	279.0	264.0	276.7	313.6	321.5	272.6	248.6	124.1	125.3	131.1	141.3	204.0

Numbers may not add due to rounding.

Table 1b
Base OM&A - DNNP Facilities ($M)

Line No.	Function	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	DNNP Facilities						
1	DNNP Facilities	0.0	0.0	0.0	0.0	18.2	66.1
2	**Total DNNP Facilities**	0.0	0.0	0.0	0.0	18.2	66.1
	Operations and Project Support						
3	Enterprise Engineering	0.4	0.5	0.5	0.6	5.0	16.6
4	Integrated Fleet Management	0.1	0.1	0.1	0.2	4.7	25.2
5	Environment, Health & Safety	0.5	0.7	0.8	0.9	1.0	0.9
6	Enterprise Projects	1.3	1.1	1.3	1.5	1.6	1.4
7	Other Support	1.6	2.0	2.2	2.3	3.8	8.8
8	Low and Intermediate Level Waste	0.0	0.0	0.0	0.0	0.0	0.0
9	**Total Operations and Project Support**	3.9	4.3	5.0	5.3	16.1	52.9
10	**Total Base OM&A**	3.9	4.3	5.0	5.3	34.4	119.0

Numbers may not add due to rounding.

Updated: 2026-03-10
EB-2025-0297
Exhibit F2
Tab 2
Schedule 1
Table 2a

Table 2a

Base OM&A - OPG Nuclear Facilities ($M)[1]

Line No.	Resource Type	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan	IR Term Percentage[2]
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	**Labour**	791.1	756.9	708.8	785.3	834.6	847.6	805.3	570.0	587.9	628.9	638.9	860.1	69.4%
2	**Non-Regular Labour[3]**	126.1	140.5	153.0	175.9	135.9	48.4	44.5	10.1	9.3	9.8	9.9	10.4	1.0%
3	**Overtime**	70.4	70.4	79.1	84.3	89.6	72.8	54.5	36.4	37.9	39.0	40.5	61.6	4.6%
4	**Augmented Staff**	13.5	13.2	9.8	9.2	8.2	2.6	0.6	1.5	1.3	1.3	1.3	1.3	0.1%
5	**Materials**	105.6	101.5	106.4	110.2	114.5	90.9	82.7	53.9	52.4	55.0	56.6	85.9	6.4%
6	**License Fees**	31.6	34.4	33.4	37.1	40.7	38.0	35.7	23.7	24.1	24.6	25.1	30.9	2.7%
7	**Other Purchased Services**	130.2	151.1	159.6	143.4	164.9	166.6	154.5	117.5	110.3	111.2	114.4	141.5	12.6%
8	**Other[4]**	45.3	47.9	55.7	73.4	45.0	36.1	32.3	27.3	27.4	28.7	30.1	33.6	3.1%
9	**Total Base OM&A**	1,313.9	1,316.0	1,305.7	1,418.9	1,433.5	1,303.0	1,210.2	840.4	850.7	898.4	916.8	1,225.4	100.0%

Notes:

1 The figures presented here for 2020 Actuals have been restated for Nuclear organizational changes and transfers from Corporate Support ((See Ex. A1-4-1 Attachment 2 and Ex. F2-2-1, Attachment 1).

2 IR Term Percentage = Sum of IR Term Resource Costs divided by Sum of IR Term Base OM&A.

3 Non-Regular labour includes costs for term and temporary staff.

4 Other costs include Low & Intermediate Level Waste expenses as per Ex. F2-2-1, Table 1a, line 9.

Numbers may not add due to rounding.

Table 2b
Base OM&A - DNNP Facilities ($M)

Line No.	Resource Type	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan	IR Term Percentage[1]
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Labour**	3.2	3.8	4.3	4.6	17.0	67.6	57.9%
2	**Non-Regular Labour[2]**	0.0	0.0	0.0	0.0	0.1	0.2	0.2%
3	**Overtime**	0.0	0.0	0.0	0.0	0.3	1.3	1.0%
4	**Augmented Staff**	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
5	**Materials**	0.1	0.0	0.1	0.1	2.7	9.4	7.3%
6	**License Fees**	0.0	0.0	0.0	0.0	0.6	4.0	2.7%
7	**Other Purchased Services**	0.5	0.3	0.4	0.5	11.8	30.1	25.7%
8	**Other**	0.1	0.1	0.1	0.2	1.8	6.4	5.2%
9	**Total Base OM&A**	3.9	4.3	5.0	5.3	34.4	119.0	100.0%

Notes:
1 IR Term Percentage = Sum of IR Term
2 Non-Regular labour includes costs for term and temporary staff.

Table 3
Combined Nuclear Base OM&A by Function ($M)
Actual - Calendar Year Ending December 31, 2020

Line No.	Function	Darlington NGS	Pickering NGS	Total OPG Nuclear Facilities	DNNP Facilities
		(a)	(b)	(c)	(d)
	Nuclear Stations[1]				
1	Operations & Maintenance	268.1	377.4	645.5	0.0
2	- Operations	90.6	124.2	214.8	
3	- Maintenance	177.5	253.2	430.7	
4	Work Management	15.4	18.6	34.1	
5	Site and Support Services	29.6	63.3	93.0	
6	Tritium Removal Facility	11.4		11.4	
7	**Total Nuclear Stations**	324.5	459.4	783.9	0.0
8	**Operations and Project Support**[1]	235.4	279.0	514.4	0.0
	CRVA Eligible Costs				
9	Fuel Channel Life Extension Project	4.3	3.5	7.8	
10	Pickering Extended Operations		7.2	7.2	
11	Optimization of Pickering Shutdown		0.5	0.5	
12	**Total CRVA Eligible Costs**	4.3	11.3	15.6	0.0
13	**Total Base OM&A**	564.2	749.7	1,313.9	0.0

Notes:

1 The figures presented here are 2020 Actuals that have been restated for Nuclear organizational changes and transfers from Corporate Support (See Ex. A1-4-1 Att. 2 and Ex. F2-2-1, Att. 1).

Table 3a
Combined Nuclear Base OM&A by Function ($M)
OEB Approved[1] - Calendar Year Ending December 31, 2020

Line No.	Function	Darlington NGS	Pickering NGS	Total OPG Nuclear Facilities	DNNP Facilities
		(a)	(b)	(c)	(d)
	Nuclear Stations[1]				
1	Operations & Maintenance	269.9	397.9	667.8	0.0
2	- Operations	95.9	130.8	226.8	
3	- Maintenance	174.0	267.1	441.0	
4	Work Management	18.8	21.2	40.0	
5	Site and Support Services	33.5	71.0	104.5	
6	Tritium Removal Facility	12.2		12.2	
7	**Total Nuclear Stations**	334.4	490.1	824.5	0.0
8	**Operations and Project Support** [1]	218.4	307.9	526.3	0.0
	CRVA Eligible Costs				
9	Fuel Channel Life Extension Project	2.4	3.6	6.0	
10	Pickering Extended Operations		0.0		
11	Optimization of Pickering Shutdown		0.0		
12	**Total CRVA Eligible Costs**	2.4	3.6	6.0	0.0
13	**Total Base OM&A**	555.2	801.6	1,356.8	0.0

Notes:
1 The figures presented here are 2020 Plan (from EB-2016-0152, Ex. F2-2-1, Table 7) that have been restated for Nuclear organizational changes and transfers from Corporate Support (See Ex. A1-4-1 Att.2 and Ex. F2-2-1, Att.1).

Table 4
Combined Nuclear Base OM&A by Function ($M)
Actual - Calendar Year Ending December 31, 2021

Line No.	Function	Darlington NGS	Pickering NGS	Total OPG Nuclear Facilities	DNNP Facilities
		(a)	(b)	(c)	(d)
	Nuclear Stations[1]				
1	Operations & Maintenance	270.1	370.1	640.2	0.0
2	- Operations	90.3	118.6	208.9	
3	- Maintenance	179.8	251.5	431.3	
4	Work Management	17.8	17.2	35.0	
5	Site and Support Services	32.6	73.0	105.6	
6	Tritium Removal Facility	14.4		14.4	
7	**Total Nuclear Stations**	334.9	460.3	795.2	0.0
8	**Operations and Project Support**[1]	241.7	264.0	505.8	0.0
	CRVA Eligible Costs				
9	Fuel Channel Life Extension Project	3.5	5.2	8.7	
10	Pickering Extended Operations		5.4	5.4	
11	Optimization of Pickering Shutdown		0.9	0.9	
12	**Total CRVA Eligible Costs**	3.5	11.5	15.0	0.0
13	**Total Base OM&A**	580.1	735.9	1,316.0	0.0

Notes:
1 The figures presented here are 2021 Actuals that have been restated for Nuclear organizational changes and transfers from Corporate Support (See Ex. A1-4-1 Att.2 and Ex. F2-2-1, Att.1).

Table 4a
Combined Nuclear Base OM&A by Function ($M)
OEB Approved[1] - Calendar Year Ending December 31, 2021

Line No.	Function	Darlington NGS	Pickering NGS	Total OPG Nuclear Facilities	DNNP Facilities
		(a)	(b)	(c)	(d)
	Nuclear Stations[1]				
1	Operations & Maintenance	269.7	400.4	670.1	0.0
2	- Operations	95.1	127.3	222.5	
3	- Maintenance	174.6	273.0	447.6	
4	Work Management	14.6	23.2	37.8	
5	Site and Support Services	35.5	72.2	107.6	
6	Tritium Removal Facility	12.5		12.5	
7	**Total Nuclear Stations**	332.3	495.8	828.0	0.0
8	**Operations and Project Support**[1]	220.7	314.8	535.4	0.0
	CRVA Eligible Costs				
9	Fuel Channel Life Extension Project	2.4	3.6	6.0	
10	Pickering Extended Operations		0.0		
11	Optimization of Pickering Shutdown		0.0		
12	**Total CRVA Eligible Costs**	2.4	3.6	6.0	0.0
13	**Total Base OM&A**	555.3	814.1	1,369.5	0.0

Notes:
1 The figures presented here are 2021 Plan (from EB-2016-0152, Ex. F2-2-1, Table 8) that have been restated for Nuclear organizational changes and transfers from Corporate Support (See Ex. A1-4-1, Att.2 and Ex. F2-2-1, Att. 1).

Table 5
Combined Nuclear Base OM&A by Function ($M)
Actual - Calendar Year Ending December 31, 2022

Line No.	Function	Darlington NGS	Pickering NGS	Total OPG Nuclear Facilities	DNNP Facilities
		(a)	(b)	(c)	(d)
	Nuclear Stations[1]				
1	Operations & Maintenance	267.1	365.0	632.1	0.0
2	- Operations	87.5	114.6	202.1	
3	- Maintenance	179.6	250.4	430.0	
4	Work Management	24.4	16.4	40.8	
5	Site and Support Services	34.8	68.6	103.4	
6	Tritium Removal Facility	11.4		11.4	
7	**Total Nuclear Stations**	337.6	450.0	787.7	0.0
8	**Operations and Project Support**[1]	229.9	276.7	506.6	0.0
	CRVA Eligible Costs				
9	Fuel Channel Life Extension Project	3.9	5.8	9.7	
10	Pickering Extended Operations		0.0	0.0	
11	Optimization of Pickering Shutdown		1.7	1.7	
12	**Total CRVA Eligible Costs**	3.9	7.5	11.4	0.0
13	**Total Base OM&A**	571.4	734.3	1,305.7	0.0

Notes:

1 The figures presented here are 2022 Actuals that have been restated for Nuclear organizational changes and transfers from Corporate Support (See Ex. A1-4-1, Att. 2 and Ex. F2-2-1, Att. 1).

Numbers may not add due to rounding.

Table 5a
Combined Nuclear Base OM&A by Function ($M)
OEB Approved[1] - Calendar Year Ending December 31, 2022

Line No.	Function	Darlington NGS	Pickering NGS	Total OPG Nuclear Facilities	DNNP Facilities
		(a)	(b)	(c)	(d)
	Nuclear Stations[1]				
1	Operations & Maintenance	271.7	374.1	645.8	0.0
2	- Operations	94.7	111.8	206.5	
3	- Maintenance	177.0	262.3	439.3	
4	Work Management	15.9	17.9	33.7	
5	Site and Support Services	33.3	66.9	100.2	
6	Tritium Removal Facility	14.5		14.5	
7	**Total Nuclear Stations**	335.4	458.8	794.2	0.0
8	**Operations and Project Support**[1]	244.3	283.7	528.0	0.0
	CRVA Eligible Costs				
9	Fuel Channel Life Extension Project	2.4	3.5	5.9	
10	Pickering Extended Operations		0.0	0.0	
11	Optimization of Pickering Shutdown		5.8	5.8	
12	**Total CRVA Eligible Costs**	2.4	9.4	11.7	0.0
13	**Total Base OM&A**	582.1	751.9	1,334.0	0.0

Notes:

1 The figures presented here are 2022 Plan (from EB-2020-0290, Ex. F2-2-1, Table 9) that have been restated for Nuclear organizational changes and transfers from Corporate Support (See Ex. A1-4-1, Att.2 and Ex. F2-2-1, Att. 1).

Table 6
Combined Nuclear Base OM&A by Function ($M)
Actual - Calendar Year Ending December 31, 2023

Line No.	Function	Darlington NGS	Pickering NGS	Total OPG Nuclear Facilities	DNNP Facilities
		(a)	(b)	(c)	(d)
	Nuclear Stations[1]				
1	Operations & Maintenance	282.2	410.3	692.5	0.0
2	- Operations	90.2	123.5	213.8	
3	- Maintenance	192.0	286.8	478.8	
4	Work Management	15.6	15.6	31.2	
5	Site and Support Services	30.6	95.4	126.0	
6	Tritium Removal Facility	11.9		11.9	
7	**Total Nuclear Stations**	340.3	521.3	861.6	0.0
8	**Operations and Project Support**[1]	241.2	313.6	554.8	0.0
	CRVA Eligible Costs				
9	Fuel Channel Life Extension Project	0.5	0.7	1.1	
10	Pickering Extended Operations		0.0	0.0	
11	Optimization of Pickering Shutdown		1.4	1.4	
12	**Total CRVA Eligible Costs**	0.5	2.0	2.5	0.0
13	**Total Base OM&A**	581.9	837.0	1,418.9	0.0

Notes:
1 The figures presented here are 2023 Actuals that have been restated for Nuclear organizational changes and transfers from Corporate Support (See Ex. A1-4-1, Att.2 and Ex. F2-2-1, Att. 1).

Numbers may not add due to rounding.

Table 6a
Combined Nuclear Base OM&A by Function ($M)
OEB Approved[1] - Calendar Year Ending December 31, 2023

Line No.	Function	Darlington NGS	Pickering NGS	Total OPG Nuclear Facilities	DNNP Facilities
		(a)	(b)	(c)	(d)
	Nuclear Stations[1]				
1	Operations & Maintenance	268.6	370.3	638.9	0.0
2	- Operations	86.9	108.1	195.0	
3	- Maintenance	181.7	262.2	443.8	
4	Work Management	18.0	16.0	34.0	
5	Site and Support Services	32.5	68.2	100.7	
6	Tritium Removal Facility	14.7		14.7	
7	**Total Nuclear Stations**	333.8	454.5	788.2	0.0
8	**Operations and Project Support**[1]	249.9	279.5	529.4	0.0
	CRVA Eligible Costs				
9	Fuel Channel Life Extension Project	1.7	2.6	4.3	
10	Pickering Extended Operations		0.0		
11	Optimization of Pickering Shutdown		2.7	2.7	
12	**Total CRVA Eligible Costs**	1.7	5.2	7.0	0.0
13	**Total Base OM&A**	585.4	739.2	1,324.6	0.0

Notes:

1 The figures presented here are 2023 Plan (from EB-2020-0290, Ex. F2-2-1, Table 10) that have been restated for Nuclear organizational changes and transfers from Corporate Support (See Ex. A1-4-1, Att. 2 and Ex. F2-2-1, Att.1).

Table 7
Combined Nuclear Base OM&A by Function ($M)
Actual - Calendar Year Ending December 31, 2024

Line No.	Function	Darlington NGS	Pickering NGS	Total OPG Nuclear Facilities	DNNP Facilities
		(a)	(b)	(c)	(d)
	Nuclear Stations[1]				
1	Operations & Maintenance	293.9	393.3	687.2	0.0
2	- Operations	104.4	120.4	224.8	
3	- Maintenance	189.5	272.9	462.4	
4	Work Management	22.6	13.7	36.4	
5	Site and Support Services	33.2	61.8	94.9	
6	Tritium Removal Facility	11.7		11.7	
7	**Total Nuclear Stations**	361.4	468.8	830.2	0.0
8	**Operations and Project Support**[1]	278.9	321.5	600.4	0.0
	CRVA Eligible Costs				
9	Fuel Channel Life Extension Project	(0.1)	0.0	(0.1)	
10	Pickering Extended Operations		0.0	0.0	
11	Optimization of Pickering Shutdown		3.0	3.0	
12	**Total CRVA Eligible Costs**	(0.1)	3.0	2.8	0.0
13	**Total Base OM&A**	640.1	793.3	1,433.5	0.0

Notes:
1 The figures presented here are 2024 Actuals that have been restated for Nuclear organizational changes and transfers from Corporate Support (See Ex. A1-4-1, Att. 2 and Ex. F2-2-1, Att. 1).

Table 7a
Combined Nuclear Base OM&A by Function ($M)
OEB Approved[1] - Calendar Year Ending December 31, 2024

Line No.	Function	Darlington NGS	Pickering NGS	Total OPG Nuclear Facilities	DNNP Facilities
		(a)	(b)	(c)	(d)
	Nuclear Stations[1]				
1	Operations & Maintenance	277.2	352.7	630.0	0.0
2	- Operations	90.5	103.8	194.3	
3	- Maintenance	186.7	248.9	435.7	
4	Work Management	16.6	13.3	29.9	
5	Site and Support Services	31.0	65.3	96.3	
6	Tritium Removal Facility	15.1		15.1	
7	**Total Nuclear Stations**	340.0	431.3	771.3	0.0
8	**Operations and Project Support**[1]	251.0	283.2	534.2	0.0
	CRVA Eligible Costs				
9	Fuel Channel Life Extension Project	0.3	0.5	0.8	
10	Pickering Extended Operations		0.0		
11	Optimization of Pickering Shutdown		4.8	4.8	
12	**Total CRVA Eligible Costs**	0.3	5.3	5.6	0.0
13	**Total Base OM&A**	591.3	719.9	1,311.2	0.0

Notes:
1 The figures presented here are 2024 Plan (from EB-2020-0290, Ex. F2-2-1, Table 11) that have been restated for Nuclear organizational changes and transfers from Corporate Support (See Ex. A1-4-1 Att. 2 and Ex. F2-2-1, Att.1).

Numbers may not add due to rounding.

Table 8
Combined Nuclear Base OM&A by Function ($M)
Budget - Calendar Year Ending December 31, 2025

Line No.	Function	Darlington NGS	Pickering NGS	Total OPG Nuclear Facilities	DNNP Facilities
		(a)	(b)	(c)	(d)
	Nuclear Stations				
1	Operations & Maintenance	299.7	308.8	608.5	0.0
2	- Operations	111.5	86.3	197.8	
3	- Maintenance	188.2	222.5	410.7	
4	Work Management	23.3	10.5	33.8	
5	Site and Support Services	35.6	51.4	87.0	
6	Tritium Removal Facility	13.4		13.4	
7	**Total Nuclear Stations**	371.9	370.8	742.7	0.0
8	**Operations and Project Support**	287.3	272.6	559.8	0.0
	CRVA Eligible Costs				
9	Fuel Channel Life Extension Project	0.4	0.0	0.4	
10	Pickering Extended Operations		0.0	0.0	
11	Optimization of Pickering Shutdown		0.0	0.0	
12	**Total CRVA Eligible Costs**	0.4	0.0	0.4	0.0
13	**Total Base OM&A**	659.6	643.3	1,303.0	0.0

Notes:

Numbers may not add due to rounding.

Table 8a
Combined Nuclear Base OM&A by Function ($M)
OEB Approved - Calendar Year Ending December 31, 2025

Line No.	Function	Darlington NGS	Pickering NGS	Total OPG Nuclear Facilities	DNNP Facilities
		(a)	(b)	(c)	(d)
	Nuclear Stations				
1	Operations & Maintenance	274.9	252.9	527.8	0.0
2	- Operations	90.4	59.9	150.2	
3	- Maintenance	184.6	193.0	377.6	
4	Work Management	20.0	7.4	27.4	
5	Site and Support Services	37.3	56.7	94.0	
6	Tritium Removal Facility	14.2		14.2	
7	**Total Nuclear Stations**	346.4	317.0	663.4	0.0
8	**Operations and Project Support**	238.5	177.7	416.2	0.0
	CRVA Eligible Costs				
9	Fuel Channel Life Extension Project	0.2	0.3	0.4	
10	Pickering Extended Operations		0.0		
11	Optimization of Pickering Shutdown		0.0		
12	**Total CRVA Eligible Costs**	0.2	0.3	0.4	0.0
13	**Total Base OM&A**	585.0	495.0	1,080.0	0.0

Numbers may not add due to rounding.

Table 9
Combined Nuclear Base OM&A by Function ($M)
Budget - Calendar Year Ending December 31, 2026

Line No.	Function	Darlington NGS	Pickering NGS	Total OPG Nuclear Facilities	DNNP Facilities
		(a)	(b)	(c)	(d)
	Nuclear Stations				
1	Operations & Maintenance	299.6	257.4	557.0	0.0
2	- Operations	105.6	72.7	178.4	
3	- Maintenance	194.0	184.6	378.6	
4	Work Management	21.2	7.6	28.9	
5	Site and Support Services	38.7	40.7	79.4	
6	Tritium Removal Facility	13.8		13.8	
7	**Total Nuclear Stations**	373.3	305.7	679.0	0.0
8	**Operations and Project Support**	282.6	248.6	531.2	3.9
	CRVA Eligible Costs				
9	Fuel Channel Life Extension Project		0.0		
10	Pickering Extended Operations		0.0		
11	Optimization of Pickering Shutdown		0.0		
12	**Total CRVA Eligible Costs**	0.0	0.0	0.0	0.0
13	**Total Base OM&A**	655.9	554.3	1,210.2	3.9

Numbers may not add due to rounding.

Table 9a
Combined Nuclear Base OM&A by Function ($M)
OEB Approved - Calendar Year Ending December 31, 2026

Line No.	Function	Darlington NGS	Pickering NGS	Total OPG Nuclear Facilities	DNNP Facilities
		(a)	(b)	(c)	(d)
	Nuclear Stations				
1	Operations & Maintenance	290.0	0.0	290.0	0.0
2	- Operations	91.1		91.1	
3	- Maintenance	198.8		198.8	
4	Work Management	16.3		16.3	
5	Site and Support Services	37.0		37.0	
6	Tritium Removal Facility	14.5		14.5	
7	**Total Nuclear Stations**	357.7	0.0	357.7	0.0
8	**Operations and Project Support**	264.0	(0.0)	264.0	0.0
	CRVA Eligible Costs				
9	Fuel Channel Life Extension Project	0.0	0.0	0.0	
10	Pickering Extended Operations		0.0	0.0	
11	Optimization of Pickering Shutdown		0.0	0.0	
12	**Total CRVA Eligible Costs**	0.0	0.0	0.0	0.0
13	**Total Base OM&A**	621.7	(0.0)	621.7	0.0

Numbers may not add due to rounding.

Table 10
Combined Nuclear Base OM&A by Function ($M)
Plan - Calendar Year Ending December 31, 2027

Line No.	Function	Darlington NGS	Pickering NGS	Total OPG Nuclear Facilities	DNNP Facilities
		(a)	(b)	(c)	(d)
	Nuclear Stations				
1	Operations & Maintenance	321.4	6.4	327.8	0.0
2	- Operations	110.8	6.4	117.2	
3	- Maintenance	210.6	0.0	210.6	
4	Work Management	32.7	0.0	32.7	
5	Site and Support Services	40.5	1.7	42.2	
6	Tritium Removal Facility	14.4		14.4	
7	**Total Nuclear Stations**	409.0	8.1	417.1	0.0
8	**Operations and Project Support**	299.2	124.1	423.3	4.3
	CRVA Eligible Costs				
9	Fuel Channel Life Extension Project		0.0		
10	Pickering Extended Operations		0.0		
11	Optimization of Pickering Shutdown		0.0		
12	**Total CRVA Eligible Costs**	0.0	0.0	0.0	0.0
13	**Total Base OM&A**	708.2	132.2	840.4	4.3

Numbers may not add due to rounding.

Table 11
Combined Nuclear Base OM&A by Function ($M)
Plan - Calendar Year Ending December 31, 2028

Line No.	Function	Darlington NGS	Pickering NGS	Total OPG Nuclear Facilities	DNNP Facilities
		(a)	(b)	(c)	(d)
	Nuclear Stations				
1	Operations & Maintenance	330.0	13.9	343.9	0.0
2	- Operations	112.0	11.3	123.2	
3	- Maintenance	218.0	2.6	220.6	
4	Work Management	18.9	0.0	18.9	
5	Site and Support Services	42.2	1.7	43.8	
6	Tritium Removal Facility	14.8		14.8	
7	**Total Nuclear Stations**	405.9	15.5	421.4	0.0
8	**Operations and Project Support**	303.9	125.3	429.2	5.0
	CRVA Eligible Costs				
9	Fuel Channel Life Extension Project		0.0		
10	Pickering Extended Operations		0.0		
11	Optimization of Pickering Shutdown		0.0		
12	**Total CRVA Eligible Costs**	0.0	0.0	0.0	0.0
13	**Total Base OM&A**	709.8	140.9	850.7	5.0

Numbers may not add due to rounding.

Table 12
Combined Nuclear Base OM&A by Function ($M)
Plan - Calendar Year Ending December 31, 2029

Line No.	Function	Darlington NGS	Pickering NGS	Total OPG Nuclear Facilities	DNNP Facilities
		(a)	(b)	(c)	(d)
	Nuclear Stations				
1	Operations & Maintenance	348.1	18.0	366.1	0.0
2	- Operations	121.7	14.3	136.0	
3	- Maintenance	226.5	3.7	230.1	
4	Work Management	25.2	0.0	25.2	
5	Site and Support Services	43.3	4.3	47.6	
6	Tritium Removal Facility	15.7		15.7	
7	**Total Nuclear Stations**	432.3	22.3	454.5	0.0
8	**Operations and Project Support**	312.8	131.1	443.9	5.3
	CRVA Eligible Costs				
9	Fuel Channel Life Extension Project		0.0		
10	Pickering Extended Operations		0.0		
11	Optimization of Pickering Shutdown		0.0		
12	**Total CRVA Eligible Costs**	0.0	0.0	0.0	0.0
13	**Total Base OM&A**	745.1	153.4	898.4	5.3

Table 13
Combined Nuclear Base OM&A by Function ($M)
Plan - Calendar Year Ending December 31, 2030

Line No.	Function	Darlington NGS	Pickering NGS	Total OPG Nuclear Facilities	DNNP Facilities
		(a)	(b)	(c)	(d)
	Nuclear Stations				
1	Operations & Maintenance	354.8	15.5	370.3	6.0
2	- Operations	124.1	14.6	138.7	3.3
3	- Maintenance	230.7	0.9	231.6	2.7
4	Work Management	22.5	0.0	22.5	0.4
5	Site and Support Services	44.3	9.2	53.5	11.8
6	Tritium Removal Facility	15.8		15.8	
7	**Total Nuclear Stations**	437.4	24.6	462.1	18.2
8	**Operations and Project Support**	313.4	141.3	454.7	16.1
	CRVA Eligible Costs				
9	Fuel Channel Life Extension Project		0.0		
10	Pickering Extended Operations		0.0		
11	Optimization of Pickering Shutdown		0.0		
12	**Total CRVA Eligible Costs**	0.0	0.0	0.0	0.0
13	**Total Base OM&A**	750.8	166.0	916.8	34.4

Numbers may not add due to rounding.

Table 14
Combined Nuclear Base OM&A by Function ($M)
Plan - Calendar Year Ending December 31, 2031

Line No.	Function	Darlington NGS	Pickering NGS	Total OPG Nuclear Facilities	DNNP Facilities
		(a)	(b)	(c)	(d)
	Nuclear Stations				
1	Operations & Maintenance	366.3	187.4	553.7	35.6
2	- Operations	128.6	67.1	195.7	22.0
3	- Maintenance	237.7	120.3	358.0	13.6
4	Work Management	19.2	11.1	30.2	3.0
5	Site and Support Services	45.7	57.2	102.9	27.5
6	Tritium Removal Facility	16.5		16.5	
7	**Total Nuclear Stations**	447.6	255.6	703.3	66.1
8	**Operations and Project Support**	318.1	204.0	522.2	52.9
	CRVA Eligible Costs				
9	Fuel Channel Life Extension Project		0.0		
10	Pickering Extended Operations		0.0		
11	Optimization of Pickering Shutdown		0.0		
12	**Total CRVA Eligible Costs**	0.0	0.0	0.0	0.0
13	**Total Base OM&A**	765.8	459.7	1,225.4	119.0

DETAILS OF OM&A PROJECTS – NUCLEAR

1.0 PURPOSE

This evidence provides project listings and supporting information, including business case summaries ("BCS"), for allocated Project OM&A expenditures within Nuclear Operations.

2.0 OVERVIEW

The following tiered reporting structure, consistent with the OEB's filing requirements issued in EB-2024-0136, has been used to present the evidence for all allocated OM&A projects that have budgeted expenses in the bridge period or the IR term, or have been completed since EB-2020-0290. The structure of the accompanying tables setting out the project listing details is consistent with EB-2020-0290. The BCS are provided for Tier 1 projects with expenses in the IR term.

Tier 1

This tier comprises individual projects with a total cost of $20M or more. For these projects, summary level information is provided in Ex. F2-3-3, Table 1, and BCS are provided in Attachment 1. There are six Tier 1 projects, of which two are ongoing projects from EB-2020-0290, two are completed projects from EB-2020-0290, and two are new projects. Further information on Tier 1 is provided in Section 3.0.

Tier 2

This tier comprises individual projects with a total cost of more than $5M but less than $20M, for which summary level information is provided in Ex. F2-3-3, Tables 2a, 2b, and 2c. There are 29 Tier 2 projects.

Tier 3

This tier comprises individual projects with a total cost of less than $5M, for which aggregated information is provided in Ex. F2-3-3, Table 3. There are 38 allocated Tier 3 projects, with an average cost of $1.6M.

Unallocated Projects

There are eight unallocated Portfolio Projects which are currently in the project identification or project initiation phases, with a total cost of more than $5M. These projects are presented in Ex. F3-3-3, Table 4. OPG expects in conjunction with its asset management program (Ex. D2-1-1, Section 3.1), that some of these listed projects (or other projects yet to be identified) will move from the project identification and initiation phases into project definition or execution phase as part of the ongoing portfolio management process. One of these projects has the potential to cost more than $20M.

3.0 PROJECT-SPECIFIC INFORMATION – TIER 1 PROJECTS

The following information relates to projects identified in Ex. F2-3-3, Table 1.

3.1 New Projects

There are two new Tier 1 projects undertaken since EB-2020-0290.

Project #87117, PN U8 Boiler Secondary Side Advanced Scale Conditioning

The purpose of this project was to perform a secondary side Advanced Scale Conditioning Agent chemical cleaning in all 12 Pickering Unit 8 boilers (steam generators) to address boiler level oscillations that can limit station operations. Detailed investigations found sludge and deposits on the secondary side as the main contributing cause leading to the oscillations. This project helped reduce the quantity of sludge and deposits at support locations to mitigate the risk of a unit derate before in support of Pickering's extended "first life" operations to September 2026. The total project cost was $26.8M and completion in December 2024. This work was executed under the Fuel Channel Life Extension Ongoing funding category, which covers expenditures for incremental work required to enable fuel channel and other major component (e.g. steam generators) operation until a nuclear station's beyond original design targets, and is Capacity Refurbishment Variance Account eligible (Ex. H1-1-1, Section 5.6).

Project #87908, Darlington Unit 1 Steam Generator Primary Side Clean

The purpose of this project is to perform targeted cleaning of the primary side tubes for the four Darlington Unit 1 Steam Generators. To meet regulatory requirements, inspections are required to be performed on the steam generator tubes to locate and characterize any flaws that may exist, and to demonstrate fitness for service. While performing these inspections on the Darlington Unit 1 Steam Generators, due to a non-uniform layer of inner diameter magnetite masking tube wall conditions, there were challenges in obtaining some of the data planned for collection. This challenge was not present in other units. As a result, a primary side cleaning campaign was required to remove the magnetite profile remaining on the Unit 1 Steam Generators that was affecting the collection of the data by inspection. The total project cost is estimated to be $20.6M, with a planned completion in December 2025.

3.2 Completed Projects

Two Tier 1 projects have been completed since EB-2020-0290.

Project #80014, Fuel Channel Life Extension was completed under budget at $63.6M versus its budget of $69.3M.

Project #80067, DN Irradiated Fuel Bay Stack Frames was completed under budget at $20.9M versus budget of $29.7M.

3.3 Project Cost Variances

There is currently one ongoing Tier 1 project for which total forecast project cost variance currently exceeds 10% as compared to total forecast project cost provided in EB-2020-0290.

Project# 84484, DN U0 Switchgear Refurbishment

The current total project cost is forecast to be $48.2M, which is an increase of $26.9M from the development phase Class 5 estimated total project cost of $21.3M provided in EB-2020-0290. The total project cost is outside the accuracy range of a Class 5 estimate. The total project cost provided in EB-2020-0290 was based on the development phase BCS estimate, which relied on conceptual design. This estimate was provided prior to the completion of

preliminary engineering, in the absence of detailed design inputs and a defined scope of work. The final completion date is targeted for July 2028.

The Darlington Unit 0 Switchgear Station Buses (Classes II, III, and IV) provide power to both nuclear safety and essential economic loads (such as the Tritium Removal Facility ("TRF")). The inspection of this switchgear is committed to the Canadian Nuclear Safety Commission through an Integrated Implementation Plan commitment and must be completed before December 15, 2027. Due to the critical importance of these loads, no maintenance has been performed on these buses since Darlington began operation.

In December 2021, a first-of-a-kind ("FOAK") Class IV bus maintenance initially planned in the TRF T2101 outage was delinked from the outage. This decision, driven by the TRF's critical role in supporting CANDU fleet operations across Canada, led a change in strategy for the project, leading to the following:

1. *Challenges in Securing Execution Windows:*
    - Major shift in execution dates which mandated new pre-requisites and additional temporary modifications ("TMOD").
    - Execution windows to maintain the buses outside the TRF outage resulted in an extended schedule leading to additional oversight and equipment rental costs.
    - Requirement for additional execution permits mandated an increased demand for Operations resources.

Additionally, the following challenges were experienced related to the execution of the Class IV bus maintenance, which led to a further cost increase to the project in order to meet the revised execution schedule:

2. *FOAK Class IV Bus Maintenance and TMOD Installation Challenges*:
    - Additional TMOD engineering required to be completed on a compressed recovery plan.

- Development of new contingency measures by the project to ensure plant reliability (e.g., preparation of a spare TMOD for the station Main Vacuum Pump).
- Installation and commissioning challenges due to inconsistencies between the legacy drawings and field configuration resulted in delays to the bus maintenance.
- Multiple recovery plans were required for the FOAK installation deploying additional resources working on day and night shifts.
- Identifying and updating critical operational manuals and procedures prior to execution
- Onboarding additional subject matter experts to limit delays and rework.

Lessons learned from the pilot Class IV bus maintenance are currently being applied as applicable to improve planning and execution efficiency for the remaining Class II and III scope.

LIST OF ATTACHMENTS

Attachment 1: Business Case Summaries for OM&A Projects of $20M or more[1]

Note: Business Case Summaries included in Attachment 1 are marked “Confidential” or “Internal Use Only”. However, OPG has determined them to be non-confidential either in their entirety or with redactions as indicated.

[1] For projects with spend in the IR term

ATTACHMENT 1

Business Case Summaries for OM&A Projects of $20M or more[1]

Tab No	Project Number	Title	Date Approved
ONGOING PROJECTS FROM EB-2020-0290			
1	84484	Darlington U0 Switchgear Refurbishment	Jul-25

[1] For projects with spend in the IR term

Numbers may not add due to rounding.

Filed: 2025-12-12
EB-2025-0297
Exhibit F2
Tab 3
Schedule 3
Table 1

Table 1
OM&A Project Listing - OPG Nuclear Facilities
Projects ≥ $20M Total Project Cost (Allocated)[1]

Line No.	Facility	Project Name	Project No.	Category	Start Date	Final Completion Date	Total Project Cost[2] (M$)	Partial/Devmt Release ($M)	Initial Full Release ($M)	Superceding Full Release ($M)	2020 Actual ($M)	2021 Actual ($M)	2022 Actual ($M)	2023 Actual ($M)	2024 Actual ($M)	2025 Budget ($M)	2026 Budget ($M)	2027 Plan ($M)	2028 Plan ($M)	2029 Plan ($M)	2030 Plan ($M)	2031 Plan ($M)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)
		ONGOING PROJECTS FROM EB-2020-0290																				
1	DN	DN Primary Heat Transport Pump Motor Oil Leak Repair	84415	Sustaining	Jan-20	Apr-27	29.8	47.4	29.8	n/a	0.2	(0.4)	4.9	5.8	3.9	8.8	1.4	0.0	0.0	0.0	0.0	0.0
2	DN	DN U0 Switchgear Refurbishment	84484	Sustaining	Jul-20	Jul-28	48.2	48.2	n/a	n/a	0.5	6.1	11.5	3.5	0.5	1.5	3.8	5.3	0.3	0.0	0.0	0.0
		Subtotal					78.0				0.7	5.7	16.4	9.3	4.4	10.3	5.2	5.3	0.3	0.0	0.0	0.0
		COMPLETED PROJECTS FROM EB-2020-0290																				
3	ENG	Fuel Channel Life Extension Project	80014	Value Enhancing	Nov-13	Dec-25	63.6	105.8	69.3	n/a	0.7	5.0	3.2	1.9	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	DN	DN Irradiated Fuel Bay Stack Frames	80067	Sustaining	Dec-14	May-23	20.9	33.0	29.7	n/a	1.3	4.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Subtotal					84.5				2.0	9.8	3.2	1.9	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		PROJECTS NOT IN EB-2020-0290																				
5	PN	PN U8 Boiler Secondary Side Advanced Scale Conditioning	87117	Sustaining	Jan-23	Completed	26.8	n/a	n/a	n/a	0.0	0.0	0.0	26.2	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	DN	DN U1 Steam Generator Primary Side Clean	87908	Sustaining	Feb-24	Dec-25	20.6	n/a	25.7	n/a	0.0	0.0	0.0	0.0	20.5	0.1	0.0	0.0	0.0	0.0	0.0	0.0
		Subtotal					20.6				0.0	0.0	0.0	26.2	21.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0

Notes:
1 Projects with expenditures during IR Term AND Completed/Deferred Projects (from EB-2020-0290 or subsequent).
2 Total Project Cost reflects BCS amounts at the time of preparing the 2025-2031 Business Plan, with the exception of Completed/Deferred/Cancelled Projects (for which actual costs are shown). BCS amounts reflect point estimates or, if range estimate or no estimate is provided in lieu of a point estimate, the current estimate of total project cost.

Table 2a
OM&A Project Listing - OPG Nuclear Facilities
Projects $5M - $20M Total Project Cost (Allocated)[1]

Line No.	Facility	Project Name	Project No.	Category	Project Description	Start Date	Final Completion Date	Total Project Cost[2] ($M)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		ONGOING PROJECTS FROM EB-2020-0290						
1	AIM	Inspection Qualification	66105	Regulatory	Demonstrate compliance with the Canadian Standards Association Standard N285.4 Periodic Inspection of CANDU Nuclear Power Plant Components by proving a systematic and well-documented approach to non-destructive examination qualification.	Nov-06	Jun-26	15.3
2	DN	DN Reduced HTS Pressure-Temperature Envelope Modifications	80016	Regulatory	Implement modifications necessary to meet the revised pressure-temperature envelope during cooldown arising from results of the Fuel Channel Life Management project.	Jan-14	Jun-26	10.0
3	DN	DN Aging Management Scope Defining Inspections	80110	Sustaining	Oversight for the execution of the Integrated Implementation Plans (IIP) for both Refurbishment and the new D-PSR IIPs.	Feb-15	Dec-28	8.1
4	PN	Pickering 58 Digital Control Computer Hardware Modernization	80135	Sustaining	Test and qualify Digital Control Computer hardware components acquired from other CANDU units to increase reliability of Pickering 58 DCCs.	Oct-16	Dec-28	8.7
5	DN	Darlington DCC/CP/SEM Computers Software Shipments	82825	Sustaining	Software shipments are a new version of the DCC/CP/SEM computer software, created to maintain configuration control over the real time process control and monitoring software changes, to incorporate the existing software patches into program source as final design implementation, to clear outstanding issues, and to implement necessary changes that cannot be addressed through the software patching process.	May-16	Dec-32	8.6
6	DN	DN Fuel Handling Computer Software Release	82826	Sustaining	Modify and update DNGS Fuel Handling Control Computer (FHCC) software to address software deficiencies identified since the previous software update approximately 15 years ago.	Jan-20	Sep-28	11.8
7	DN	DN Annunciation Modifications And Post-Accident Monitoring Configuration Management	83545	Regulatory	Improve control schemes for silencing, acknowledging and resetting annunciations in the Control room to reduce the potential for errors.	Jan-17	Dec-28	9.2
8	AIM	DN PRECISE-D Scrape Tooling	84872	Sustaining	Co-develop and lease/rent a new tooling system and test rig, to reliability perform BOT and RJ scrape at DNGS and testing of tools prior to reactor deployment.	Apr-20	Dec-25	5.3
		Subtotal						**76.9**
	Table continues on Ex. F2-3-3 Table 2b							

Notes:
1 Projects with expenditures during IR Term AND Completed/Deferred Projects (from EB-2020-0290 or subsequent).
2 "Total Project Cost" reflects BCS amounts, with the exception of Completed/Deferred Projects (for which actual costs are shown).

Table 2b
OM&A Project Listing - OPG Nuclear Facilities
Projects $5M - $20M Total Project Cost (Allocated)[1]

Line No.	Facility	Project Name	Project No.	Category	Project Description	Start Date	Final Completion Date	Total Project Cost[2] ($M)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		COMPLETED/DEFERRED/CANCELLED FROM EB-2020-0290						
9	DN	DN Boiler Blowdown Piping Replacement	31506	Sustaining	Redesign Boiler Blowdown System piping and supports based on dynamic load analysis to address significant vibration and pipe movement arising from steam/water hammer and thermal shock during intermittent blowdown operations.	Dec-12	Aug-20	19.2
10	DN	DN GFP Sample Delay & Alternative PHT Sampling Point	31514	Sustaining	Modify the sample lines of the Gaseous Fission Product (GFP) Monitoring system to ensure adequate Heat Transport System (HTS) sample delay in order to correct a legacy design deficiency discovered during commissioning of the new system and allow the GFP Monitoring system to function within its design requirements; and provide an alternate HTS sampling point.	Dec-12	Dec-20	5.8
11	DN	DN PHT LRV Modifications (Waterhammer)	38933	Regulatory	Developmental activities to investigate waterhammer and Primary Heat Transport Liquid Relief Valve designs that would address issues with original valves and configuration.	Dec-08	Apr-24	9.7
12	PN	PN Instrumentation & Control Obsolescence	41024	Sustaining	Specify and qualify replacement instrumentation and control devices to replace obsolete components in a number of different systems.	Dec-12	Dec-19	7.9
13	PN	DCC Aging Management	62553	Sustaining	Participate in CANDU Owners' Group joint project to manage the aging of digital control computers vital to the operation of the units.	Mar-04	Mar-24	15.7
14	PN	PN Equipment Reliability Initiatives	80060	Sustaining	Address selected equipment and/or system degradation to ensure improvement in forced loss rate.	Feb-14	Dec-20	16.1
15	DN	DN New Primary Heat Transport Pump Seals	80071	Sustaining	Install new design Heat Transport Pump seals that address the operating deficiencies and poor reliability of the existing seals.	Dec-14	Jul-19	15.1
16	DN	DN Aging Management	80079	Sustaining	Fund a dedicated team initially for 2 years at station to strategize and manage the aging management scope in collaboration with Station and Refurbishment stakeholders and eventually manage these issues into Darlington station business plan.	Nov-14	Dec-19	9.1
17	DN	DN Annulus Spacer Life Management	83280	Sustaining	The project objective is to conduct R&D work to assess Darlington annulus spacer degradation mechanism for extended operations to the start of last unit refurbishment.	Jun-17	Sep-24	15.4
18	PN	Pickering Fuelling Machine Ram Seal Improvement	83302	Sustaining	Participate in CANDU Owners' Group joint project to develop and qualify improved ram seals to improve performance.	Sep-16	Mar-23	10.6
19	DN	DN Civil Building Structure Repairs	83479	Regulatory	Repair degraded civil structures based on inspection findings and assessments performed from 2013 to 2016, to ensure structures can withstand the service conditions safely and reliability throughout their predicted lifetime. The scope is specifically for civil structures specified by the Integrated Improvement Plan (IIP) items. There currently are no other significant civil structures requiring attention.	Mar-20	Jan-25	12.4
20	ENG	Asset Management Implementation	83824	Sustaining	Implement a formal asset investment management program in Nuclear that would optimize allocation of resources within budget constraints and risk tolerances.	Dec-17	Dec-25	5.3
21	DN	DN Resin Transfer Modification	84380	Sustaining	Improve access to the Moderator spent resin transfer station by repositioning existing steam and condensate piping.	May-19	Jul-22	6.8
22	DN	DN Periodic Safety Review	84589	Regulatory	Project in support of DNGS relicensing submission to CNSC that assesses the overall safety of the plant against modern codes and standards and identifies gaps and plans to close the identified gaps.	Feb-20	Nov-24	10.7
23	DN	DN PHT Pump Motor R01 Refurbishment	84766	Sustaining	Replace partially refurbished pump motor Unit 3, PM1 with a refurbished spare, refurbish PM1 and return to spares inventory.	Dec-19	Dec-24	5.6
24	DN	X-Lab Wireless Sensor Portfolio	84999	Sustaining	Development of a portfolio of wireless sensors for use by the Monitoring & Diagnostic (M&D) Centre and to support the broader Enterprise Innovation portfolio.	Jun-20	Feb-25	7.0
		Subtotal						172.1
	Table continues on Ex. F2-3-3 Table 2c							

Notes:
1 Projects with expenditures during IR Term AND Completed/Deferred Projects (from EB-2020-0290 or subsequent).
2 "Total Project Cost" reflects BCS amounts, with the exception of Completed/Deferred Projects (for which actual costs are shown).

Table 2c
OM&A Project Listing - OPG Nuclear Facilities
Projects $5M - $20M Total Project Cost (Allocated)[1]

Line No.	Facility	Project Name	Project No.	Category	Project Description	Start Date	Final Completion Date	Total Project Cost[2] ($M)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		PROJECTS NOT IN EB-2020-0290						
25	AIM	Matrix Inspection For Tubular Components	84850	Sustaining	Development of a next generation inspection tool for tubular components, including fuel channels and large tube heat exchangers based on Matrix Inspection Technique (MIT), OPG's proprietary technology.	Jan-21	Deferred	14.2
26	AIM	Laser Induced Breakdown Spectroscopy Hydride Characterization Tool	86174	Sustaining	Address the issues and challenges presented by current pressure tube hydrogen content measurement methodologies employed by AIM by conducting necessary research and development to determine and optimize the LIBS system parameters for use in HC measurements in CANDU fuel channels,	Apr-22	Jun-28	7.5
27	PN	Public Address System Core Upgrade	87152	Sustaining	Upgrade existing core components of the existing Public Address System (controllers, consoles and amplifiers) to reduce the operational failure risk due to obsolescent issues and lack of critical spare parts.	Mar-23	Dec-25	6.9
28	DN	Fuel Channel Life Management Phase V Project	87175	Sustaining	Complete additional pressure tube Burst Tests and uncertainty analysis work for the Fracture Toughness models recommended by the industry expert panel, approved by the current Phase 4 COG Fuel Channel Joint Project Executive Oversight Committee.	Jun-23	Dec-27	14.6
29	PN	PN Forebay Dredging	87187/ 87892	Sustaining	Perform marine works to dredge the Pickering NGS 058 Forebay to prescribed levels to mitigate the risk of silt ingress into the station during periods of low lake levels.	Mar-23	Dec-25	15.2
		Subtotal						**58.4**

Notes:
1 Projects with expenditures during IR Term AND Completed/Deferred Projects (from EB-2020-0290 or subsequent).
2 "Total Project Cost" reflects BCS amounts, with the exception of Completed/Deferred Projects (for which actual costs are shown).

Numbers may not add due to rounding.

Table 3
OM&A Project Listing - OPG Nuclear Facilities
Projects < $5M Total Project Cost[1]

Line No.	Sponsoring Division	Number of Projects	Total Project Cost ($M)	Average Cost Of All Projects ($M)
		(a)	(b)	(c)
1	**Darlington NGS**	14	13.9	1.0
2	**Pickering NGS**	18	31.6	1.8
3	**Operations and Project Support**	6	14.8	2.5
	Total	38	60.3	1.6

Notes:
1 Projects with expenditures during IR Term.

Table 4
OM&A Project Listing - OPG Nuclear Facilities
Portfolio Projects (Unallocated)[1]

Line No.	Project Name	Category	Potential Start Date
	(a)	(b)	(c)
	Darlington NGS - Projects With Potential Cost >$5M and < $20M		
1	86299 - DN HFD & LISS D2O Feed Line Cut & Cap	Sustaining	2025
2	89280 - DN Software Inventory Management 69000	Sustaining	2025
	Darlington NGS - Projects With Potential Cost ≥ $20M		
3	89223 - DN U2 Primary Heat Transport Pump Motors Oil Leak Repairs	Sustaining	2025
	Pickering NGS - Projects With Potential Cost >$5M and < $20M		
4	89802 - PN Pickering For The Future (P4F)	Sustaining	2026
5	89807 - PN Primary Heat Transport & Auxiliaries Inspections	Sustaining	2029
6	89808 - PN Buried Piping Inspections	Sustaining	2027
	Pickering NGS - Projects With Potential Cost ≥ $20M		
7	89800 - PN Vacuum Building Civil Structures	Sustaining	2026
	Advanced Inspection and Maintenance - Projects With Potential Cost ≥ $20M		
8	89282 - AIM End of Life Fuel Channel Component Retrieval	Sustaining	2027

Notes:
1 Projects with potential expenditures during IR Term.

Table 5
OM&A Projects - OPG Nuclear Facilities
Listing of Business Case Summaries Filed[1]

Line No.	Business Case Summary (BCS) Title	Project Number	BCS Approval Date	Project Stage	BCS Status	BCS Status in EB-EB-2020-0290
	(a)	(b)	(c)	(d)	(e)	(f)
	ONGOING PROJECTS FROM EB-2020-0290					
1	DN U0 Switchgear Refurbishment	84484	Jul-25	Execution	Superseding	Full Development

Notes:
1 For Projects with expenditures in the IR term.

COMPARISON OF NUCLEAR OUTAGE AND PICKERING CYCLICAL MAINTENANCE OM&A COSTS

1.0 PURPOSE

This evidence presents period-over-period comparisons of OPG's nuclear facilities outage OM&A costs by station, Pickering Cyclical Maintenance OM&A costs and Darlington New Nuclear Program ("DNNP") facilities outage OM&A for 2020-2031, in support of the approval of these forecast costs for the IR term.

Nuclear facilities outage OM&A costs and DNNP facilities outage OM&A costs are impacted by the frequency, duration and scope of planned outages ("PO"), as well as specific outage initiatives requiring support work.

Period-over-period variances are presented in Ex. F2-4-2, Table 1a and 1b and are explained below, along with the extent to which the above factors influence outage OM&A costs in the 2027-2031 IR term. Net reportable variances and period-over-period changes (10% or greater, subject to a minimum materiality limit of $1.0M), are discussed below.

All comparisons to OEB-approved amounts are before any settlement or OEB adjustments.

2.0 PERIOD-OVER-PERIOD CHANGES – IR TERM, OPG NUCLEAR FACILITIES

2027 Plan versus 2026 Budget

OPG Nuclear Facilities Outage OM&A

Planned outage OM&A in 2027 is $223.7M, which is $14.4M or 6.9% higher than the 2026 Budget of $209.4M. The variance is attributable to Darlington outages ($67.8M or 43.5% increase), partially offset by Pickering outages ($53.5M or 100.0% decrease).

The reportable variances are as follows:

- Darlington PO costs are higher due to an extended outage which includes capital funded projects such as the Darlington Steam Generator Primary Moisture Separators ("PMS")

Replacement projects to replace the primary moisture separators on all four steam generators in Unit 2 (compared to primary moisture separators replacement on two steam generators in Unit 3 in 2026) and the Unit 2 Turbine Control and Auxiliary Systems Upgrade project, in addition to the Darlington Vacuum Building Outage ("VBO"), as compared to one regular PO, Unit 4 refurbishment cyclical outage work and one post-refurbishment outage in 2026, (Darlington station $62.7M or 50.7% increase and related Operations and Project Support $5.1M or 15.8% increase).

- Pickering PO costs are lower due to the completion of PO scope on one unit in 2026 and Pickering Units 5-8 entering into refurbishment in 2027 (Pickering station $39.9M or 100.0% decrease and related Operations and Project Support $13.5M or 100.0% decrease).

Pickering Cyclical Maintenance OM&A

Planned Cyclical Maintenance OM&A in 2027 is $168.4M, which is $143.4M or 573.4% higher than the 2026 Budget of $25.0M. The variance is attributable to Pickering station ($133.3M or 533.4% increase) and related Operations and Project Support ($10.0M or 100.0% increase).

The reportable variance is attributable to Pickering Units 5-8 being in the refurbishment outage for the full year in 2027 compared to the last three months in 2026. The increase in Pickering Cyclical Maintenance OM&A is offset by the year-over-year reduction in station level Base OM&A costs (Ex. F2-2-1, Table 1a, line 2).

2028 Plan versus 2027 Plan

OPG Nuclear Facilities Outage OM&A

Planned outage OM&A in 2028 is $112.7M, which is $111.0M or 49.6% lower than the 2027 planned amount of $223.7M. The variance is attributable to Darlington outages ($111.0M or 49.6% decrease).

The reportable variances are as follows:

- Darlington PO costs are lower due to one regular PO in 2028 as compared to an extended outage and the Darlington VBO in 2027 (Darlington station $104.6M or 56.1% decrease and related Operations and Project Support $6.4M or 17.2% decrease).

Pickering Cyclical Maintenance OM&A

Planned Cyclical Maintenance OM&A in 2028 is $160.9M, which is $7.4M or 4.4% lower than the 2027 planned amount of $168.4M. The variance is attributable to Pickering station ($7.8M or 4.9% decrease), partially offset by related Operations and Project Support ($0.3M or 3.5% increase).

There are no reportable variances during this timeframe.

2029 Plan versus 2028 Plan

OPG Nuclear Facilities Outage OM&A

Planned outage OM&A in 2029 is $219.1M, which is $106.4M or 94.3% higher than the 2028 planned amount of $112.7M. The variance is attributable to Darlington outages ($106.4M or 94.3% increase).

The reportable variances are as follows:

- Darlington PO costs are higher in 2029 due to two POs in 2029 as compared to one regular PO in 2028 (Darlington station $86.6M or 105.9% increase and related Operations and Project Support $19.7M or 63.7% increase).

Pickering Cyclical Maintenance OM&A

Planned Cyclical Maintenance OM&A in 2029 is $168.9M, which is $8.0M or 5.0% higher than the 2028 planned amount of $160.9M. The variance is attributable to Pickering station ($7.4M or 4.9% increase) and related Operations and Project Support ($0.6M or 5.4% increase).

There are no reportable variances during this timeframe.

2030 Plan versus 2029 Plan

OPG Nuclear Facilities Outage OM&A

Planned outage OM&A in 2030 is $121.6M, which is $97.5M or 44.5% lower than the 2029 planned amount of $219.1M. The variance is attributable to Darlington outages ($97.5M or 44.5% decrease).

The reportable variances are as follows:

- Darlington PO costs are lower due to one regular PO in 2030 as compared to two POs in 2029 (Darlington station $78.0M or 46.3% decrease and related Operations and Project Support $19.4M or 38.4% decrease).

OPG Pickering Cyclical Maintenance OM&A

Planned Cyclical Maintenance OM&A in 2030 is $169.9M, which is $1.0M or 0.6% higher than the 2029 planned amount of $168.9M. The variance is attributable to Pickering station ($0.9M or 0.6% increase) and related Operations and Project Support ($0.2M or 1.5% increase).

There are no reportable variances during this timeframe.

2031 Plan versus 2030 Plan

OPG Nuclear Facilities Outage OM&A

Planned outage OM&A in 2031 is $142.2M, which is $20.6M or 16.9% higher than the 2030 planned amount of $121.6M. The variance is attributable to Pickering outages ($26.5M or 100.0% increase), partially offset by Darlington outages ($5.9M or 4.8% decrease).

The reportable variance is as follows:

- Pickering PO costs are higher due to one post-refurbishment outage in 2031, as compared to no regular PO in 2030 (Pickering station $26.5M or 100.0% increase).

Pickering Cyclical Maintenance OM&A

Planned Cyclical Maintenance OM&A in 2031 is $106.6M, which is $63.3M or 37.3% lower than the 2030 planned amount of $169.9M. The variance is attributable to Pickering station

($58.5M or 36.8% decrease) and related Operations and Project Support ($4.8M or 43.6% decrease).

The reportable variance is attributable to the Unit 5 return to service planned in May 2031, with the ongoing scope of preventative maintenance and other ongoing activities transitioning in large part back to Base OM&A funding for operating units.

4.0 PERIOD-OVER-PERIOD CHANGES – BRIDGE YEARS, OPG NUCLEAR FACILITIES

2026 Budget versus 2026 OEB-Approved

OPG Nuclear Facilities Outage OM&A

Planned outage OM&A in 2026 is $209.4M, which is $148.1M or 241.4% higher than the 2026 OEB-approved budget of $61.3M. The variance is attributable to Darlington outages ($94.6M or 154.2% increase) and Pickering outages ($53.5M or 100.0% increase).

The reportable variances are as follows:

- Darlington PO costs are higher due to moving the Unit 3 regular PO from 2027 to 2026, partially offset by reduced Cyclical outage costs for Unit 4 due to the earlier than planned return to service from refurbishment (Darlington station $65.9M or 114.0% increase and related Operations and Project Support $28.7M or 810.4% increase).
- Pickering PO costs are higher due to the addition of a Unit 6 PO, related to the extension of Units 5-8 operations into 2026 relative to the assumed shutdown of the station in EB-2020-0290 (Pickering station $39.9M or 100.0% increase and related Operations and Project Support $13.5M or 100.0% increase).

Pickering Cyclical Maintenance OM&A

Planned Cyclical Maintenance OM&A in 2026 is $25.0M, which is $25.0M or 100.0% higher than the 2026 OEB-approved budget of $0.0M. The variance is attributable to Pickering station ($25.0M or 100.0% increase).

The reportable variance is attributable to the refurbishment of Pickering Units 5-8 not being assumed in EB-2020-0290 as the Pickering station was then planned to shut down in 2025.

2026 Budget versus 2025 Budget

OPG Nuclear Facilities Outage OM&A

Planned outage OM&A in 2026 is $209.4M, which is $82.4M or 64.9% higher than the 2025 budget amount of $127.0M. The variance is attributable to Darlington outages ($90.6M or 138.5% increase), partially offset by Pickering outages ($8.2M or 13.3% decrease).

The reportable variances are as follows:

- Darlington PO costs are higher due to one regular PO in 2026 as compared to no regular POs in 2025, partially offset by lower Cyclical outage costs for Unit 4 due to the earlier return to service date (Darlington station $69.0M or 126.3% increase and related Operations and Project Support $21.5M or 200.7% increase).
- Pickering PO related Operations and Project Support costs are $6.7M or 33.1% lower due to less inspection and maintenance support required for the Unit 6 PO.

Pickering Cyclical Maintenance OM&A

Planned Cyclical Maintenance OM&A in 2026 is $25.0M, which is $25.0M or 100.0% higher than the 2025 planned amount of $0.0M. The variance is attributable to Pickering station ($25.0M or 100.0% increase).

The reportable variance is attributable to the fact that Pickering Units 5-8 are planned to enter the refurbishment outage in September 2026.

2025 Budget versus 2025 OEB-Approved

OPG Nuclear Facilities Outage OM&A

Planned outage OM&A in 2025 is $127.0M, which is $65.6M or 34.0% lower than the 2025 OEB-approved budget of $192.6M. The variance is attributable to Darlington outages ($127.2M or 66.1% decrease), partially offset by Pickering Outages ($61.6M or 100.0% increase).

The reportable variances are as follows:

- Darlington PO costs are lower primarily due to shifting the Darlington Unit 2 Turbine Control and Auxiliary Systems Upgrade project from 2025 to 2027 to support grid reliability and manage resource constraints during concurrent nuclear outages, and also not requiring one of the planned post-refurbishment outages, partially offset by increased routine station inspection and maintenance work for Unit 4 during the refurbishment cyclical outage (Darlington station $102.3M or 65.2% decrease and related Operations and Project Support $24.9M or 69.9% decrease).
- Pickering PO costs are higher due to the added Unit 5 PO to enable the extension of Unit 5 operations into 2026 relative to the assumed shutdown of the station in EB-2020-0290. (Pickering station $41.4M or 100.0% increase and related Operations and Project Support $20.2M or 100.0% increase).

Pickering Cyclical Maintenance OM&A

There are no costs planned or incurred during this timeframe.

2025 Budget versus 2024 Actual

OPG Nuclear Facilities Outage OM&A

Planned outage OM&A in 2025 is $127.0M, which was $231.1M or 64.5% lower than the 2024 actual amount of $358.1M. The variance is mainly attributable to Darlington outages ($139.3M or 68.1% decrease) and Pickering outages ($78.7M or 56.1% decrease) and CRVA eligible costs ($13.1M or 100.0% decrease).

The reportable variances are as follows:

- Darlington PO costs are lower due to no regular POs in 2025, as compared to one PO in 2024 (Darlington station $104.7M or 65.7% decrease and related Operations and Project Support $34.6M or 76.3% decrease).
- Pickering PO costs are lower due to one regular PO in 2025, as compared to two regular POs in 2024 (Pickering station $50.2M or 54.8% decrease and related Operations and Project Support $28.5M or 58.5% decrease).

- Fuel Channel Life Extension ("FCLE") Related Ongoing Costs are $1.3M or 100.0% lower due to completion of the outage OM&A expenditures for this program in 2024.
- Optimization of Pickering Shutdown outage costs are $11.8M or 100.0% lower due to completion of the outage OM&A expenditures for this program in 2024.

Pickering Cyclical Maintenance OM&A

There are no costs planned or incurred during this timeframe.

5.0 PERIOD-OVER-PERIOD CHANGES – HISTORICAL YEARS, OPG NUCLEAR FACILITIES

2024 Actual versus 2024 OEB-Approved

OPG Nuclear Facilities Outage OM&A

Actual outage OM&A in 2024 was $358.1M, which was $145.7M or 68.6% higher than the 2024 OEB-approved budget of $212.4M. The variance is attributable to Darlington outages ($110.0M or 116.2% increase), Pickering outages ($36.4M or 35.0% increase), partially offset by CRVA Eligible Costs ($0.6M or 4.7% decrease).

The reportable variances are as follows:

- Darlington PO costs are higher due to shifting the Unit 2 PO from 2023 to 2024 and an increase in routine inspection and maintenance work for Unit 4 during the refurbishment cyclical outage (Darlington station $77.3M or 94.4% increase and related Operations and Project Support $32.6M or 256.8% increase).
- Pickering PO costs are higher primarily due to increased scope added to the POs to support the extension of operations of Units 5-8 to September 2026 relative to the assumed shutdown of the station in EB-2020-0290 (Pickering station $14.6M or 19.0% increase and related Operations and Project Support $21.8M or 80.7% increase).
- FCLE Related Ongoing Costs are $1.0M or 403.3% higher primarily attributable to the manual tube plugging & locking tab scope for Pickering Unit 7.
- Pickering Optimized Shutdown PO costs are $1.7M or 12.5% lower attributable to the Unit 5 and Unit 7 inspection scope.

Pickering Cyclical Maintenance OM&A

There are no costs planned or incurred during this timeframe.

2024 Actual versus 2023 Actual

OPG Nuclear Facilities Outage OM&A

Actual outage OM&A in 2024 was $358.1M, which was $40.0M or 12.6% higher than the 2023 Actual amount of $318.1M. The variance is attributable to Darlington outages ($98.9M or 93.5% increase), partially offset by Pickering outages ($44.2M or 23.9% decrease) and CRVA eligible costs ($14.7M or 52.7% decrease).

The reportable variances are as follows:

- Darlington PO costs are higher in 2024 due to one regular PO, as compared to no such outage in 2023, increased Unit 1 and 4 refurbishment cyclical outage work, offset by lower Unit 3 refurbishment cyclical work (Darlington station $67.3M or 73.1% increase and related Operations and Project Support $31.6M or 229.8% increase).
- Pickering PO costs decrease due to conducting two regular POs in 2024 as compared to three such outages in 2023, partially offset by increased outage scope to support extension of Units 5-8 operations into 2026 (Pickering station $30.0M or 24.7% decrease and related Operations and Project Support $14.1M or 22.5% decrease).
- FCLE Related Ongoing Costs are $19.3M or 93.7% lower due to continued winding down of this program with Pickering Unit 6 and 8 scope completed in 2023.
- Pickering Optimized Shutdown PO costs are $4.6M or 64.2% higher attributable to the Unit 5 and Unit 7 inspection scope.

Pickering Cyclical Maintenance OM&A

There are no costs planned or incurred during this timeframe.

2023 Actual versus 2023 OEB-Approved

OPG Nuclear Facilities Outage OM&A

Actual outage OM&A in 2023 was $318.1M, which was $43.1M or 11.9% lower than the 2023 OEB-approved budget of $361.2M. The variance is attributable to Darlington outages ($81.4M

or 43.5% decrease), partially offset by Pickering outages ($27.2M or 17.3% increase) and CRVA eligible costs ($11.1M or 66.5% increase).

The reportable variances are as follows:

- Darlington PO costs are lower primarily due to shifting the Unit 2 PO from 2023 to 2024, partially offset by increased costs for Units 1, 3, and 4 refurbishment cyclical outage work (Darlington station $67.0M or 42.1% decrease and related Operations and Project Support $14.3M or 51.1% decrease).
- Pickering PO costs are higher primarily due to costs incurred for spindle refurbishment, and increased scope to support extension of Units 5-8 operations into 2026 relative to the assumed shutdown of the station in EB-2020-0290 (Pickering station $15.9M or 15.1% increase and related Operations and Project Support $11.3M or 21.8% increase).
- FCLE Related Ongoing Costs are $6.1M or 42.4% higher attributable to Pickering Unit 6 and Unit 8 inspection scope.
- Pickering Optimized Shutdown PO costs are $5.0M or 223.3% higher attributable to the Unit 6 and Unit 8 inspection scope.

Pickering Cyclical Maintenance OM&A

There are no costs planned or incurred during this timeframe.

2023 Actual versus 2022 Actual

OPG Nuclear Facilities Outage OM&A

Actual outage OM&A in 2023 was $318.1M, which was $53.1M or 20.0% higher than the 2022 Actual amount of $265.0M. The variance is attributable to Pickering outages ($36.2M or 24.4% increase), Darlington outages ($16.2M or 18.0% increase), and CRVA eligible costs ($0.7M or 2.7% increase).

The reportable variances are as follows:

- Darlington station PO costs are higher due to incurring pre-requisite costs for the 2024 Unit 2 regular PO along with increased Unit 1 and 4 refurbishment Cyclical Outage work,

partially offset by reduced Unit 3 refurbishment Cyclical Outage work (Darlington station $16.4M or 21.7% increase).

- Pickering PO costs increase due to conducting three regular PO in 2023 as compared to two such outages in 2022 plus the Pickering VBO (Pickering station $11.2M or 10.1% increase, and related Operations and Project Support $25.0M or 66.2% increase).
- Fuel Channel Life Extension Ongoing (consequential) PO costs are $4.7M or 18.6% lower primarily attributable to a Single Fuel Channel Replacement and other inspection scope in 2022 at Pickering.
- Pickering Optimized Shutdown PO costs are $5.4M or 308.1% higher attributable to the Unit 6 and Unit 8 inspection scope.

Pickering Cyclical Maintenance OM&A

There are no costs planned or incurred during this timeframe.

2022 Actual versus 2022 OEB-Approved

OPG Nuclear Facilities Outage OM&A

Actual outage OM&A in 2022 was $265.0M, which was $14.1M or 5.1% lower than the 2022 OEB-approved budget of $279.1M. The variance is attributable to Pickering outages ($9.0M or 5.7% decrease) and CRVA eligible costs ($5.3M or 16.4% decrease), partially offset by Darlington outages ($0.2M or 0.2% increase).

The reportable variances are as follows:

- Darlington PO related Operations and Project Support costs decrease $1.8M or 11.5% primarily due to no pre-requisite costs incurred for the Unit 2 outage that was moved to 2024, partially offset by increased Unit 1 and 3 refurbishment cyclical outage work.
- FCLE Related Ongoing Costs are $4.5M or 15.2% lower attributable to the Pickering Unit 5 scope which included a Single Fuel Channel Replacement and Scrape.
- Pickering Optimized Shutdown PO costs are $0.8M or 30.8% lower attributable to the Unit 5 and 6 inspection scope.

Pickering Cyclical Maintenance OM&A

There are no costs planned or incurred during this timeframe.

2022 Actual versus 2021 Actual

OPG Nuclear Facilities Outage OM&A

Actual outage OM&A in 2022 was $265.0M, which was $117.8M or 30.8% lower than the 2021 Actual amount of $382.8M. The variance is attributable to Darlington outages ($101.7M or 53.1% decrease), CRVA eligible costs ($26.5M or 49.5% decrease), partially offset by Pickering outages ($10.3M or 7.5% increase).

The reportable variances are as follows:

- Darlington PO costs are lower due to one post-refurbishment outage in 2022 as compared to two regular POs, partially offset by an increase in routine station inspection and maintenance work for Unit 1 during the refurbishment cyclical outages (Darlington station $83.4M or 52.4% decrease and related Operations and Project Support $18.3M or 56.6% decrease).
- Pickering PO related Operations and Project Support costs increase $8.5M or 29.1% primarily due to the Pickering VBO scheduled in 2022, partially offset by a planned unbudgeted outage for Unit 5 in 2021.
- Pickering Extended Operations PO costs are $26.1M lower or 100% due to the completion of outage OM&A expenditures for this program in 2021.

Pickering Cyclical Maintenance OM&A

There are no costs planned or incurred during this timeframe.

2021 Actual versus 2021 OEB-Approved

OPG Nuclear Facilities Outage OM&A

Actual outage OM&A in 2021 was $382.8M, which was $74.3M or 24.1% higher than the 2021 OEB-approved amount of $308.5M. The variance is primarily attributable to Darlington outages

($127.0M or 197.3% increase), CRVA eligible costs ($52.0M increase), partially offset by Pickering outages ($104.7M or 43.1% decrease).

The reportable variances are as follows:

- Darlington PO costs are higher due to moving the Unit 1 regular PO from 2020 to 2021 and adding a Unit 4 regular PO as a result of the deferred Darlington Refurbishment Program schedule. (Darlington station $104.9M or 193.7% increase and related Operations and Project Support $22.1M or 216.5% increase).
- Pickering PO costs are lower primarily due to moving the Pickering VBO from 2021 to 2022 and reducing regular POs from three to two in line with the 30-month outage cycle (Pickering station $60.5M or 35.8% decrease and related Operations and Project Support $44.2M or 60.1% decrease).
- FCLE Related Ongoing Costs are $24.0M higher primarily attributable to the addition of Waterlancing and Scrape Sample Analysis for Darlington Unit 4 and Pickering Unit 7 and Unit 8 as well as moving the Darlington Unit 1 regular PO from 2020 to 2021.
- Pickering Extended Operations PO costs are $26.1M higher primarily due to Unit 7 and Unit 8 inspection work moved from 2020 to 2021 (there were no outage OM&A costs forecast in 2021 OEB-approved). Overall Pickering Extended Operations initiative was completed within budget.
- Pickering Optimized Shutdown PO costs are $1.9M higher primarily attributable to the introduction of this work program for Unit 7 and Unit 8 inspection work.

Pickering Cyclical Maintenance OM&A

There are no costs planned or incurred during this timeframe.

2021 Actual versus 2020 Actual

OPG Nuclear Facilities Outage OM&A

Actual outage OM&A in 2021 was $382.8M, which was $89.0M or 30.3% higher than the 2020 Actual amount of $293.9M. The variance is attributable to Darlington outages ($141.4M or 283.4% increase), partially offset by Pickering outages ($38.4M or 21.8% decrease) and CRVA eligible costs ($14.1M or 20.8% decrease).

The reportable variances are as follows:

- Darlington PO costs are higher due to two regular POs in 2021, as compared to no regular POs in 2020 (Darlington station $117.2M or 280.6% increase and related Operations and Project Support $24.2M or 297.6% increase).
- Pickering planned outage costs decrease $37.8M or 25.8% due to conducting two regular POs in 2021 as compared to three such outages in 2020, partially offset by Unit 8 Single Fuel Channel Replacement and an unbudgeted outage for Unit 5 in 2021.
- FCLE Related Ongoing Costs are $5.2M higher or 25.6% primarily attributable to Pickering for Unit 5 Fuel Channel Replacement pre-requisites for the 2022 outage and Unit 7 Waterlancing and Scrape Analysis.
- Pickering Extended Operations PO costs are $21.1M lower or 44.7% primarily due to conducting two regular POs in 2021 as compared to three such outages in 2020.
- Pickering Optimized Shutdown PO costs are $1.9M higher primarily attributable to the introduction of this work program in 2021 for Unit 7 and Unit 8 inspection work.

Pickering Cyclical Maintenance OM&A

There are no costs planned or incurred during this timeframe.

2020 Actual versus 2020 OEB-Approved

OPG Nuclear Facilities Outage OM&A

Actual outage OM&A in 2020 was $293.9M, which was $100.6M or 25.5% lower than the 2020 OEB-approved amount of $394.4M. The variance is primarily attributable to Darlington outages ($128.7M or 72.1% decrease), CRVA eligible costs ($26.3M or 28.0% decrease), partially offset by Pickering outages ($54.4M or 44.6% increase).

The reportable variances are as follows:

- Darlington PO costs are lower primarily due to moving the Unit 1 regular PO from 2020 to 2021, as discussed above (Darlington station $108.9M or 72.3% decrease and related Operations and Project Support $19.8M or 70.9% decrease).
- Pickering PO costs are higher primarily due to increasing regular POs from two to three in line with the 30-month outage cycle and higher costs incurred for spindle refurbishment

- (Pickering station $46.2M or 46.1% increase and related Operations and Project Support $8.2M or 37.8% increase).
- FCLE Related Ongoing Costs are $11.9M or 141.2% higher primarily attributable to higher Single Fuel Channel Replacement costs for Darlington Unit 3 than originally planned for Darlington Unit 1.
- Pickering Extended Operations Enabling PO costs are $38.3M or 44.7% lower primarily due to the further definition post-2016 of scope, which resulted in a decrease in Pickering Extended Operations outage OM&A partially offset by increases in Pickering Extended Operations Base OM&A and Pickering Extended Operations Capital in 2020, and timing of expenditures as Unit 7 and Unit 8 inspection work was moved from 2020 to 2021.

Pickering Cyclical Maintenance OM&A

There are no costs planned or incurred during this timeframe.

6.0 PERIOD-OVER-PERIOD CHANGES – IR TERM, DNNP FACILITIES

There are no reportable variances for DNNP Facilities Outage OM&A over the 2026-2029 period.

2030 Plan versus 2029 Plan

DNNP Facilities Outage OM&A

Planned outage OM&A in 2030 is $0.1M, which is $0.1M or 100.0% higher than the 2029 planned amount of $0.0M. The variance is attributable to the DNNP facilities outages ($0.1M or 100.0% increase).

There are no reportable variances during this timeframe.

2031 Plan versus 2030 Plan

DNNP Facilities Outage OM&A

Planned outage OM&A in 2031 is $48.6M, which is $48.6M or 100.0% higher than the 2030 planned amount of $0.1M. The variance is attributable to the DNNP facilities outages ($48.6M or 100.0% increase).

The reportable variance is as follows:

- DNNP facilities PO costs are higher due to the first refuelling outage which is planned to occur 12 months after the commercial in-service date, as compared to no regular PO in 2030 (DNNP facilities $48.6M or 100.0% increase).

Numbers may not add due to rounding.

Table 1a

Comparison of Outage OM&A and Pickering Cyclical Maintenance OM&A - Combined Nuclear ($M)[1,2]

Line No.	Business Unit	2020 OEB Approved	(c)-(a) Change	2020 Actual	(g)-(c) Change	2021 OEB Approved	(g)-(e) Change	2021 Actual	(k)-(g) Change	2022 OEB Approved	(k)-(i) Change	2022 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Darlington Outages											
1	Darlington NGS	150.7	***(108.9)***	41.8	***117.2***	54.1	***104.9***	159.0	***(83.4)***	73.6	2.0	75.6
2	Operations and Project Support	27.9	***(19.8)***	8.1	***24.2***	10.2	***22.1***	32.3	***(18.3)***	15.8	***(1.8)***	14.0
3	**Total Darlington Outages**	178.6	***(128.7)***	49.9	***141.4***	64.3	***127.0***	191.3	***(101.7)***	89.4	0.2	89.6
	Pickering Outages											
4	Pickering NGS	100.2	***46.2***	146.4	***(37.8)***	169.2	***(60.5)***	108.7	1.8	118.8	(8.3)	110.5
5	Operations and Project Support	21.7	***8.2***	29.9	(0.6)	73.5	***(44.2)***	29.3	***8.5***	38.5	(0.7)	37.8
6	**Total Pickering Outages**	121.9	***54.4***	176.4	***(38.4)***	242.7	***(104.7)***	138.0	10.3	157.3	(9.0)	148.3
	CRVA Eligible Costs											
7	FCLE Related Ongoing Costs	8.4	***11.9***	20.3	***5.2***	1.5	***24.0***	25.5	(0.2)	29.8	***(4.5)***	25.3
8	Pickering Extended Operations	85.5	***(38.3)***	47.3	***(21.1)***	0.0	***26.1***	26.1	***(26.1)***	(0.0)	0.0	0.0
9	Optimization of Pickering Shutdown	0.0	0.1	0.1	***1.9***	0.0	***1.9***	1.9	(0.2)	2.6	(0.8)	1.8
10	**Total CRVA Eligible Costs**	93.9	***(26.3)***	67.6	***(14.1)***	1.5	***52.0***	53.5	***(26.5)***	32.4	***(5.3)***	27.0
11	**Total OPG Nuclear Facilities Outage OM&A Before Adjustments**	394.4	***(100.6)***	293.9	***89.0***	308.5	***74.3***	382.8	***(117.8)***	279.1	(14.1)	265.0
12	**OEB/Settlement Adjustments**		0.0		0.0		0.0		0.0	(8.4)	***8.4***	
13	**Total OPG Nuclear Facilities Outage OM&A Including Adjustments**	394.4	***(100.6)***	293.9	***89.0***	308.5	***74.3***	382.8	***(117.8)***	270.7	(5.7)	265.0
	Pickering Cyclical Maintenance											
14	Pickering NGS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Operations and Project Support	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	**Total Pickering Cyclical Maintenance OM&A**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DNNP Facilities Outages											
17	DNNP Facilities	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	Operations and Project Support	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19	**Total DNNP Facilities Outage OM&A**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Line No.	Business Unit	2022 Actual	(e)-(a) Change	2023 OEB Approved	(e)-(c) Change	2023 Actual	(i)-(e) Change	2024 OEB Approved	(i)-(g) Change	2024 Actual	(k)-(i) Change	2025 Budget
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Darlington Outages											
20	Darlington NGS	75.6	***16.4***	159.1	***(67.0)***	92.0	***67.3***	81.9	***77.3***	159.3	***(104.7)***	54.6
21	Operations and Project Support	14.0	(0.3)	28.1	***(14.3)***	13.8	***31.6***	12.7	***32.6***	45.4	***(34.6)***	10.7
22	**Total Darlington Outages**	89.6	***16.2***	187.2	***(81.4)***	105.8	***98.9***	94.7	***110.0***	204.6	***(139.3)***	65.4
	Pickering Outages											
23	Pickering NGS	110.5	***11.2***	105.8	***15.9***	121.7	***(30.0)***	77.0	***14.6***	91.6	***(50.2)***	41.4
24	Operations and Project Support	37.8	***25.0***	51.6	***11.3***	62.9	***(14.1)***	27.0	***21.8***	48.7	***(28.5)***	20.2
25	**Total Pickering Outages**	148.3	***36.2***	157.4	***27.2***	184.5	***(44.2)***	104.0	***36.4***	140.4	***(78.7)***	61.6
	CRVA Eligible Costs											
26	FCLE Related Ongoing Costs	25.3	***(4.7)***	14.5	***6.1***	20.6	***(19.3)***	0.3	***1.0***	1.3	***(1.3)***	0.0
27	Pickering Extended Operations	0.0	0.0	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Optimization of Pickering Shutdown	1.8	***5.4***	2.2	***5.0***	7.2	***4.6***	13.5	***(1.7)***	11.8	***(11.8)***	0.0
29	**Total CRVA Eligible Costs**	27.0	0.7	16.7	***11.1***	27.8	***(14.7)***	13.8	(0.6)	13.1	***(13.1)***	0.0
30	**Total OPG Nuclear Facilities Outage OM&A Before Adjustments**	265.0	***53.1***	361.2	***(43.1)***	318.1	***40.0***	212.4	***145.7***	358.1	***(231.1)***	127.0
31	**OEB/Settlement Adjustments**		0.0	(10.8)	***10.8***		0.0	(6.4)	***6.4***		0.0	
32	**Total OPG Nuclear Facilities Outage OM&A Including Adjustments**	265.0	***53.1***	350.4	(32.3)	318.1	***40.0***	206.0	***152.1***	358.1	***(231.1)***	127.0
	Pickering Cyclical Maintenance											
33	Pickering NGS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Operations and Project Support	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	**Total Pickering Cyclical Maintenance OM&A**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DNNP Facilities Outages											
36	DNNP Facilities	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
37	Operations and Project Support	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
38	**Total DNNP Facilities Outage OM&A**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Notes:

1 2020-2026 values have been restated for Nuclear organizational changes and transfers from Corporate Support (See Ex. A1-4-1 Attachment 2 and Ex. F2-2-1, Attachment 1).

2 Per EB-2020-0290 OEB Decision and Order, Schedule A, p. 25, nuclear Outage OM&A costs are reduced by 3% per year over the 2022-2026 period.

Numbers may not add due to rounding.

Table 1b

Comparison of Outage OM&A and Pickering Cyclical Maintenance OM&A - Combined Nuclear ($M)[1,2]

Line No.	Business Unit	2025 OEB Approved	(c)-(a) Change	2025 Budget	(g)-(c) Change	2026 OEB Approved	(g)-(e) Change	2026 Budget	(i)-(g) Change	2027 Plan	(k)-(i) Change	2028 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Darlington Outages											
1	Darlington NGS	156.9	***(102.3)***	54.6	***69.0***	57.8	***65.9***	123.7	***62.7***	186.4	***(104.6)***	81.8
2	Operations and Project Support	35.7	***(24.9)***	10.7	***21.5***	3.5	***28.7***	32.3	***5.1***	37.4	***(6.4)***	30.9
3	**Total Darlington Outages**	192.6	***(127.2)***	65.4	***90.6***	61.3	***94.6***	155.9	***67.8***	223.7	***(111.0)***	112.7
	Pickering Outages											
4	Pickering NGS	0.0	***41.4***	41.4	(1.5)	0.0	***39.9***	39.9	***(39.9)***	0.0	0.0	0.0
5	Operations and Project Support	0.0	***20.2***	20.2	***(6.7)***	0.0	***13.5***	13.5	***(13.5)***	0.0	0.0	0.0
6	**Total Pickering Outages**	0.0	***61.6***	61.6	***(8.2)***	0.0	***53.5***	53.5	***(53.5)***	0.0	0.0	0.0
	CRVA Eligible Costs											
7	FCLE Related Ongoing Costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Pickering Extended Operations	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Optimization of Pickering Shutdown	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	**Total CRVA Eligible Costs**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	**Total OPG Nuclear Facilities Outage OM&A Before Adjustments**	192.6	***(65.6)***	127.0	***82.4***	61.3	***148.1***	209.4	14.4	223.7	***(111.0)***	112.7
12	**OEB/Settlement Adjustments**	(5.8)	***5.8***		0.0	(1.8)	***1.8***		0.0		0.0	
13	**Total OPG Nuclear Facilities Outage OM&A Including Adjustments**	186.8	***(59.8)***	127.0	***82.4***	59.5	***149.9***	209.4	14.4	223.7	***(111.0)***	112.7
	Pickering Cyclical Maintenance											
14	Pickering NGS	0.0	0.0	0.0	***25.0***	0.0	***25.0***	25.0	***133.3***	158.3	(7.8)	150.6
15	Operations and Project Support	0.0	0.0	0.0	0.0	0.0	0.0	0.0	***10.0***	10.0	0.3	10.4
16	**Total Pickering Cyclical Maintenance OM&A**	0.0	0.0	0.0	***25.0***	0.0	***25.0***	25.0	***143.4***	168.4	(7.4)	160.9
	DNNP Facilities Outages											
17	DNNP Facilities	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	Operations and Project Support	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19	**Total DNNP Facilities Outage OM&A**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Line No.	Business Unit	2028 Plan	(c)-(a) Change	2029 Plan	(e)-(c) Change	2030 Plan	(g)-(e) Change	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Darlington Outages							
20	Darlington NGS	81.8	***86.6***	168.5	***(78.0)***	90.4	(3.5)	86.9
21	Operations and Project Support	30.9	***19.7***	50.6	***(19.4)***	31.2	(2.4)	28.8
22	**Total Darlington Outages**	112.7	***106.4***	219.1	***(97.5)***	121.6	(5.9)	115.8
	Pickering Outages							
23	Pickering NGS	0.0	0.0	0.0	0.0	0.0	***26.5***	26.5
24	Operations and Project Support	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25	**Total Pickering Outages**	0.0	0.0	0.0	0.0	0.0	***26.5***	26.5
	CRVA Eligible Costs							
26	FCLE Related Ongoing Costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	Pickering Extended Operations	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Optimization of Pickering Shutdown	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	**Total CRVA Eligible Costs**	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30	**Total OPG Nuclear Facilities Outage OM&A**	112.7	***106.4***	219.1	***(97.5)***	121.6	***20.6***	142.2
	Pickering Cyclical Maintenance							
31	Pickering NGS	150.6	7.4	158.0	0.9	158.9	***(58.5)***	100.4
32	Operations and Project Support	10.4	0.6	10.9	0.2	11.1	***(4.8)***	6.3
33	**Total Pickering Cyclical Maintenance OM&A**	160.9	8.0	168.9	1.0	169.9	***(63.3)***	106.6
	DNNP Facilities Outages							
34	DNNP Facilities	0.0	0.0	0.0	0.1	0.1	***48.6***	48.6
35	Operations and Project Support	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	**Total DNNP Facilities Outage OM&A**	0.0	0.0	0.0	0.1	0.1	***48.6***	48.6

Notes:
1 2020-2026 values have been restated for Nuclear organizational changes and transfers from Corporate Support (See Ex. A1-4-1, Att.2 and Ex. F2-2-1, Att. 1).
2 Per EB-2020-0290 OEB Decision and Order, Schedule A, p. 25, nuclear Outage OM&A costs are reduced by 3% per year over the 2022-2026 period.

DARLINGTON REFURBISHMENT PROGRAM - OM&A

1.0 PURPOSE

This section identifies the OM&A costs associated with the Darlington Refurbishment Program ("DRP").

2.0 OVERVIEW

The DRP is primarily a capital project but includes Project OM&A expenses for removal costs and volumetric low & intermediate level waste ("L&ILW") variable expenses related to disposal costs.[1] A summary of DRP OM&A expenses is provided in Ex. F2-7-1, Table 1, for 2020-2026, after which the DRP is expected to be completed.

3.0 TERM-OVER-TERM CHANGES – IR TERM

2027-2031 Plan versus 2022-2026 Actuals and Budget

As this Application includes no forecast OM&A expense for the DRP during the 2027-2031 IR term, there is no term-over-term analysis to conduct.

4.0 PERIOD-OVER-PERIOD CHANGES

Between EB-2016-0152 and EB-2020-0290, the OEB approved DRP OM&A expenditures of $48.4M for 2020, $19.7M for 2021, $24.2M for 2022, $23.6M for 2023, $29.3M for 2024, $25.0M for 2025, and $8.4M for 2026. Actual costs were $19.0M for 2020, $35.6M for 2021, $22.3M for 2022, $39.0M for 2023, and $59.7M for 2024. OPG has forecasted $10.5M for 2025 and $1.8M for 2026. A comparison of actual vs. OEB-approved DRP OM&A expenses is provided in Ex. F2-7-1, Table 2.

Across the 2020-2026 period, DRP OM&A costs are above OEB-approved by (+$9.3M) and managed within the OEB-approved $12.8B program budget. As discussed in Ex. D2-2-1, OPG is currently forecasting the final cost of the DRP to be $12.7B. Overall, the OM&A cost variance is primarily due to higher L&ILW variable expenses of (+$13.5M) as a result of higher cost rates

[1] These costs are also reflected in Ex. C2-1-1, Table 2, Line 3.

reflecting the 2022 ONFA Reference Plan (see Ex. C2-1-1), Turbine Generator Execution project ("TG Execution Project") write-off of (+$8.8M), and Steam Generator strainer project ("Strainer Project") write-off of (+$6.4M). These amounts are partially offset by lower removal costs of (-$19.2M) mainly driven by lower Fuel Handling activities.

The TG Execution Project write-off resulted from a decision to change the Units 3 and 4 stator scope from a stator swap to an in-situ rewind. By shifting from stator swap to in-situ rewind, OPG mitigated risks that could have arisen as a result of such swaps being completed infrequently in the industry. The stator lift required for the swap would have represented the heaviest and most complex lift since DRP construction began, requiring both cranes in the turbine hall at 99.9% capacity. As discussed in EB-2020-0290, this lift carries significant risks, including operational experience in the industry for safety issues.[2]

The Strainer Project write-off resulted from OPG's decision not to continue the project, which had the primary purpose of excluding foreign material during unit startup to prevent damage to the primary heat transport system. OPG successfully implemented an alternative program to mitigate this risk as described in EB-2020-0290, Ex. F2-7-1.

5.0 PERIOD-OVER-PERIOD CHANGES – BRIDGE YEARS

2026 Budget versus 2026 OEB-Approved

The forecasted OM&A cost variance for 2026 of (-$6.6M) (Ex. F2-7-1, Table 2) is primarily due to OPG no longer removing the Retube Waste Processing Building after completion of DRP. The building is being repurposed for ongoing use by Advanced Inspection Maintenance and Fuel Handling teams in support of station operations.

2025 Budget versus 2025 OEB-Approved

The forecasted OM&A cost variance for 2025 of (-$14.5M) (Ex. F2-7-1, Table 2) is primarily due to the Unit 4 RFR removal schedule advancement as discussed below.

[2] See EB-2020-0290, Tr. Tech. Conf., May 3, 2021, p. 19, lines 11-19.

6.0 PERIOD-OVER-PERIOD CHANGES – HISTORICAL YEARS

2024 Actual versus 2024 OEB-Approved

The OM&A cost variance for 2024 of (+$30.4M) (Ex. F2-7-1, Table 2) is primarily due to higher RFR removal costs for Unit 4 (+$20.4M) due to schedule advancement from early return to service of Unit 1 and higher L&ILW variable expenses (+$9.7M) due to higher cost rates reflecting the 2022 ONFA Reference Plan (see Ex. C2-1-1), partially offset by waste volume optimization.

2023 Actual versus 2023 OEB-Approved

The OM&A cost variance for 2023 of (+$15.4M) (Ex. F2-7-1, Table 2) is primarily due to higher RFR removal costs related to Units 3 and 1 (+$15.0M) largely due to the schedule shift.

2022 Actual versus 2022 OEB-Approved

The OM&A cost variance for 2022 of (-$1.9M) (Ex. F2-7-1, Table 2) is primarily due to lower Unit 1 Turbine Generator removal costs (-$1.1M) which was previously planned in EB-2020-0290 for 2022 but occurred in 2023.

2021 Actual versus 2021 OEB-Approved

The OM&A cost variance for 2021 of (+$15.8M) (Ex. F2-7-1, Table 2) is primarily due to higher RFR removal costs related to Unit 3 (+$25.5M) largely due to the schedule shift as a result of delays due to the COVID-19 pandemic, partially offset by the timing of forecasted Unit 1 RFR removal costs (-$9.1M) which was previously planned in EB-2016-0152 to start in 2021 but actually started in 2022.

2020 Actual versus 2020 OEB-Approved

The OM&A cost variance for 2020 of (-$29.4M) (Ex. F2-7-1, Table 2) is primarily due to the Unit 3 schedule shift deferring RFR removal costs (-$29.0M), which was previously planned in EB-2016-0152 for 2020 but actually occurred in 2021 due to the COVID-19 pandemic, and lower Fuel Handling removal activities (-$11.0M) due to Power Track change of project scope. These variances are partially offset by the write-offs to the TG Execution Project (+$8.8M) and Strainer Project (+$6.4M) as discussed above.

Numbers may not add due to rounding.

Table 1
OM&A - Darlington Refurbishment Program ($M)

Line No.	Description	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Budget	2028 Budget	2029 Budget	2030 Budget	2031 Budget
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	**Darlington Refurbishment Program - Unit Refurbishment**[1]	19.0	35.6	22.3	39.0	59.7	10.5	1.8	0.0	0.0	0.0	0.0	0.0
2	**Facilities and Infrastructure Projects**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	**Safety Improvement Opportunities**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	**Total Darlington Refurbishment Program OM&A**	19.0	35.6	22.3	39.0	59.7	10.5	1.8	0.0	0.0	0.0	0.0	0.0

Notes:
1 The Unit Refurbishment 2021-2026 amounts include removal costs of existing structures or facilities, and L&ILW variable expense. L&ILW expenses are shown below:

Darlington Refurbishment Program Cost	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Budget	2028 Budget	2029 Budget	2030 Budget	2031 Budget
L&ILW variable expenses	1.4	6.4	6.1	7.9	18.0	6.1	1.8	0.0	0.0	0.0	0.0	0.0

Numbers may not add due to rounding.

Updated: 2026-03-10
EB-2025-0297
Exhibit F2
Tab 7
Schedule 1
Table 2

Table 2
Comparison of OM&A - Darlington Refurbishment Program ($M)

Line No.	Business Unit	2020 OEB Approved	(c)-(a) Change	2020 Actual	(g)-(c) Change	2021 OEB Approved	(g)-(e) Change	2021 Actual	(k)-(g) Change	2022 OEB Approved	(k)-(i) Change	2022 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**Darlington Refurbishment Program - Unit Refurbishment[1]**	48.4	(29.4)	19.0	16.6	19.7	15.8	35.6	(13.2)	24.2	(1.9)	22.3
2	**Facilities and Infrastructure Projects**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	**Safety Improvement Opportunities**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	**Total Darlington Refurbishment Program OM&A**	48.4	(29.4)	19.0	16.6	19.7	15.8	35.6	(13.2)	24.2	(1.9)	22.3

Line No.	Business Unit	2022 Actual	(e)-(a) Change	2023 OEB Approved	(e)-(c) Change	2023 Actual	(i)-(e) Change	2024 OEB Approved	(i)-(g) Change	2024 Actual	(k)-(i) Change	2025 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
5	**Darlington Refurbishment Program - Unit Refurbishment[1]**	22.3	16.6	23.6	15.4	39.0	20.7	29.3	30.4	59.7	(49.2)	10.5
6	**Facilities and Infrastructure Projects**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	**Safety Improvement Opportunities**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**Total Darlington Refurbishment Program OM&A**	22.3	16.6	23.6	15.4	39.0	20.7	29.3	30.4	59.7	(49.2)	10.5

Line No.	Business Unit	2025 OEB Approved	(c)-(a) Change	2025 Plan	(g)-(c) Change	2026 OEB Approved	(g)-(e) Change	2026 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
9	**Darlington Refurbishment Program - Unit Refurbishment[1]**	25.0	(14.5)	10.5	(8.7)	8.4	(6.6)	1.8
10	**Facilities and Infrastructure Projects**	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	**Safety Improvement Opportunities**	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	**Total Darlington Refurbishment Program OM&A**	25.0	(14.5)	10.5	(8.7)	8.4	(6.6)	1.8

Notes:
1 The Unit Refurbishment 2020-2026 amounts include removal costs of existing structures or facilities prior to construction modication, and L&ILW variable expense. Breakdown provided in F2-7-1 Table 1.

ALLOCATION OF SUPPORT SERVICES COSTS

1.0 PURPOSE

This evidence provides OPG's centre-led Support Services costs assigned and allocated to OPG's regulated hydroelectric facilities and nuclear facilities, and the Darlington New Nuclear Program ("DNNP") facilities, describes the Support Services functions and their evolution since EB-2020-0290, and presents an independent benchmarking study of these functional costs.

2.0 OVERVIEW

The centre-led Support Services discussed in this exhibit, which provide services to OPG's regulated hydroelectric business, OPG's regulated nuclear business and the DNNP facilities are: Corporate & Technology Services ("CTS", formerly called Chief Information Office or "CIO"), Real Estate, Supply Chain, Finance, Human Resources, and the Corporate Centre. Section 3.0 discusses the Support Services costs. A description of Support Services by function is provided in Attachment 1.

Support Services costs are either directly assigned or allocated to the regulated businesses. OPG directly assigns costs that are specific to a business. For example, Support Services employees working at and solely in support of a business are directly assigned to that business. Support Services costs that are associated with services utilized by more than one business are allocated. Cost allocation is based on appropriate cost drivers, which reflect cost causation or the benefits a business receives. OPG continues to use an established cost allocation methodology to perform this attribution of Support Services costs to each of the regulated businesses. The methodology remains consistent with that presented and applied in EB-2020-0290 and prior OPG proceedings and is discussed further in Ex. F3-1-4. As in EB-2020-0290, it has been independently validated by Elenchus Research Associates ("Elenchus"), in a report found at Ex. F3-1-4, Attachment 1.

As discussed in Ex. A1-4-4, DNNP LP is entering into a lease for the DNNP facilities with OPG. DNNP LP will undertake the development, construction, and operation of the DNNP facilities, with OPG contracted to act as the project manager and operator of the facilities. The Application assumes that DNNP LP enters into the lease and associated arrangements at the end of 2025. DNNP LP will not have its own workforce and will contract for all applicable services with OPG and will therefore reimburse OPG for its fully allocated costs of providing the services, including the applicable Support Services costs determined using OPG's cost allocation methodology. As validated by Elenchus, the same cost allocation methodology has been applied to attribute Support Services costs to the DNNP facilities, including during their construction, as for OPG's regulated businesses.[1] While the DNNP facilities will be allocated an appropriate share of existing Support Services costs using this methodology, OPG expects that its Support Services cost structure will be able to absorb the addition of these assets without a notable change in overall cost levels.

Support Services costs for OPG's regulated hydroelectric facilities for 2016-2024 (actual) and 2025-2026 (budget), for OPG's nuclear facilities for 2020-2024 (actual) and 2025-2026 (budget), and for the DNNP facilities for 2026 (budget) are provided in Ex. F3-1-1, Tables 1-7. Forecast Support Services costs for the regulated hydroelectric facilities for the 2027 test year are $55.3M (Ex. F3-1-1, Table 2). Forecast allocated Support Services costs for OPG's nuclear facilities over the IR term are $417.5M for 2027, $412.1M for 2028, $432.7M for 2029, $444.7M for 2030, and $471.6M for 2031 (Ex. F3-1-1, Table 3). Forecast allocated Support Services costs for the DNNP facilities over the IR term are: $28.6M for 2027, $31.5M for 2028, $29.4M for 2029, $30.6M for 2030, and $32.4M for 2031 (Ex. F3-1-1, Table 3c). Exhibit F3-1-1, Table 1 summarizes the Total OPG Support Services costs over the historical, bridge, and IR term period.

Like other parts of the organization, Support Services have experienced elevated inflationary cost increases since EB-2020-0290, including higher labour cost escalation reflecting bargaining process outcomes including, as a result of the repeal of the *Protecting a Sustainable*

[1] Ex. F3-1-4, Attachment 1, S. 3.2.1.

Public Sector for Future Generations Act, 2019 ("Bill 124"), as discussed in Ex. F4-3-1, Section 6.2. In parallel, IT software and licensing costs have increased significantly since 2020 driven by both the broader market and OPG's transition away from perpetual licenses to subscription and usage-based models and the adoption of cloud-based platforms. As shown in Ex. F3-1-1, Table 4, these software and licensing costs have increased 92% between 2020-2024 and are expected to increase by another 86% by 2031. To control these costs, OPG consistently reviews software needs and examines licenses on an annual basis to ensure they are required. In addition, cloud server storage is managed so that only required data is migrated to the cloud in order to control consumption costs. These cloud-based tools are foundational to OPG's ability to deliver on its projects and sustain operational excellence through continuous improvement and the optimized use of resources. Excluding the impact of software and licensing costs, Total OPG Support Services costs increase by approximately 2.75% per year over the 2024-2031 period.

Where applicable, OPG has restated the presentation of actual (2016-2024) and EB-2020-0290 Nuclear OEB-approved (2022-2026) Support Services costs for subsequent organizational changes including transfers to/from Enterprise Operations and Enterprise Projects Support groups to provide an appropriate basis of comparison with the forecast period information. These transfers are further described in Ex. A1-4-1, Attachment 2.

As in EB-2020-0290, OPG engaged The Hackett Group to perform an independent benchmarking study of OPG's Support Services functions and their operating costs (the "Hackett Study"). This study identifies that, overall, OPG's total cost for the areas benchmarked remain slightly better than median of the peer group's total cost. The Hackett Study report is discussed in Section 6.0 and provided in Attachment 2.

The remainder of this evidence is organized as follows:

- Section 3.0 discusses the overall Support Services OM&A costs over the historical, bridge and IR term.
- Section 4.0 discusses the changes made to the information technology support services strategy since EB-2020-0290.

- Section 5.0 presents the results of the corporate cost benchmarking study.

3.0 SUPPORT SERVICES COSTS – TOTAL OM&A

As in EB-2020-0290, OPG's support organizations are designed to capture common best practice elements found across the Company and apply them in a centralized and standardized manner to maintain the corporate infrastructure and deliver common services. These functions underpin all of the Company's operations, projects and initiatives and are integral to sustaining core organizational processes, providing appropriate risk management, enabling workforce activities, ensuring the necessary governance, oversight and compliance, and advancing community and Indigenous engagement. As such, OPG continuously seeks opportunities to align organizational structure, reporting relationships, and resources of Support Services to OPG's strategic objectives to better support operational efficiency and decision-making. Support Services are described in Attachment 1 and organizational changes since EB-2020-0290 are further explained in Ex. A1-4-1, Attachment 2.

Evolving external factors have increased the complexity and impacted the cost of the work performed by Support Services, including:

- Changes in the trade environment and competitive vendor market landscape such as export controls and tariffs, supply chain inflation and demand, and shifts toward strategic supplier relationships, all of which have made procurement activities more complex (see Ex. F3-3-1).
- Competition in the labour market, increasing and evolving labour relations landscape (see Ex. F4-3-1), as well as ongoing advancements in technology (see Ex. D3-1-1), that are collectively impacting resource availability and acquisition strategies, skill requirements, workflows and oversight and functional coordination, resulting in a greater demand for specialized skills, more dynamic and adaptive work processes, enhanced monitoring and evaluation practices, and the need for improved collaboration across various departments.

- Substantial capital investments being undertaken by OPG in support of Ontario's energy needs have increased the scope and complexity of financing requirements and associated structures, resulting in increased effort to manage OPG's borrowing needs and other potential funding sources in a cost-effective manner.
- Emerging technology needs in areas such as cyber security, operations and engineering technology improvement, and data management require continued investment in technological solutions to pursue continuous improvement and avoid obsolescence, aligned to the Company's technology strategy. More specifically, with respect to the DNNP facilities, OPG must implement new digital tools and applications necessary to enable the workforce structure and operating model for the Small Modular Reactors, including smart devices, digital worker technologies, and applicable new asset management system (see Ex. D3-1-1 and Ex. D3-1-2).

The work performed across Support Services is underpinned by OPG's Reconciliation Action Plan, which reinforces a commitment to building strong partnerships and taking meaningful actions that deliver shared benefits across Indigenous communities and with Rightsholders. This includes practices and initiatives that promote the expansion and capacity of diverse suppliers, as well as Indigenous economic empowerment and growth (see Ex. A2-2-1, Section 3.5).

Support Services' Base OM&A costs over the IR term reflect higher expenses associated with the Company's information technology ("IT") infrastructure, and the impact of the repeal of Bill 124 to wages (Ex. F4-3-1, Section 6.2) and for the nuclear business, the planned return to service of Pickering Unit 5 in 2031. Notwithstanding the complexity of the external environment and internal landscape, discussed above, overall Support Services full-time equivalents ("FTEs") are generally stable over the IR term (Ex. F3-1-1, Tables 7 and 8). Until Unit 5 returns to service, some of the workforce in Human Resources, Supply Chain and certain other functions will directly support and be funded by the PRP. Given OPG's Support Services' economies of scale, the operation of DNNP Unit 1 will not materially impact Total OPG Support Services' costs.

Support Services will continue to play a critical role in sustaining the core business operations as Pickering operations extend to September 2026 and transition into the four-unit refurbishment outage thereafter. During the refurbishment outage, the Pickering site will remain active and require continued support to ensure safety, sustain reliability, and meet governance requirements while maintaining the required infrastructure. Support Services will continue to carry out these functions, including IT and telecommunication support, facilities services, workforce support, financial operations and oversight, certain supply chain and procurement services, communications and stakeholder relations. Cyber security protections will remain critical to safeguard sensitive operational and security-related data. In addition, Real Estate costs for utilities and facilities maintenance to upkeep the physical infrastructure and property will continue to be required to ensure that the site remains safe, functional and compliant through the refurbishment period and prepared for return to service and post refurbishment operations.

Since EB-2020-0290, Support Services have undertaken a number of initiatives that have enabled OPG to partly mitigate the cost impact of the growing internal demand for services and increasing complexity in the external landscape. OPG has implemented initiatives that have controlled costs by:

1. Optimizing OPG's real estate footprint by investing in a new corporate headquarters for OPG's non-plant employees to control lease and other real estate operating costs (see Ex. D3-1-1, Section 3.2);
2. Strategically utilizing resources through the workforce strategy, including redeployment opportunities and the use of employee classifications such as Term Employees to control compensation costs (se Ex. F4-3-1);
3. Leveraging procurement initiatives and practices that improve supplier performance, streamline supplier nuclear qualifications, and continue to refine and improve strategic sourcing and company-wide category management (see Ex. F3-3-1); and
4. Repatriating New Horizons System Solutions ("NHSS") employees to OPG in 2022 in support of technology services and projects, as discussed in Section 4.0 (Ex. F3-1-1, Table 4).

In this IR term, Support Services will continue to monitor performance and focus on controlling costs by:

1. Streamlining processes as OPG undertakes key system and technology lifecycle upgrades, ensuring long-term value;
2. Continuing to optimize supplier relationship management, onboarding, capability and capacity management, materials and inventory management, and warehouse efficiencies;
3. Supporting the Company's continued ability to access cost-effective financing by focusing on maintaining a strong credit rating, optimizing funding sources, and establishing ability to access US bond markets (see Ex. C1-1-2); and
4. Utilizing workforce strategies to secure an engaged and capable workforce across the enterprise while managing workforce risks and ensuring sufficient resourcing flexibility, using tools such as redeployment strategies, upskilling and reskilling, and succession planning (see Ex. F4-3-1).

In addition to these initiatives, Support Services will continue to evaluate and implement opportunities to organize its structure and services to meet evolving business requirements.

4.0 INFORMATION TECHNOLOGY SUPPORT SERVICES

Prior to 2022, OPG operated under a contract with NHSS for core IT services, as well as additional services as needed. To manage these costs and requirements, OPG evaluated alternatives to renewing the NHSS IT Services Agreement, which was set to expire in 2022.

After reviewing its options and requirements, OPG determined that an outsourced IT service model would no longer be suitable, as vendor proposals proved more expensive than bringing both core and additional IT services back in-house. Additionally, the rapid pace of technological advancement necessitated a more diverse IT service offering, including capabilities in artificial intelligence and data analytics, to effectively support evolving business needs. As a result, OPG decided to repatriate approximately 250 NHSS staff represented by the Power Workers' Union in February 2022 and those represented by the Society of United Professionals in November 2022, transitioning the CTS organization to a blended sourcing model.

Under this new blended sourcing model, OPG staff employees deliver ongoing services and IT project work, while vendors are engaged strategically to address peak workloads or provide specialized expertise. This approach enables OPG to achieve greater value in areas such as cybersecurity and to advance initiatives in artificial intelligence and innovation. It also fosters closer collaboration with business units to better understand their needs and identify appropriate technology solutions, and is helping the organization to more quickly implement new technologies and innovate IT services to meet business demands. For example, OPG has been able to rapidly develop and deploy "ChatOPG" as a secure AI platform for employees and operational tools such as ServiceNow to monitor IT service volume and quality, and continues to proactively identify emerging needs through OPG's digital strategy. Additionally, leveraging external resources with specialized skills benefits OPG staff by providing an opportunity for upskilling as new requirements and technologies arise.

Moreover, in-sourcing IT services and adopting a blended sourcing model has restored direct control by OPG over its data, service scope, and staff training and development—factors that are increasingly critical given the organization's complexity and the accelerating pace of digitization and technological change. Exhibit F3-1-1, Tables 4, 5, and 6 provide an overview of CTS support costs, including NHSS contract costs up to 2023, after which all costs are reported under CTS Support Costs.

5.0 BENCHMARKING STUDY

In the OEB-approved settlement proposal in EB-2020-0290 and consistent with recent applications, OPG committed to undertake an independent benchmarking study of corporate support costs. The Hackett Group ("Hackett"), which completed OPG's last two corporate support costs benchmarking studies, was retained to carry out this study. A copy of the Hackett Study report is filed as Attachment 2.

Hackett benchmarked OPG against peers using 2024 data to reflect the most recently completed fiscal year at the time of the benchmarking exercise. Support Services' costs assigned and allocated to both OPG's nuclear and regulated hydroelectric businesses were

included in the scope of the benchmarking study. Hackett's most recent previous study had used 2019 data and was submitted in EB-2020-0290.

Consistent with their standard practice, Hackett normalized OPG's corporate costs based on key demand drivers for each function. For IT, the number of end users was used to benchmark costs per end user. For Human Resources, the number of employees was used to benchmark costs per employee. For Procurement, spend was used to benchmark costs as a percentage of spend. For Finance, Real Estate, and Executive and Corporate Services, revenues were used to benchmark costs as a percentage of revenues.

In providing data to Hackett, OPG closely followed Hackett's methodology, cost definitions and taxonomy to ensure OPG's Support Services functions and costs were benchmarked against peers on a comparable basis. OPG's data was reviewed by Hackett.

The 2024 Hackett Study found that on an overall basis, OPG's cost (including both Process Costs and Technology Costs) is slightly better than the median of the peer group, demonstrating the following results by function:

- While OPG's IT costs have moved from the first to the second quartile since the 2019 Hackett study, they continue to be better than the median of the peer group, with a benchmarking cost of about $1,600 per employee below the 2024 peer median. The change in the results reflects a strategic investment in technology that OPG is making to sustain or modernize its systems and support operational reliability, regulatory compliance, and secure operations, and advance innovation to meet evolving business needs.
- Finance process costs remain in the third quartile compared to the peer group median but have improved slightly compared to the 2019 Hackett study. OPG has been able to maintain these results while managing increased finance support needs driven by of project work across the organization, and increasingly complex corporate financing activities in support of major project investments.
- Human Resources process costs remain in the third quartile primarily reflecting intensified recruitment and onboarding efforts and other support required through a period of increased hiring and workforce transition; however, Human Resources costs are planned

to decrease below 2024 Actuals, starting in 2026 (Ex. F3-1-1, Table 1) until 2031 as the first Pickering unit comes back online from refurbishment.

- OPG's Procurement process costs as a percentage of spend improved by 0.03%, while the peer group median increased by 0.03%. OPG's Procurement results continue to be in the fourth quartile.
- The Executive & Corporate Services process costs shifted into the third quartile from the second quartile. Despite the increasing complexity of OPG's external operating environment, these costs as a percentage of revenue have decreased by 0.01% since 2019. The peer group median has improved by 0.04% of revenue.
- Real Estate & Facilities Management costs remain in the third quartile compared to the peer group median but have improved compared to the 2019 Hackett study.

6.0 CONCLUSION

Aside from higher IT-related expenses reflecting market trends and OPG's adoption of more modern technology platforms, Support Services costs allocated to the nuclear and regulated hydroelectric businesses are projected to remain stable throughout the IR term, with increases anticipated only as support levels are restored to Pickering when Unit 5 returns to service in 2031. OPG expects to largely absorb the support required for DNNP Unit 1, once it comes online in late 2030, within the existing Support Services' cost structure. Overall, Support Services' cost structure remains slightly better than the median of the peer group. OPG will continue to execute on Support Services' initiatives to control costs and support evolving business needs during the IR term.

LIST OF ATTACHMENTS

Attachment 1:	Description of Corporate Support Functions
Attachment 2:	Benchmarking Study of OPG's Corporate Support Function Costs prepared by The Hackett Group

ATTACHMENT 1 - DESCRIPTION OF CORPORATE SUPPORT FUNCTIONS

1.0 INTRODUCTION

This Attachment describes the corporate Support Services functions that support nuclear and regulated hydroelectric production and whose costs are assigned or allocated to the regulated business and form part of the nuclear and regulated hydroelectric revenue requirement.

2.0 CORPORATE TECHNOLOGY & SERVICES

The Corporate Technology & Services department (“CTS”, formerly Chief Information Office) oversees OPG's information management and information technology needs. CTS is accountable for the strategic planning, management, and operations of all business and technical information systems, except for process computers that control plant systems and operations. The CTS group also administers OPG’s information management and governing documents framework and includes the Shared Services organization, further described below.

2.1 Digital Technology & Services

2.1.1 Portfolio Planning & Controls: Develops standards and oversight of IT projects in accordance with OPG governance and best practices, while monitoring controls across labour and non-labour budgets.

2.1.2 Application Development Services: Supports key business capabilities by coordinating teams for both application enhancements and ongoing sustainment, ensuring stability while adapting technology to evolving organizational needs.

2.1.3 Data Services: Delivers centralized data capabilities that empower insights, analytics, and informed decision-making across IT, while supporting digital innovation through technologies aligned with business goals.

2.1.4 Telecommunications, Hardware and Software: Manages core hardware and software, infrastructure, IT operations management, network management and telecommunications.

2.1.5 Enterprise Services: Supports the enterprise technology services and platforms, such as the suite of Microsoft products and the service management platform.

2.1.6 Customer Experience: Supports end-user computing and field services. The team also supports the IT Service Management (ITSM) and DTS service desk.

2.1.7 Cyber Security Services: Responsible for protecting digital assets, monitoring networks, conducting risk assessments, and ensuring compliance. The team leads incident response efforts, mitigates potential damage from security breaches, and educates employees on best practices to maintain a secure IT environment.

2.1.8 Information Management Execution: Manages OPG's records and information assets to ensure accessibility, accuracy, and security.

2.2 Shared Services

Shared Services provides transaction processing and administrative support across the organization. This team handles a wide range of essential services, including: HR Service Center and Payroll Services to address employee inquiries and payroll issues; Financial Services, such as accounts payable, general accounting, corporate card management, and business travel and expense processing; Business Information Management Services oversee office supplies, mail and courier handling, and printing services to support daily operational needs.

3.0 REAL ESTATE

The Real Estate group provides centralized support services through Real Estate Services, Facilities Services, and Projects and Accommodations.

3.1 Real Estate Services

On a corporate-wide basis, Real Estate Services acquires, manages and disposes of real estate rights and interests; manages all commercial leases; consults on municipal planning issues; maintains real estate and property documents; develops and implements accommodation strategies to meet space requirements outside the generating stations; and

provides property tax services for all property owned by OPG. In addition, this group manages the Heritage Assessment program, waterfront leasing, and the employee relocation program.

3.2 Facilities Services

Facility Services provides property management services including maintenance and inspection of buildings and technical site infrastructure at OPG's facilities, except for RG facilities and most buildings within the protected areas of the nuclear sites. The systems and facilities addressed include mechanical, electrical, fire/life safety, plumbing, waste management, lighting, parking lots, roadways and bridges. Custodial services, grounds maintenance (snow clearing and landscaping), and food services are also provided by this group. In addition, Facilities Services operates three garages, which provide inspection and maintenance for all motorized work equipment at the nuclear sites.

3.3 Projects and Accommodations

Projects and Accommodations is responsible for developing the long-range facilities and accommodations plans, managing employee office moves and the budgeting, planning and executing of all facility construction, maintenance, demolition and workplace reconfiguration projects. Oversight of contractors involved in facility and reconfiguration projects is also provided by this group.

3.4 Employee Experience

Employee Experience supports the company's efforts to create a strong culture and an effective workforce by delivering communications and change management support to build employee engagement across the organization.

4.0 SUPPLY CHAIN

Supply Chain is responsible for procuring products and services, managing commercial contracts, and performing inventory management. Supply Chain focuses on maintaining the integrity of the procurement process with a goal of delivering value for money by leveraging enterprise spend across many different categories of products and services to support OPG's operations.

4.1 Supply Chain Project Support

The Supply Chain Project Support group procures project related services (e.g., engineering procurement and construction contracts) and supports the procurement of materials for major project business units.

4.2 Supply Chain Quality Assurance

The Supply Chain Quality Assurance group conducts key quality assurance activities including supplier audits, oversight of supplier's quality performance, source and receipt inspections, and maintenance of approved supplier lists.

4.3 Category Management

Category Management conducts market analysis to develop and executes product and service category strategies to take to market with a goal of establishing commercial contracts/agreements.

4.4 Strategic Programs

Strategic Programs conducts supplier relationship management, contract management and Indigenous and diverse supplier relations development.

4.5 Purchasing

The Purchasing group issues purchase orders utilizing established commercial contracts/agreements as well as standalone purchases. This group also includes Inventory & Materials Management, which manages the OPG Nuclear Inventory catalog/sku (stock-keeping unit) item list; assures appropriate purchasing standards and procedures; and confirms that stocking parameters are accurate and up to date.

4.6 Plant Operations

The Plant Operations team primarily manages warehousing & logistics of OPG’s Nuclear material inventory held within the central warehouse facility and the internal station warehouse stores located at Pickering and Darlington.

5.0 FINANCE

Finance provides strategic advice, services, and support in the areas of commercial integration and strategy, business enablement and technology solutions, treasury, corporate finance and controllership, investment strategy and business development, and assurance and risk management. The specific accountabilities by organization are described below.

5.1 Finance and Controllership

The Finance and Controllership group includes Operations Controllership, Controllership and Finance Projects, Business Planning & Reporting, and Income Tax.

5.1.1 The Operations Controllership group: provides services directly to Nuclear and Hydroelectric sites, and Operations and Project Support functions. Where possible, staff are directly assigned to the business units and are located at the production or project sites they support.

5.1.2 The Controllership and Finance Projects group: provides services for subsidiaries, actuarial calculations and forecasting, and engages in finance projects.

5.1.3 The Business Planning & Reporting group: provides services for external reporting, business planning, management reporting, corporate controllership, revenue accounting and settlements. Within Business Planning and Reporting, the External Reporting and Policy group prepares consolidated financial statements, external reporting, and maintains accounting policies and procedures in accordance with U.S. Generally Accepted Accounting Principles.

5.1.4 The Income Tax group: deals with tax returns and compliance, provides OPG's business unit support and consulting, and offers tax code advice to OPG's accounts payable, accounts receivables and procurement teams.

5.2 Treasury

The Treasury group is responsible for OPG's financing, cash management, financial exposure management, capital structure management, credit market risk, and insurance. The Insurance department is responsible for both insurance contracting and claims processing.

5.3 Internal Audit and Enterprise Risk Management

The Internal Audit group provides independent, objective assurance of the organization's operations; evaluates the effectiveness of governance and controls; and maintains a strategic audit plan which includes key risk audits, mandatory audits, cyclical audits, major project audits, contract audits, and other audits and reviews. The Enterprise Risk Management group assesses, reports, and provides risk mitigation recommendations focused on the enterprise and specific business activities.

5.4 Commercial Integration and Strategy & New Growth

The Commercial Integration and Strategy group is responsible for the organization's regulatory finance, nuclear liability management and corporate development functions. The New Growth group is responsible for driving long-term sustainable revenue growth by strategically developing and seeking new business investment and partnership opportunities.

5.5 Business Enablement Hub

The Business Enablement Hub group is primarily responsible for information technology improvement and innovation initiatives associated with the overall Finance function.

5.6 Fund Management

Fund Management group includes the oversight of OPG's Nuclear Segregated Funds (the Decommissioning Segregated Fund and the Used Fuel Segregated Fund) and OPG's Pension Fund. The investment management of these funds are outsourced to third-party investment managers. Management and oversight of these funds includes activities such as investment strategy design and implementation for each of the funds; performance monitoring and reporting; selection of investment managers; investment risk monitoring; and daily fund operations.

6.0 HUMAN RESOURCES

Human Resources ("HR") enables OPG and its leaders to build a productive, engaged workforce with the right people, possessing the right skills, in the right roles to achieve business results. The Human Resources function is responsible for labour relations, compensation and

benefits, enterprise HR strategy, talent programs, leadership training, and recruitment. Its specific accountabilities by organization are described below.

6.1 HR Business Partnering

The HR Business Partnering group provides strategic advice to the business units and leads the implementation of Human Resources programs across OPG.

6.2 Labour Relations

The Labour Relations group oversees OPG's collective bargaining efforts, manages all labour relations activities to ensure compliance with collective agreements and labour legislation, and to ensure policies for represented staff are applied consistently and correctly.

6.3 Compensation and Benefits

The Compensation and Benefits group develops and manages the compensation and benefits program to achieve the company's business objectives and provides analytical support related to workforce planning and HR program management.

6.4 HR Projects

The HR Projects team leads business changes from a human resource perspective, manages talent and change, provides human resources continuous improvement and support HR projects including the implementation of new systems and enables process changes.

6.5 Talent Management & Leadership Development

Talent Management & Leadership Development acts to develop and retain staff with the skills and experience required to meet the company's needs. It co-ordinates succession planning to ensure that critical skills and business knowledge are maintained and that corporate leadership requirements are met.

6.6 Recruitment & Onboarding

Recruitment works to recruit talent and successfully onboard skilled staff. It ensures that staff successfully settle in their roles and can thrive within OPG's environment.

6.7 Workforce Planning

The Workforce Planning group assists in the resource planning strategy of the organization. This group is also responsible for providing the reporting and analytics to inform workforce strategies.

6.8 Ethics and Equity

The Ethics team is responsible for investigations and the development and maintenance of ethics-related governance such as Harassment and Human Rights and the Business Code of Conduct. The Equity department is focused on furthering the advancement of OPG's workforce equity and strategies that support an inclusive work environment.

6.9 Health Services

The Health Services team delivers programs and resources that support employee well-being, including effective disability management and initiatives that promote physical and mental health in line with applicable standards.

7.0 CORPORATE CENTRE

7.1 Executive Office

The Executive Office is responsible for the overall management and strategy of the company.

7.2 Commercial Management

The Commercial Management team is responsible for oversight of commercial contracts and vendor management for OPG's large projects.

7.3 Law Division

The Law division provides legal advice and services to support all business units across OPG, including support for various procurement activities and corporate and commercial matters. Law's legal group provides advice related to OPG's pension and nuclear funds; real estate; Bruce lease and related agreements and water resources; municipal approvals and land use planning; energy markets and regulatory matters, including the OEB payment amount applications; environmental approvals and compliance; nuclear licensing; litigation; First

Nations and Métis issues; freedom of information requests; occupational health and safety compliance; and labour, employment and privacy law.

7.4 The Corporate Governance and Corporate Secretary

This function under law supports OPG's Board of Directors and the Executive Office, and interfaces between the OPG's Board of Directors, management and OPG's shareholder. It also contains the Freedom of Information and Intellectual Property ("FOI&IP") function. FOI&IP provides access to information in the custody or control of OPG.

7.5 Environment, Social & Governance functions ("ESG")

The ESG is responsible for advancing and reporting on OPG's ESG performance. ESG engages with key audiences and supports other Business Units to achieve these goals, including coordinating OPG's annual ESG reporting, monitoring and aligning with external ESG reporting frameworks and researching and analyzing ESG risks and opportunities.

7.6 Enterprise Strategy

The Enterprise Strategy team acts as the central group responsible for ensuring the company's strategic direction is clear, well-informed, and actionable, supporting OPG's mission to provide clean, reliable, and cost-effective power for Ontario. Enterprise Strategy is responsible for developing and updating OPG's corporate strategy.

7.7 Indigenous Relations

Indigenous Relations works with Indigenous communities, proximate to OPG's present and potential future operations to foster positive and mutually beneficial relationships that will create social and economic benefits through partnerships and collaboration. The Reconciliation Action Plan is OPG's road map for how we intend to work in partnership with Indigenous communities, businesses, and organizations to advance Reconciliation.

7.8 Stakeholder Relations & Government Affairs

Stakeholder Relations provides communications support and public and stakeholder outreach as part of ongoing efforts to ensure transparency, accountability and to earn and maintain strong local relationships and social license for OPG to operate its facilities. Major focus areas

are ensuring clear and timely communications on key projects, public safety efforts, water management, and operations performance. This includes ensuring timely information sharing with safety regulators like the Canadian Nuclear Safety Commission. Government Affairs ensures an ongoing and timely flow of information to support policy and program formulation and to build awareness of key business priorities across all levels of government. Internally, this group helps ensure awareness of and alignment with government priorities and policies.

7.9 Regulatory Affairs

Regulatory Affairs is responsible for OPG's interactions with economic and grid reliability regulators. These include the OEB, IESO, CER, NPCC, NERC, and other Canadian and U.S. regulators that affect OPG’s operations. Regulatory Affairs provides strategy and advice, and also manages regulatory interactions to obtain approvals and outcomes that allow OPG to accomplish its business goals. Additionally, Regulatory Affairs develops and administers company-wide programs to ensure compliance with market and reliability rules and regulations and is responsible for OPG’s major rate applications before the OEB.



ONTARIO POWER GENERATION

The Hackett Group®
World Class Defined and Enabled

Benchmark Results Presentation

November 2025

Agenda

- Executive Summary
- Benchmark Methodology
- Peer Overview
- Results

Executive Summary

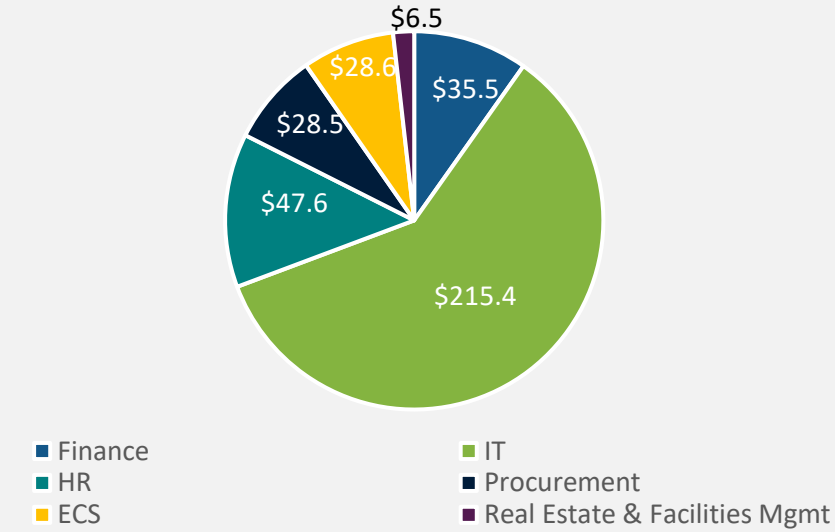
Overview

- Ontario Power Generation (OPG) has engaged The Hackett Group to perform an independent benchmarking study of OPG's corporate support functions and operating costs for the regulated business
- Hackett leveraged its expertise and well-defined taxonomy to deliver the following cost assessment to Peers

2024 Study General Observations

- Overall OPG 2024 cost (Process Cost and Technology Cost) for the in-scope areas is $362.1 million, which is slightly below the median of the peer group.
- OPG's IT cost, including technology cost across all in-scope functions, is 11% below the peer median.
- Finance costs as a % of revenue decreased since 2019 while the median of the peer group's costs increased. Cost performance remain in the 3rd quartile of the peer group.
- HR process costs increased from 2019 to $4,742 per employee and remain in the 3rd quartile of the peer group.
- Since 2019 OPG's ECS process cost as a % of revenue decreased 2%, however the median of peer group's cost as a % of revenue decreased by 8%. The result is OPG moved into the 3rd Quartile of the peer group.
- Real Estate & Facilities Management process costs as a % of revenue slightly decreased since 2019 and remain in the 3rd quartile of the peer group.
- Procurement process costs as a % of spend decreased by 4% since 2019 and remain in the 4th quartile of the peer group.

OPG 2024 Total Cost (Process Cost + Tech Cost[1]) in millions



[1]Technology cost included within the IT function cost

The Hackett Group

© 2025 The Hackett Group, Inc. All rights reserved. Reproduction of this document or any portion thereof without prior written consent is prohibited.

Agenda

- Executive Summary
- Benchmark Methodology
- Peer Overview
- Results

Benchmark Methodology

Data Guidelines and Benchmark Scope

- **Scope:** All OPG Regulated Operations
- **Benchmark data collection period:** Fiscal Year 2024
- All monetary values are in Canadian Dollars (CAD)
  - PPP (Purchasing Power Parity) was used to adjust the peer data from USD to CAD
  - Applied inflation rates published by the IMF to adjust peer cost data to ensure comparability with OPG's 2024 data
- Technology Costs are captured and compared within the IT Function
- Out of scope - the below items were excluded from the peer group to mirror the scope of OPG's functions:
  - Finance: Revenue Cycle processes
  - Procurement: Product Development, Design and Support
  - Executive & Corporate Services: Security, Legal – M&A, Cafeteria & Catering Services
- Hackett's process taxonomy is applied independent of OPG's organizational structure and functional reporting lines, thereby facilitating an "apples to apples" comparison

2019 Procurement Cost Adjustment

- OPG has significantly increased capital procurement spend since 2019
- To align with the 2024 benchmarking study, OPG adjusted 2019 procurement costs to include support for capital projects, mainly for the Darlington Refurbishment Project
- The adjustment increased 2019 Procurement process costs by $2.35M, increasing OPG's cost ratio from 0.75% to 0.85% of spend
- The revised 2019 benchmark results remained in the fourth quartile

Benchmark Comparison

- **Peer Group**
  - Represents the median of a group of companies that have similar industry characteristics and size to OPG

Normalization of Benchmark Data

- **Finance and Executive & Corporate Services (ECS) Functions : Based on Revenue**
  - 2024 - $5.58 billion
  - 2019 - $5.07 billion
- **IT Function: Based on End-User Equivalents (EUE)**
  - 2024 - 16,562
  - 2019 - 14,664
- **HR Function: Based on average employees**
  - 2024 - 10,034
  - 2019 - 9,878
- **Procurement Function: Based on spend**
  - 2024 - $3.47 billion
  - 2019 - $2.27 billion

Revenue: *External Revenue Only, intercompany revenue not included. OPG includes revenue associated with regulated operations only. OPG revenue is adjusted to account for revenue deferred to future periods.*

End-User Equivalents (EUE): *An individual (typically either an employee or contractor) that spends at least 10% of his or her time using a company provided, funded, supported computing device that is part of the company's IT infrastructure (i.e. desktops, laptops, hand-held devices, etc.) to support his or her business function. The user must have direct access to internal applications/systems to execute specific transactions on behalf of the company. OPG used LAN IDs as a proxy for end users. OPG included end users associated with regulated operations only.*

Employees: *Full-time, part-time, temporary, seasonal, and contingent employees . OPG included employees associated with regulated operations only.*

Spend: *Spend refers to the cost of direct and indirect materials and services purchased (i.e., disbursements) in the period measured by this benchmark. OPG included spend associated with regulated operations only.*

© 2025 The Hackett Group, Inc. All rights reserved. Reproduction of this document or any portion thereof without prior written consent is prohibited.

Hackett's process taxonomy was applied to ensure an apples-to-apples comparison

Finance

- **Transactional**
  - Cash Disbursements
  - General Accounting & External Reporting
- **Control and Risk Management**
  - Tax Management
  - Treasury Management
  - Compliance Management
- **Financial Planning and Analysis**
  - Planning and Forecasting
  - Business Performance Reporting & Analysis
- **Management & Administration**
  - Finance Function Management

Procurement

- **Operations and Compliance**
  - Supply Data Management
  - Requisition and PO Processing
  - Supplier Scheduling
  - Receipt Processing
  - Compliance Management
- **Sourcing and Supply Base Management**
  - Customer Management
  - Sourcing Execution
  - Supplier Management and Development
- **Planning and Strategy**
  - Sourcing and Supply Base Strategy
- **Management and Administration**
  - Function Strategy and Performance Management
  - Procurement Function Management

Real Estate & Facilities Management

- **Real Estate & Facilities Management**
  - Facilities Management (for office space)
  - Real Estate Management

Human Resources

- **Transactional**
  - Total Rewards Administration
  - Payroll Services
  - Data Mgmt., Reporting, & Compliance
  - Exit Management
- **Employee Life Cycle**
  - Recruiting & Staffing
  - Performance and Talent Development
  - Organizational Effectiveness Services
- **Planning and Strategy**
  - Total Rewards Planning
  - Strategic Workforce Planning
- **Management and Administration**
  - HR Function Management

Information Technology

- **Plan**
  - IT Business Relationship Management
  - Enterprise Architecture & Emerging Technologies
  - IT Demand & Portfolio Management
- **Build**
  - Infrastructure Development & Deployment
  - Application Development & Deployment
  - Information Data Sourcing & Integration
- **Run**
  - Infrastructure Management
  - End User Support
  - Application Maintenance
  - Risk & Security Management
- **Manage**
  - IT Function Management

Executive & Corporate Services (ECS)

- **Administrative Services**
- **Legal**
- **Risk and Environmental Health & Safety**
- **Corporate Communications**
- **Executive Office**
- **Other**
  - Government Affairs
  - Planning and Strategy

The Hackett Group

© 2025 The Hackett Group, Inc. All rights reserved. Reproduction of this document or any portion thereof without prior written consent is prohibited.

Agenda

- Executive Summary
- Benchmark Methodology
- Peer Overview
- Results

OPG Peer Group

Peer Group

Composite Peer Group

Algonquin Power & Utilities Corporation
Consumers Energy
EPCOR Utilities Inc.
National Grid plc
NiSource
NW Natural
Portland General Electric Company
Sacramento Municipal Utility District

Nuclear Operators

Ameren
Exelon
Pacific Gas and Electric Company
Pinnacle West Capital Corporation
Public Service Energy Group
Xcel Energy

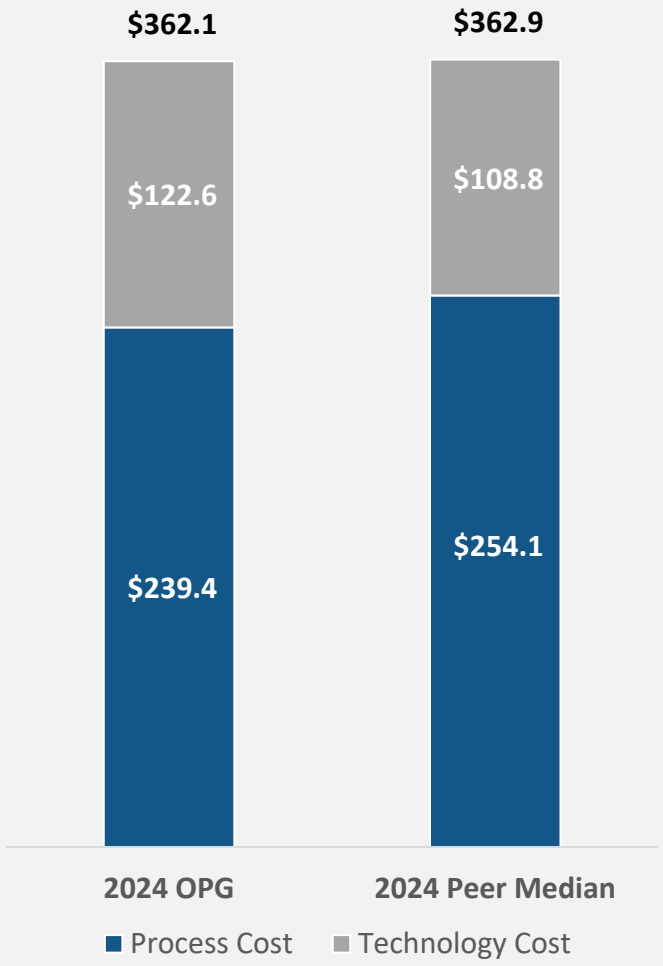
© 2025 The Hackett Group, Inc. All rights reserved. Reproduction of this document or any portion thereof without prior written consent is prohibited.

Agenda

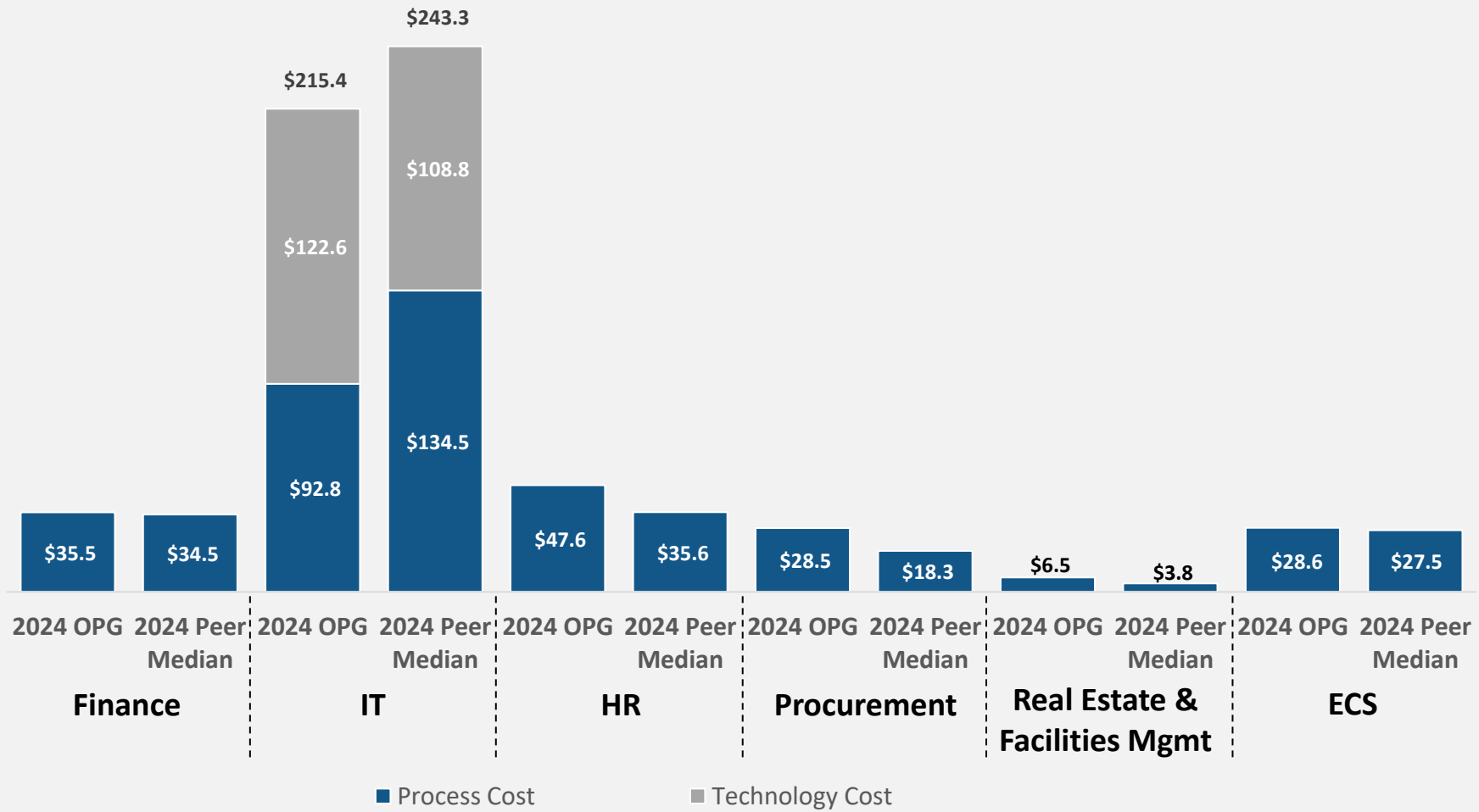
- Executive Summary
- Benchmark Methodology
- Peer Overview
- Results

Process Cost and Technology Cost Comparison by Function

Process Cost and Technology Cost ($M)



Cost by Function ($M)

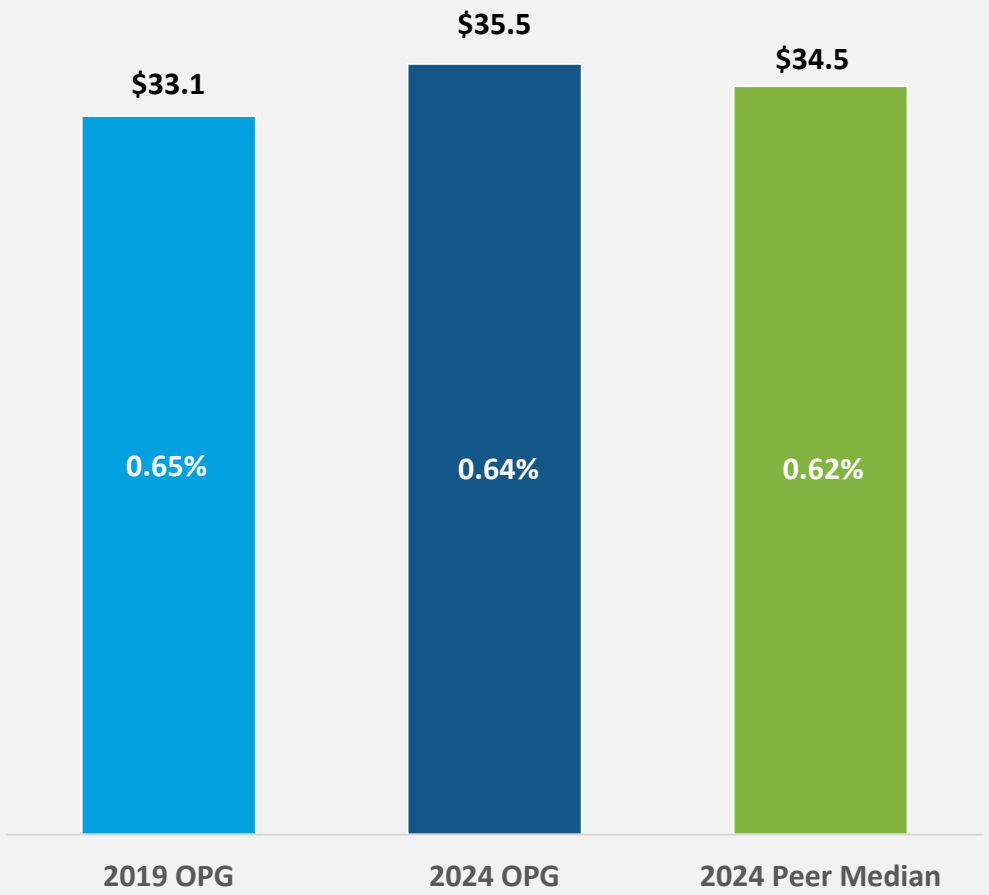


The Hackett Group

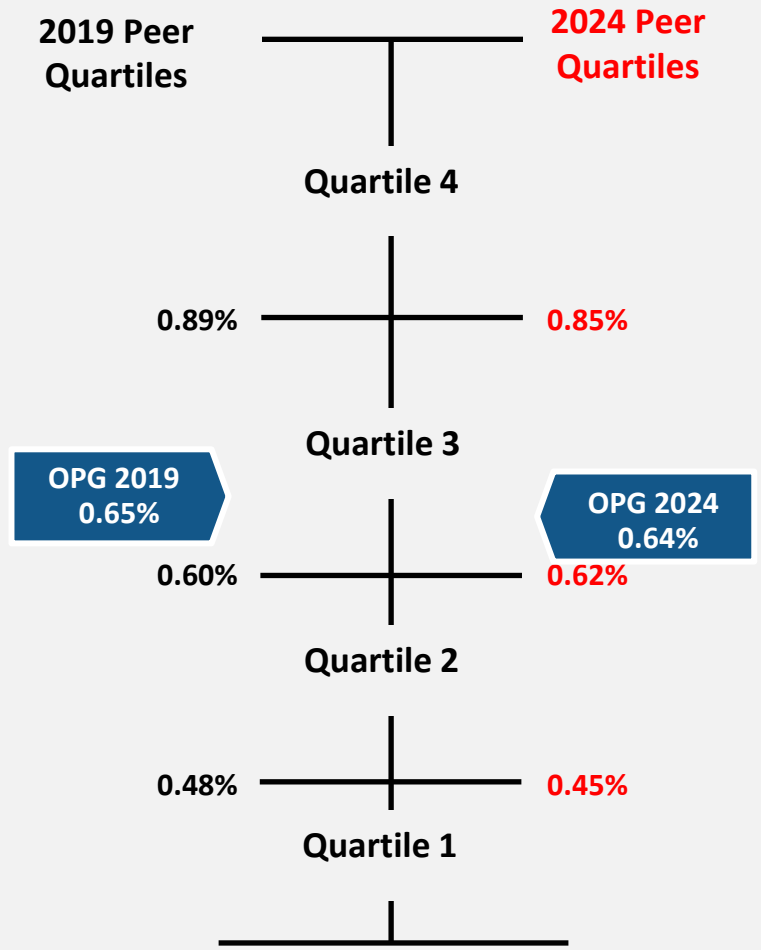
© 2025 The Hackett Group, Inc. All rights reserved. Reproduction of this document or any portion thereof without prior written consent is prohibited.

Finance Function

Finance Process Cost
in millions & % of Revenue



Finance Quartile Analysis vs. Peer Group as a % of Revenue

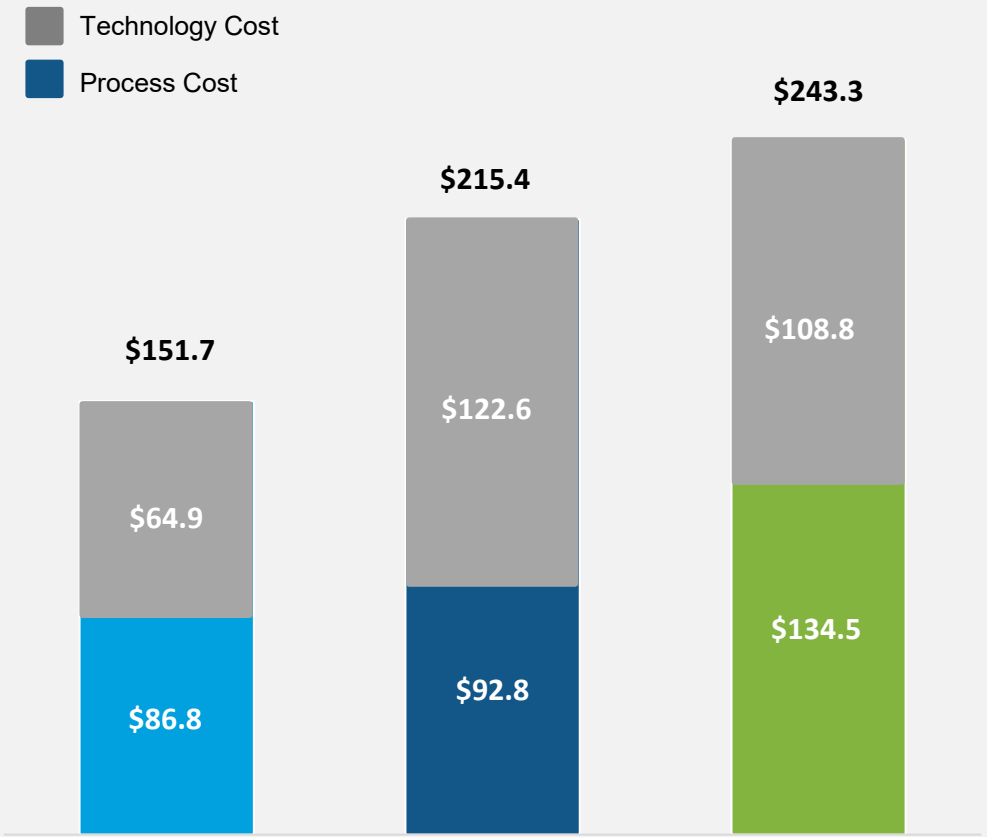


The Hackett Group

© 2025 The Hackett Group, Inc. All rights reserved. Reproduction of this document or any portion thereof without prior written consent is prohibited.

IT Function

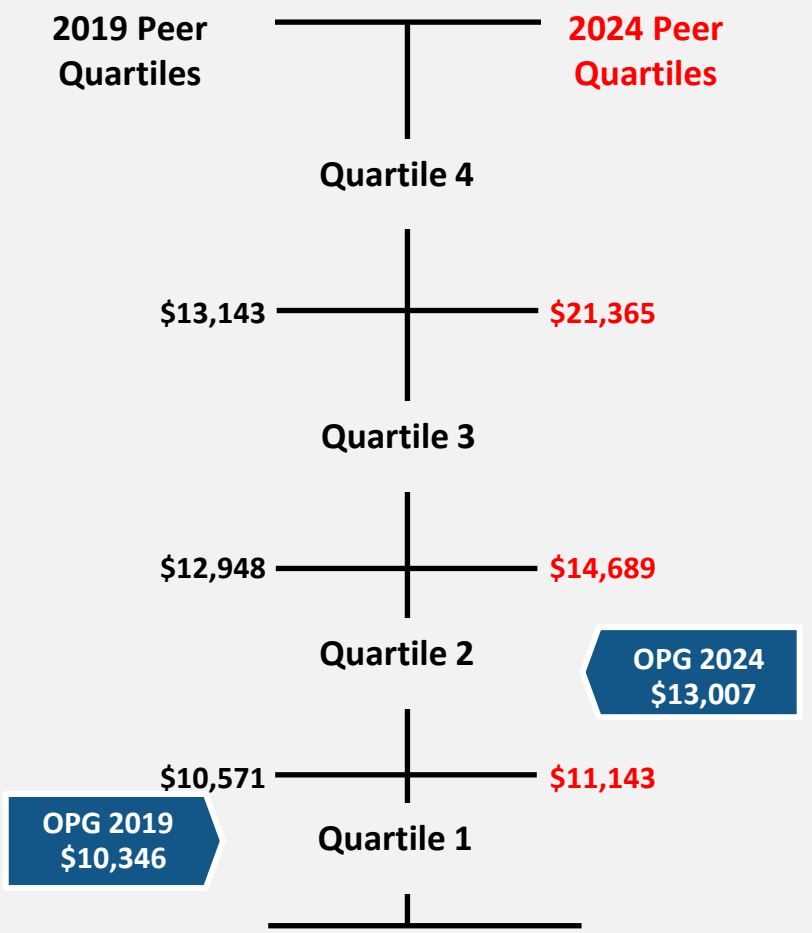
IT Process + Technology Cost
in millions & per EUE



	2019 OPG*	2024 OPG	2024 Peer Median
Cost per EUE	$10,346	$13,007	$14,689

*Updated OPG's 2019 mix of IT costs to be consistent with Hackett methodology. The total cost did not change.

IT Quartile Analysis vs. Peer Group per EUE

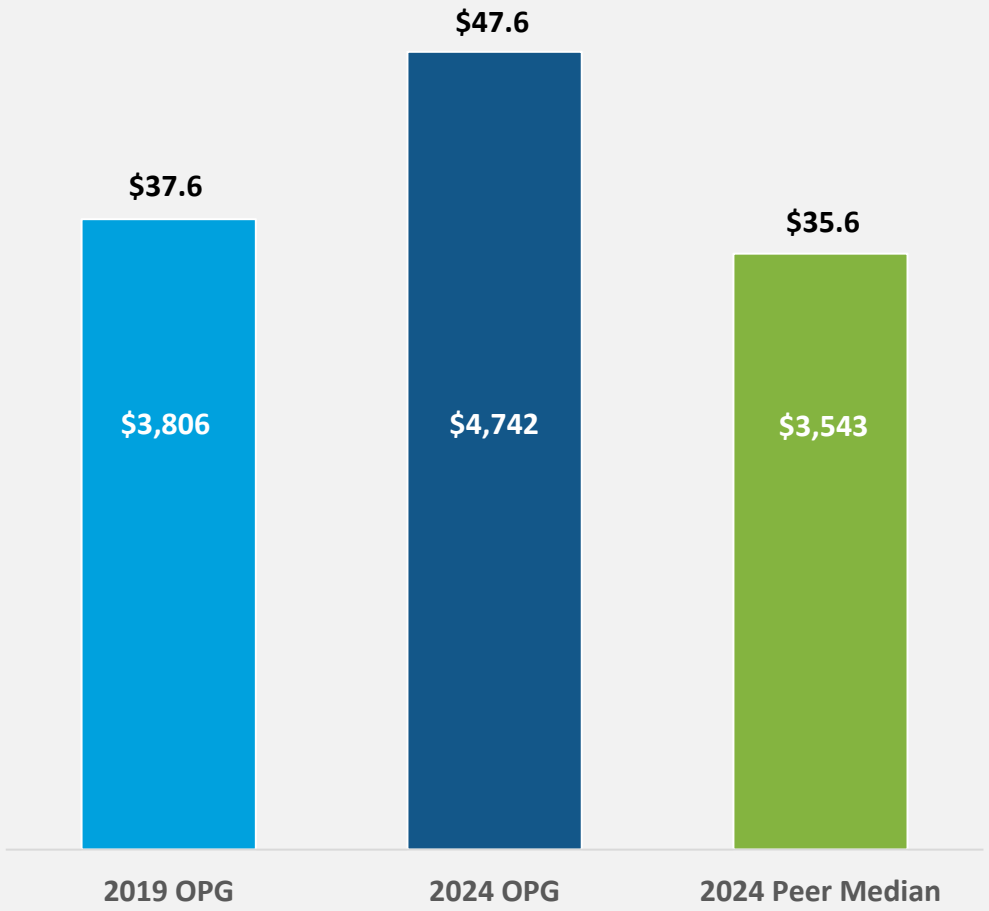


The Hackett Group

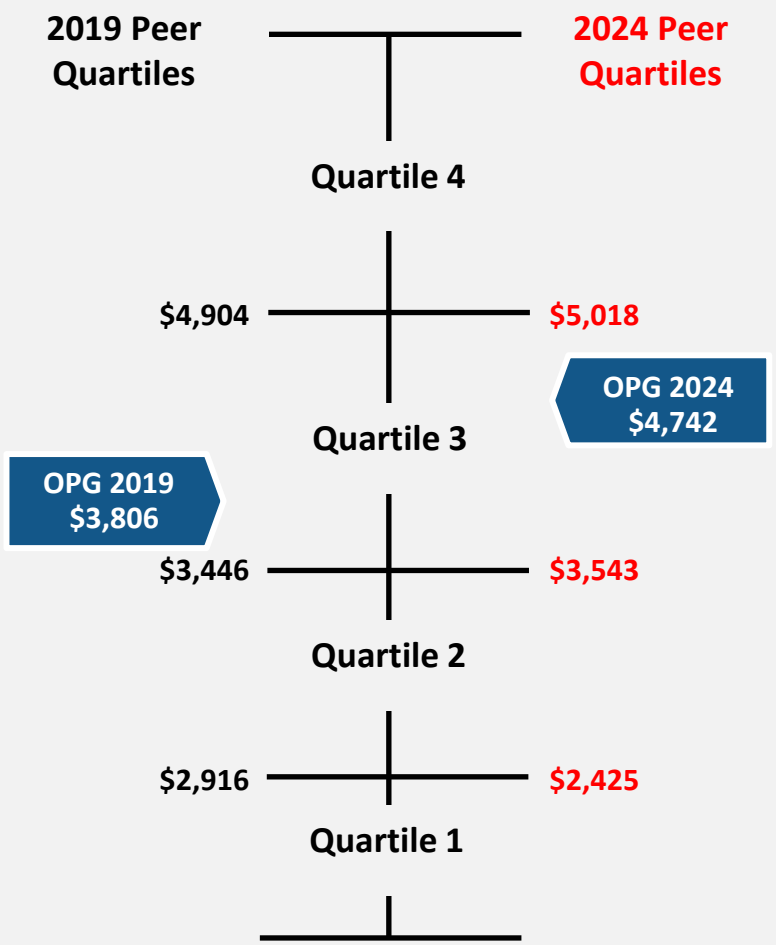
© 2025 The Hackett Group, Inc. All rights reserved. Reproduction of this document or any portion thereof without prior written consent is prohibited.

HR Function

HR Process Cost
in millions & per employee



HR Quartile Analysis vs. Peer Group per Employee

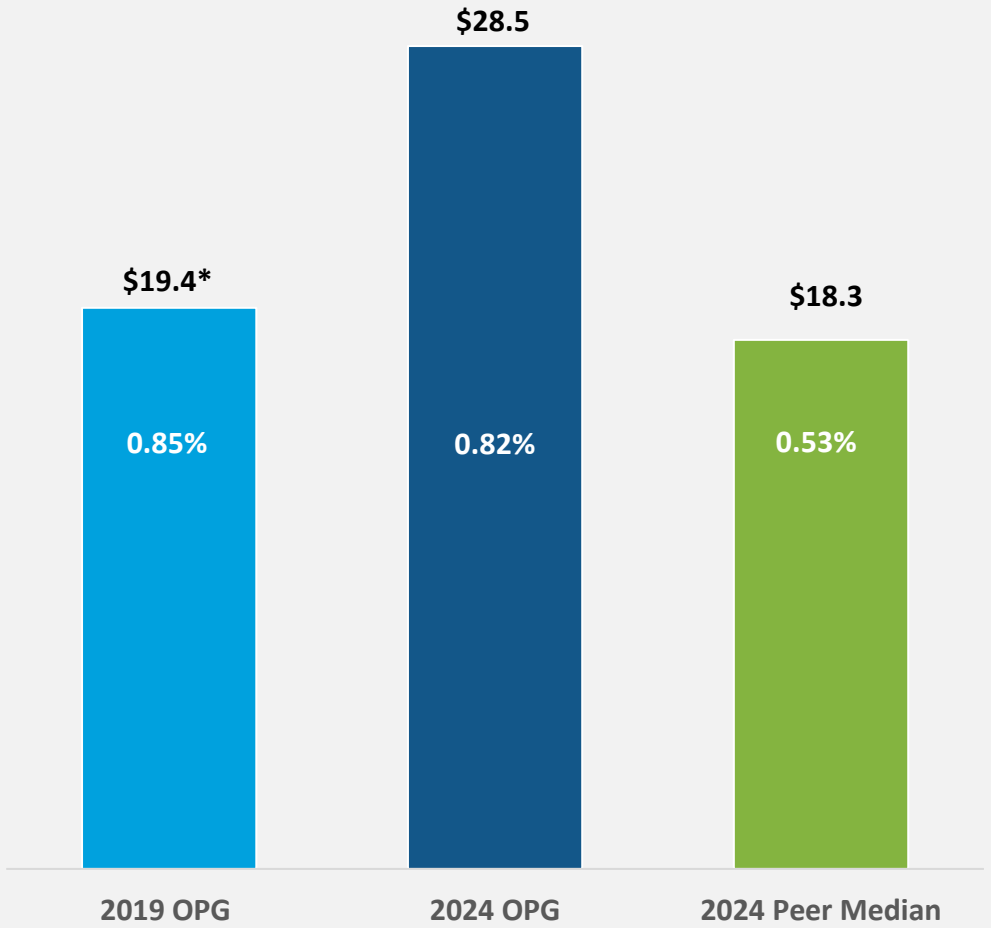


The Hackett Group

© 2025 The Hackett Group, Inc. All rights reserved. Reproduction of this document or any portion thereof without prior written consent is prohibited.

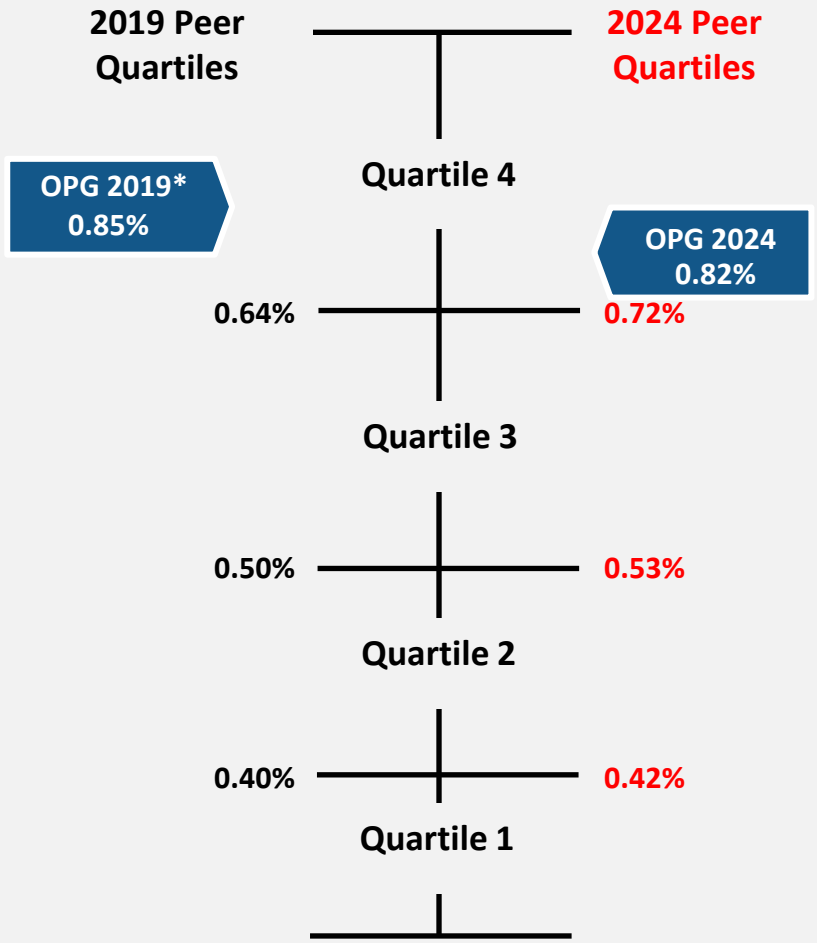
Procurement Function

Procurement Process Cost
in millions & % of Spend



*Adjustment for procurement support cost associated with managing capital spend

Procurement Quartile Analysis vs. Peer Group as a % of Spend

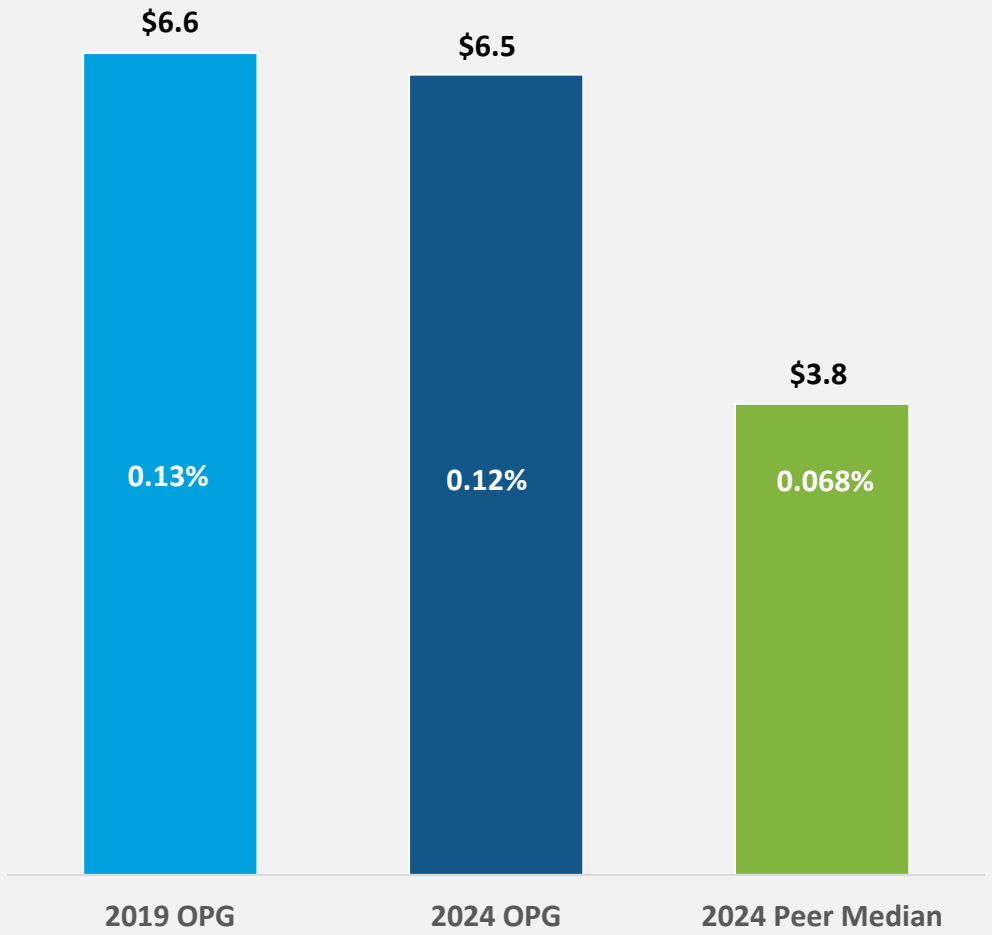


The Hackett Group

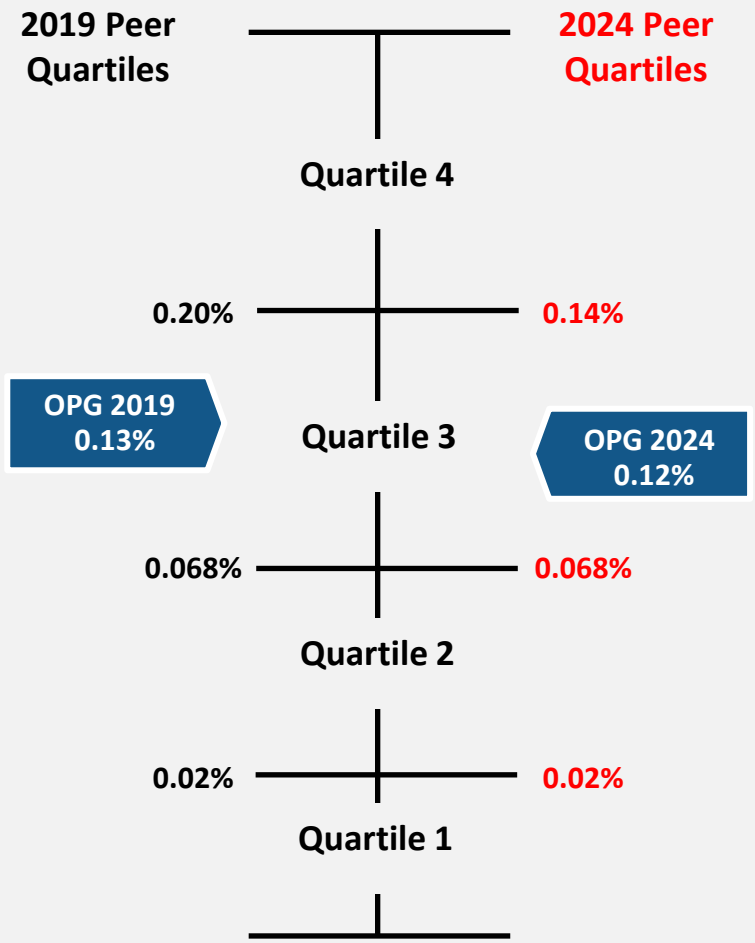
© 2025 The Hackett Group, Inc. All rights reserved. Reproduction of this document or any portion thereof without prior written consent is prohibited.

Real Estate and Facilities Management Function

Real Estate & Facilities Mgmt. Process Cost
in millions & as % of revenue



Real Estate & Facilities Mgmt. Quartile Analysis vs. Peer Group as a % of Revenue

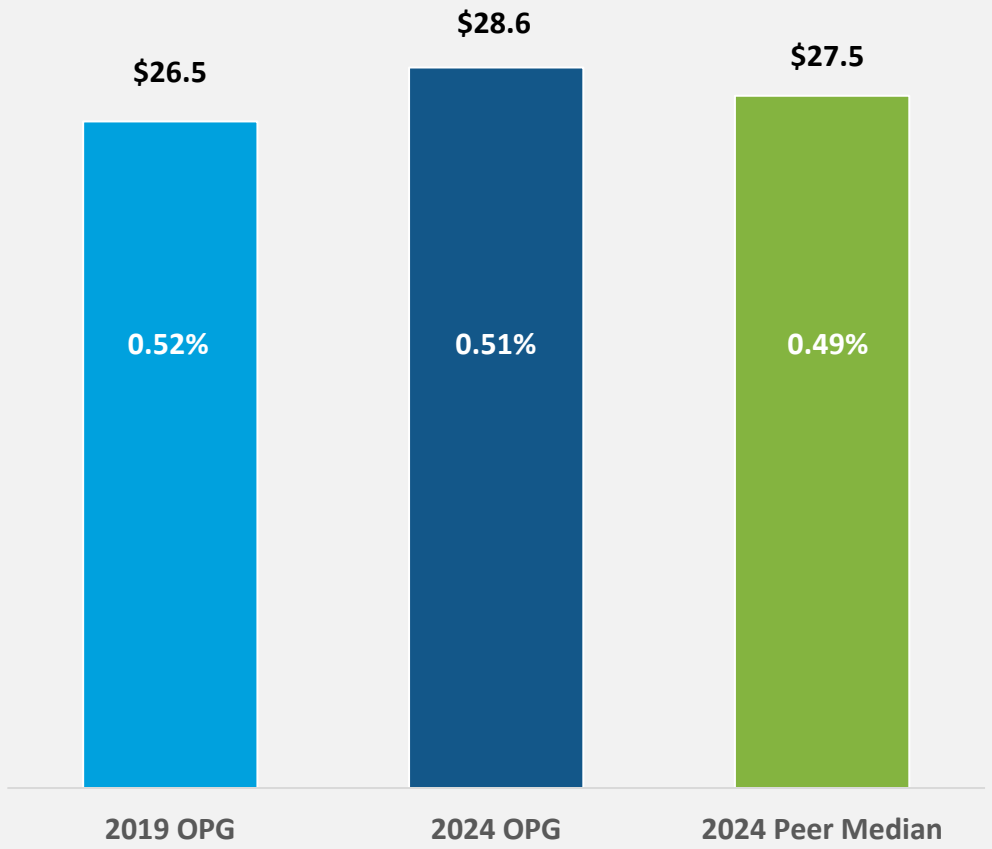


The Hackett Group

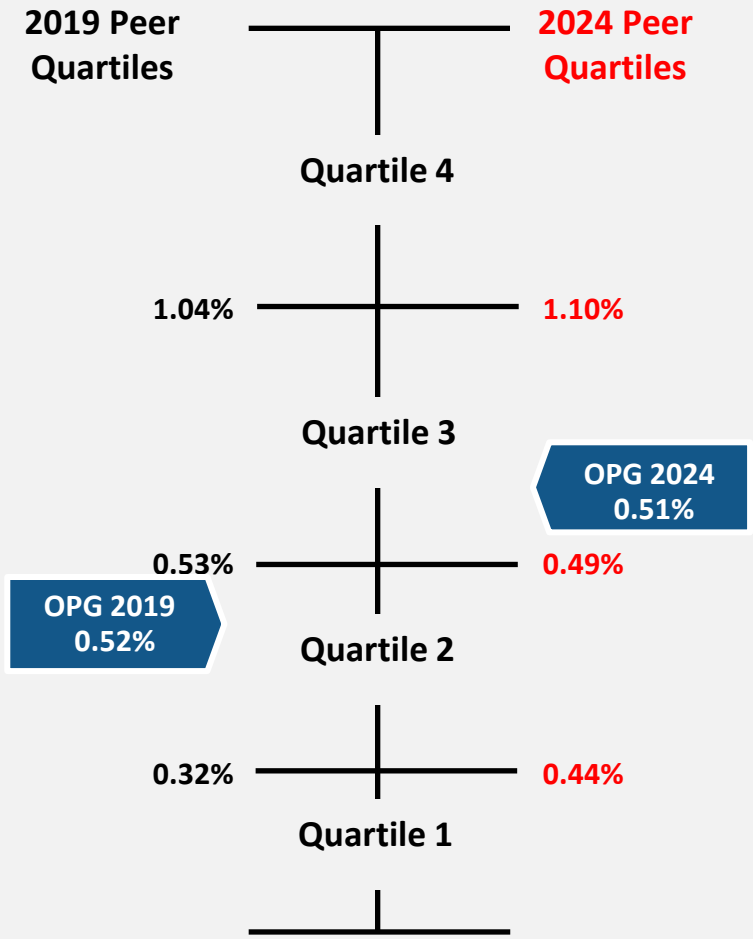
© 2025 The Hackett Group, Inc. All rights reserved. Reproduction of this document or any portion thereof without prior written consent is prohibited.

Executive & Corporate Services Overall

ECS Process Cost
in millions & as % of revenue



ECS Quartile Analysis vs. Peer Group as a % of Revenue

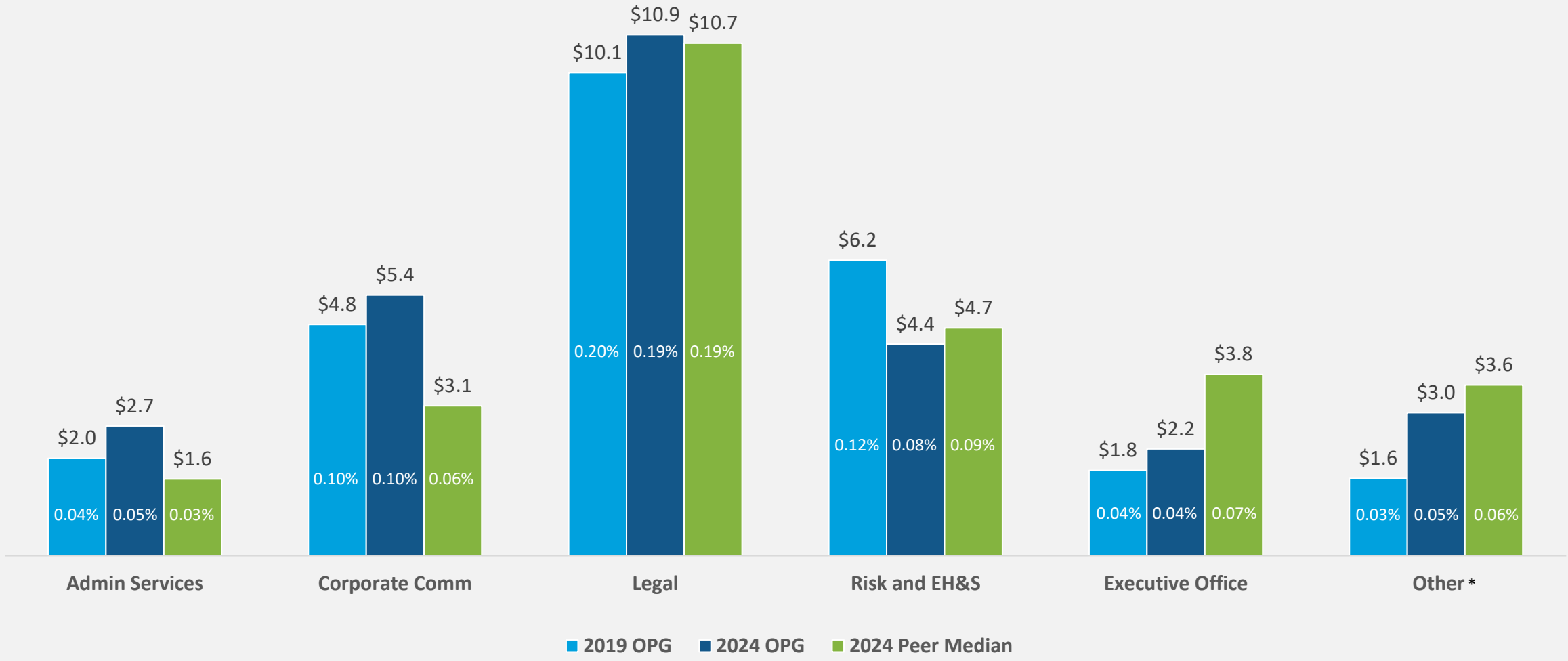


The Hackett Group

© 2025 The Hackett Group, Inc. All rights reserved. Reproduction of this document or any portion thereof without prior written consent is prohibited.

Executive & Corporate Services (ECS) Function by Sub-Process

ECS Process Cost by Sub-Process in millions & % of revenue



*Other includes Government Affairs and Planning & Strategy processes

The Hackett Group

© 2025 The Hackett Group, Inc. All rights reserved. Reproduction of this document or any portion thereof without prior written consent is prohibited.



The Hackett Group®

World Class Defined and Enabled

www.thehackettgroup.com

Numbers may not add due to rounding.

Table 1

Corporate Support & Administrative Groups OM&A Costs - OPG ($M)[1]

Line No.	Corporate Costs	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Base OM&A												
1	Corporate & Technology Services	148.1	159.1	165.2	168.2	180.4	173.5	187.3	188.2	196.7	207.9	218.2	240.0
2	Real Estate[2]	50.9	49.9	45.8	55.4	52.4	54.4	57.7	62.4	63.0	66.5	67.6	72.2
3	Supply Chain	48.2	47.1	49.3	56.3	56.1	50.4	51.1	52.0	49.6	51.4	53.3	62.9
4	Finance	41.3	38.1	41.4	47.9	48.9	59.6	63.7	65.8	67.6	71.0	72.9	75.2
5	Human Resources	32.3	32.1	36.8	48.0	41.4	45.6	40.9	36.6	37.9	39.3	39.9	43.6
6	Corporate Centre	52.5	53.9	49.8	59.2	59.4	69.0	71.2	68.5	67.3	71.2	76.4	76.6
7	**Total Base OM&A**	373.3	380.2	388.3	434.9	438.6	452.7	471.8	473.5	482.2	507.4	528.3	570.4
8	**Leases & Utilities**	27.3	26.2	28.5	28.6	27.7	31.1	27.7	30.0	25.2	24.6	24.9	25.4
9	**Project OM&A**	25.0	26.4	22.8	37.2	30.4	36.1	47.4	51.4	48.0	46.1	44.6	42.2
10	**Total OM&A**	425.5	432.8	439.6	500.8	496.8	519.9	546.9	554.9	555.3	578.1	597.8	638.0

Notes:

1 Corporate Support & Administrative costs have been restated from EB-2020-0290 for organizational changes and transfers to/from Enterprise Operations and Enterprise Projects as described in Ex. F3-1-1.

2 Excludes amounts captured in the Asset Service Fee (Ex. F3-2-1).

Numbers may not add due to rounding.

Table 2
Allocation of Corporate Support & Administrative OM&A Costs - Regulated Hydroelectric ($M)

Line No.	Corporate Group	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Base OM&A												
1	Corporate & Technology Services	19.0	17.5	18.0	17.8	10.7	11.3	12.7	12.8	13.6	14.8	17.3	18.0
2	Real Estate[1]	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.7	0.9	1.0	0.9	1.1
3	Supply Chain	3.1	3.6	3.1	2.8	2.5	2.3	2.3	2.3	2.9	4.2	4.0	4.1
4	Finance	7.5	6.8	7.0	7.1	6.7	5.7	6.0	6.5	8.1	8.3	9.2	9.3
5	Human Resources	4.8	5.2	5.6	5.5	5.5	5.0	6.3	7.5	6.7	7.0	6.5	5.8
6	Corporate Centre	10.1	10.1	8.7	10.5	9.7	10.4	8.5	11.0	12.9	9.8	9.9	10.1
7	**Total Base OM&A**	45.0	43.6	43.0	44.3	35.6	35.3	36.4	40.8	45.2	45.2	47.7	48.5
8	**Leases & Utilities**	0.2	0.7	1.0	1.0	0.8	1.2	1.8	1.7	2.9	3.1	4.1	2.8
9	**Project OM&A**	5.9	4.1	3.0	1.9	2.1	2.2	1.7	2.8	1.9	2.5	2.2	4.1
10	**Total OM&A**	51.0	48.4	47.1	47.1	38.4	38.7	39.9	45.3	50.0	50.7	54.0	55.3

Notes:
1 Excludes amounts captured in the Asset Service Fee (Ex. F3-2-1).

Numbers may not add due to rounding.

Table 3

Allocation of Corporate Support & Administrative OM&A Costs - OPG Nuclear Facilities ($M)[1]

Line No.	Corporate Group	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Base OM&A												
1	Corporate & Technology Services	130.1	139.6	144.5	145.4	157.9	149.2	152.3	149.6	154.5	164.4	172.8	191.5
2	Real Estate[2]	49.3	47.3	42.2	52.7	49.4	48.9	51.0	55.0	55.2	58.5	59.3	60.5
3	Supply Chain	44.2	43.0	45.8	52.5	51.4	44.5	44.3	44.6	41.9	43.6	43.9	50.4
4	Finance	27.2	26.7	29.1	33.4	31.2	38.5	38.4	38.0	38.5	40.9	41.4	42.5
5	Human Resources	24.5	24.8	28.1	37.3	32.2	35.2	30.2	26.4	27.2	28.4	28.7	31.2
6	Corporate Centre	34.1	34.0	31.0	32.8	33.7	42.2	40.4	38.5	37.2	39.8	42.1	42.3
7	**Total Base OM&A**	309.4	315.3	320.8	354.1	355.8	358.5	356.6	352.1	354.6	375.5	388.2	418.3
8	**Leases & Utilities**	22.7	22.5	23.1	22.9	20.8	26.8	21.9	25.8	21.1	20.9	20.9	20.5
9	**Project OM&A**	20.6	21.9	22.3	29.3	24.3	26.2	37.6	39.6	36.5	36.3	35.6	32.8
10	**Total OM&A**	352.7	359.7	366.2	406.3	400.8	411.5	416.1	417.5	412.1	432.7	444.7	471.6

Notes:

1 Corporate Support & Administrative costs have been restated from EB-2020-0290 for organizational changes and transfers to/from Enterprise Operations and Enterprise Projects as described in Ex. F3-1-1.

2 Excludes amounts captured in the Asset Service Fee (Ex. F3-2-1).

Numbers may not add due to rounding.

Table 3a

Allocation of Corporate Support & Administrative OM&A Costs - OPG Nuclear Facilities - Darlington ($M)[1]

Line No.	Corporate Group	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Base OM&A												
1	Corporate & Technology Services	62.9	65.6	67.6	69.7	75.8	75.8	69.0	73.3	74.7	80.0	83.2	87.5
2	Real Estate[2]	23.2	23.0	20.2	27.9	26.8	29.0	31.5	33.0	33.0	34.4	34.8	35.8
3	Supply Chain	20.1	19.8	19.9	23.1	23.1	24.7	21.8	25.3	23.5	24.3	24.3	26.8
4	Finance	15.8	16.3	17.3	18.0	16.6	20.5	18.0	17.1	15.8	16.1	14.7	15.9
5	Human Resources	11.7	12.7	14.1	17.4	15.9	18.9	14.4	12.6	12.5	12.8	12.9	13.8
6	Corporate Centre	19.3	21.0	17.5	18.4	17.4	22.8	19.0	17.4	15.4	15.9	15.2	16.0
7	**Total Base OM&A**	153.0	158.3	156.6	174.5	175.6	191.7	173.8	178.6	174.9	183.5	185.1	195.7
8	**Leases & Utilities**	11.1	11.8	11.8	11.0	10.3	13.9	11.2	13.4	10.9	10.8	10.7	10.6
9	**Project OM&A**	11.1	12.2	10.8	13.7	11.0	14.0	15.6	21.8	20.0	20.6	18.8	16.2
10	**Total OM&A**	175.2	182.3	179.2	199.2	196.9	219.6	200.6	213.7	205.8	214.9	214.6	222.4

Notes:

1 Corporate Support & Administrative costs have been restated from EB-2020-0290 for organizational changes and transfers to/from Enterprise Operations and Enterprise Projects as described in Ex. F3-1-1.

2 Excludes amounts captured in the Asset Service Fee (Ex. F3-2-1).

Numbers may not add due to rounding.

Table 3b

Allocation of Corporate Support & Administrative OM&A Costs - OPG Nuclear Facilities - Pickering ($M)[1]

Line No.	Corporate Group	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Base OM&A												
1	Corporate & Technology Services	67.2	74.0	76.9	75.7	82.1	73.4	83.3	76.3	79.9	84.3	89.6	104.1
2	Real Estate[2]	26.0	24.3	22.0	24.9	22.6	19.9	19.5	22.0	22.3	24.1	24.5	24.7
3	Supply Chain	24.1	23.2	25.9	29.4	28.3	19.8	22.5	19.3	18.3	19.2	19.6	23.6
4	Finance	11.4	10.4	11.8	15.4	14.7	18.0	20.3	20.9	22.7	24.8	26.7	26.6
5	Human Resources	12.8	12.1	14.0	19.8	16.3	16.3	15.8	13.8	14.7	15.6	15.8	17.4
6	Corporate Centre	14.8	13.0	13.6	14.4	16.2	19.4	21.4	21.1	21.8	24.0	26.9	26.3
7	**Total Base OM&A**	156.4	157.0	164.2	179.6	180.2	166.8	182.7	173.5	179.7	192.0	203.1	222.7
8	**Leases & Utilities**	11.6	10.7	11.3	11.9	10.4	12.9	10.7	12.4	10.2	10.1	10.2	10.0
9	**Project OM&A**	9.5	9.7	11.5	15.6	13.3	12.2	22.0	17.8	16.5	15.7	16.9	16.5
10	**Total OM&A**	177.5	177.4	187.0	207.1	203.9	191.9	215.5	203.7	206.4	217.8	230.1	249.1

Notes:

1 Corporate Support & Administrative costs have been restated from EB-2020-0290 for organizational changes and transfers to/from Enterprise Operations and Enterprise Projects as described in Ex. F3-1-1.

2 Excludes amounts captured in the Asset Service Fee (Ex. F3-2-1).

Numbers may not add due to rounding.

Updated: 2026-03-10
EB-2025-0297
Exhibit F3
Tab 1
Schedule 1
Table 3c

Table 3c
Allocation of Corporate Support & Administrative OM&A Costs - DNNP Facilities ($M)

Line No.	Corporate Group	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	Base OM&A						
1	Corporate & Technology Services	8.3	10.4	11.9	10.9	10.0	9.9
2	Real Estate[1]	1.1	1.5	1.7	1.7	1.9	4.9
3	Supply Chain	0.8	1.2	1.4	1.4	2.5	4.7
4	Finance	3.7	5.0	5.7	5.7	6.4	4.2
5	Human Resources	1.3	1.4	1.6	1.4	1.3	1.5
6	Corporate Centre	2.9	4.1	4.5	4.6	5.3	2.8
7	**Total Base OM&A**	18.1	23.6	26.8	25.8	27.3	28.0
8	**Leases & Utilities**	0.1	0.1	0.2	0.1	0.3	0.8
9	**Project OM&A**	4.8	4.8	4.5	3.5	3.0	3.7
10	**Total OM&A**	23.0	28.6	31.5	29.4	30.6	32.4

Notes:
1 Excludes amounts captured in the Asset Service Fee (Ex. F3-2-1).

Numbers may not add due to rounding.

Table 4
Corporate & Technology Services Base OM&A Costs - OPG ($M)

Line No.	Costs	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	**Hardware / Software / Telecommunications**	32.2	39.5	48.8	55.1	61.9	61.6	74.7	81.4	87.7	95.0	102.8	115.4
2	NHSS Base Costs	55.9	54.9	34.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	IT Support Costs	28.7	33.1	48.4	78.8	83.6	76.7	79.7	78.5	80.0	82.9	84.6	90.1
4	**Total NHSS and IT Support Costs**[1]	84.7	88.1	82.4	78.8	83.6	76.7	79.7	78.5	80.0	82.9	84.6	90.1
5	**Shared Services**	31.2	31.4	34.0	34.3	34.9	35.2	32.9	28.3	29.0	30.1	30.9	34.5
6	**Total**	148.1	159.1	165.2	168.2	180.4	173.5	187.3	188.2	196.7	207.9	218.2	240.0

Notes:
1 New Horizons System Solutions employees were repatriated to OPG in 2022 as described in Ex. F3-1-1.

Numbers may not add due to rounding.

Table 5

Allocation of Corporate & Technology Services Base OM&A Costs - Regulated Hydroelectric ($M)

Line No.	Costs	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	**Hardware / Software / Telecommunications**	2.7	2.7	2.7	3.1	2.2	2.7	3.5	4.1	4.6	5.1	6.7	7.6
2	NHSS Base Costs	7.1	5.8	5.5	5.8	3.9	3.7	2.5	0.0	0.0	0.0	0.0	0.0
3	IT Support Costs	4.4	4.7	7.0	6.2	2.0	2.3	3.4	5.6	5.9	5.9	6.8	7.0
4	**Total NHSS and IT Support Costs**[1]	11.5	10.5	12.6	12.0	5.8	6.0	5.8	5.6	5.9	5.9	6.8	7.0
5	**Shared Services**	4.7	4.2	2.8	2.7	2.7	2.6	3.3	3.1	3.0	3.8	3.7	3.4
6	**Total**	19.0	17.5	18.0	17.8	10.7	11.3	12.7	12.9	13.6	14.8	17.3	18.0

Notes:

1 New Horizons System Solutions employees were repatriated to OPG in 2022 as described in Ex. F3-1-1.

Numbers may not add due to rounding.

Table 6

Allocation of Corporate & Technology Services Base OM&A Costs - OPG Nuclear Facilities ($M)

Line No.	Costs	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	**Hardware / Software / Telecommunications**	28.4	34.9	43.3	48.9	55.0	54.1	61.2	65.4	69.6	75.7	82.1	92.7
2	NHSS Base Costs	49.4	48.6	30.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	IT Support Costs	24.9	28.8	42.0	67.0	72.5	65.2	64.4	62.1	62.4	65.1	66.6	71.2
4	**Total NHSS and IT Support Costs**[1]	74.3	77.4	72.2	67.0	72.5	65.2	64.4	62.1	62.4	65.1	66.6	71.2
5	**Shared Services**	27.4	27.3	29.0	29.5	30.5	29.9	26.7	22.1	22.5	23.5	24.1	27.6
6	**Total**	130.1	139.6	144.5	145.4	157.9	149.2	152.3	149.6	154.5	164.4	172.8	191.5

Notes:

1 New Horizons System Solutions employees were repatriated to OPG in 2022 as described in Ex. F3-1-1.

Numbers may not add due to rounding.

Table 6a

Allocation of Corporate & Technology Services Base OM&A Costs - OPG Nuclear Facilities - Darlington ($M)

Line No.	Costs	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	**Hardware / Software / Telecommunications**	13.4	15.8	19.6	22.8	26.1	27.5	27.4	31.0	32.8	36.0	38.6	41.6
2	NHSS Base Costs	23.4	22.0	13.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	IT Support Costs	11.8	13.0	19.0	31.2	34.3	32.9	28.8	29.8	29.7	31.3	31.6	32.3
4	**Total NHSS and IT Support Costs**[1]	35.2	35.0	32.7	31.2	34.3	32.9	28.8	29.8	29.7	31.3	31.6	32.3
5	**Shared Services**	14.3	14.8	15.3	15.8	15.4	15.4	12.9	12.5	12.2	12.8	13.0	13.6
6	**Total**	62.9	65.6	67.6	69.7	75.8	75.8	69.0	73.3	74.7	80.0	83.2	87.5

Notes:

1 New Horizons System Solutions employees were repatriated to OPG in 2022 as described in Ex. F3-1-1.

Numbers may not add due to rounding.

Table 6b

Allocation of Corporate & Technology Services Base OM&A Costs - OPG Nuclear Facilities - Pickering ($M)

Line No.	Costs	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	**Hardware / Software / Telecommunications**	15.0	19.1	23.7	26.1	28.9	26.6	33.9	34.4	36.8	39.7	43.5	51.1
2	NHSS Base Costs	26.1	26.6	16.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	IT Support Costs	13.0	15.8	22.9	35.8	38.2	32.2	35.6	32.4	32.7	33.9	35.0	38.9
4	**Total NHSS and IT Support Costs**[1]	39.1	42.4	39.5	35.8	38.2	32.2	35.6	32.4	32.7	33.9	35.0	38.9
5	**Shared Services**	13.1	12.5	13.8	13.7	15.0	14.5	13.8	9.6	10.3	10.8	11.1	14.0
6	**Total**	67.2	74.0	76.9	75.7	82.1	73.4	83.3	76.3	79.9	84.3	89.6	104.1

Notes:

1 New Horizons System Solutions employees were repatriated to OPG in 2022 as described in Ex. F3-1-1.

Numbers may not add due to rounding.

Updated: 2026-03-10
EB-2025-0297
Exhibit F3
Tab 1
Schedule 1
Table 6c

Table 6c
Allocation of Corporate & Technology Services Base OM&A Costs - DNNP Facilities ($M)

Line No.	Costs	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1	Hardware / Software / Telecommunications	3.6	4.7	5.5	5.2	4.8	5.2
2	IT Support Costs	3.6	4.3	4.8	4.3	3.7	3.8
3	Shared Services	1.1	1.4	1.6	1.5	1.4	0.9
4	**Total**	8.3	10.4	11.9	10.9	10.0	9.9

Numbers may not add due to rounding.

Table 7a

Allocation of Corporate Support Staff Summary - Regular and Non-Regular (FTEs) - Regulated Hydroelectric - 2016-2019

Line No.	Group	2016 Actual	2017 Actual	2018 Actual	2019 Actual
		(a)	(b)	(c)	(d)
	Regulated Hydroelectric OM&A:				
1	**Regular Staff**	167.2	158.3	162.3	158.2
	Non-Regular Staff				
2	Temporary	9.5	9.5	9.9	11.7
3	**Subtotal RegulatedHydroelectric**	176.7	167.8	172.2	169.9
	Regulated Hydroelectric Capital:				
4	**Regular Staff**	2.2	3.0	3.8	6.4
	Non-Regular Staff				
5	Temporary	0.0	0.0	0.2	0.0
6	**Subtotal Regulated Hydroelectric**	2.2	3.0	4.0	6.4
7	**Total Regulated Hydroelectric**	179.0	170.8	176.2	176.3

Numbers may not add due to rounding.

Table 7b

Allocation of Corporate Support Staff Summary - Regular and Non-Regular (FTEs) - Regulated Hydroelectric - 2020-2027

Line No.	Group	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Hydroelectric OM&A:								
1	**Regular Staff**	121.1	105.0	117.9	130.0	153.1	157.1	155.6	147.4
	Non-Regular Staff								
2	Temporary	10.5	12.7	15.1	14.2	13.7	12.8	8.4	6.2
3	**Subtotal Regulated Hydroelectric OM&A**	131.6	117.6	133.0	144.3	166.8	169.9	164.0	153.6
	Hydroelectric Capital:								
4	**Regular Staff**	6.3	7.6	10.0	10.0	11.5	27.5	29.9	36.4
	Non-Regular Staff								
5	Temporary	0.1	0.1	0.0	0.9	0.7	0.1	0.0	0.4
6	**Subtotal Regulated Hydroelectric Capital**	6.4	7.7	10.0	10.9	12.2	27.5	29.9	36.8
7	**Total Regulated Hydroelectric**	137.9	125.4	143.0	155.1	179.0	197.5	193.9	190.3

Numbers may not add due to rounding.

Table 8
Allocation of Corporate Support Staff Summary - Regular and Non-Regular (FTEs) - OPG Nuclear Facilities

Line No.	Group	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Nuclear OM&A:												
1	**Regular Staff**	854.9	799.2	880.2	1,049.6	1,124.5	1,167.9	1,077.1	639.8	621.4	616.4	612.4	653.5
	Non-Regular Staff												
2	Term/ETE/PECO Temporary	57.4	76.1	79.2	61.9	53.0	39.0	33.3	0.0	0.0	0.0	0.0	0.0
3	Temporary	146.9	156.0	168.5	186.2	152.1	102.5	73.4	42.3	42.8	40.8	41.8	45.0
4	EPSCA	24.6	25.3	22.1	21.6	15.7	27.1	28.1	23.0	23.0	23.0	23.0	26.9
5	**Total Non-Regular Staff**	229.0	257.3	269.8	269.7	220.8	168.6	134.7	65.3	65.8	63.8	64.7	71.9
6	**Subtotal Nuclear OM&A**	1,083.9	1,056.6	1,150.0	1,319.2	1,345.3	1,336.4	1,211.8	705.1	687.2	680.2	677.1	725.3
	Nuclear Capital:												
7	**Regular Staff**	14.7	14.2	21.5	42.5	45.5	111.2	116.3	86.1	84.4	86.3	83.8	78.2
	Non-Regular Staff												
8	Term/ETE/PECO Temporary	2.6	1.3	1.1	2.7	5.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Temporary	1.0	0.0	0.0	10.8	11.1	0.8	0.0	1.5	1.5	1.5	1.5	1.5
10	EPSCA	10.7	10.2	1.0	2.8	1.7	0.9	0.9	0.9	0.9	0.9	0.9	0.9
11	**Total Non-Regular Staff**	14.3	11.5	2.1	16.3	18.4	1.8	0.9	2.4	2.4	2.4	2.4	2.4
12	**Subtotal Nuclear Capital**	29.0	25.7	23.6	58.8	63.9	112.9	117.2	88.5	86.8	88.8	86.2	80.6
	Darlington Refurbishment:												
13	**Regular Staff**	37.4	33.4	31.5	32.4	37.3	38.2	17.0	0.0	0.0	0.0	0.0	0.0
	Non-Regular Staff												
14	Temporary	10.6	12.2	9.3	10.2	6.9	4.0	0.0	0.0	0.0	0.0	0.0	0.0
15	EPSCA	6.7	8.9	7.8	7.2	8.0	6.0	0.0	0.0	0.0	0.0	0.0	0.0
16	**Total Non-Regular Staff**	17.3	21.1	17.2	17.4	14.9	10.0	0.0	0.0	0.0	0.0	0.0	0.0
17	**Subtotal Darlington Refurbishment**	54.7	54.5	48.7	49.9	52.2	48.2	17.0	0.0	0.0	0.0	0.0	0.0
	Pickering Refurbishment:												
18	**Regular Staff**	0.0	0.0	0.0	0.9	29.7	104.7	145.7	672.4	675.4	684.2	688.0	636.0
	Non-Regular Staff												
19	Term/ETE/PECO Temporary	0.0	0.0	0.0	0.0	2.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	Temporary	0.0	0.0	0.0	0.0	4.4	0.0	1.0	17.8	15.4	15.0	15.9	15.9
21	EPSCA	0.0	0.0	0.0	0.0	4.5	3.0	8.0	13.0	13.0	13.0	13.0	10.4
22	**Total Non-Regular Staff**	0.0	0.0	0.0	0.0	11.0	3.0	9.0	30.9	28.4	28.1	28.9	26.2
23	**Subtotal Pickering Refurbishment**	0.0	0.0	0.0	0.9	40.7	107.7	154.7	703.3	703.8	712.2	716.9	662.2
	Darlington New Nuclear Program:												
24	**Regular Staff**	0.0	0.0	9.9	14.0	21.9	33.3	0.0	0.0	0.0	0.0	0.0	0.0
	Non-Regular Staff												
25	Temporary	0.0	0.0	0.2	0.3	1.7	2.0	0.0	0.0	0.0	0.0	0.0	0.0
26	EPSCA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	**Total Non-Regular Staff**	0.0	0.0	0.2	0.3	1.8	2.0	0.0	0.0	0.0	0.0	0.0	0.0
28	**Subtotal New Nuclear DN Capital**	0.0	0.0	10.2	14.2	23.7	35.3	0.0	0.0	0.0	0.0	0.0	0.0
	Darlington New Nuclear & Other New Nuclear OM&A:												
29	**Regular Staff**	4.8	25.4	0.3	4.6	7.6	24.0	41.8	0.0	0.0	0.0	0.0	0.0
	Non-Regular Staff												
30	Temporary	0.4	2.1	0.0	0.2	0.3	1.0	1.0	0.0	0.0	0.0	0.0	0.0
31	**Subtotal Darlington & Other New Nuclear OM&A**	5.2	27.6	0.3	4.9	7.8	25.0	42.8	0.0	0.0	0.0	0.0	0.0
	Nuclear Provision:												
32	**Regular Staff**	16.3	14.5	16.1	15.3	27.6	65.5	59.1	58.1	56.5	49.1	50.2	50.4
	Non-Regular Staff												
33	Term/ETE/PECO Temporary	0.6	1.1	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Temporary	1.5	0.5	2.0	2.4	2.5	1.0	1.0	1.0	1.0	1.0	1.0	1.0
35	EPSCA	0.0	0.0	0.0	0.0	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	**Total Non-Regular Staff**	2.1	1.6	2.0	2.4	4.4	1.0	1.0	1.0	1.0	1.0	1.0	1.0
37	**Subtotal Nuclear Provision**	18.4	16.1	18.1	17.8	31.9	66.5	60.1	59.1	57.5	50.1	51.2	51.4
38	**Total Nuclear**	1,191.3	1,180.5	1,250.8	1,465.6	1,565.7	1,732.2	1,603.6	1,555.9	1,535.2	1,531.3	1,531.5	1,519.4

Numbers may not add due to rounding.

Updated: 2026-03-10
EB-2025-0297
Exhibit F3
Tab 1
Schedule 1
Table 9

Table 9

Allocation of Corporate Support Staff Summary - Regular and Non-Regular (FTEs) - DNNP Facilities ($M)

Line No.	Group	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	DNNP Facilities OM&A:						
1	**Regular Staff**	52.4	64.1	71.7	66.3	70.8	68.2
	Non-Regular Staff						
2	Temporary	6.9	10.3	10.9	10.5	5.9	2.8
3	EPSCA	0.0	0.0	0.0	0.0	0.1	0.2
4	**Total Non-Regular Staff**	6.9	10.3	10.9	10.5	5.9	3.0
5	**Subtotal DNNP Facilities OM&A**	59.3	74.4	82.5	76.9	76.7	71.2
	DNNP Facilities Capital:						
6	**Regular Staff**	40.5	42.6	38.1	22.3	13.6	9.9
	Non-Regular Staff						
7	Temporary	0.0	0.2	0.3	0.3	0.3	0.3
8	**Subtotal DNNP Facilities Capital**	40.5	42.8	38.4	22.6	13.8	10.2
9	**Total DNNP Facilities**	99.8	117.2	120.9	99.5	90.5	81.4

COMPARISON OF ALLOCATION OF SUPPORT SERVICES COSTS

1.0 PURPOSE

This evidence presents the period-over-period comparisons of the Support Services OM&A costs.

Consistent with the OEB's letter dated September 17, 2024, issued in EB-2024-0136, OPG has included nine years of historical data for the regulated hydroelectric business, for the period 2016-2024. As there is no OEB-approved regulated hydroelectric Support Services OM&A costs information for 2015 onwards, OPG has provided year-over-year variance analyses for the historical period (2016-2024), bridge period (2025-2026), and test year (2027).

Where applicable, OPG has restated the presentation of actual (2016-2024) and EB-2020-0290 Nuclear OEB-approved (2022-2026) Support Services costs for subsequent organizational changes including transfers to/from Operations and Project Support groups to provide an appropriate basis of comparison with the forecast period information. These transfers are further described in Ex. A1-4-1, Attachment 2.

Exhibit F3-1-2, Tables 1a and 1b provide the period-over-period changes in the allocated Support Services costs for OPG's regulated hydroelectric facilities. Exhibit F3-1-2, Tables 2a and 2b provide the period-over-period changes in the allocated Support Services costs for OPG's nuclear facilities. Exhibit F3-1-2, Table 2c provides the period-over-period changes in the allocated Support Services costs for the DNNP facilities.

All comparisons to OEB-approved amounts are before any OEB or OEB-approved settlement adjustments.

Net reportable variances and period-over-period changes by category of expense (10% or greater at the function level, subject to a minimum materiality limit of $1M) are discussed below.[1] Key drivers of variance are identified.

2.0 PERIOD-OVER-PERIOD CHANGES – TEST YEAR, REGULATED HYDROELECTRIC

2027 Plan versus 2026 Budget

Support Services costs in the 2027 Plan are $55.3M, which is $1.3M higher than the 2026 Budget of $54.0M.

The reportable variances by category of expense are as follows:

- Leases and Utilities ($1.3M or 31.0% decrease): due to a reduction in lease costs in 2027 related to the assumed exit of the 800 Kipling Avenue lease that currently houses the existing Renewable Generation Training Centre. As discussed in Ex. D3-1-1, OPG will lease and fit out a new Renewable Generation Training Centre location as the current lease at 800 Kipling Avenue is not expected to extend past 2026.
- Project OM&A ($1.9M or 83.1% increase): due to higher spend on information technology ("IT") projects including hydroelectric applications and the progression of Enterprise System Modernization projects (e.g., Asset Management, Finance Enterprise Resource Planning ("ERP") and Supply Chain ERP), discussed in Ex. D3-1-1 and Ex. D3-1-2.

3.0 PERIOD-OVER-PERIOD CHANGES – BRIDGE YEARS, REGULATED HYDROELECTRIC

2026 Budget versus 2025 Budget

Support Services costs in the 2026 Budget are $54.0M, which is $3.3M higher than the 2025 Budget of $50.7M.

The reportable variances by category of expenses are as follows:

[1] All comparisons are before OEB or settlement adjustments.

- Corporate & Technology Services ($2.4M or 16.3% increase): due to increased requirements for and cost of digital tools across the business resulting in higher software and hardware costs (Ex. F3-1-1 and Ex. D3-1-1).

2025 Budget versus 2024 Actual

Support Services costs in the 2025 Budget are $50.7M, which is $0.7M higher than the 2024 Actual costs of $50.0M. This is partly offset by the impact of the 53rd fiscal week in 2024.[2]

In addition to the above, the reportable variances by category of expense are as follows:

- Supply Chain ($1.3M or 44.2% increase): due to a refinement in the allocation of Supply Chain cost allocation methodology that resulted in a reallocation of costs to the regulated hydroelectric business (discussed in the report by Elenchus Research Associates at Ex. F3-1-4, Attachment 1, S. 3.1.1, "Elenchus Report"). Supply Chain's Total OPG OM&A costs in 2025 are lower than in 2024 (Ex. F3-1-1, Table 1, lines 3, line 3).
- Corporate Centre ($3.1M or 24.0% decrease): due to a refinement in the Corporate Affairs cost allocation methodology that results in a reallocation of costs from the regulated hydroelectric business (discussed in the Elenchus Report, Ex. F3-1-4, Attachment 1, S. 3.1.2). This is partly offset by higher Regulatory Affairs costs as discussed in Ex. F3-1-3.

4.0 PERIOD-OVER-PERIOD CHANGES – HISTORICAL YEARS, REGULATED HYDROELECTRIC

2024 Actual versus 2023 Actual

Support Services 2024 Actual costs were $50.0M, which is $4.7M higher than the 2023 Actual costs of $45.3M. All Support Services organizations were impacted by higher labour cost escalation in 2024 reflecting collective bargaining process outcomes including, as a result of the repeal of the *Protecting a Sustainable Public Sector for Future Generations Act, 2019* ("Bill 124"), as discussed in Ex. F4-3-1, Section 6.2. Another contributor to the increase in Base OM&A costs was the impact of the 53rd fiscal week in 2024.

[2] Annual labour cost budgets are calculated on a weekly basis times the number of weeks in the fiscal calendar year; most years have 52 weeks, but some years, like 2024, have 53 numbered weeks.

The reportable variances by category of expenses are as follows and are inclusive of the aforementioned higher labour cost escalation and 53rd fiscal week impact, with the additional drivers of variance identified below where applicable:

- Finance ($1.6M or 25.4% increase): due to a higher portion of costs allocated to the regulated hydroelectric business as a result of their higher relative capital expenditures which are used as a cost driver under OPG's cost allocation methodology (Ex. F3-1-4).
- Corporate Centre ($1.9M or 17.6% increase): due to higher Regulatory Affairs costs as discussed in Ex. F3-1-3 and costs in support of OPG's Reconciliation Action Plan (Ex. A2-2-1).
- Leases and Utilities ($1.2M or 71.3% increase): due to an increase in the estimated use of the 800 Kipling Avenue site by the regulated hydroelectric business subsequent to the sale and leaseback of the building. Leases and Utilities' Total OPG OM&A costs are lower in 2024 compared to 2023 (Ex. F3-1-1, Table 1, line 8).

2023 Actual versus 2022 Actual

Support Services 2023 Actual costs were $45.3M, which is $5.4M higher than the 2022 Actual costs of $39.9M. All Support Services organizations were impacted by higher labour cost escalation in 2023, reflecting collective bargaining process outcomes including, as a result of the repeal of Bill 124, as discussed in Ex. F4-3-1.

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

- Human Resources ($1.2M or 19.1% increase): due to temporarily higher staffing levels to support operations recruitment and onboarding requirements as discussed in Ex. F4-3-1.
- Corporate Centre ($2.5M or 28.9% increase): due to higher Regulatory Affairs costs as discussed in Ex. F3-1-3 and costs in support of OPG's Reconciliation Action Plan (Ex. A2-2-1).
- Project OM&A ($1.1M or 66.9% increase): due to a write-off in 2023 of the life-to-date costs incurred for the previously planned Clarington Corporate Campus project as discussed (Ex. H1-1-1, Section 5.23 and Ex. D3-1-1).

2022 Actual versus 2021 Actual

Support Services 2022 Actual costs were $39.9M, which is $1.2M higher than the 2021 Actual costs of $38.7M.

The reportable variances by category of expenses are as follows:

- Corporate & Technology Services ($1.4M or 12.3% increase): due to higher staffing levels to support increased IT requirements across OPG and increased requirements for and cost of digital tools across the business, resulting in higher software and hardware costs.
- Human Resources ($1.2M or 24.5% increase): due to temporarily higher staffing levels to support operations recruitment and onboarding requirements as discussed in Ex. F4-3-1.
- Corporate Centre ($1.8M or 17.7% decrease): primarily due to lower Regulatory Affairs costs as discussed in Ex. F3-1-3.

2021 Actual versus 2020 Actual

Support Services 2021 Actual costs were $38.7M, which is $0.3M higher than the 2020 Actual costs of $38.4M.

The reportable variances by category of expenses are as follows:

- Finance ($1.0M or 15.3% decrease): due to lower staffing levels from unfilled vacancies.

2020 Actual versus 2019 Actual

Support Services 2020 Actual costs were $38.4M, which is $8.7M lower than the 2019 Actual costs of $47.1M.

The reportable variances by category of expenses are as follows:

- Corporate & Technology Services ($7.1M or 39.7% decrease): due to a change in allocation methodology to use IT end users as the cost driver, as discussed in EB-2020-0290, Ex. F3-1-4, Attachment 1, S. 4.1.4.

2019 Actual versus 2018 Actual

Support Services Actual 2019 costs were $47.1M, which is $0.1M higher than the 2018 Actual costs of $47.1M.

The reportable variances by category of expenses are as follows:

- Corporate Centre ($1.8M or 20.7% increase): due to higher Regulatory Affairs costs in 2019 based on the OEB payment amounts application cycle.
- Project OM&A ($1.2M or 39.2% decrease): due to projects in Corporate & Technology Services.

2018 Actual versus 2017 Actual

Support Services 2018 Actual costs were $47.1M, which is $1.4M lower than the 2017 Actual costs of $48.4M, which includes the impact of the 53rd fiscal week in 2017.[3]

The reportable variances by category of expenses are as follows:

- Corporate Centre ($1.4M or 13.4% decrease): due to lower Regulatory Affairs costs due to a smaller scale application in 2018 (EB-2018-0243) compared to 2017 (EB-2016-0152). Project OM&A ($1.1M or 25.7% decrease): due to projects in Corporate & Technology Services.

2017 Actual versus 2016 Actual

Support Services Actual costs in 2017 were $48.4M, which is $2.6M lower than the 2016 Actual costs of $51.0M. The decrease in Base OM&A costs would have been greater but for the impact of the 53rd fiscal week in 2017.

The reportable variances by category of expenses are as follows:

- Project OM&A ($1.8M or 30.0% decrease): due to projects in Corporate & Technology Services.

[3] Annual labour cost budgets are calculated on a weekly basis times the number of weeks in the fiscal calendar year; most years have 52 weeks, but some years, like 2017, have 53 numbered weeks.

5.0 TERM-OVER-TERM COMPARISON – PROJECT OM&A COSTS, REGULATED HYDROELECTRIC

The Application is requesting the approval of forecasted regulated hydroelectric Support Services allocated project OM&A expenditures of $4.1M in 2027. This represents an increase of $1.9M from the previous period's average annual expenditure of $2.2M over 2022-2026. The increase in project OM&A expenditures is primarily due to an increase in the scope and cost of technology projects allocated or directly supporting the regulated hydroelectric business in 2027, including hydroelectric applications and as part of the Enterprise System Modernization projects such as Asset Management, Finance ERP and Supply Chain ERP, further discussed in Ex. D3-1-1 and Ex. D3-1-2. Term-over-term amounts are shown in Ex. F3-1-2, Table 1b.

6.0 PERIOD-OVER-PERIOD CHANGES – IR TERM, OPG NUCLEAR FACILITIES

2027 Plan versus 2026 Budget

Support Services costs in the 2027 Plan are $417.5M, which is $1.4M higher than the 2026 Budget of $416.1M.

The reportable variances by category of expense are as follows:

- Human Resources ($3.8M or 12.6% decrease): due to staff being deployed to support the Pickering Refurbishment Program ("PRP") directly.
- Leases and Utilities ($3.9M or 17.8% increase): due to lease costs for the planned lease of a Nuclear central warehouse to replace the existing Nuclear warehouse in the Durham Region in support of increased storage requirements, whereby there is a period of overlap in lease costs to support the retrofit of the newly leased warehouse and relocate the material (Ex. D3-1-1).

2028 Plan versus 2027 Plan

Support Services costs in the 2028 Plan are $412.1M, which is $5.3M lower than the 2027 Plan of $417.5M.

The reportable variances by category of expense are as follows:

- Leases and Utilities ($4.7M or 18.4% decrease): due to a reduction in the leasing footprint in the Durham Region through continued workplace optimization and higher costs in 2027 due to an overlap in lease costs to support the retrofit of the newly leased warehouse.

2029 Plan versus 2028 Plan

Support Services costs in the 2029 Plan are $432.7M, which is $20.6M higher than the 2028 Plan of $412.1M

There are no reportable variances by category of expense.

2030 Plan versus 2029 Plan

Support Services costs in the 2030 Plan are $444.7M, which is $12.0M higher than the 2029 Plan of $432.7M.

There are no reportable variances by category of expense.

2031 Plan versus 2030 Plan

Support Services costs in the 2031 Plan are $471.6M, which is $26.8M higher than the 2030 Plan of $444.7M.

The reportable variances by category of expense are as follows:[4]

- Corporate & Technology Services ($18.8M or 10.9% increase): due to the increased cost of digital tools resulting in higher software costs, and the return of staff from the PRP to support operations following Pickering Unit 5 returning to service.
- Supply Chain ($6.5M or 14.7% increase): due to the return of staff from the PRP to support operations following Pickering Unit 5 returning to service.

[4] Support Services groups including Corporate & Technology Services and Supply Chain are expected to deploy staff directly to the PRP in 2027 which reduces their Base OM&A costs. The variance is not reportable in 2027 as a result of offsetting factors in both organizations.

7.0 PERIOD-OVER-PERIOD CHANGES – BRIDGE YEARS, OPG NUCLEAR FACILITIES

2026 Budget versus 2026 OEB-Approved

Support Services costs in the 2026 Budget are $416.1M, which is $165.6M higher than the 2026 OEB-approved amount of $250.5M.

The reportable variances are largely due to the planned extension of Pickering Units 5-8 operations until September 2026, prior to refurbishment, while the OEB-approved costs reflected the then-anticipated permanent shutdown of the entire Pickering station by the end of 2025. In addition, all Support Services organizations were impacted by higher labour cost escalation than forecasted in EB-2020-0290, reflecting collective bargaining process outcomes including, as a result of the repeal of Bill 124, as discussed in Ex. F4-3-1. There are no reportable variances by category of expenses that are not explained by these drivers.

2026 Budget versus 2025 Budget

Support Services costs in the 2026 Budget are $416.1M, which is $4.5M higher than the 2025 Budget of $411.5M.

The reportable variances by category of expenses are as follows:

- Human Resources ($4.9M or 14.0% decrease): due to lower staffing levels to support operations recruitment and onboarding requirements as discussed in Ex. F4-3-1.
- Leases and Utilities ($4.9M or 18.4% decrease): due to a reduction in leases following the move to OPG's new Corporate Headquarters, discussed in Ex. D3-1-1.
- Project OM&A ($11.4M or 43.5% increase): due to site specific Real Estate projects and projects in Corporate & Technology Services including the progression of Enterprise System Modernization projects (e.g., Asset Management, Finance ERP and Supply Chain ERP), discussed in Ex. D3-1-1 and Ex. D3-1-2.

2025 Budget versus 2025 OEB-Approved

Support Services costs in the 2025 Budget are $411.5M, which is $87.1M higher than the 2025 OEB-approved amount of $324.5M. All Support Services organizations were impacted by

higher labour cost escalation than forecasted in EB-2020-0290, reflecting collective bargaining process outcomes including, as a result of the repeal of Bill 124, as discussed in Ex. F4-3-1.

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

- Corporate & Technology Services ($28.1M or 23.2% increase): due to increased requirements for and cost of digital tools across the business resulting in higher software and hardware costs (discussed in Ex. F3-1-1 and Ex. D3-1-1) and higher staffing levels including information management and administrative services to support Pickering Units 5-8 extension to September 2026 and through to the Pickering Refurbishment.
- Supply Chain ($11.2M or 33.5% increase): due to higher staffing levels to support Pickering Units 5-8 extension to September 2026 and through to the Pickering Refurbishment, increased project activity in the business, advancing of procurement strategies, vendor diversification efforts (Ex. F3-3-1), and costs in support of OPG's Reconciliation Action Plan (Ex. A2-2-1).
- Finance ($9.6M or 33.0% increase): due to higher staffing levels and third-party services costs to support increased project activity across the business, corporate financing activities, and OEB payment amounts application preparation.
- Human Resources ($12.0M or 51.9% increase): due to temporarily higher staffing levels to support operations recruitment and onboarding requirements as discussed in Ex. F4-3-1.
- Corporate Centre ($14.8M or 54.1% increase): due to a refinement in the Corporate Affairs cost allocation methodology that results in a reallocation of costs to OPG's nuclear business (discussed in the Elenchus Report at Ex. F3-1-4, Attachment 1, S. 3.1.2) and higher Regulatory Affairs costs as discussed in Ex. F3-1-3.
- Leases and Utilities ($6.5M or 32.0% increase): due to changes in the timing of previously assumed lease exits as the then-planned Clarington Corporate Campus was assumed to be completed in 2024 (EB-2020-0290) while OPG's new Corporate Headquarters became available in 2025.
- Project OM&A ($8.3M or 46.2% increase): due to the reprioritization of Real Estate projects and projects in Corporate & Technology Services, and the initiation of Enterprise System

Modernization projects (e.g., Asset Management, Finance ERP and Supply Chain ERP), discussed in Ex. D3-1-1 and Ex. D3-1-2.

2025 Budget versus 2024 Actual

Support Services costs in the 2025 Budget are $411.5M, which is $10.7M higher than the 2024 Actual costs of $400.8M. All Support Services organizations were impacted by higher labour cost escalation in 2025 reflecting collective bargaining process outcomes including, as a result of the repeal of Bill 124, as discussed in Ex. F4-3-1, partly offset by the impact of the 53rd fiscal week in 2024.

The reportable variances by category of expenses are as follows and are inclusive of the aforementioned higher labour cost escalation and 53rd fiscal week impact, with additional drivers of variance identified below where applicable:

- Supply Chain ($6.8M or 13.3% decrease): due to reduced support required for Pickering operations reflecting the shutdown of Units 1 and 4 in 2024 and Units 5-8 approaching the planned refurbishment.
- Finance ($7.3M or 23.3% increase): due to higher staffing levels and third-party services costs, including in support of increased project activity across the business, increased corporate financing activities, and the OEB payment amounts application preparation.
- Corporate Centre ($8.6M or 25.4% increase): due to a refinement in the Corporate Affairs cost allocation methodology that results in a reallocation of costs to OPG's nuclear business (discussed in the Elenchus Report at Ex. F3-1-4, Attachment 1, S. 3.1.2) and higher Regulatory Affairs costs as discussed in Ex. F3-1-3
- Leases and Utilities Costs ($6.1M or 29.2% increase): primarily due to higher utilities costs and an over accrual of costs in 2023 that was subsequently reversed in 2024.

8.0 PERIOD-OVER-PERIOD CHANGES - HISTORICAL YEARS, OPG NUCLEAR FACILITIES

2024 Actual versus 2024 OEB-Approved

Support Services 2024 Actual costs were $400.8M, which is $42.0M higher than the 2024 OEB-approved amount of $358.8M. All Support Services organizations were impacted by

higher labour cost escalation than forecasted in EB-2020-0290, reflecting collective bargaining process outcomes including, as a result of the repeal of Bill 124, as discussed in Ex. F4-3-1.

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

- Corporate & Technology Services ($26.2M or 19.9% increase): increased requirements for and cost of digital tools across the business resulting in higher software and hardware costs.
- Supply Chain ($9.9M or 23.9% increase): due to higher staffing levels to support increased project activity across the business, advancing of procurement strategies, vendor diversification efforts (Ex. F3-3-1), and costs in support of OPG's Reconciliation Action Plan (discussed in Ex. A2-2-1).
- Human Resources ($8.8M or 37.6% increase): due to temporarily higher staffing levels to support operations recruitment and onboarding requirements as discussed in Ex. F4-3-1.
- Corporate Centre ($3.4M or 11.2% increase): due to costs in support of OPG's Reconciliation Action Plan (discussed in Ex. A2-2-1) and higher community engagement costs.
- Leases and Utilities ($5.6M or 21.1% decrease): due to lower costs from an over accrual in 2023 that was subsequently reversed in 2024.
- Project OM&A ($2.4M or 10.8% increase): due to a reprioritization of Real Estate and Corporate & Technology Services projects.

2024 Actual versus 2023 Actual

Support Services Actual costs in 2024 were $400.8M, which is $5.5M lower than the 2023 Actual costs of $406.3M. All Support Services organizations were impacted by higher labour cost escalation in 2024 reflecting collective bargaining process outcomes including, as a result of the repeal of Bill 124, as discussed in Ex. F4-3-1. Another contributor to the increase in Base OM&A costs is the impact of the 53rd fiscal week in 2024.[5]

[5] Annual labour cost budgets are calculated on a weekly basis times the number of weeks in the fiscal calendar year; most years have 52 weeks, but some years, like 2024, have 53 numbered weeks.

The reportable variances by category of expenses are as follows and are inclusive of the aforementioned higher labour cost escalation and the 53rd fiscal week impact, with additional drivers of variance identified below where applicable:

- Human Resources ($5.1M or 13.6% decrease): due to lower staffing levels to support operations recruitment and onboarding requirements as discussed in Ex. F4-3-1.
- Project OM&A ($5.1M or 17.2% decrease): due to a write-off in 2023 of the life-to-date costs incurred for the previously planned Clarington Corporate Campus project (discussed in Ex. H1-1-1, Section 5.23, Ex. D3-1-1, Section 3).

2023 Actual versus 2023 OEB-Approved

Support Services 2023 Actual costs were $406.3M, which is $38.5M higher than the 2023 OEB-approved amount of $367.8M. All Support Services organizations were impacted by higher labour cost escalation than forecasted in EB-2020-0290, reflecting collective bargaining process outcomes including, as a result of the repeal of Bill 124, as discussed in Ex. F4-3-1.

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

- Supply Chain ($10.5M or 25.0% increase): due to higher staffing levels to support increased project activity across the business, advancing of procurement strategies, vendor diversification efforts (Ex. F3-3-1), and costs in support of OPG's Reconciliation Action Plan (Ex. A2-2-1).
- Human Resources ($11.9M or 47.2% increase): due to temporarily higher staffing levels to support operations recruitment and onboarding requirements as discussed in Ex. F4-3-1.
- Leases and Utilities ($3.9M or 14.6% decrease): due to lower leasing costs for buildings in the Durham Region and lower utilities costs, partly offset by an over accrual of costs in 2023 that was subsequently reversed in 2024.
- Project OM&A ($10.0M or 51.5% increase): primarily due to a write-off in 2023 of the life-to-date costs incurred for the previously planned Clarington Corporate Campus project (discussed in Ex. D3-1-1) and recorded in the Clarington Corporate Campus Deferral Account (Ex. H1-1-1, Section 5.23).

2023 Actual versus 2022 Actual

Support Services 2023 Actual costs were $406.3M, which is $40.1M higher than the 2022 Actual costs of $366.2M. All Support Services organizations were impacted by higher labour cost escalation in 2023 reflecting collective bargaining process outcomes including, as a result of the repeal of Bill 124, as discussed in Ex. F4-3-1.

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

- Real Estate ($10.5M or 25.0% increase): due to increased nuclear site-specific infrastructure repairs and other support requirements, and higher staffing levels from previously unfilled vacancies.
- Supply Chain ($6.7M or 14.6% increase): due to higher staffing levels to support increased project activity, advancing of procurement strategies, vendor diversification efforts (Ex. F3-3-1), and costs in support of OPG's Reconciliation Action Plan (Ex. A2-2-1).
- Finance ($4.3M or 14.7% increase): due to higher staffing levels from previously unfilled vacancies.
- Human Resources ($9.2M or 32.9% increase): due to temporarily higher staffing levels to support operations recruitment and onboarding requirements as discussed in Ex. F4-3-1.
- Project OM&A ($7.0M or 31.5% increase): due to a write-off in 2023 of the life-to-date costs incurred for the previously planned Clarington Corporate Campus project (discussed in Ex. H1-1-1, Section 5.23 and Ex. D3-1-1).

2022 Actual versus 2022 OEB-Approved

Support Services 2022 Actual costs were $366.2M, which is $10.0M lower than the 2022 OEB-approved amount of $376.3M.

The reportable variances by category of expenses are as follows:

- Real Estate ($10.2M or 19.5% decrease): due to lower staffing levels from the assumed ongoing enhanced cleaning protocol requirements not materializing, and unfilled vacancies.
- Human Resources ($2.7M or 10.6% increase): due to temporarily higher staffing levels to support operations recruitment and onboarding requirements as discussed in Ex. F4-3-1.
- Leases and Utilities ($4.8M or 17.3% decrease): due to lower occupancy across company buildings through transition out of COVID-19 protocols.
- Project OM&A ($3.7M or 14.1% decrease): due to reprioritization of projects in Corporate & Technology Services.

2022 Actual versus 2021 Actual

Support Services Actual costs are $366.2M, which is $6.5M higher than the 2021 Actual costs of $359.7M.

The reportable variances by category of expenses are as follows:

- Real Estate ($5.0M or 10.7% decrease): primarily due to lower staffing levels from a reduction in enhanced cleaning protocols through transition out of COVID-19 protocols.
- Human Resources ($3.3M or 13.1% increase): due to temporarily higher staffing levels to support operations recruitment and onboarding requirements as discussed in Ex. F4-3-1.

2021 Actual versus 2021 OEB-Approved Budget

Support Services 2021 Actual costs were $359.7M, which is $9.2M lower than the 2021 OEB-approved amount of $368.9M.

The reportable variances by category of expenses are as follows:

- Corporate & Technology Services ($15.5M or 12.5% increase): due to increased requirements for and cost of digital tools resulting in higher software and hardware costs and higher staffing levels.
- Supply Chain ($7.4M or 14.7% decrease): due to lower staffing levels.

- Finance ($11.6M or 30.3% decrease): due to lower staffing levels and temporarily unfilled vacancies.
- Leases and Utilities ($10.8M or 32.3% decrease): due to vacating three floors at 700 University Avenue office and lower occupancy in company buildings as a result of COVID-19 protocols.
- Project OM&A ($8.5M or 63.4% increase): reprioritization of projects in Corporate & Technology Services.

2021 Actual versus 2020 Actual

Support Services 2021 Actual costs were $359.7M, which is $7.1M higher than the 2020 Actual costs of $352.7M.

There are no reportable variances by category of expense.

2020 Actual versus 2020 OEB-Approved

Support Services 2020 Actual costs in 2020 were $352.7M, which is $8.6M lower than the 2020 OEB-approved amount of $361.3M.

The reportable variances by category of expense are as follows:

- Finance ($10.6M or 28.1% decrease): due to lower staffing levels and temporarily unfilled vacancies.
- Leases and Utilities ($8.9M or 28.3% decrease): due to lower occupancy in buildings because of COVID-19 protocols.
- Project OM&A ($7.4M or 56.1% increase): due to the reprioritization of projects in Corporate & Technology Services.

9.0 TERM-OVER-TERM COMPARISON – PROJECT OM&A, OPG NUCLEAR FACILITIES

The Application is requesting the approval of forecasted OPG nuclear Support Services allocated project OM&A expenditures of $180.7M during the IR term. This represents an increase of $41.0M from the previous period's expenditures of $139.7M over 2022-2026. The increase in project OM&A expenditures is primarily due to an increase in the scope and cost

of technology projects allocated or directly supporting OPG's nuclear business over the 2027-2031 term, including as part of Enterprise System Modernization project such as Asset Management, Finance ERP and Supply Chain ERP, further discussed in Ex. D3-1-1 and Ex. D3-1-2. Term-over-term amounts are shown in Ex. F3-1-2, Table 2b.

10.0 PERIOD-OVER-PERIOD CHANGES – IR TERM, DNNP FACILITIES

Exhibit F3-1-1, Table 3c, provides the OM&A Support Services costs for the IR term. Corporate Support costs allocated to the DNNP facilities are consistent with OPG's Cost allocation methodology as described in Ex. F3-1-4, Elenchus Report. Upon commercial operations of Unit 1 in late 2030 and all of 2031, additional costs to support the station such as facilities maintenance, information technology requirements, finance controllership, Human Resource business partners and other support are described.

2027 Plan versus 2026 Budget

Support Services costs in the 2027 Plan are $28.6M, which is $5.6M higher than the 2026 Budget of $23.0M.

The reportable variances by category of expense are as follows:

- Corporate & Technology Services ($2.1M or 25.3% increase): due to a higher portion of costs allocated to the DNNP facilities as a result of an increase in the number of their IT end users which are used as a cost driver under OPG's cost allocation methodology (Ex. F3-1-4).
- Finance ($1.3M or 35.1% increase): due to a higher portion of costs allocated to the DNNP facilities as a result of their higher relative capital expenditures which are used a cost driver under OPG's cost allocation methodology (Ex. F3-1-4).
- Corporate Centre ($1.2M or 41.4% increase): due to a higher portion of costs allocated to DNNP facilities as a result of their higher relative capital expenditures which are used as a cost driver under OPG's cost allocation methodology, and higher Regulatory Affairs costs as discussed in Ex. F3-1-3.

2028 Plan versus 2027 Plan

Support Services costs in the 2028 Plan are $31.5M, which is $2.9M higher than the 2027 Plan of $28.6M.

The reportable variances by category of expense are as follows:

- Corporate & Technology Services ($1.5M or 14.4% increase): due to a higher portion of costs allocated to the DNNP facilities as a result of an increase in the number of IT end users which are used as a cost driver under OPG's cost allocation methodology (Ex. F3-1-4).

2029 Plan versus 2028 Plan

Support Services costs in the 2029 Plan are $29.4M, which is $2.1M lower than the 2028 Plan of $31.5M.

The reportable variances by category of expense are as follows:

- Project OM&A ($1.0M or 22.2% decrease): due to lower Corporate & Technology Services projects costs related to DNNP Enterprise Asset Management and Finance ERP.

2030 Plan versus 2029 Plan

Support Services costs in the 2030 Plan are $30.6M, which is $1.3M higher than the 2029 Plan of $29.4M.

The reportable variances by category of expense are as follows:

- Supply Chain ($1.1M or 78.6% increase): due to expected procurement, category management, and warehousing requirements upon DNNP facilities Unit 1 entering commercial operations in 2030.

2031 Plan versus 2030 Plan

Support Services costs in the 2031 Plan are $32.4M, which is $1.8M higher than the 2030 Plan of $30.6M.

The reportable variances by category of expense are as follows:

- Real Estate ($3.0M or 157.9% increase): due to a full year of expected facilities maintenance requirements compared to less than three months in 2030.
- Supply Chain ($2.2M or 88.0% increase): due to a full year of expected procurement, category management, and warehousing requirements compared to less than three months in 2030.
- Finance ($2.2M or 34.4% decrease): due to a lower portion of costs allocated to the DNNP facilities upon Unit 1 entering commercial operations in 2030 and therefore lower relative capital expenditures which are used as a cost driver under OPG's cost allocation methodology (Ex. F3-1-4).
- Corporate Centre ($2.5M or 47.2% decrease): due to a lower portion of costs allocated to the DNNP facilities upon Unit 1 entering commercial operations in 2030 and therefore lower relative capital expenditures which are used as a cost driver under OPG's cost allocation methodology (Ex. F3-1-4).

11.0 TERM-OVER-TERM COMPARISON – PROJECT OM&A, DNNP FACILITIES

The DNNP Facilities do not have any Project OM&A expenditures prior to 2026 in the 2022-2026 term. For purposes of comparison, the 2022-2026 term is represented by the 2026 budget of $4.8M as shown in Ex. F3-1-1, Table 3c. The Application is requesting the approval of forecasted DNNP facilities Support Services allocated Project OM&A expenditures of $19.5M during the IR term, which averages to $3.9M per year and represents an annual decrease of $0.9M compared to the previous period's expenditure in 2026. This decrease is primarily related to IT OM&A project costs allocated or directly supporting the DNNP facilities over the 2027-2031 term including Finance ERP and DNNP Enterprise Asset Management, further discussed in Ex. D3-1-1 and Ex. D3-1-2. Exhibit F3-1-2, Table 2d provides the term-over-term amounts.

12.0 PROJECT SPECIFIC INFORMATION – PROJECT OM&A – TIER 1 PROJECTS

There is one Tier 1 OM&A project with costs greater than $20M and is within the category of New Projects approved since EB-2020-0290. Ex. F3-1-2, Table 3 presents the Tier 1 project discussed below. The business case summary is provided in Ex. D3-1-2, Attachment 1, Tab

4. Other projects with Project OM&A amounts, by tier, including descriptions as required, are shown in Ex. D3-1-2, Tables 4, 5, and 6.

12.1 New Projects not in EB-2020-0290

Finance Enterprise Resource Planning Solution (89274) is a sustaining project to update the current SAP on-premise system, which is at its end-of-life, with SAP S/4 HANA and update the associated business processes. The project is expected to result in improved data integration, business agility and decision-making. SAP S/4HANA Enterprise Resource Planning solution optimizes Finance processes and services in line with industry best practice and digitizes them with a modern technology solution, to ensure business continuity and support OPG's current and future needs. This is part of OPG’s Enterprise System Modernization, discussed further in Ex. D3-1-1. The project started in 2025 and is scheduled to be completed in December 2031 with an estimated OM&A project cost of $22.4M.

Numbers may not add due to rounding.

Table 1a

Comparison of Allocation of Corporate Support & Administrative Costs ($M) 2016-2026

Regulated Hydroelectric

Line No.	Business Unit	2016 Actual	(c)-(a) Change	2017 Actual	(e)-(c) Change	2018 Actual	(g)-(e) Change	2019 Actual	(i)-(g) Change	2020 Actual	(k)-(i) Change	2021 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Base OM&A											
1	Corporate & Technology Services	19.0	(1.5)	17.5	0.6	18.0	(0.3)	17.8	***(7.1)***	10.7	0.6	11.3
2	Real Estate[1]	0.5	0.0	0.5	0.0	0.5	(0.0)	0.5	(0.0)	0.5	0.1	0.6
3	Supply Chain	3.1	0.5	3.6	(0.5)	3.1	(0.3)	2.8	(0.4)	2.5	(0.1)	2.3
4	Finance	7.5	(0.7)	6.8	0.2	7.0	0.2	7.1	(0.4)	6.7	***(1.0)***	5.7
5	Human Resources	4.8	0.4	5.2	0.4	5.6	(0.1)	5.5	(0.0)	5.5	(0.5)	5.0
6	Corporate Centre	10.1	(0.0)	10.1	***(1.4)***	8.7	***1.8***	10.5	(0.9)	9.7	0.7	10.4
7	**Total Base OM&A**	45.0	(1.3)	43.6	(0.6)	43.0	1.3	44.3	***(8.7)***	35.6	(0.3)	35.3
8	**Lease/Utilities**	0.2	0.5	0.7	0.3	1.0	(0.0)	1.0	(0.2)	0.8	0.4	1.2
9	**Project OM&A**	5.9	***(1.8)***	4.1	***(1.1)***	3.0	***(1.2)***	1.9	0.2	2.1	0.1	2.2
10	**Total OM&A**	51.0	(2.6)	48.4	(1.4)	47.1	0.1	47.1	***(8.7)***	38.4	0.2	38.7

Line No.	Business Unit	2021 Actual	(c)-(a) Change	2022 Actual	(e)-(c) Change	2023 Actual	(g)-(e) Change	2024 Actual	(i)-(g) Change	2025 Budget	(k)-(i) Change	2026 Budget
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Base OM&A											
11	Corporate & Technology Services	11.3	***1.4***	12.7	0.2	12.8	0.7	13.6	1.2	14.8	***2.4***	17.3
12	Real Estate[1]	0.6	0.1	0.6	0.1	0.7	0.2	0.9	0.1	1.0	(0.1)	0.9
13	Supply Chain	2.3	(0.1)	2.3	0.1	2.3	0.6	2.9	***1.3***	4.2	(0.2)	4.0
14	Finance	5.7	0.3	6.0	0.5	6.5	***1.6***	8.1	0.1	8.3	0.9	9.2
15	Human Resources	5.0	***1.2***	6.3	***1.2***	7.5	(0.7)	6.7	0.3	7.0	(0.6)	6.5
16	Corporate Centre	10.4	***(1.8)***	8.5	***2.5***	11.0	***1.9***	12.9	***(3.1)***	9.8	0.1	9.9
17	**Total Base OM&A**	35.3	1.1	36.4	***4.4***	40.8	***4.4***	45.2	0.0	45.2	2.5	47.7
18	**Lease/Utilities**	1.2	0.6	1.8	(0.1)	1.7	***1.2***	2.9	0.1	3.1	1.0	4.1
19	**Project OM&A**	2.2	(0.5)	1.7	***1.1***	2.8	(0.9)	1.9	0.6	2.5	(0.2)	2.2
20	**Total OM&A**	38.7	1.2	39.9	***5.4***	45.3	***4.7***	50.0	0.7	50.7	3.3	54.0

Notes:

1 Excludes amounts captured in the Asset Service Fee (Ex. F3-2-1).

Numbers may not add due to rounding.

Table 1b

Comparison of Allocation of Corporate Support & Administrative Costs ($M) 2026-2027

Regulated Hydroelectric

Line No.	Business Unit	2026 Budget	(c)-(a) Change	2027 Plan
		(a)	(b)	(c)
	Base OM&A			
1	Corporate & Technology Services	17.3	0.7	18.0
2	Real Estate[1]	0.9	0.2	1.1
3	Supply Chain	4.0	0.1	4.1
4	Finance	9.2	0.1	9.3
5	Human Resources	6.5	(0.6)	5.8
6	Corporate Centre	9.9	0.2	10.1
7	**Total Base OM&A**	47.7	0.7	48.5
8	**Lease/Utilities**	4.1	***(1.3)***	2.8
9	**Project OM&A**	2.2	***1.9***	4.1
10	**Total OM&A**	54.0	1.3	55.3

Line No.	Business Unit	2022-2026 Average	(c)-(a) Change	2027 Plan
		(a)	(b)	(c)
11	**Project OM&A**	2.2	***1.9***	4.1

Notes:

1 Excludes amounts captured in the Asset Service Fee (Ex. F3-2-1).

Numbers may not add due to rounding.

Table 2a

Comparison of Allocation of Corporate Support & Administrative Costs ($M)[1] 2020-2025

OPG Nuclear Facilites

Line No.	Business Unit	2020 OEB Approved	(c)-(a) Change	2020 Actual	(g)-(c) Change	2021 OEB Approved	(g)-(e) Change	2021 Actual	(k)-(g) Change	2022 OEB Approved	(k)-(i) Change	2022 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Base OM&A											
1	Corporate & Technology Services	122.8	7.3	130.1	9.5	124.1	***15.5***	139.6	4.9	137.1	7.4	144.5
2	Real Estate[2]	45.2	4.1	49.3	(2.0)	46.5	0.8	47.3	***(5.0)***	52.4	***(10.2)***	42.2
3	Supply Chain	49.0	(4.8)	44.2	(1.2)	50.4	***(7.4)***	43.0	2.8	42.3	3.6	45.8
4	Finance	37.8	***(10.6)***	27.2	(0.4)	38.3	***(11.6)***	26.7	2.4	32.2	(3.1)	29.1
5	Human Resources	24.9	(0.4)	24.5	0.3	25.4	(0.6)	24.8	***3.3***	25.4	***2.7***	28.1
6	Corporate Centre	36.9	(2.7)	34.1	(0.1)	37.5	(3.5)	34.0	(2.9)	32.9	(1.9)	31.0
7	**Total Base OM&A**	316.5	(7.1)	309.4	6.0	322.2	(6.9)	315.3	5.4	322.3	(1.5)	320.8
8	**Lease/Utilities**	31.6	***(8.9)***	22.7	(0.1)	33.3	***(10.8)***	22.5	0.6	28.0	***(4.8)***	23.1
9	**Project OM&A**	13.2	***7.4***	20.6	1.2	13.4	***8.5***	21.9	0.4	26.0	***(3.7)***	22.3
10	**Total OM&A Before Adjustments**	361.3	(8.6)	352.7	7.1	368.9	(9.2)	359.7	6.5	376.3	(10.0)	366.2
11	**OEB/Settlement Adjustments[3]**	(45.0)	45.0	0.0	0.0	(45.0)	45.0	0.0	0.0	(11.3)	11.3	0.0
12	**Total OM&A Including Adjustments**	316.3	36.4	352.7	7.1	323.9	35.8	359.7	6.5	365.0	1.3	366.2

Line No.	Business Unit	2022 Actual	(e)-(a) Change	2023 OEB Approved	(e)-(c) Change	2023 Actual	(i)-(e) Change	2024 OEB Approved	(i)-(g) Change	2024 Actual	(k)-(i) Change	2025 Budget
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Base OM&A											
13	Corporate & Technology Services	144.5	0.9	137.3	8.1	145.4	12.6	131.7	***26.2***	157.9	(8.7)	149.2
14	Real Estate[2]	42.2	***10.5***	52.5	0.3	52.7	(3.3)	51.8	(2.4)	49.4	(0.5)	48.9
15	Supply Chain	45.8	***6.7***	42.0	***10.5***	52.5	(1.2)	41.5	***9.9***	51.4	***(6.8)***	44.5
16	Finance	29.1	***4.3***	32.4	1.0	33.4	(2.1)	31.9	(0.7)	31.2	***7.3***	38.5
17	Human Resources	28.1	***9.2***	25.3	***11.9***	37.3	***(5.1)***	23.4	***8.8***	32.2	3.0	35.2
18	Corporate Centre	31.0	1.7	32.1	0.7	32.8	0.9	30.3	***3.4***	33.7	***8.6***	42.2
19	**Total Base OM&A**	320.8	***33.3***	321.6	***32.5***	354.1	1.7	310.6	***45.2***	355.8	2.7	358.5
20	**Lease/Utilities**	23.1	(0.3)	26.8	***(3.9)***	22.9	(2.1)	26.3	***(5.6)***	20.8	***6.1***	26.8
21	**Project OM&A**	22.3	7.0	19.3	***10.0***	29.3	(5.1)	21.9	***2.4***	24.3	1.9	26.2
22	**Total OM&A Before Adjustments**	366.2	***40.1***	367.8	***38.5***	406.3	(5.5)	358.8	***42.0***	400.8	10.7	411.5
23	**OEB/Settlement Adjustments[3]**	0.0	0.0	(11.1)	11.1	0.0	0.0	(10.9)	10.9	0.0	0.0	0.0
24	**Total OM&A Including Adjustments**	366.2	40.1	356.7	49.6	406.3	(5.5)	347.9	52.9	400.8	10.7	411.5

Notes

1 Corporate Support & Administrative costs have been restated from EB-2020-0290 for organizational changes and transfers to/from Enterprise Operations and Enterprise Projects as described in Ex. F3-1-1.

2 Excludes amounts captured in the Asset Service Fee (Ex. F3-2-1).

3 OEB Adjustments to approved values in 2020-2021 include the annual $30M disallowed in compensation (EB-2016-0152 Decision and Order, p. 84). Per EB-2020-0290 OEB Decision and Order, Schedule A, p. 25, OM&A costs are reduced by 3% per year over the 2022-2026 period.

Numbers may not add due to rounding.

Table 2b
Comparison of Allocation of Corporate Support & Administrative Costs ($M)[1] 2025-2031
OPG Nuclear Facilities

Line No.	Business Unit	2025 OEB Approved	(c)-(a) Change	2025 Budget	(g)-(c) Change	2026 OEB Approved	(g)-(e) Change	2026 Budget	(i)-(g) Change	2027 Plan	(k)-(i) Change	2028 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Base OM&A											
1	Corporate & Technology Services	121.0	***28.1***	149.2	3.1	90.9	***61.4***	152.3	(2.7)	149.6	4.9	154.5
2	Real Estate[2]	52.3	(3.4)	48.9	2.1	32.6	***18.5***	51.0	4.0	55.0	0.2	55.2
3	Supply Chain	33.3	***11.2***	44.5	(0.3)	27.5	***16.8***	44.3	0.3	44.6	(2.7)	41.9
4	Finance	29.0	***9.6***	38.5	(0.2)	25.8	***12.6***	38.4	(0.4)	38.0	0.5	38.5
5	Human Resources	23.2	***12.0***	35.2	***(4.9)***	16.9	***13.3***	30.2	***(3.8)***	26.4	0.8	27.2
6	Corporate Centre	27.4	***14.8***	42.2	(1.8)	24.1	***16.3***	40.4	(1.9)	38.5	(1.3)	37.2
7	**Total Base OM&A**	286.2	***72.3***	358.5	(1.9)	217.8	***138.8***	356.6	(4.5)	352.1	2.5	354.6
8	**Lease/Utilities**	20.3	***6.5***	26.8	***(4.9)***	17.8	***4.1***	21.9	***3.9***	25.8	***(4.7)***	21.1
9	**Project OM&A**	17.9	***8.3***	26.2	11.4	14.9	***22.7***	37.6	2.0	39.6	(3.1)	36.5
10	**Total OM&A Before Adjustments**	324.5	***87.1***	411.5	4.5	250.5	***165.6***	416.1	1.4	417.5	(5.3)	412.1
11	**OEB/Settlement Adjustments[3]**	(9.8)	9.8	0.0	0.0	(7.5)	7.5	0.0	0.0	0.0	0.0	0.0
12	**Total OM&A Including Adjustments**	314.7	96.9	411.5	4.5	242.9	173.1	416.1	1.4	417.5	(5.3)	412.1

Line No.	Business Unit	2028 Plan	(c)-(a) Change	2029 Plan	(e)-(c) Change	2030 Plan	(g)-(e) Change	2031 Plan	2022-2026 Actuals & Budget	(k)-(i) Change	2027-2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(i)	(j)	(k)
	Base OM&A										
13	Corporate & Technology Services	154.5	9.8	164.4	8.4	172.8	***18.8***	191.5			
14	Real Estate[2]	55.2	3.2	58.5	0.9	59.3	1.2	60.5			
15	Supply Chain	41.9	1.7	43.6	0.3	43.9	***6.5***	50.4			
16	Finance	38.5	2.4	40.9	0.5	41.4	1.1	42.5			
17	Human Resources	27.2	1.2	28.4	0.3	28.7	2.5	31.2			
18	Corporate Centre	37.2	2.6	39.8	2.3	42.1	0.1	42.3			
19	**Total Base OM&A**	354.6	21.0	375.5	12.7	388.2	30.1	418.3			
20	**Lease/Utilities**	21.1	(0.2)	20.9	0.0	20.9	(0.4)	20.5			
21	**Project OM&A**	36.5	(0.2)	36.3	(0.7)	35.6	(2.9)	32.8	139.7	***41.1***	180.7
22	**Total OM&A**	412.1	20.6	432.7	12.0	444.7	26.8	471.6			

Notes
1 Corporate Support & Administrative costs have been restated from EB-2020-0290 for organizational changes and transfers to/from Enterprise Operations and Enterprise Projects as described in Ex. F3-1-1.
2 Excludes amounts captured in the Asset Service Fee (Ex. F3-2-1).
3 Per EB-2020-0290 OEB Decision and Order, Schedule A, p. 25, OM&A costs are reduced by 3% per year over the 2022-2026 period.

Numbers may not add due to rounding.

Updated: 2026-03-10
EB-2025-0297
Exhibit F3
Tab 1
Schedule 2
Table 2c

Table 2c
Comparison of Allocation of Corporate Support & Administrative Costs ($M) 2026-2031
DNNP Facilities

Line No.	Business Unit	2026 Budget	(e)-(c) Change	2027 Plan	(g)-(e) Change	2028 Plan	(i)-(g) Change	2029 Plan	(k)-(i) Change	2030 Plan	(c)-(a) Change	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Base OM&A											
1	Corporate & Technology Services	8.3	***2.1***	10.4	***1.5***	11.9	(1.0)	10.9	(0.9)	10.0	(0.1)	9.9
2	Real Estate[1]	1.1	0.5	1.5	0.1	1.7	0.1	1.7	0.1	1.9	***3.0***	4.9
3	Supply Chain	0.8	0.4	1.2	0.2	1.4	0.0	1.4	***1.1***	2.5	***2.2***	4.7
4	Finance	3.7	***1.3***	5.0	0.7	5.7	0.0	5.7	0.6	6.4	***(2.2)***	4.2
5	Human Resources	1.3	0.2	1.4	0.2	1.6	(0.2)	1.4	(0.1)	1.3	0.2	1.5
6	Corporate Centre	2.9	***1.2***	4.1	0.4	4.5	0.1	4.6	0.7	5.3	***(2.5)***	2.8
7	**Total Base OM&A**	18.1	***5.5***	23.6	***3.2***	26.8	(1.0)	25.8	1.5	27.3	0.6	28.0
											0.0	
8	**Lease/Utilities**	0.1	(0.0)	0.1	0.1	0.2	(0.1)	0.1	0.2	0.3	0.5	0.8
											0.0	
9	**Project OM&A**	4.8	0.1	4.8	(0.3)	4.5	***(1.0)***	3.5	(0.5)	3.0	0.7	3.7
10	**Total OM&A**	23.0	***5.6***	28.6	***2.9***	31.5	(2.1)	29.4	1.3	30.6	1.8	32.4

Line No.	Business Unit	2026 Budget	(g)-(e) Change	2027-2031 Average
		(a)	(b)	(c)
	Base OM&A			
1	Corporate & Technology Services	8.3	***2.3***	10.6
2	Real Estate[1]	1.1	***1.3***	2.3
3	Supply Chain	0.8	***1.4***	2.3
4	Finance	3.7	***1.7***	5.4
5	Human Resources	1.3	0.2	1.5
6	Corporate Centre	2.9	***1.4***	4.3
7	**Total Base OM&A**	18.1	***8.2***	26.3
8	**Lease/Utilities**	0.1	0.2	0.3
9	**Project OM&A**	4.8	(0.9)	3.9
10	**Total OM&A**	23.0	***7.5***	30.5

Notes
1 Excludes amounts captured in the Asset Service Fee (Ex. F3-2-1).

Numbers may not add due to rounding.

Table 3
OM&A Project Listing - Corporate
Projects ≥ $20M Total Project Cost (Allocated)

Line No.	Facility	Project Name	Project No.	Allocation	Category	Start Date	Final Completion Date	Total Project Cost (M$)	Partial/Devmt Release ($M)	Initial Full Release ($M)	Superceding Full Release ($M)	2020 Actual ($M)	2021 Actual ($M)	2022 Actual ($M)	2023 Actual ($M)	2024 Actual ($M)	2025 Budget ($M)	2026 Budget ($M)	2027 Plan ($M)	2028 Plan ($M)	2029 Plan ($M)	2030 Plan ($M)	2031 Plan ($M)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)
		PROJECTS NOT IN EB-2020-0290																					
1	Corporate	Finance ERP Solution	89274	Common	Sustaining- Enterprise System Modernization Projects	Jul-25	Dec-31	22.4	4.7	n/a	n/a	0.0	0.0	0.0	0.0	1.6	0.0	1.0	5.2	7.6	2.3	2.3	2.3
2		**Subtotal**						22.4				0.0	0.0	0.0	0.0	1.6	0.0	1.0	5.2	7.6	2.3	2.3	2.3

Notes:
1 Projects with expenditures during IR Term.

Table 4

OM&A Project Listing - Corporate[1]

Projects $5M - $20M Total Project Cost (Allocated)

Line No.	Facility	Project Name	Project No.	Category	Project Description	Start Date	Final Completion Date	Total Project Cost (M$)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		PROJECTS NOT IN EB-2020-0290						
1	Corporate	Demo Building 125, 302FST, 125BH, and 311SS	84381	Sustaining	Address the outdated and end of life Real Estate Facilities infrastructure at Darlington.	Mar-19	Dec-20	11.5
2	Corporate	Asset Suite 9 Upgrade	84976	Sustaining	Complete the upgrade of Asset Suite to avoid technical obsolescence and address the potential operational and cyber security risk associated with an outdated version.	Jul-20	Dec-22	7.0
3	Corporate	Nuclear East Facilities Building Demo	84401	Sustaining	Revitalize and reconfigure the Pickering site with the plan to end commercial operations in 2025.	Dec-21	May-23	6.2
4	Corporate	Phase 2 Info Protection	87251	Sustaining	Execute the discovery, requirements gathering, and procurement of cybersecurity improvements to data protection/data loss prevention controls.	Dec-23	Dec-24	5.7
5	Corporate	Darlington Road Resurfacing & Line Painting	86948	Sustaining	Develop a strategic site-wide plan to execute the required roadway repairs, resurfacing, and line painting at the Darlington site.	Oct-25	Dec-31	8.5
6		**Subtotal**						38.9

Notes:

1 Projects with expenditures during IR Term.

Numbers may not add due to rounding.

Table 5
OM&A Project Listing - Corporate
Projects < $5M Total Project Cost[1]

Line No.	Sponsoring Division	Number of Projects	Total Project Cost ($M)	Average Cost Of All Projects ($M)
	(a)	(b)	(c)	(d)
1	Digital Technology & Services	241	149.7	0.6
2	Real Estate	37	36.9	1.0
3	**Total**	278	186.6	0.7

Notes:
1 Projects with expenditures during IR Term.

Table 6
OM&A Project Listing - Corporate
Portfolio Projects (Unallocated)[1]

Line No.	Project Name	Category	Potential Start Date
	(a)	(b)	(c)
	Projects With Potential Cost >$5M and < $20M		
1	Supply Chain Enterprise Resource Planning	Sustaining	2026
	Projects With Potential Cost ≥ $20M		
2	Enterprise Asset Management	Sustaining	2026

Notes:
1 Projects with planned expenditures during the IR Term without a current approved BCS.

Table 7
OM&A Projects - Corporate
Listing of Business Case Summaries Filed[1]

Line No.	Business Case Summary (BCS) Title	Project Number	BCS Approval Date	Project Stage	BCS Status	BCS Status in EB-2020-0290
	(a)	(b)	(c)	(d)	(e)	(f)
1	ERP Finance Solution[2]	89274	Oct-25	Ongoing	Development	n/a

Notes:

1 Projects with expenditures during IR Term.

2 BCS filed in Ex. D3-1-2

ASSET SERVICE FEES

1.0 PURPOSE

This evidence describes OPG's Asset Service Fee ("ASF") methodology and explains the calculation of the proposed service fees for the IR term.

2.0 BACKGROUND

Virtually all of OPG's in-service fixed and intangible assets continue to be exclusively or near exclusively associated with specific generation facilities or groups of hydroelectric generation facilities. As in prior OPG proceedings, OPG's fixed and intangible assets used by multiple generating businesses or those within a generating business used by both regulated and unregulated operations, are not included in the rate base or the associated depreciation and amortization expense component of the revenue requirement. Instead, the corresponding generating businesses, now including the Darlington New Nuclear Program ("DNNP") facilities, are charged an ASF for the use of these assets, which are included in the respective OM&A expenses presented in this Application.

The ASF methodology used in this Application is the same as that accepted in the EB-2020-0290 OEB-approved settlement proposal and by the OEB in previous OPG applications. In its review of OPG's cost allocation methodology for this proceeding, Elenchus Research Associates ("Elenchus") has concluded that OPG's ASF approach remains reasonable given the operation of OPG's business and is consistent with the cost causality principle.[1] This conclusion is similar to that reached in prior independent expert reviews of OPG's cost allocation methodology.

The ASF methodology considers that to the extent that 90% or more of the beneficial use of a joint-use asset relates to a particular business, the related assets are fully attributed to that business. For an OPG regulated business, this means that such assets are included in the rate base.

[1] Ex. F3-1-4, Attachment 1, S. 3.5.

As discussed in Ex. A1-4-4, Darlington New Nuclear Program Limited Partnership Inc. ("DNNP LP") is entering into a lease for the DNNP facilities with OPG. DNNP LP will undertake the development, construction, and operation of the DNNP facilities, with OPG contracted to act as the project manager and operator of the facilities. The Application assumes that DNNP LP enters into the lease and associated arrangements at the end of 2025. OPG's fixed and intangible assets to be used exclusively or near exclusively for the DNNP facilities are not included in OPG or DNNP LP's rate base or associated depreciation and amortization expense component of the revenue requirement. Instead, the DNNP facilities are expected to be charged a corresponding ASF under the respective agreement between the parties.

Beginning in the IR term, asset services fees are no longer charged for the leasehold improvements at 700 University Avenue and the Wesleyville site. The ASF for the 800 Kipling Avenue site was discontinued following the site's sale in 2022.

3.0 ASSET SERVICE FEES

Asset Service Fees are computed in a cost-based manner. The costs included in the computation of the ASF, as applicable, are depreciation expense, certain operating costs, and property taxes, and a tax-adjusted return on capital to be earned by OPG on these assets.

OPG's facilities, including the DNNP facilities and excluding its wholly owned subsidiaries, are charged an ASF for the use of the following assets, which are discussed below:

- The OPG Corporate Headquarters ("CHQ") located in Oshawa, Ontario.
- Corporate Information Technology (together, "IT Assets").[2]

In addition, during the IR term, OPG includes ASFs for:

- Joint-use Renewable Generation assets which are shared by the regulated and unregulated business.
- Nuclear Isotopes Asset Usage Fee – This fee represents a fee charged by the regulated nuclear business for the use of the Darlington nuclear facility for the production of medical

[2] IT Assets include Energy Market related assets that support OPG's facilities, such as the Market Renewal Program tools implemented by OPG's Corporate & Technology Services department.

isotopes by the unregulated business. It is reflected as a credit to the regulated nuclear business.

- DNNP IT Asset Service Fees – A fee charged to the DNNP facilities for DNNP IT operational readiness projects that OPG is undertaking.

Ex. F3-2-1, Table 1 provides the ASF amounts charged by asset category to the regulated hydroelectric facilities in the years 2016-2027 and Table 2 provides the ASF amounts charged by asset category to the OPG Nuclear facilities for the years 2020-2031 and the DNNP facilities for the years 2026-2031. A summary of each asset category and the amounts for the IR term are discussed below.

OPG Corporate Headquarters ("CHQ")

OPG's CHQ is used by employees from OPG's regulated and unregulated business and is discussed further in Ex. D3-1-1 and Ex. D3-1-2. The ASF for the use of the CHQ site is computed based on an allocation of depreciation expense, operating costs related to maintaining the building, property taxes, and a tax-adjusted return on the capital invested in these assets. The building acquisition cost and subsequent renovations are included in the ASF. The costs are allocated to the regulated business based on a blend of planned OM&A costs and capital expenditures, which is the primary cost driver of Support Services costs under OPG's cost allocation methodology (Ex. F3-1-4). OPG also owns undeveloped land on the CHQ site which is not included in the ASF.

The return on capital amounts are computed using after-tax rates of return which are consistent with the proposed weighted average cost of capital rates for OPG's regulated operations as per Exhibit C1-1-1, Tables 1-5. The return on equity portion is grossed up by OPG's budgeted statutory tax rate over the IR term. The tax-adjusted rate of return is applied to the average undepreciated net book value of the assets for the respective year.

The ASF for the CHQ is shown below in Charts 1, 2, and 3:

Chart 1 – OPG Nuclear Facilities Components of CHQ ASF – 2027-2031*

CHQ	OPG Nuclear Facilities				
$M	**2027**	**2028**	**2029**	**2030**	**2031**
Depreciation Expense	3.6	3.8	4.1	4.2	4.4
Tax-adjusted Return	11.9	12.6	12.5	12.0	12.1
Other Costs	5.6	5.7	5.8	5.8	6.0
Total	**$21.1**	**$22.1**	**$22.4**	**$22.0**	**$22.6**

*Numbers may not add due to rounding

Chart 2 – DNNP Facilities Components of CHQ ASF – 2027-2031*

CHQ	DNNP Facilities				
$M	**2027**	**2028**	**2029**	**2030**	**2031**
Depreciation Expense	0.4	0.5	0.6	0.6	0.2
Tax-adjusted Return	2.1	2.5	2.4	2.5	0.9
Other Costs	0.7	0.8	0.8	0.8	0.3
Total	**$3.2**	**$3.9**	**$3.7**	**$3.9**	**$1.5**

*Numbers may not add due to rounding

Chart 3 – Regulated Hydroelectric Components of CHQ ASF – 2027*

CHQ	Regulated Hydroelectric
$M	**2027**
Depreciation Expense	0.7
Tax-adjusted Return	2.2
Other Costs	1.0
Total	**$4.0**

*Numbers may not add due to rounding

Corporate Information Technology Assets

Corporate IT assets during the IR term include computer systems and applications used throughout the enterprise. Examples include the enterprise resource planning and asset management systems, human resources and payroll enterprise systems, corporate cyber security assets, document management and archiving systems, computer network hardware and the remote access system, as well as information technology systems, applications, and

infrastructure related to generation portfolio management and related administrative functions such as transaction settlements. OPG's IT ASF capital expenditures are discussed in Ex. D3-1-1 and Ex. D3-1-2.

These assets are used by the regulated businesses and the Support Services groups that support them. The ASF for the use of IT assets is computed based on a portion of depreciation expense and a tax-adjusted return on capital. The costs are allocated to the regulated business based on the number of IT-end users which is the primary cost driver of IT related Support Services costs under OPG's cost allocation methodology (Ex. F3-1-4). The return on capital amounts are calculated in the same manner as the CHQ ASF described above.

The ASFs and associated components for IT Assets are presented below in Chart 4, 5, and 6:

Chart 4 – OPG Nuclear Facilities Components of Corporate IT ASF – 2027-2031*

Corporate IT Assets	**OPG Nuclear Facilities**				
$M	**2027**	**2028**	**2029**	**2030**	**2031**
Depreciation Expense	59.8	70.6	82.6	89.3	86.5
Tax-adjusted Return	13.6	15.8	19.6	20.2	21.8
Total	**$73.4**	**$86.3**	**$102.3**	**$109.5**	**$108.3**

*Numbers may not add due to rounding

Chart 5 – DNNP Components of Corporate IT ASF – 2027-2031*

Corporate IT Assets	**DNNP Facilities**				
$M	**2027**	**2028**	**2029**	**2030**	**2031**
Depreciation Expense	4.3	5.6	5.6	5.2	4.8
Tax-adjusted Return	1.4	1.8	1.9	1.6	1.7
Total	**$5.7**	**$7.4**	**$7.5**	**$6.9**	**$6.5**

*Numbers may not add due to rounding

Chart 6 – Regulated Hydroelectric Components of Corporate IT ASF – 2027-2031*

Corporate IT Assets	Regulated Hydroelectric
$M	**2027**
Depreciation Expense	7.0
Tax-adjusted Return	1.6
Total	**$8.5**

*Numbers may not add due to rounding

Being the single largest ASF category, a detailed calculation of the Corporate IT ASF, by above component for each of the OPG nuclear, regulated hydroelectric business and DNNP facilities, is provided in Ex F3-3-1, Table 3.

Joint-use Renewable Generation Assets

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

To the extent that 90% or more of aggregate station capacity, as measured by the Maximum Continuous Rating,[3] serviced by the joint-use asset relates to the regulated facilities, the related assets are included in rate base. Joint-use assets not passing this use test are not included in regulated rate base but are subject to the ASF's charged to the regulated and unregulated renewable generation facilities based on the relative direct base OM&A of the stations that benefit from the joint-use assets. The ASF structure is otherwise the same as that used to charge for CHQ and Corporate IT assets.

The components used to establish the ASF for Joint-use Renewable Generation Assets are presented below in Chart 7.

[3] MCR is the maximum electrical power output that can be continuously generated, provided adequate inflow is available. The unit is assumed to be operating at unity power factor and at the indicated reference gross head. MCR observes generator and turbine limitations.

Chart 7 – Regulated Hydroelectric Components of Joint Use ASF – 2027*

$M	2027
Depreciation Expense	8.3
Tax-adjusted Return	3.8
Other Costs	0.5
Total	**$12.7**

*Numbers may not add due to rounding

Nuclear Isotopes Asset Usage Fee

Beginning in 2025, Darlington reactors are expected to be utilized for the commercial production of medical isotopes such as Molybdenum-99, Yttrium-90, and Lutetium-177 by OPG's unregulated subsidiary, Laurentis Energy Partners, and Cobalt-60 by OPG. Consistent with OPG's approach to the production of the Molybdenum-99 isotope accepted by the OEB in EB-2020-0290 through the approval of a settlement proposal[4] (as outlined in EB-2020-0290, Ex. F3-1-4, Section 4.0) and validated by Elenchus in Ex. F3-1-4, Attachment 1, OPG will charge an asset usage fee for the use of the Darlington reactors by the unregulated business.[5] Neither the costs of the modifications required to be made at Darlington to enable this isotope production nor the associated ongoing operating costs are included in OPG's rate base or revenue requirement.

The components of the asset usage fee are based on the depreciation expense and the return on capital component for the applicable Darlington reactor assets to be used in the production of medical isotopes. The depreciation expense and return components are apportioned between the Nuclear generation business and the unregulated business using the relative undepreciated book value of investments into the Darlington generation assets and the respective modifications required to produce the isotopes. The after-tax rates of return used are consistent with the proposed weighted average cost of capital rates for OPG's regulated operations as per Exhibit C1-1-1, Tables 1-5. Chart 8 below reflects the components of this asset usage fee. The amounts in the table are presented as negative as they represent a

[4] Decision and Order, EB-2020-0290, November 15, 2021, Schedule A, pp. 41-43.

[5] Ex. F3-1-4, Attachment 1, S. 3.5.

recovery by the nuclear business, and therefore, a reduction in OPG's proposed nuclear revenue requirement over the IR term.

Chart 8 – Components of Nuclear Isotopes Asset Usage Fees – 2027-2031*

$M	2027	2028	2029	2030	2031
Depreciation Expense	(7.0)	(10.9)	(10.9)	(10.7)	(10.6)
Tax-adjusted Return	(13.9)	(20.9)	(20.1)	(19.1)	(18.1)
Other Costs	(1.0)	(2.8)	(4.2)	(2.8)	(2.9)
Total	**$(21.9)**	**$(34.5)**	**$(35.2)**	**$(32.6)**	**$(31.5)**

*Numbers may not add due to rounding.

Consistent with EB-2020-0290 and confirmed in the current review of OPG's cost allocation methodology, Elenchus has concluded that the isotope ASF methodology continues to reasonably align with sound cost allocation principles for the reasons set out in the previous review.[6]

DNNP Facilities Information Technology Assets

During the IR term, OPG will undertake IT projects to enable the operational readiness of DNNP facilities Unit 1 in 2030 such as DNNP's Enterprise Asset Management solution. The ASF for the exclusive or near exclusive use[7] of these assets is expected to be computed based on the depreciation expense and a tax-adjusted return on capital amount for these investments. The after-tax rates of return are consistent with the proposed weighted average cost of capital rates for DNNP facilities as per Exhibit C1-1-1, Tables 1-5. Further details on the DNNP IT assets are discussed in Ex. D3-1-1 and Ex. D3-1-2. The ASFs and associated components for DNNP IT Assets for the years 2027-2031 are presented below in Chart 9:

[6] Ex. F3-1-4, Attachment 1, S. 3.5.

[7] As DNNP facilities unit 1 approaches commercial operations, OPG and DNNP LP will assess the extent to which any of the assets included in the rate base for OPG's nuclear facilities should be considered joint-use assets amongst the combined nuclear facilities and where material, implement additional asset service fee mechanisms in subsequent applications. At the time of this Application, no such material joint-use assets have been identified.

Chart 9 – Components of DNNP Facilities IT Asset Service Fee – 2027-2031*

$M	2027	2028	2029	2030	2031
Depreciation Expense	-	-	-	5.5	27.2
Tax-adjusted Return	-	-	-	3.0	14.2
Total	**-**	**-**	**-**	**$8.5**	**$41.4**

*Numbers may not add due to rounding

As it relates to the figures in Chart 9, Elenchus has concluded that OPG's treatment of the ASF associated directly with the DNNP facilities is reasonable, consistent with the overall methodology of an ASF and ensures proper attribution of the underlying costs.[8]

A detailed calculation of the DNNP IT Assets by component is included in Ex. F3-3-1, Table 2.

[8] Ex. F3-1-4, Attachment 1, S. 3.5.

Numbers may not add due to rounding.

Table 1

Corporate Asset Service Fees - Regulated Hydroelectric ($M)

Line No.	Business Unit	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	**Corporate Information Technology Assets**	2.7	3.0	3.4	4.4	3.8	4.5	5.9	5.6	5.8	6.8	8.4	8.5
2	**Kipling Ave. Office, Wesleyville Property & 700 University Ave. Office**	3.2	2.9	2.5	3.5	2.3	2.2	2.0	1.1	1.3	0.5	0.3	0.0
3	**OPG Corporate Headquarters**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	1.8	3.1	4.0
4	**Joint-use Renewable Generation Assets**	0.9	1.6	1.3	1.2	2.6	3.9	5.8	8.3	8.3	9.5	9.6	12.7
5	**Total**	6.8	7.5	7.1	9.1	8.6	10.6	13.7	15.0	16.0	18.7	21.5	25.2

Numbers may not add due to rounding.

Updated: 2026-03-10
EB-2025-0297
Exhibit F3
Tab 2
Schedule 1
Table 2

Table 2
Corporate Asset Service Fees - Combined Nuclear ($M)

Line No.	Business Unit	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	OPG Nuclear Facilities												
1	**Corporate Information Technology Assets**	48.2	58.2	65.4	67.5	70.1	72.7	76.5	73.4	86.3	102.3	109.5	108.3
2	**Kipling Ave. Office, Wesleyville Property & 700 University Ave. Office**	7.4	6.8	5.6	5.6	5.1	2.7	1.8	0.0	0.0	0.0	0.0	0.0
3	**OPG Corporate Headquarters**	0.0	0.0	0.0	1.2	1.9	10.4	16.6	21.1	22.1	22.4	22.0	22.6
4	**Nuclear Isotopes Asset Usage Fee**	0.0	0.0	0.0	0.0	0.0	(0.2)	(1.7)	(21.9)	(34.5)	(35.2)	(32.6)	(31.5)
5	**Total OPG Nuclear Facilities**	55.6	65.0	71.1	74.3	77.1	85.6	93.3	72.7	73.9	89.5	99.0	99.4
	DNNP Facilities												
6	**DNNP Information Technology Assets**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.5	41.4
7	**Corporate Information Technology Assets**	0.0	0.0	0.0	0.0	0.0	0.0	5.0	5.7	7.4	7.5	6.9	6.5
8	**OPG Corporate Headquarters**	0.0	0.0	0.0	0.0	0.0	0.0	1.9	3.2	3.9	3.7	3.9	1.5
9	**Total DNNP Facilities**	0.0	0.0	0.0	0.0	0.0	0.0	6.9	8.9	11.2	11.2	19.3	49.4

Numbers may not add due to rounding.

Table 3
Nuclear Fuel Service Fee - DNNP Facilities ($M)

Line No.	Cost Item	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)
1	**Depreciation**[1]	0.0	0.0	0.0	0.3	1.5
2	**Cost of Capital**					
3	**DNNP Fuel Rate Base**[1]	75.0	114.0	104.6	87.2	168.2
4	**Cost of Debt**	0.0	0.0	0.0	0.0	0.0
5	**Return On Equity** [2]	6.8	10.4	9.5	7.9	15.3
6	**Total Cost of Capital** (Line 4 + Line 5)	6.8	10.4	9.5	7.9	15.3
7	**Tax gross up** (Line 5 * (25% / (1 - 25%))	2.3	3.5	3.2	2.6	5.1
8	**ASF Tax-Adjusted Return** (Line 6 + Line 7)	9.1	13.8	12.7	10.6	20.4
9	**Nuclear Fuel Expense** [3]	0.0	0.0	0.0	7.2	27.8
10	**Total DNNP Facilities Fuel Service Fee** (Line 1 + Line 8 + Line 9)	9.1	13.8	12.7	18.1	49.8

Notes:
1

Line No.	Rate Base Item	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)
1	Gross Plant at Cost Opening Balance (Line 3 of preceeding year)	0.0	0.0	0.0	0.0	78.1
2	In- Service Additions- DNNP Capitalized Fuel (Ex D 2-1-3, Table 4b, Line 77)	0.0	0.0	0.0	78.1	25.0
3	Gross Plant at Cost Ending Balance (Line 1 + Line 2)	0.0	0.0	0.0	78.1	103.2
4	Accumulated Depreciation and Amortization Opening Balance	0.0	0.0	0.0	0.0	0.3
5	Depreciation on DNNP New Fuel (60 year depreciation life)*	0.0	0.0	0.0	0.3	1.5
6	Accumulated Depreciation and Amortization Ending Balance	0.0	0.0	0.0	0.3	1.8
7	Net Plant Opening Balance (Line 1 - Line 4)	0.0	0.0	0.0	0.0	77.8
8	Net Plant Change (Line 2 -Line 5)	0.0	0.0	0.0	77.8	23.5
9	Net Plant Ending Balance (Line 3 - Line 6)	0.0	0.0	0.0	77.8	101.4
10	Net Plant - Rate Base (line 7 + line 9)/2*	0.0	0.0	0.0	16.1	89.6
11	Opening Fuel Inventory (Ex. B1-1-1, Chart 2, Line 20)	45.4	104.7	123.3	86.0	56.2
12	Ending Fuel Inventory (Ex. B1-1-1, Chart 2, Line 20)	104.7	123.3	86.0	56.2	101.0
13	Fuel Inventory- Rate Base (Line 11 + Line 12)/2	75.0	114.0	104.6	71.1	78.6
14	Total Rate Base (Line 10 + Line 13)	75.0	114.0	104.6	87.2	168.2

* 2030 weighted for unit 1 in-service date of October 17, 2030 (2.5 months); (Line 7 + Line 9 - Line 2)/2 + Line 2 x 2.5 months/12 months

2 Line 3 x Ex. C1-1-1 Tables 14 -18, col. (b), Line 4 x Ex. C1-1-1 Tables 14 -18, col. (c), Line 4

3 Ex. F2-5-1, Table 1b, Line 5

4 All components of the DNNP Fuel Service Fee is 100% attributable to the DNNP Facilities

Numbers may not add due to rounding.

Table 4
IT Asset Service Fee - DNNP Facilities ($M)

Line No.	Cost Item	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)
1	**Depreciation**[1]	0.0	0.0	0.0	5.5	27.2
2	**Cost of Capital**					
3	**Total Rate Base**[1]	0.0	0.0	0.0	24.9	116.8
4	**Cost of Debt**	0.0	0.0	0.0	0.0	0.0
5	**Return On Equity** [2]	0.0	0.0	0.0	2.3	10.6
6	**Total Cost of Capital** (Line 4 + Line 5)	0.0	0.0	0.0	2.3	10.6
7	**Tax gross up** (Line 5 * (25% / (1 - 25%))	0.0	0.0	0.0	0.8	3.5
8	**ASF Tax-Adjusted Return** (Line 6 + Line 7)	0.0	0.0	0.0	3.0	14.2
9	**Total DNNP Facilities IT Asset Service Fee** (Line 1 + Line 8)	0.0	0.0	0.0	8.5	41.4

Notes:
1

Line No.	Rate Base Item	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)
1	Gross Plant at Cost Opening Balance	0.0	0.0	0.0	0.0	132.6
2	In- Service Additions- DNNP IT Capital (D3-1-2, Table 5b, Line 17)	0.0	0.0	0.0	132.6	6.5
3	Gross Plant at Cost Ending Balance (Line 1 + Line 2)	0.0	0.0	0.0	132.6	139.2
4	Accumulated Depreciation and Amortization Opening Balance	0.0	0.0	0.0	0.0	5.5
5	Depreciation on DNNP IT Assets (5 year depreciation life)*				5.5	27.2
6	Accumulated Depreciation and Amortization Ending Balance	0.0	0.0	0.0	5.5	32.7
7	Net Plant Opening Balance (Line 1 - Line 4)	0.0	0.0	0.0	0.0	127.1
8	Net Plant Change (Line 2 - Line 5)	0.0	0.0	0.0	127.1	(20.7)
9	Net Plant Ending Balance (Line 3 - Line 6)	0.0	0.0	0.0	127.1	106.5
10	Net Plant - Rate Base (Line 7 + Line 9)/2*	0.0	0.0	0.0	24.9	116.8

* 2030 weighted for unit 1 in-service date of October 17, 2030 (2.5 months); (Line 7 + Line 9 - Line 2)/2 + Line 2 x 2.5 months/12 months

2 Line 3 x Ex. C1-1-1 Tables 14 -18, col. (b), Line 4 x Ex. C1-1-1 Tables 14 -18, col. (c), Line 4

3 All components of the DNNP Fuel Service Fee is 100% attributable to the DNNP Facilities

Numbers may not add due to rounding.

Table 5
Corporate Information Technology Assets - OPG ($M)

Line No.	Cost Item	OPG Nuclear Facilities					Darlington New Nuclear Program (DNNP) Facilities					Regulated Hydroelectric
		2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan	2027 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**Total Depreciation**	74.2	88.6	103.3	111.3	106.8	74.2	88.6	103.3	111.3	106.8	74.2
2	**% Allocated**	81%	80%	80%	80%	81%	6%	6%	5%	5%	5%	9%
3	**ASF Depreciation (Line 1 x Line 2)**	59.8	70.6	82.6	89.3	86.5	4.3	5.6	5.6	5.2	4.8	7.0
4	**Cost of Capital**											
5	**Total Rate Base**	197.6	229.6	282.8	289.7	309.5	197.6	229.6	282.8	289.7	309.5	197.6
6	**Cost of Debt**[1]	4.4	5.3	6.7	6.9	7.4	0.0	0.0	0.0	0.0	0.0	4.4
7	**Return On Equity**[2]	9.4	10.9	13.4	13.7	14.7	18.0	20.9	25.8	26.4	28.2	9.4
8	**Total Cost of Capital (Line 6 + Line 7)**	13.7	16.1	20.0	20.6	22.1	18.0	20.9	25.8	26.4	28.2	13.7
9	**ASF Cost of Capital (Line 2 x Line 8)**	11.1	12.9	16.0	16.6	17.9	1.0	1.3	1.4	1.2	1.3	1.3
10	**Tax gross up (Line 7 * Line 2 * (25% / (1-25%)))**	2.5	2.9	3.6	3.7	4.0	0.3	0.4	0.5	0.4	0.4	0.3
11	**ASF Tax-Adjusted Return (Line 9 + Line 10)**	13.6	15.8	19.6	20.2	21.8	1.4	1.8	1.9	1.6	1.7	1.6
12	**Total Asset Service Fee (Line 3 + Line 11)**	73.4	86.3	102.3	109.5	108.3	5.7	7.4	7.5	6.9	6.5	8.5

Notes:

1 Line 5 x Ex. C1-1-1 Tables 1-5, col. (c), Line 4 x Ex. C1-1-1 Tables 1-5, col. (b), Line 4

2 Line 5 x Ex. C1-1-1 Tables 1-5, col. (c), Line 5a x Ex. C1-1-1 Tables 1-5, col. (b), Line 5b

COMPARISON OF ASSET SERVICE FEES

1.0 PURPOSE

This evidence presents the period-over-period changes in the Asset Service Fees ("ASF") charged to the regulated business.

2.0 OVERVIEW

This evidence supports the ASF set out in Ex. F3-2-2, Tables 1, 2a, and 2b and provides a comparison of year over year for the regulated business and actual to OEB approved for the nuclear business.

3.0 TERM-OVER-TERM CHANGES – IR TERM, REGULATED HYDROELECTRIC

2027 Plan versus 2026 Budget

The ASF in the 2027 Plan is $25.2M, which is $3.7M higher than the 2026 Budget amount of $21.5M. The increase is primarily due to the in-service of the Kenora Work Centre Building (Ex. D1-1-2, Table 2b) and the relocated Renewable Generation Training Centre in 2027 (Ex. D3-1-2 Table 2e). The Kenora Work Centre Building supports staff servicing five Western Region stations and the relocation of the Renewable Generation Training Centre is required following OPG's exit of the 800 Kipling Avenue lease.

4.0 PERIOD-OVER-PERIOD CHANGES – BRIDGE YEARS, REGULATED HYDROELECTRIC

2026 Budget versus 2025 Budget

The ASF in the 2026 Budget is $21.5M, which is $2.8M higher than the 2025 Budget of $18.7M. The increase is primarily due to the full year impact of the Company's Integrated HR Service Delivery project (discussed in Ex. D3-1-2, Section 3.3). The increase is also driven by the full year of operation of the OPG Corporate Headquarters ("CHQ"), Ex. D3-1-1.

2025 Budget versus 2024 Actual

The ASF in the 2025 Budget is $18.7M, which is $2.7M higher than the 2024 Actual of $16.0M. The increase is primarily due to the in-service of CHQ and the Integrated HR Service Delivery project part way through 2025. In addition, Renewable Generation joint-use assets increased due to the in-service of a Supervisory Control and Data Acquisition software system to monitor and control generating assets and auxiliary equipment.

2024 Actual versus 2023 Actual

The ASFs are relatively stable in the 2024 actual compared to the 2023 actual.

2023 Actual versus 2022 Actual

The ASFs are relatively stable in the 2023 actual compared to the 2022 actual.

2022 Actual versus 2021 Actual

The ASF Actual in 2022 is $13.7M, which is $3.1M higher than the 2021 Actual of $10.6M. This increase is primarily due to the full year impact of the Asset Suite 9 (“AS9”) upgrade that was placed in-service in 2021, and a further in-service in 2022 (discussed in Ex. D3-1-2, Section 3). The increase was also due to higher asset service fees for joint-use projects supporting RG operations.

2021 Actual versus 2020 Actual

The ASF Actual in 2021 is $10.6M, which is $1.9M higher than the 2020 Actual of $8.6M. This increase is partially due to the initial in-service of the AS9 upgrade project at the end of 2021. In addition, hydroelectric Joint-use assets increased primarily due to Renewable Generation’s operational information systems upgrade.

2020 Actual vs 2019 Actual

The ASFs are relatively stable in the 2020 actual compared to the 2019 actual.

2019 Actual versus 2018 Actual

The ASF Actual in 2019 is $9.1M, which is $2.0M higher than the 2018 Actual of $7.1M. This increase is primarily due to the in-service of the Company's IT and Real Estate assets driven by the Network Segmentation project and the 700 University Avenue Workplace Transformation project.

2018 Actual vs 2017 Actual

The ASFs are relatively stable in the 2018 actual compared to the 2017 actual.

2017 Actual vs 2016 Actual

The ASFs are relatively stable in the 2017 actual compared to the 2016 actual.

5.0 PERIOD-OVER-PERIOD CHANGES – IR TERM, OPG NUCLEAR FACILITIES

2027 Plan vs 2026 Budget

The ASF in the 2027 Plan is $72.7M, which is $20.6M lower than the 2026 Budget amount of $93.3M. The decrease is primarily due to the increase in the service fee charged to the unregulated business reflecting the forecast in-service of additional modifications on the Darlington reactors to produce medical isotopes (discussed in Ex. F3-2-1).

2028 Plan versus 2027 Plan

The ASFs are relatively stable in the 2028 Plan compared to the 2027 Plan.

2029 Plan versus 2028 Plan

The ASF in the 2029 Plan is $89.5M, which is $15.6M higher than the 2028 Plan amount of $73.9M. The increase is primarily due to the partial planned in-service of the Supply Chain ERP Solution project, the full year impact of the planned in-service of the Finance ERP Solution project in 2028 and further planned in-service of the Finance ERP Solution project in 2029.

2030 Plan versus 2029 Plan

The ASF in the 2030 Plan is $99.0M, which is $9.5M higher than the 2029 Plan amount of $89.5M. The increase is primarily due to the planned partial in-service of the Company's Enterprise Asset Management project, Supply Chain ERP Solution project, and the remaining in-service of the Finance ERP Solution project.

2031 Plan versus 2030 Plan

The ASFs are relatively stable in the 2031 Plan compared to the 2030 Plan.

6.0 PERIOD-OVER-PERIOD CHANGES – BRIDGE YEARS, NUCLEAR FACILITIES

2026 Budget versus 2026 OEB-Approved

The ASF in the 2026 Budget is $93.3M, which is $28.7M higher than the 2026 OEB-approved amount of $64.6M. The main driver is higher than planned in-service for the AS9 upgrade project and new projects since EB-2020-0290 such as the Integrated HR Service Delivery cloud platform, Finance ERP Solution, and Enterprise Asset Management projects (discussed in Ex. D3-1-2).

2026 Budget versus 2025 Budget

The ASFs are relatively stable in the 2026 budget compared to the 2025 budget.

2025 Budget versus 2025 OEB-Approved

The ASF in the 2025 Budget is $85.6M, which is $16.5M higher than the 2025 OEB-approved amount of $69.0M. The main driver is higher than planned in-service for the AS9 upgrade project and new projects since EB-2020-0290 such as the Integrated HR Service Delivery cloud platform, and Enterprise Service Management projects (discussed in Ex. D3-1-2).

2025 Budget versus 2024 Actual

The ASF in the 2025 Budget is $85.6M, which is $8.5M higher than the 2024 Actual amount of $77.1M. The increase is primarily due to the in-service of CHQ part way in 2025.

7.0 PERIOD-OVER-PERIOD CHANGES – HISTORICAL YEARS, NUCLEAR FACILITIES

2024 Actual versus 2024 OEB-Approved

The Actual ASF in 2024 is $77.1M, which is $12.8M higher than the 2024 OEB-approved amount of $64.3M. The increase is primarily due to higher in-service from the AS9 upgrade project and new projects since EB-2020-0290 such as the Data Center Migration and Enterprise Service Management projects.

2024 Actual versus 2023 Actual

The ASFs are relatively stable in the 2024 actual compared to the 2023 actual.

2023 Actual versus 2023 OEB-Approved

The Actual ASF in 2023 is $74.3M, which is $20.1M higher than the 2023 OEB-approved amount of $54.3M. The increase is primarily due to higher in-service from the AS9 upgrade project and new projects since EB-2020-0290 such as the Data Center Migration and Enterprise Service Management projects.

2023 Actual versus 2022 Actual

The ASFs are relatively stable in the 2023 actual compared to the 2022 actual.

2022 Actual versus 2022 OEB-Approved

The Actual ASF in 2022 is $71.1M, which is $20.4M higher than the 2022 OEB-approved amount of $50.7M. The increase is primarily due to higher in-service for new projects since EB-2020-0290 such as the Data Center Migration and the Equipment Status Monitoring II Lifecycle projects.

~~2~~2022 Actual versus 2021 Actual

The ASFs are relatively stable in the 2022 actual compared to the 2021 actual.

2021 Actual versus 2021 OEB-Approved Budget

The Actual ASF in 2021 is $65.0M, which is $44.3M higher than the 2021 OEB-approved amount of $20.8M. The main driver is higher than planned in-service as a result of the advancement of the IT digital strategy underpinning the EB-2020-0290 application.

2021 Actual versus 2020 Actual

The Actual ASF in 2021 is $65.0M, which is $9.4M higher than the 2020 actuals of $55.6M. The increase is primarily due to higher in-service for the Reimagine project and Reimagine 2.0 project (see Ex. D3-1-2, Table 2a).

2020 Actual versus 2020 OEB-Approved

The Actual ASF in 2020 is $55.6M, which is $32.7M higher than the 2020 OEB-approved amount of $22.9M. The main driver is higher than planned in-service as a result of the advancement of the IT digital strategy underpinning the EB-2020-0290 application.

8.0 PERIOD-OVER-PERIOD CHANGES - IR TERM, DNNP FACILITIES

2027 Plan vs 2026 Budget

The ASF in the 2027 Plan is $8.9M, which is $2.0M higher than the 2026 Budget amount of $6.9M. The increase is primarily due to the increase in the in-service of IT portfolio projects with smaller individual in-service amounts.

2028 Plan vs 2027 Plan

The ASF in the 2028 Plan is $11.2M, which is $2.4M higher than the 2027 Plan amount of $8.9M. The increase is primarily due to the partial planned in-service of the Finance ERP Solution project in 2028.

2029 Plan vs 2028 Plan

The ASF in the 2029 Plan is $11.2M, which is comparable to the 2028 Plan amount of $11.2M.

2030 Plan versus 2029 Plan

The ASF in the 2030 Plan is $19.3M, which is $8.1M higher than the 2029 Plan amount of $11.2M. The increase is primarily due to the partial planned in-service of the Operational Readiness Technology projects, including the DNNP Enterprise Asset Management project discussed in Ex. D3-1-1 and described in Ex. D3-1-2.

2031 Plan versus 2030 Plan

The ASF in the 2031 Plan is $49.4M, which is $30.0M higher than the 2030 Plan amount of $19.3M. The increase is primarily due to the full year impact of the DNNP Operational Readiness Technology projects including the DNNP Enterprise Asset Management project discussed in Ex. D3-1-1 and described in Ex. D3-1-2.

Numbers may not add due to rounding.

Filed: 2025-12-12
EB-2025-0297
Exhibit F3
Tab 2
Schedule 2
Table 1

Table 1
Comparison of Corporate Asset Service Fees - Regulated Hydroelectric ($M)

Line No.	Business Unit	2016 Actual	(c)-(a) Change	2017 Actual	(e)-(c) Change	2018 Actual	(g)-(e) Change	2019 Actual	(i)-(g) Change	2020 Actual	(k)-(i) Change	2021 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**Corporate Information Technology Assets**	2.7	0.3	3.0	0.3	3.4	1.0	4.4	(0.6)	3.8	0.8	4.5
2	**Kipling Ave. Office, Wesleyville Property & 700 University Ave. Office**	3.2	(0.3)	2.9	(0.4)	2.5	1.0	3.5	(1.2)	2.3	(0.1)	2.2
3	**OPG Corporate Headquarters**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	**Joint-use Renewable Generation Assets**	0.9	0.7	1.6	(0.3)	1.3	(0.0)	1.2	1.3	2.6	1.3	3.9
5	**Total**	6.8	0.7	7.5	(0.4)	7.1	***2.0***	9.1	(0.5)	8.6	***1.9***	10.6

Line No.	Business Unit	2021 Actual	(c)-(a) Change	2022 Actual	(e)-(c) Change	2023 Actual	(g)-(e) Change	2024 Actual	(i)-(g) Change	2025 Budget	(k)-(i) Change	2026 Budget
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
6	**Corporate Information Technology Assets**	4.5	1.4	5.9	(0.3)	5.6	0.2	5.8	1.1	6.8	1.6	8.4
7	**Kipling Ave. Office, Wesleyville Property & 700 University Ave. Office**	2.2	(0.2)	2.0	(0.9)	1.1	0.3	1.3	(0.8)	0.5	(0.2)	0.3
8	**OPG Corporate Headquarters**	0.0	0.0	0.0	0.0	0.0	0.5	0.5	1.3	1.8	1.3	3.1
9	**Joint-use Renewable Generation Assets**	3.9	1.9	5.8	2.5	8.3	0.0	8.3	1.2	9.5	0.0	9.6
10	**Total**	10.6	***3.1***	13.7	1.3	15.0	1.0	16.0	***2.7***	18.7	***2.8***	21.5

Line No.	Business Unit	2026 Budget	(c)-(a) Change	2027 Plan
		(a)	(b)	(c)
11	**Corporate Information Technology Assets**	8.4	0.1	8.5
12	**Kipling Ave. Office, Wesleyville Property & 700 University Ave. Office**	0.3	(0.3)	0.0
13	**OPG Corporate Headquarters**	3.1	0.9	4.0
14	**Joint-use Renewable Generation Assets**	9.6	3.1	12.7
15	**Total**	21.5	***3.7***	25.2

Numbers may not add due to rounding.

Filed: 2025-12-12
EB-2025-0297
Exhibit F3
Tab 2
Schedule 2
Table 2a

Table 2a
Comparison of Corporate Asset Service Fees - OPG Nuclear Facilities ($M)

Line No.	Business Unit	2020 OEB Approved	(c)-(a) Change	2020 Actual	(g)-(c) Change	2021 OEB Approved	(g)-(e) Change	2021 Actual	(k)-(g) Change	2022 OEB Approved	(k)-(i) Change	2022 Actual	(m)-(k) Change	2023 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	OPG Nuclear Facilities													
1	**Corporate Information Technology Assets**	19.4	28.8	48.2	10.0	17.2	41.0	58.2	7.2	48.0	17.4	65.4	2.1	67.5
2	**Kipling Ave. Office, Wesleyville Property & 700 University Ave. Office**	3.5	3.9	7.4	(0.6)	3.5	3.3	6.8	(1.2)	5.0	0.6	5.6	(0.0)	5.6
3	**OPG Corporate Headquarters**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.2	1.2
4	**Nuclear Isotopes Asset Usage Fee**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(2.3)	2.3	0.0	0.0	0.0
5	**Total OPG Nuclear Facilities before adjustments**	22.9	***32.7***	55.6	***9.4***	20.8	***44.3***	65.0	6.0	50.7	***20.4***	71.1	3.3	74.3
6	**OEB/Settlement Adjustments[1,2]**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(1.5)	1.5	0.0	0.0	0.0
7	**Total OPG Nuclear Facilities including adjustments**	22.9	32.7	55.6	9.4	20.8	44.3	65.0	6.0	49.2	21.9	71.1	3.3	74.3

Line No.	Business Unit	2023 OEB Approved	(c)-(a) Change	2023 Actual	(g)-(c) Change	2024 OEB Approved	(g)-(e) Change	2024 Actual	(k)-(g) Change	2025 OEB Approved	(k)-(i) Change	2025 Budget	(m)-(k) Change	2026 Budget
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	OPG Nuclear Facilities													
8	**Corporate Information Technology Assets**	51.8	15.7	67.5	2.5	54.0	16.1	70.1	2.6	53.8	18.9	72.7	3.9	76.5
9	**Kipling Ave. Office, Wesleyville Property & 700 University Ave. Office**	4.6	1.0	5.6	(0.5)	4.4	0.8	5.1	(2.4)	2.8	(0.1)	2.7	(0.9)	1.8
10	**OPG Corporate Headquarters**	0.0	1.2	1.2	0.7	8.0	(6.0)	1.9	8.5	16.0	(5.6)	10.4	6.2	16.6
11	**Nuclear Isotopes Asset Usage Fee**	(2.2)	2.2	0.0	0.0	(2.0)	2.0	0.0	(0.2)	(3.5)	3.3	(0.2)	(1.5)	(1.7)
12	**Total OPG Nuclear Facilities before adjustments**	54.3	***20.1***	74.3	2.8	64.3	***12.8***	77.1	***8.5***	69.0	***16.5***	85.6	7.7	93.3
13	**OEB/Settlement Adjustments[1,2]**	(1.6)	1.6	0.0	0.0	(9.7)	9.7	0.0	0.0	(17.6)	17.6	0.0	0.0	0.0
14	**Total OPG Nuclear Facilities including adjustments**	52.6	21.7	74.3	2.8	54.6	22.5	77.1	8.5	51.4	34.1	85.6	7.7	93.3

Notes:
1 Per EB-2020-0290 OEB Decision and Order, Schedule A, p. 25, OM&A costs are reduced by 3% per year over the 2022-2026 period.
2 OEB approved values reflect settlement adjustments for Clarington Corporate Campus (2024-2026) per p. 25 of the Settlement Proposal.

Numbers may not add due to rounding.

Updated: 2026-03-10
EB-2025-0297
Exhibit F3
Tab 2
Schedule 2
Table 2b

Table 2b
Comparison of Corporate Asset Service Fees - Combined Nuclear ($M)

Line No.	Business Unit	2026 OEB Approved	(c)-(a) Change	2026 Budget	(e)-(c) Change	2027 Plan	(g)-(e) Change	2028 Plan	(i)-(g) Change	2029 Plan	(k)-(i) Change	2030 Plan	(m)-(k) Change	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	OPG Nuclear Facilities													
1	**Corporate Information Technology Assets**	51.3	25.3	76.5	(3.1)	73.4	12.9	86.3	15.9	102.3	7.3	109.5	(1.2)	108.3
2	**Kipling Ave. Office, Wesleyville Property & 700 University Ave. Office**	1.3	0.5	1.8	(1.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	**OPG Corporate Headquarters**	15.3	1.4	16.6	4.5	21.1	1.0	22.1	0.4	22.4	(0.4)	22.0	0.6	22.6
4	**Nuclear Isotopes Asset Usage Fee**	(3.2)	1.6	(1.7)	(20.2)	(21.9)	(12.6)	(34.5)	(0.7)	(35.2)	2.6	(32.6)	1.1	(31.5)
5	**Total OPG Nuclear Facilities before adjustments**	64.6	***28.7***	93.3	***(20.6)***	72.7	1.2	73.9	***15.6***	89.5	***9.5***	99.0	0.5	99.4
6	**OEB/Settlement Adjustments[1,2]**	(16.7)	16.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	**Total OPG Nuclear Facilities including adjustments**	47.8	45.4	93.3	(20.6)	72.7	1.2	73.9	15.6	89.5	9.5	99.0	0.5	99.4
	DNNP Facilities													
8	**DNNP Information Technology Assets**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.5	8.5	32.8	41.4
9	**Corporate Information Technology Assets**	0.0	5.0	5.0	0.7	5.7	1.7	7.4	0.2	7.5	(0.7)	6.9	(0.3)	6.5
10	**OPG Corporate Headquarters**	0.0	1.9	1.9	1.3	3.2	0.7	3.9	(0.2)	3.7	0.2	3.9	(2.5)	1.5
11	**Total DNNP Facilities**	0.0	6.9	6.9	***2.0***	8.9	***2.4***	11.2	0.0	11.2	***8.1***	19.3	***30.0***	49.4

Notes:
1 OEB approved values reflect settlement adjustments for Clarington Corporate Campus (2024-2026) per p. 25 of the Settlement Proposal.
2 Per EB-2020-0290 OEB Decision and Order, Schedule A, p. 25, OM&A costs are reduced by 3% per year over the 2022-2026 period.

TAXES

1.0 PURPOSE

This evidence describes the basis for income taxes, commodity taxes and property taxes, and presents the regulatory income tax expense and the property tax expense for OPG's regulated hydroelectric facilities and nuclear facilities, and the Darlington New Nuclear Program ("DNNP") facilities. It also discusses the proposed federal Clean Electricity Investment Tax Credits ("CEITCs").

2.0 OVERVIEW

The forecast regulatory income tax expense and property tax expense for OPG's regulated hydroelectric facilities is $27.3M and $2.1M, respectively, for 2027, as presented in Ex. F4-2-1, Table 1. The forecast regulatory income tax expense are also presented for 2028-2031, as they underpin the calculation of the custom capital factor for the annual adjustment mechanism for the hydroelectric payment amounts under the proposed price-cap index Custom IR framework. These amounts are $70.3M for 2028, $87.6M for 2029, $101.6M for 2030, and $110.7M for 2031, as presented in Ex. F4-2-1, Table 3b.[1] The proposed Custom IR framework for the regulated hydroelectric facilities is described in Ex. A1-3-2.

As presented in Ex. F4-2-1, Table 2, the forecast regulatory income tax recovery for OPG's nuclear facilities is -$16.6M for each of the years from 2027 to 2031, while the forecast property tax expense is $14.0M for 2027, $14.2M for 2028, $14.5M for 2029, $14.8M for 2030, and $15.0M for 2031. As presented in F4-2-1, Table 2a, the forecast regulatory income tax expense for the DNNP facilities is $0.0M for each of the years from 2027-2031, and the forecast property tax expense is $0.0M for 2027 to 2029, $0.8M for 2030, and $3.7M for 2031. The regulatory tax loss carried forward to the next IR term is $1,808.8M for OPG's nuclear facilities and $575.1M for the DNNP facilities (attributable to taxable partners).

[1] Income taxes for the regulated hydroelectric facilities are included within the calculation of the incremental capital funding requirement used to derive the proposed C-factor on the basis that they are predominantly (though not entirely) capital-related.

For all income tax matters regarding OPG's prescribed facilities addressed in this exhibit, the same principles and methodology have been applied as in EB-2020-0290. Income tax expense and property tax expense included in the determination of Bruce Lease net revenues are discussed in Ex. G2-2-1.

As discussed in Ex. A1-4-4, DNNP LP is an Ontario limited partnership that was formed to facilitate investment in the DNNP. In September 2025, the Canada Growth Fund Inc. and Building Ontario Fund entered into an equity commitment agreement, which upon contribution that is subject to satisfaction of certain conditions, will grant the parties minority ownership rights in DNNP LP. DNNP LP is expected to be a newly prescribed generator for the purposes of section 78.1 of the Act.[2]

For the purposes of calculating income taxes for the DNNP facilities, it is assumed that these assets will be transferred on December 31, 2025 and are presented separately beginning with the 2026 taxation year. Income taxes for OPG's prescribed facilities include the impacts of the DNNP facilities through 2024. Regulatory income taxes are calculated separately for DNNP LP beginning with the 2026 year.

Consistent with OPG's 2025-2031 Business Plan, the Application does not reflect potential impacts from the 2025 Federal Budget introduced on November 4, 2025. These impacts include the reissuance of draft legislation to provide a 15% refundable CEITC with respect to investments in certain clean electricity property and extending the accelerated investment incentive property ("AIIP") program that provides the ability to claim higher CCA deductions, among others.

If legislated, the revenue requirement impacts of the CEITCs on OPG's prescribed facilities would be captured in the proposed Clean Electricity ITC Variance Account (OPG), to the extent they are not captured in another existing account such as the Capacity Refurbishment

[2] Pursuant to s.78.1 of the *Ontario Energy Board Act, 1998* and section 8 of O. Reg. 53/05, DNNP LP is expected to be prescribed subject to an order made by the OEB in which it specifies that certain conditions have been met. The Application expects these conditions to be met on December 31, 2025.

Variance Account ("CRVA") or the Nuclear Development Variance Account ("NDVA"). For the DNNP facilities, these impacts will be captured in the proposed Clean Electricity ITC Variance Account (DNNP), to the extent they are not captured in an existing account such as the Darlington New Nuclear Project Variance Account re Development ("DNNPVARD").

Revenue requirement impacts of extending the AIIP during the bridge years and IR term as it relates to OPG's prescribed facilities will continue to be captured in the Income & Other Taxes Variance Account (OPG), to the extent not captured in another existing account such as the CRVA or NDVA. For the DNNP facilities, these impacts during the IR term will be captured in the proposed Income & Other Taxes Variance Account (DNNP), to the extent not captured in an existing account such as the DNNPVARD. Refer to Ex. H1-1-1 for further discussion regarding these variance accounts. See Section 3.2.1 for further discussion on AIIP rules and Section 3.5 for further discussion on the CEITCs.

Beyond the discussion of the Federal Budget 2025, the layout of this evidence is largely unchanged from prior applications, with the exception of Section 3.2.9 that addresses the excessive interest and financing expenses limitation ("EIFEL") rules established by Bill C-59, the Fall Economic Statement Implementation Act, 2023 ("Bill C-59"), which can limit tax deductible interest expense for taxation years beginning on or after October 1, 2023.

Section 3.4 addresses the utilization of scientific research and experimental development ("SR&ED") investment tax credits ("ITCs") for the regulated hydroelectric business as of the effective date of the payment amounts order in this proceeding, as directed by the OEB.[3]

3.1 Calculation of Regulatory Income Tax Expense

Under the *Electricity Act, 1998,* OPG is required to make payments in lieu of corporate income taxes to the Ontario Electricity Financial Corporation ("OEFC") and to file federal and provincial income tax returns with the Ontario Ministry of Finance. The tax payments are calculated in

[3] In its Decision and Order in EB-2016-0152, the OEB stated that "OPG's next application should consider the utilization of SR&ED ITCs and explain its proposal" (p. 88). Since OPG did not file a hydroelectric payment amounts application in EB-2020-0290, details regarding the proposed treatment of the regulated hydroelectric SR&ED ITCs are provided in this proceeding.

accordance with the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by the *Electricity Act, 1998* and related regulations. This effectively results in OPG paying taxes similar to what would be imposed under federal and Ontario tax legislation.

Under Canadian tax laws, partnerships such as DNNP LP do not pay income taxes; instead, each partner is required to include their share of the partnership taxable income or loss in their tax return. In this Application, regulatory income taxes for the DNNP facilities have been calculated, on a standalone basis, using the same income tax requirements that underpin the regulatory income taxes for OPG's prescribed facilities. Additionally, given that DNNP LP is a limited partnership, these regulatory income taxes have been calculated with respect to the tax status of the partners in DNNP LP, such that the regulatory income taxes reflect the portion of the regulatory taxable income that is attributable to taxable partners. Since tax-exempt partners are not required to pay income taxes, any portion of DNNP LP's regulatory taxable income attributable to such partners does not give rise to regulatory income taxes to be included in payment amounts. The Canada Growth Fund Inc. and Building Ontario Fund are presently tax-exempt and as such their share of regulatory taxable income does not give rise to regulatory income taxes. The Application proposes to establish the Impact of Change in Tax Status Variance Account (DNNP), discussed in Ex. H1-1-1, Section 8.7, to capture the impact on forecast regulatory income taxes reflected in the revenue requirement approved by the OEB of any changes to the tax status of current and future partners of DNNP LP.

The Application uses the taxes payable method for determining regulatory income taxes. Under the taxes payable method, only the current income tax expense is reflected in the revenue requirement. Regulatory income taxes are determined by applying the statutory tax rates to the regulatory taxable income of the prescribed facilities and reducing the resulting amount by the recognized SR&ED ITCs.

Regulatory taxable income is computed by making additions and deductions to regulatory earnings before tax for items affected by differences in regulatory accounting treatment and tax treatment reflecting applicable requirements of the tax legislation. These additions and deductions are described in Section 3.2 below and are detailed in the calculation of annual

regulatory income taxes for OPG's prescribed facilities at Ex. F4-2-1, Table 3 for 2020-2026, Ex. F4-2-1, Table 3b (regulated hydroelectric facilities) and Table 3d (OPG's nuclear facilities) for 2027-2031, and for the DNNP facilities at Ex. F4-2-1, Table 3g for 2026-2031.

Regulatory income taxes for OPG's prescribed facilities for the historical and bridge periods continue to be determined by applying statutory tax rates to the regulatory taxable income of the combined prescribed nuclear and hydroelectric facilities, and subtracting SR&ED ITCs. Total regulatory income taxes before SR&ED ITCs are then allocated based on each business' regulatory taxable income, with SR&ED ITCs predominantly directly attributed to each business based on the underlying expenditures giving rise to the ITCs.

For IR term ratemaking purposes, the standalone forecast annual regulatory income taxes for OPG's prescribed nuclear facilities and prescribed hydroelectric facilities are presented for the 2027-2031 period, and are determined by applying statutory tax rates to the forecast regulatory taxable income of such facilities, and subtracting any corresponding forecast SR&ED ITCs.[4] In a situation where a tax loss is forecast for an OPG regulated business in a given year of the IR term, the loss is applied (carried back or carried forward) to reduce such business' regulatory taxable income in other years of the IR term, as applicable, with any remaining tax losses carried forward to future IR terms. This approach is consistent with the cost allocation principle of direct assignment, whereby costs directly related to a business are directly assigned to that business, and was similarly applied in EB-2020-0290 and EB-2016-0152.[5] Forecast regulatory income taxes for OPG's regulated nuclear business presented for the IR term take into account the carryover of forecast tax losses for these facilities from the 2022-2026 IR term, determined using the above approach in the EB-2020-0290 Payment Amounts Order.[6]

[4] As in prior applications, the SR&ED ITCs reduce regulatory tax expense even when there is no income tax payable in a given year.
[5] See discussion in EB-2016-0152, Ex. A1-3-2, pp. 15-16 and Ex. L-11.2-1 Staff-253, and the OEB-approved settlement proposal, p. 15.
[6] EB-2020-0290, Payment Amounts Order, App. A, Table 22.

Similarly, for the DNNP facilities, the standalone forecast annual regulatory income taxes for the 2026-2031 period are determined by applying statutory tax rates to the portion of the forecast regulatory taxable income of these facilities attributable to the taxable partners of DNNP LP, and subtracting any corresponding forecast SR&ED ITCs attributable to such partners. In a situation where a tax loss is forecast for the DNNP facilities in a given year of the IR term, the portion of the loss attributable to the taxable partners is applied (carried back within the IR term or carried forward) to reduce the regulatory taxable income in other years of the IR term, with any remaining tax losses carried forward to future IR terms. Tax losses attributed to non-taxable partners cannot be utilized and therefore cannot be carried forward.

There have been no changes in the statutory income tax rates in the historic period, and none are included in the forecast for the bridge or IR term. SR&ED ITCs are discussed in Section 3.5.

As discussed in Section 3.3, the income tax impacts associated with amounts recorded in deferral and variance accounts continue to be considered in the calculation of regulatory taxable income in the periods they are recovered from or refunded to ratepayers, rather than in the periods in which these amounts arise. Therefore, additions or deductions that reverse amounts reflected in regulatory earnings before tax are presented net of any corresponding additions recorded in deferral and variance accounts in the period, and any return on rate base recorded in deferral or variance accounts in the period is also reversed.[7]

Attachment 1 provides, as confidential material, OPG's most recent corporate income tax returns and the associated notices of assessment. The returns are for the 2024 taxation year, for the same companies included in EB-2020-0290. Exhibit F4-2-1, Table 4 presents the reconciliation of OPG's consolidated taxable income based on its 2024 tax returns to the calculation of regulatory taxable income for OPG's prescribed facilities for that year. Given that DNNP LP was formed in 2025, no tax returns have been filed to date.

[7] The reversal of return on rate base amounts recorded in deferral and variance accounts continues to be presented as a separate adjustment to regulatory earnings before tax in the historical and bridge years at Ex. F4-2-1, Table 3, line 21. As no such deferral and variance account additions are forecasted for the purposes of determining regulatory earnings before tax in the IR term, the adjustment is not required for the 2027-2031 period.

3.2 Description of Additions and Deductions to Regulatory Earnings Before Tax

3.2.1 Depreciation and Amortization/Capital Cost Allowance ("CCA")

Accounting depreciation and amortization of fixed/intangible assets is not deductible for income tax purposes; however, CCA is deductible. Therefore, depreciation and amortization expense is an addition to regulatory earnings before tax, while CCA is deducted from regulatory earnings before tax. Accounting depreciation and amortization of fixed/intangible assets for OPG's prescribed facilities and the DNNP facilities are determined as described in Ex. F4-1-1.

The amount of depreciation/amortization expense added back to regulatory earnings before tax at Ex. F4-2-1, Table 3 for OPG's prescribed facilities is net of depreciation amounts for OPG's prescribed facilities recorded (or forecasted to be recorded) in the applicable years as net debit additions (or increased by such net credit additions) to the respective authorized deferral and variance accounts.

OPG's 2024 income tax returns provided in Attachment 1 include the calculations of CCA deductions by applying, by asset class, a prescribed rate to the Undepreciated Capital Cost ("UCC") balance (i.e., Schedule 8 of Ex. F4-2-1, Attachment 1). These schedules contain consolidated information for both OPG's regulated and unregulated assets. The UCC and CCA schedules for OPG's prescribed nuclear assets are provided in Ex. F4-2-1, Tables 21-27 for 2020-2026 and in Ex. F4-2-1, Tables 28-32 for 2027-2031 and reflect, up to and including 2024, any such amounts related to the DNNP facilities. The UCC and CCA schedules for OPG's prescribed hydroelectric assets are provided in Ex. F4-2-1, Tables 5-15 for 2016-2026 and in Tables 16-20 for 2027-2031.

The UCC and CCA schedules are provided for the DNNP facilities in Ex. F4-2-1, Tables 33-37 for 2027-2031. The forecasted UCC and CCA balances are nil prior to 2027, the year in which DNNP LP will first become eligible to claim CCA based on the "rolling start" and "long-term project" rules (discussed below). The UCC includes costs incurred by OPG and reimbursed by DNNP LP as part of the transfer of certain assets from OPG to DNNP LP (refer to Ex. A1-4-4,

Section 2.0), and DNNP LP's subsequent expenditures toward the DNNP. As leasehold interests, DNNP LP's assets are subject to CCA Class 13 under existing tax legislation.

For projects that take longer than two years to put into service or complete, CCA can be calculated taking into account the "rolling start" rule, which allows CCA to be claimed on property acquired two years ago that has not been placed in service, and the "long-term project" rule that permits property acquired after the second year of a long-term project to become eligible for CCA deductions earlier than it otherwise would under the "rolling start" rule, subject to certain thresholds. These rules have been reflected in the forecast CCA amounts for the Darlington Refurbishment Program ("DRP"), Pickering Refurbishment Program ("PRP") and other material projects applicable to OPG's prescribed facilities, and the DNNP facilities.

The CCA amounts also reflect the ability to claim higher CCA deductions on AIIP[8] stemming from the passage of Bill C-97, the *Budget Implementation Act, 2019, No. 1*. The AIIP is property acquired after November 20, 2018, and put into service after that date.[9] Under the existing legislation, the ability to claim the higher CCA under these rules phases out by the end 2027. The AIIP rules under the existing legislation have been reflected in the forecast CCA amounts in the Application.[10]

In November 2025, the federal government introduced draft legislation proposing to reinstate the AIIP measures for qualifying property acquired on or after January 1, 2025, and that becomes available for use before 2034. As noted, the effect of these proposals is not reflected in OPG's 2025-2031 Business Plan or this Application and, if enacted, will be returned to ratepayers through one of the authorized deferral and variance accounts noted above.

[8] The application of these rules includes property subject to the "rolling start" rule and "long-term project" election.
[9] Bill C-97 received Royal Assent on June 21, 2019. The changes generally resulted in a CCA allowance of three times the normal first-year CCA for assets acquired after November 20, 2018, and put into service before 2024 and two times the normal first-year CCA for assets acquired after November 20, 2018 and put into service during the 2024-2027 period.
[10] Until such time as the hydroelectric payment amounts are rebased, OPG continues to record the impact of the higher CCA deductions arising from the AIIP rules to its regulated hydroelectric facilities, in full, in the Income and Other Taxes Variance Account (OPG) or, for the applicable projects, in the CRVA. These accounts are discussed further in Ex. H1-1-1, Sections 5.5. and 5.6 respectively.

3.2.2 Nuclear Waste Management Variable Expenses

Consistent with the provisions of the *Income Tax Act* (Canada), accounting expenses accrued by OPG relating to its obligations for decommissioning its nuclear facilities and managing used nuclear fuel and low and intermediate level waste produced by these facilities (collectively, the "nuclear liabilities") are not deductible for tax purposes. Therefore, used fuel storage and disposal and low and intermediate level waste management variable expenses incurred in the period in relation to OPG's prescribed nuclear assets are added back to OPG's regulatory earnings before tax. These expenses are presented in Ex. C2-1-1, Table 2, lines 2 and 3. The amount added back to regulatory earnings before tax for these expenses in Ex. F4-2-1, Table 3 is net of amounts recorded (or forecasted to be recorded) in the applicable years as net debit additions (or increased by such net credit additions) to the respective authorized deferral and variance accounts.

3.2.3 Cash Expenditures for Nuclear Waste Management and Decommissioning

Cash expenditures incurred and charged against the nuclear liabilities for waste management and decommissioning activities are generally deductible for tax purposes in accordance with the regulations under the *Electricity Act*, *1998*. Such expenditures for OPG's prescribed nuclear facilities are presented in Ex. C2-1-1, Table 2, line 5.

The full amount of cash expenditures relating to OPG's prescribed nuclear facilities is presented at line 17 in Ex. F4-2-1, Table 3 for 2020-2026 and in Table 3d, line 16 for 2027-2031, as a deduction from OPG's regulatory earnings before tax. As part of Other additions presented at line 14 in Ex. F4-2-1, Table 3 for 2020-2026 and in Table 3d, line 13 for 2027-2031, and as noted in Section 3.2.8 below, a portion of these expenditures deemed to be capital for tax purposes is added back to OPG's regulatory earnings before tax in order to adjust the amount of cash expenditures deducted in arriving at OPG's regulatory taxable income. The CCA deduction discussed in Section 3.2.1 includes CCA related to these expenditures.

3.2.4 Segregated Fund Contributions and Receipts

The regulations under the *Electricity Act, 1998* allow OPG a tax deduction for contributions made to segregated funds pursuant to the Ontario Nuclear Funds Agreement ("ONFA"). The ONFA contribution schedule based on the current approved ONFA Reference Plan is used to determine OPG's contributions to the segregated funds. The contribution amounts for OPG's prescribed nuclear facilities are presented in Ex. C2-1-1, Table 2, line 14 and are deducted from OPG's regulatory earnings before tax.

When OPG receives disbursements from the funds for reimbursement of eligible expenditures, the amounts received are taxable as per the regulations under the *Electricity Act, 1998*. The amounts related to OPG's prescribed nuclear facilities are presented in Ex. C2-1-1, Table 2, line 15 and are added to OPG's regulatory earnings before tax.

3.2.5 Pension and Other Post-Employment Benefits

Pension and other post-employment benefits ("OPEB") accrual costs recorded by OPG for accounting purposes (discussed in Ex. F4-3-2) are not deductible for tax purposes per the provisions of the *Income Tax Act* (Canada). Therefore, these costs are added back to OPG's regulatory earnings before tax. OPG's cash contributions to its registered pension plan as well as the payments for its OPEB and supplementary pension plans are deductible for tax purposes, and are reflected as deductions from OPG's regulatory earnings before tax.

The amount added back to OPG's regulatory earnings before tax for pension and OPEB accrual costs in Ex. F4-2-1, Table 3, line 5 is net of amounts recorded (or forecasted to be recorded) as net debit additions (or increased by such net credit additions) in the applicable years in the respective authorized deferral and variance accounts.[11] Pension and OPEB accrual costs are provided in Ex. F4-3-2, Chart 1 for OPG's regulated nuclear facilities and Ex. F4-3-2, Chart 2 for OPG's regulated hydroelectric facilities, and are added to OPG's earnings before tax. Pension and OPEB cash amounts are provided in Ex. F4-3-2, Chart 4 for OPG's

[11] As discussed in Ex. F4-3-2, the regulated hydroelectric revenue requirement proposed in the Application reflects pension and OPEB accrual costs and as of the effective date of the payment amounts order of this proceeding.

regulated nuclear facilities and Ex. F4-3-2, Chart 5 for OPG's regulated hydroelectric facilities are deducted from regulatory earnings before tax.

Once charged to DNNP LP by OPG, any pension and OPEB accruals become cash expenditures of DNNP LP by virtue of being payable to OPG under the respective service agreements between the parties. As such, the amount of pension and OPEB costs incurred by DNNP LP is expected to be deductible under the *Income Tax (Act)*. Pension and OPEB costs are provided in Ex. F4-3-2, Chart 3 for the DNNP facilities.

3.2.6 Adjustment Related to Financing Cost for Nuclear Liabilities

The calculation of OPG's regulatory earnings before tax adds back an adjustment in respect of the financing cost (i.e., return on rate base) for OPG's prescribed facilities' portion of the nuclear liabilities. This adjustment is required as a result of the methodology for the recovery of the revenue requirement impact of the nuclear liabilities (approved in EB-2007-0905 and applied in all subsequent payment amounts proceedings) and the inclusion of tax deductions for nuclear segregated fund contributions and cash expenditures on nuclear liabilities.

As part of the approved methodology discussed in Ex. C2-1-1, the revenue requirement treatment of the nuclear liabilities includes an amount derived by applying the weighted average accretion rate to the lesser of the average unfunded nuclear liabilities and the average unamortized asset retirement costs for the prescribed facilities. This amount is deducted in determining OPG's regulatory earnings before tax. For years 2020-2031, the derivation of this amount is presented in Ex. C1-1-1, Tables 1-12, line 7. The nuclear segregated fund contributions also include financing costs related to the nuclear liabilities and are also deducted in determining OPG's regulatory taxable income, as discussed in Section 3.2.4 above. Therefore, an adjustment is included as an addition to regulatory earnings before tax to remove an otherwise duplicate deduction between the return on rate base at the weighted average accretion rate and deductions for the nuclear segregated fund contributions and the cash expenditures on nuclear liabilities. The amount added to OPG's regulatory earnings before tax in Ex. F4-2-1, Table 3 is net of amounts recorded as net debit additions (or increased by such net credit additions) during applicable years in the respective authorized deferral and variance accounts.

3.2.7 Nuclear Fuel Expense Half-Charge Adjustment

Fifty percent of OPG's nuclear fuel expense (i.e., nuclear fuel bundle cost) incurred for its prescribed facilities in the year is not deductible for tax purposes until the following year. Accordingly, 50% of a given year's nuclear fuel expense is added to OPG's regulatory earnings before tax for the given year and 50% of the prior year's nuclear fuel expense is deducted from OPG's regulatory earnings before tax for the given year. The resulting adjustment is presented as a net addition or net deduction to OPG's regulatory earnings before tax at Ex. F4-2-1, Tables 3 and 3d. OPG's nuclear fuel bundle costs are provided at Ex. F2-5-1, Table 1a, line 3.

Once charged to DNNP LP by OPG in the form nuclear fuel service fees (discussed in Ex. F2-5-1, Section 5.0), nuclear fuel related costs become an operating expense of the DNNP LP and as such are expected to be deductible as incurred.

3.2.8 Other

This category includes other required additions or deductions to regulatory earnings before tax, such as:

- Nuclear materials and supplies obsolescence expenses recorded for accounting purposes as part of nuclear base OM&A costs (as noted in Ex. F2-2-1, Section 3.1) that are not deductible for tax purposes as per the *Income Tax Act* (Canada).
- Computer equipment expenditures that are expensed for accounting purposes but must be capitalized and are eligible for CCA deductions for tax purposes.
- Meals and entertainment expenses that are subject to the 50% tax deduction limitation.
- Adjustment to decrease the reduction for OPG's cash expenditures on nuclear waste management and decommissioning by the portion of such expenditures deemed to be capital for tax purposes, as discussed in Section 3.2.3.

3.2.9 Interest Deductibility Limits

On June 20, 2024, Bill C-59 received Royal Assent, which introduced the EIFEL rules under the *Income Tax Act* (Canada), effective for taxation years beginning on or after October 1, 2023. Under these rules, the tax-deductible amounts of net interest and financing expenses could be restricted in a given year.

Under EIFEL rules, the maximum net interest and financing expense deductible for tax purposes in a given year is limited to 30% of their adjusted taxable income, termed the base deduction capacity. The adjusted taxable income is computed, for regulatory purposes, by adding back to regulatory taxable income after loss carry-over the CCA and the net interest and financing expense for the year. If the net interest and financing expense for the year are above the base deduction capacity, the excess is restricted from being deducted in that year, subject to available excess capacity carried forward from prior years. If the net interest and financing expense for the year is below the base deduction capacity, the remaining deduction room represents excess capacity. Any excess capacity must first be utilized to deduct any net restricted interest and financing expenses carried forward. Any remaining unused excess capacity can be carried forward for three years to deduct net interest and financing expenses that would otherwise be restricted from being deducted due to the EIFEL rules.

Any restricted net interest and financing expense is added back to regulatory earnings before tax in the calculation of regulatory taxable income, as shown in Ex. F4-2-1, Table 3, line 10; Table 3b, line 6; Table 3d, line 10; Ex. F4-2-1, Table 3g, line 4. The application of the EIFEL rules does not result in restricted net interest and financing expense in this Application. The EIFEL calculations have been performed with reference to the deemed debt levels of the businesses.

The 2025 Federal Budget has reiterated the government’s intention to reintroduce an elective exemption for Canadian regulated energy utility businesses, first announced in the 2024 Fall Economic Statement, with respect to the EIFEL rules. Under this proposal, a Canadian regulated energy utility business would be able elect to exclude the interest and financing expenses incurred on arm’s length debt for the purposes of the EIFEL rules and the income from the regulated energy utility business would also be excluded from the adjusted taxable income. The election would effectively result in the EIFEL restrictions not applying to interest incurred on borrowings used to finance the Canadian regulated utility business. Although they produced no restricted interest expense, the EIFEL calculations for the purposes of this application did not include the impact of making such an election.

3.3 Regulatory Tax Treatment of Deferral and Variance Account Recovery

Amounts recorded in deferral and variance accounts in a given period, which are reported as regulatory assets or liabilities for accounting purposes, typically impact actual taxable income in a different period. As a result, amounts recognized for accounting purposes as regulatory assets or liabilities in the period are reversed from regulatory earnings before tax in determining actual taxable income (e.g., Ex. F4-2-1, Table 4, col. (a), lines 19-22). It is noted that while the discussion below is presented with respect to OPG's prescribed facilities, it is expected that similar considerations will be applied to the DNNP facilities in subsequent proceedings, once DNNP LP begins recording and disposing of amounts in its deferral and variance accounts.

For regulatory purposes, as in prior OPG payments amounts proceedings, the tax impact (i.e., tax benefits or costs) to be recovered from, or provided to, ratepayers of the amounts recorded in deferral and variance accounts is reflected in the calculation of regulatory taxable income over the same period as these amounts are recovered from, or refunded to, ratepayers. This approach is intended to result in the same total tax impact as the actual tax payable in respect of recovery or refund of the amounts, considering the entire period from when the variance or deferral account balance is initially recorded to when the balance is fully recovered or refunded. This regulatory treatment provides for a matching of costs and benefits in accordance with the principle that the party who bears a cost should be entitled to any related tax savings or benefits.

In calculating earnings, the balance of the deferral and variance accounts recovered or refunded through payment amounts in the period is reflected in both the regulated revenues and the amortization expense (or amortization credit) for that period. Amortization is not deductible for income tax purposes. Since the amounts of revenue and amortization typically would be equal and offsetting, there is no net impact on regulatory earnings before tax for the period. In calculating regulatory income taxes, no adjustment to regulatory earnings before tax is made for the amortization, subject to the discussion below, because the amount that would otherwise be added back to, or deducted from, such earnings before tax as amortization expense/credit is the same as the amount that would be deducted from, or added back to, the earnings before tax in order to attribute the associated benefit or cost to ratepayers.

To the extent that there is no tax benefit/cost to be matched to the variance or deferral account recovery or refund, there is a net income tax impact associated with the amounts recorded in these accounts. In instances where this impact is not otherwise reflected in the account balance itself, an adjustment to regulatory earnings before tax is required in the period of recovery.

The Nuclear Liability Deferral Account, the CRVA, the Pension and OPEB Cost Variance Account, the NDVA and the Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account are the principal accounts of OPG that currently record amounts for the prescribed facilities that do not have a matching tax benefit.[12] These accounts reflect the associated income tax impacts as part of amounts recorded in the account, and therefore no adjustment to earnings before tax is required in respect of the recovery of these balances. With respect to the Pension & OPEB Cash Versus Accrual Differential Deferral Account, the associated income tax impacts are not recorded in the account. As addressed in EB-2018-0243, and continued in EB-2020-0290, EB-2023-0336 and this Application, these impacts are being recovered through the appliable deferral and variance account riders (see Ex. H1-2-1).

An adjustment to regulatory earnings before tax continues to be required to address the impact of the regulatory treatment of the Bruce Lease net revenues on the disposition of the Bruce Lease Net Revenues Variance Account. The forecast net revenues from the Bruce Lease are applied against OPG's nuclear revenue requirement and therefore the earnings before tax for OPG's prescribed facilities, as shown in Ex. F4-2-1, Table 3f, Note 1. To the extent that there is a difference between the forecast and actual net revenues from the Bruce Lease (i.e., an entry into the Bruce Lease Net Revenues Variance Account), there is a difference in the regulatory earnings before tax and therefore the income taxes for OPG's prescribed facilities. Hence, an adjustment to regulatory earnings before tax is required in the year of

[12] Components of the Income & Other Taxes Variance Account (OPG) also reflect the associated income tax impacts (i.e., gross-up) as part of the amounts recorded therein. Given the modest balances being sought for disposition in this proceeding, an adjustment to regulatory earnings before tax continues to be shown in Ex. F4-2-1, Table 3, line 8 for the combined prescribed facilities, and in Table 3b, line 5 and Table 3d, line 8 for the regulated hydroelectric and nuclear facilities, respectively, for the full balance of the account. Going forward, OPG will seek to ensure that all components of the account consistently reflect the income tax impacts, eliminating the need for this adjustment to earnings before tax.

recovery/refund of the variance recorded in the Bruce Lease Net Revenues Variance Account to ensure that any over-collection of, or shortfall in, regulatory taxes is also refunded to, or recovered from, ratepayers. Accordingly, the amortization of the Bruce Lease Net Revenues Variance Account is added back to OPG's regulatory earnings before tax, as shown in Ex. F4-2-1, Tables 3 and 3d, line 6. In addition to historical and bridge years, this adjustment is included for years 2027 to 2029 to reflect amortization amounts for the Bruce Lease Net Revenues Variance Account proposed in this Application (see Ex. H1-2-1).

3.4 SR&ED Investment Tax Credits

OPG and DNNP LP can claim non-refundable federal ITCs equal to 15% and an Ontario ITC of 3.5% (4.5% prior to June 1, 2016) of the qualifying SR&ED expenditures incurred in the year. OPG files annual ITC claims based on qualifying expenditures identified; DNNP LP is expected to do the same. The federal ITCs reduce the federal portion of corporate income taxes (or payments in lieu thereof) otherwise payable and are taxable in the subsequent year. The Ontario ITCs reduce the Ontario portion of corporate income taxes (or payments in lieu thereof) otherwise payable and are taxable in the year earned. Additionally, certain expenditures that are capitalized for accounting purposes are deductible for income tax purposes as SR&ED qualifying expenditures in the year incurred (and are also eligible for SR&ED ITCs). These expenditures are deducted from regulatory earnings before tax in computing regulatory taxable income, as shown in Ex. F4-2-1, Table 3, line 22; Table 3b, line 14; Table 3d, line 21; and Table 3g, line 12.

In November 2025, the federal government introduced draft legislation to allow the expensing of capital expenditures other than land or a leasehold interest in land and incurred with respect to SR&ED activities, made after December 16, 2024. The impact of this proposal has not been reflected in this Application as the legislation has not been adopted yet, and it is also not reflected in OPG's 2025-2031 Business Plan. The tax deduction benefit of these changes, once implemented, will be credited to the Income and Other Taxes Variance Account (OPG) for OPG's prescribed facilities and, as proposed in Ex. H1-1-1, the Income and Other Taxes Variance Account (DNNP) for the DNNP facilities. The SR&ED ITCs would be credited to the

SR&ED ITC Variance Account (OPG) for OPG's prescribed facilities and, as proposed in Ex. H1-1-1, the SR&ED ITC Variance Account (DNNP) for the DNNP facilities.

As in prior payment amounts applications, the amount of SR&ED ITCs recognized by OPG for accounting purposes is determined based on an assessment of the likelihood of their allowance, in accordance with generally accepted accounting principles ("GAAP"). Under US GAAP, the amount of SR&ED ITCs recognized in the period is recorded as a reduction to income tax expense for that period. This reduction to income tax expense from 2022-2026 for OPG's prescribed facilities is presented at Ex. F4-2-1, Table 3, line 30; Ex. F4-2-1, Table 3b, line 22; Table 3d, line 29. As of the effective date of the payment amounts order in this proceeding, the Application proposes adopting the same treatment for any SR&ED ITCs that recognized by DNNP LP. The reduction to income tax expense for the DNNP facilities is presented at Ex. F4-2-1, Table 3g, line 21. Consistent with the 2025-2031 Business Plan and the approach in EB-2020-0290, forecast SR&ED ITCs for OPG's prescribed facilities are based on the actual amounts claimed for the most recent completed taxation year, being 2024, excluding amounts related to the DNNP facilities.

In determining actual and forecast income tax expense for its regulated nuclear business and hydroelectric businesses, OPG continues to recognize 75% of the SR&ED ITCs for taxation years that are subject to audit. For years the audit of which has been resolved, the previously recognized amounts are adjusted, as necessary, to reflect the audit resolution. Until May 31, 2017, to the extent the ultimate percentage of recognition for SR&ED ITCs differed from that applied in reducing regulatory income tax expense reflected in approved payment amounts, OPG recorded the difference in the SR&ED ITCs, including the tax on the difference, in the Income and Other Taxes Variance Account for both its prescribed nuclear and regulated hydroelectric facilities. This treatment remains in place for the regulated hydroelectric facilities. As directed by the OEB in EB-2016-0152 and subsequently continued in EB-2020-0290, starting June 1, 2017, any difference between the forecast SR&ED ITCs reflected in approved payment amounts for OPG's prescribed nuclear facilities and such actual SR&ED ITCs as determined after any tax audits, including the tax on the difference, is recorded in the SR&ED

ITC Variance Account (OPG). Refer to Ex. H1-1-1, Section 5.20 for further discussion of the account.

In its Decision and Order in EB-2016-0152, the OEB instructed OPG to consider the utilization of SR&ED ITCs for its regulated nuclear and hydroelectric businesses in its next application.[13] The treatment of SR&ED ITCs described above was reflected in the OEB-approved settlement proposal in EB-2020-0290 for OPG's nuclear facilities. It remains reasonable for the IR term as the circumstances observed at the time of EB-2016-0152 and continued in EB-2020-0290 related to the inherent difficulty in forecasting such ITCs have not substantially changed, particularly as OPG moves through the execution of the PRP. The PRP will contain certain scopes of work not previously performed as part of the DRP (see Ex. D2-3-5). OPG proposed no change to the treatment of the SR&ED ITCs for the regulated hydroelectric business in EB-2020-0290 as the hydroelectric base payment amounts were not then rebased and instead were set by O. Reg 53/05. For this IR term, the Application proposes that the same treatment be adopted for the SR&ED ITCs for OPG's regulated hydroelectric facilities as for its nuclear facilities, including the operation of the SR&ED ITC Variance Account (OPG). In addition to the benefits of consistency, this is reasonable due to the inherently greater difficulty in forecasting such ITCs as a result of the increased capital program for the hydroelectric facilities going forward.

The Application does not reflect any forecast SR&ED ITCs for the DNNP facilities during the bridge year or the IR term because this project is unique and not similar to any other project undertaken by OPG given that it is the first of its kind. As such there is significant uncertainty associated with the potential SR&ED eligibility of projects. The Application proposes to address this uncertainty by establishing the SR&ED ITC Variance Account (DNNP), to record such actual SR&ED ITCs, net of tax thereon, on the same basis as the SR&ED ITC Variance Account (OPG). Refer to Ex. H1-1-1, section 8.3 for further discussion of the proposed account.

[13] EB-2016-0152, Decision and Order, December 28, 2017, p. 88.

3.5 Clean Electricity ITC

The federal government has proposed a 15% refundable CEITC with respect to investments in certain clean electricity property and certain refurbishment projects. The proposed CEITC would be available to income tax exempt entities such as OPG. As a limited partnership, for DNNP LP, CEITC eligibility would be determined based on whether the respective partner is eligible to receive the CEITC. To be entitled to the full 15% CEITC, DNNP LP is required to meet certain prevailing wage and apprenticeship requirements. The federal government reissued draft legislation to institute the CEITC in November 2025. At the time of filing the Application, this legislation has not yet been adopted. The CEITCs are not reflected in OPG's 2025-2031 Business Plan or the proposed revenue requirements in this Application.

For income tax purposes, the CEITC is taxable in the year received. However, OPG and DNNP LP can make an election to reduce the UCC pool that resulted in the CEITC, by the amount of the CEITC received, instead of including it in taxable income. Since the election is more advantageous from a tax perspective, OPG and DNNP LP expect to make the election to reduce the UCC pool by the amount of the CEITC received. This will result in a reduction of the annual CCA available to shelter taxable income in the future.

The CEITCs are expected to be recorded for eligible projects when they are received. The CEITC would reduce the cost of the related asset as required under US GAAP. US GAAP also requires that a reserve be recorded for amounts that may not be realized. The reserve would be released upon the completion of the audit for the relevant taxation year.

To ensure the benefit of the CEITCs is realized by ratepayers (if the CEITC is legislated), the Application proposes to record the revenue requirement impacts in two newly proposed variance accounts:

1) Clean Electricity ITC Variance Account (OPG) – As discussed in Ex. H1-1-1, Section 7.3, this account is proposed to record the revenue requirement impact of CEITCs received for eligible investments in OPG's prescribed facilities to the extent it is not captured in existing accounts.

2) Clean Electricity ITC Variance Account (DNNP) – As discussed in Ex. H1-1-1, Section 8.6, this account is proposed to record the revenue requirement impact of CEITCs received for eligible investments in the DNNP facilities to the extent it is not captured in existing accounts.

For OPG's CRVA eligible projects including the PRP and major hydroelectric turbine-generator refurbishments, the revenue requirement impacts of the CEITCs will be captured in the CRVA. For the DNNP, these impacts will be captured in DNNPVARD.

The revenue requirement impact of CEITCs will be realized through a reduction in the capital related revenue requirement. Specifically, the recognized CEITCs will reduce in-service rate base, associated depreciation expense and cost of capital amounts and the attendant tax effects, while reducing the available CCA deductions as discussed above.

Additionally, the CEITCs are expected to reduce the amount of PRP and DNNP capital expenditures for which recovery of interest is provided prior to such assets being placed in service pursuant to O. Reg. 53/05. These amounts are subject to and, as necessary, will be reconciled through the Pickering B Refurbishment Project Variance Account (for the PRP) and Darlington New Nuclear Project Variance Account re Capital Cost Amounts (for the DNNP). These accounts are discussed in Ex. I1-1-3.

4.0 INCOME TAX EXPENSE TREND

The actual (2020-2024) and forecast (2025 and 2026) annual regulatory income tax expense for OPG's prescribed facilities, the forecast income tax expense (2027-2031) for the regulated hydroelectric facilities and the forecast income tax expense (2027-2031) for OPG's nuclear facilities has been computed using the approach described in Section 3. The 2020-2026 regulatory income tax expense calculations are shown in Ex. F4-2-1, Table 3. The 2027-2031 regulatory income tax expense calculations for the regulated hydroelectric facilities is shown in Ex. F4-2-1, Table 3b and the 2027-2031 regulatory income tax expense calculations for OPG's nuclear facilities are shown in Ex. F4-2-1, Table 3d. The income taxes for the regulated

hydroelectric facilities for the 2016-2026 period are presented in Ex. F4-2-1 Table 1; for the nuclear facilities, income taxes for the 2020-2026 period are shown in Ex. F4-2-1, Table 2.

The forecast tax expense for the regulated hydroelectric facilities over the forecast period is $27.3M in 2027, $70.3M in 2028, $87.6M in 2029, $101.6M in 2030 and $110.7M in 2031. There were no carryover tax losses from prior periods attributed to the regulated hydroelectric facilities and no tax losses are projected for these facilities. The increase in regulatory income taxes over the forecast period reflects the growth in regulatory earnings before tax commensurate with the increase in the rate base, and some variability in CCA deductions.

The forecast tax expense for the nuclear facilities in the IR term is -$16.6M in 2027, -$16.6M in 2028, -$16.6M in 2029, -$16.6M in 2030 and -$16.6M in 2031. The negative tax expense for 2027-2031 represents the forecast amount of SR&ED ITCs attributed to the nuclear facilities in those years and reflects the impact of the carryover of EB-2020-0290 forecast nuclear regulatory tax losses of $373.4M at the end of 2026[14] and projected nuclear regulatory tax losses of $20.6M, $111.5M, $504.5M, $634.2M, and $164.6M arising in 2027, 2028, 2029, 2030, and 2031, respectively. The nuclear regulatory tax loss balance at the end of 2031 of $1,808.8M would be carried forward to the next rate-setting period. The regulatory tax loss carry-forward schedule for the nuclear facilities is presented at Ex. F4-2-1, Table 3e.

The forecasted income tax expense for the DNNP facilities during the IR term is nil each year. This is because regulatory tax losses are forecasted for years 2027 to 2030 due to a combination of nil or low regulatory earnings before tax, combined with CCA deductions. Although taxable income is forecasted in 2031, it is entirely offset by regulatory tax losses carried forward from the earlier years. For the reasons discussed in Section 3.4, no SR&ED ITCs have been forecasted for the DNNP facilities.

Over the historical period, the regulatory income taxes for OPG's prescribed facilities fluctuate mainly with the variability in regulatory earnings before tax and also reflect a trend of increasing CCA deductions, driven by OPG's expanding capital program.

[14] EB-2020-0290, Payment Amounts Order, App. A, Table 22.

5.0 COMMODITY TAX

Pursuant to the *Excise Tax Act* (Canada), OPG is subject to the 13% Harmonized Sales Tax ("HST") on almost all of its purchases of goods and services. The recoverable portion of HST paid by OPG is claimed as input tax credits on returns filed monthly. The recoverable portion of HST forecast to be paid is therefore not included in the revenue requirement. As in prior payment amounts applications, the impact of HST is incorporated into the computation of the cash working capital component of rate base presented in Ex. B1-1-2. DNNP LP is similarly subject to the HST.

Where applicable, OPG continues to pay duty under the *Customs Act (*Canada) on goods imported into Canada. Some of these imports continue to be either exempt or have duty free status through the United States–Mexico–Canada Agreement. For supply and installation contracts, the contractor's price includes duty, if applicable, on the goods imported to perform the work. Any duty paid forms part of the cost of the underlying item.

6.0 PROPERTY TAX EXPENSE

The nature, basis, and components of OPG's property tax expenses are unchanged from the evidence presented in prior payment amounts applications.

For OPG's hydroelectric portfolio, conventional municipal property taxes are payable on certain assets (e.g. workshops, service centers, etc.) which support hydroelectric facilities. Tax information on these facilities is presented by region in Ex. F4-2-1, Table 1. These property taxes are paid at Current Value Assessment and are typically forecasted to increase by approximately $0.1M to $0.2M annually.

OPG's nuclear portfolio remains responsible for both the payment of municipal property taxes and a payment in lieu of property tax to the OEFC. The total of these two payments is intended to represent what a commercial generating company would pay as property tax, based on full Current Value Assessment ("CVA"), and represents OPG's property tax expense. OPG's property tax expense for the regulated nuclear facilities is presented in Ex. F4-2-1, Table 2, for the historical, bridge periods, and IR term years. The property tax expense for the regulated

nuclear facilities gradually increases over the bridge period and IR term, reflecting differences in municipal property tax rates and changes in property assessment values.

Property tax for DNNP facilities is discussed in Section 6.3 below.

Municipal property taxes paid by OPG for properties that are not directly associated with specific generation business units and are held centrally, are part of the asset service fees as discussed in Ex. F3-2-1. Property taxes associated with the Bruce assets are presented separately in Ex. G2-2-1.

6.1 Municipal Property Taxes

Municipal property taxes are regulated under the *Assessment Act, R.S.O. 1990* (the "Act"). For prescribed nuclear and Bruce assets, property tax payments to municipalities continue to be paid based on a statutory assessment rate of $86.11 per square meter for most of the ground floor area of "generating" buildings (e.g., buildings that are used in, or auxiliary to, the generating process, such as a powerhouse, water treatment plant, pump houses, etc.) pursuant to the Act, and at CVA for "non-generating" buildings (e.g., administration/office buildings). For both "generating" and "non-generating" buildings, the Municipal Property Assessment Corporation issues notices of assessments annually and the local municipality levies a local tax rate against the assessed value of the property. Additionally, for "generating" buildings, OPG continues to be subject to payment in lieu of property tax discussed below.

For hydroelectric assets, OPG continues to pay municipal property tax under the Act only for properties that are not associated with a generating station or dam site. These property taxes are paid at CVA. For 2027, a $1.0M annual increase reflects the anticipated construction of a new facility required to support Western Region Operations.

6.2 Payment in Lieu of Property Tax

Payment in lieu of property tax is regulated through O. Reg. 423/11 (previously O. Reg 224/00) under the *Electricity Act, 1998* and is paid to the OEFC. The payment in lieu of property tax represents taxes based on the difference between CVA and the prescribed municipal

assessment rate of $86.11 per square meter for most of the ground floor area of certain generating assets.

As noted in prior applications, the assessment basis under O. Reg. 423/11 has not been updated since 1999. Consequently, the CVA used for payment in lieu of property tax calculations and the payments in lieu of tax amounts themselves remain subject to a possible update. Property tax expense forecasts for all years presented in this application assume that the assessed values set out in O. Reg. 423/11 will not be updated within the reporting period. Changes in property taxes resulting from a change in O. Reg. 423/11 would be recorded in the Income and Other Taxes Variance Account, as per the OEB-approved scope of the account.

6.3 Darlington New Nuclear Program

The small modular reactors to be built as part of the DNNP will be sited on existing OPG land holdings adjacent to Darlington. There are three components to the property tax payable to consider for a property of this type, including: application of the statutory rate, calculation of the payments in lieu of property tax, and application of CVA to those property components not eligible for the statutory rate. Given that this technology includes a facility layout that is markedly different from other nuclear facilities in Ontario, the assessment of property taxes is currently uncertain. For the purposes of estimating the property-based taxes payable for the DNNP facilities, the following assumptions have been made.

First, it is assumed that the reactor buildings are the only building components that will be eligible for the statutory rate. On this basis, calculation of the municipal tax payable on the reactor buildings is estimated based on the statutory rate, applied to the gross first floor area, plus any payments in lieu (“PIL”) of property tax payable. In terms of calculating the PIL, the PIL property tax payable at the Bruce site has been used as a proxy to determine the assessment rate for the DNNP as it is the most recent market example available. This proxy is applied to the estimated gross floor area of the reactor buildings, together with the local tax rate in Clarington, to estimate the PIL payable. The property tax payable for all other buildings is limited to municipal property tax only, which has been estimated on the CVA basis.

The Application proposes to record the impact of changes in property-based taxes payable on the DNNP resulting from an update to the statutory assessment rates as noted in 6.2 above in the proposed Income and Other Taxes Variance Account (DNNP), as discussed further in Ex. H1-1-1, Section 8.4.

LIST OF ATTACHMENTS

Attachment 1: Income Tax Returns and associated Notices of Assessment for 2024
(filed entirely in confidence)

Includes:
Part 1 – T2 Corporation Income Tax Return Ontario Power Generation Inc.
Part 2 – T2 Corporation Income Tax Return OPG – Huron A Inc.
Part 3 – T2 Corporation Income Tax Return OPG – Huron B Inc.
Part 4 – T2 Corporation Income Tax Return OPG – Huron Common Facilities Inc.
Part 5 – Notices of Assessment – Hydro Payment in Lieu

Exhibit F4-02-01, Attachment 1, Part 1

T2 Corporation Income Tax Return

Ontario Power Generation Inc.

This Attachment was filed as confidential information in its entirety.

Exhibit F4-02-01, Attachment 1, Part 2

T2 Corporation Income Tax Return

OPG – Huron A Inc.

This Attachment was filed as confidential information in its entirety.

Exhibit F4-02-01, Attachment 1, Part 3

T2 Corporation Income Tax Return

OPG – Huron B Inc.

This Attachment was filed as confidential information in its entirety.

Exhibit F4-02-01, Attachment 1, Part 4

T2 Corporation Income Tax Return

OPG – Huron Common Facilities Inc.

This Attachment was filed as confidential information in its entirety.

Exhibit F4-02-01, Attachment 1, Part 5

Notices of Assessment – Hydro Payment in Lieu

This Attachment was filed as confidential information in its entirety.

Numbers may not add due to rounding.

Table 1

Taxes - Regulated Hydroelectric[3] ($M)

Line No.	Cost Item	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	**Income Tax[1,2]**	17.4	10.3	87.7	77.5	93.0	87.9	103.8	60.2	(3.3)	68.8	(3.3)	27.3
	Property Tax:												
2	**Niagara Region**	0.3	0.4	0.4	0.5	0.6	0.5	0.4	0.4	0.4	0.5	0.4	0.4
3	**Eastern Region**	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
4	**Western Region**	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	1.2
5	**Subtotal**	0.9	0.9	0.9	1.0	1.1	1.1	1.0	1.1	1.1	1.1	1.0	2.1
6	**Total**	18.3	11.2	88.6	78.6	94.1	88.9	104.8	61.2	(2.2)	69.9	(2.3)	29.4

Notes:

1 The income tax expense is calculated on a combined basis for OPG's prescribed facilities for the years 2020 to 2026. As described in Ex. F4-2-1, the resulting expense is allocated between the regulated hydroelectric and nuclear businesses on the basis of each business's taxable income and, for SR&ED ITCs, on the basis of the underlying expenditures.

2 Amounts for 2027 are from Ex. F4-2-1, Table 3b, line 24, col. (a).

3 Operating Region descriptions effective 2021 (see Ex. A1-4-2).

Numbers may not add due to rounding.

Table 2
Taxes - OPG Nuclear Facilities ($M)

Line No.	Cost Item	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	**Income Tax[1,2]**	158.6	(20.2)	81.0	83.5	(59.9)	170.7	(36.9)	(16.6)	(16.6)	(16.6)	(16.6)	(16.6)
	Property Tax:												
2	**Darlington NGS**	7.2	7.3	7.4	7.6	7.9	9.2	10.4	10.8	11.0	11.2	11.4	11.6
3	**Pickering NGS**	4.0	4.3	4.4	4.6	4.7	3.0	3.1	3.2	3.2	3.3	3.4	3.4
4	**Sub-total**	11.1	11.6	11.8	12.1	12.6	12.2	13.5	14.0	14.2	14.5	14.8	15.0
5	**Total**	169.7	(8.5)	92.8	95.7	(47.3)	182.9	(23.4)	(2.7)	(2.4)	(2.1)	(1.8)	(1.6)

Notes:

1 The income tax expense is calculated on a combined basis for OPG's prescribed facilities for the years 2020 to 2026. As described in Ex. F4-2-1, the resulting expense is allocated between the regulated hydroelectric and nuclear businesses on the basis of each business's taxable income and, for SR&ED ITCs, on the basis of the underlying expenditures.

2 Amounts for 2027-2031 are from Ex. F4-2-1, Table 3d, line 32.

Numbers may not add due to rounding.

Table 2a
Taxes - DNNP Facilities ($M)

Line No.	Cost Item	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Income Tax[1,2]**	0.0	0.0	0.0	0.0	0.0	0.0
2	**Property Tax**	0.0	0.0	0.0	0.0	0.8	3.7
3	**Total**	0.0	0.0	0.0	0.0	0.8	3.7

Notes:

1 As a Canadian partnership not subject to income taxes, DNNP LP's income tax expense is determined based on the tax status of the partners in the entity. Partners are subject to income tax on their share of the taxable income from DNNP LP. Therefore, income from DNNP LP attributable to taxable partners will result in the estimated tax payable by these partners being recovered in rates. Income from DNNP LP attributable to tax-exempt partners will not result in related income taxes recovered in rates.

2 Amounts for 2026 to 2031 are from Ex. F4-2-1, Table 3g, line 29.

Table 3
Calculation of Regulatory Income Taxes for Prescribed Facilities ($M)
Years Ending December 31, 2020-2026

Line No.	Particulars	Note	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Determination of Regulatory Taxable Income								
1	**Regulatory Earnings Before Tax**	1	1,355.5	913.3	1,126.4	1,327.6	490.9	1,470.9	590.0
	Additions for Regulatory Tax Purposes:								
2	**Depreciation and Amortization**		756.6	482.7	714.2	629.5	731.5	675.3	726.9
3	**Nuclear Waste Management Expenses**		65.6	67.2	76.3	58.7	68.3	70.5	30.1
4	**Receipts from Nuclear Segregated Funds**		64.5	88.9	117.4	114.3	156.6	501.7	534.2
5	**Pension and OPEB Accrual**		269.7	269.2	356.3	336.5	318.6	266.6	224.6
6	**Regulatory Asset Amortization - Bruce Lease Net Revenues Variance Account**		(10.2)	49.1	28.0	28.0	28.4	21.8	21.8
7	**Regulatory Asset Amortization - Pension & OPEB Cash Versus Accrual Differential Deferral Account**		51.1	51.1	177.0	177.0	215.6	203.1	203.1
8	**Regulatory Liability Amortization - Income and Other Taxes Variance Account**		(2.1)	(4.6)	(5.7)	(5.7)	(9.8)	(8.3)	(8.3)
9	**Adjustment Related to Financing Cost for Nuclear Liabilities**		13.7	12.7	9.8	14.4	9.4	(1.9)	(7.5)
10	**Restricted Net Interest and Financing Expenses**		0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	**Disallowance of Heavy Water Storage and Drum Handling Facility ("D2O") Project Expenditures**		0.0	90.3	0.0	0.0	0.0	0.0	0.0
12	**Taxable SR&ED Investment Tax Credits**	4	30.6	32.2	32.9	31.3	32.1	19.9	19.9
13	**Nuclear fuel Expense Half Charge Adjustment**		0.2	(17.2)	(5.1)	6.9	3.0	19.3	0.6
14	**Other**		100.0	56.7	114.8	90.8	73.9	112.6	109.2
15	**Total Additions**		1,339.5	1,178.2	1,615.7	1,481.5	1,627.6	1,880.6	1,854.6
	Deductions for Regulatory Tax Purposes:								
16	**CCA**	2	889.9	938.5	1,035.7	1,196.2	1,097.3	1,170.9	1,371.5
17	**Cash Expenditures for Nuclear Waste Management & Decommissioning**		237.8	282.0	247.3	252.7	442.2	604.9	653.5
18	**Contributions to Nuclear Segregated Funds**		102.5	102.5	200.1	200.1	200.1	116.4	39.2
19	**Pension Plan Contributions**		172.9	163.4	174.9	151.2	189.3	116.0	119.9
20	**OPEB/SPP Payments**		96.8	105.8	104.1	126.0	124.8	137.7	136.2
21	**Reversal of Return on Rate Base Recorded in Deferral and Variance Accounts**		(10.1)	8.2	22.4	77.0	36.8	52.3	89.2
22	**Deductible SR&ED Qualifying Expenditures**		83.8	89.2	102.4	118.6	150.9	106.4	106.4
23	**Other**		20.1	30.7	23.2	16.9	29.5	9.0	9.8
24	**Total Deductions**		1,593.6	1,720.3	1,910.2	2,138.7	2,270.8	2,313.6	2,525.6
25	**Regulatory Taxable Income/(Loss) Before Tax Loss Carry-Over** (line 1 + line 15 - line 24)		1,101.3	371.1	832.0	670.3	(152.3)	1,037.8	(81.0)
26	**Tax Loss Carry-Over**		0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	**Regulatory Taxable Income After Tax Loss Carry-Over** (line 25 + line 26)		1,101.3	371.1	832.0	670.3	(152.3)	1,037.8	(81.0)
28	**Regulatory Income Taxes - Federal** (line 27 x line 32)		165.2	55.7	124.8	100.5	(22.8)	155.7	(12.2)
29	**Regulatory Income Taxes - Provincial** (line 27 x line 33)		110.1	37.1	83.2	67.0	(15.2)	103.8	(8.1)
30	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		(23.8)	(25.1)	(23.2)	(23.9)	(25.1)	(19.9)	(19.9)
31	**Total Regulatory Income Taxes** (line 28 + line 29 + line 30)	3	251.6	67.7	184.8	143.7	(63.2)	239.5	(40.2)
	Income Tax Rate:								
32	**Federal Tax**		15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
33	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
34	**Total Income Tax Rate**		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%

For notes see Table 3a.

Table 3a
Notes to Table 3
Calculation of Regulatory Income Taxes for Prescribed Facilities ($M)
Years Ending December 31, 2020-2026

Notes:

1 Regulatory Earnings Before Tax for 2020 and 2021 are from Ex. C1-1-1, Tables 12a and 11a, line 9, col. (c), respectively. Regulatory Earnings Before Tax for 2022, 2023 and 2024 are from Ex. C1-1-1, Tables 10a, 9a and 8a, line 10, col. (c), respectively. Regulatory Earnings Before Tax for 2025 and 2026 are from Ex. I1-1-1, Tables 4 and 5, line 18, col. (c), respectively.

2 Amounts are the sum of CCA for the regulated hydroelectric facilities, as shown in Ex. F4-2-1, Tables 9-15, col. (j) minus (i), and for the nuclear facilities, as shown in Ex. F4-2-1, Tables 21-27, col. (j) minus (i) or col. (l) minus (i), as applicable.

3 To enable reconciliation to historical and bridge year regulatory ROE calculations, adjustments are made to the regulatory income taxes presented at line 33: line (b) is to reflect the inclusion of income tax amounts in certain deferral and variance accounts (i.e., the impact of tax additions and deductions that represent items for which the tax cost or benefit is being passed on to ratepayers through deferral and variance accounts); and line (c) is to exclude the benefit of tax losses forecasted in EB-2020-0290 to be carried forward beyond the 2022-2026 period.

		2020	2021	2022	2023	2024	2025	2026
(a)	Regulatory Income Taxes (line 32)	251.6	67.7	184.8	143.7	-63.2	239.5	-40.2
(b)	Income Tax Amounts Recorded in Deferral and Variance Accounts	15.5	37.4	-1.1	75.8	67.0	52.1	64.3
(c)	Tax Losses Carried Forward Beyond 2022-2026 (per EB-2020-0290 PAO, App. A, Table 22)[+]	0.0	32.5	35.7	26.1	-18.0	-6.0	-24.7
(d)	Regulatory Income Taxes for Regulatory ROE Purposes: (line (a) + (b) + (c))[++]	267.1	137.6	219.4	245.6	-14.2	285.6	-0.5

[+] The individual year amounts at line (c) for 2022-2026 are calculated as the year-over-year change in the forecast tax losses for the 2022-2026 period per EB-2020-0290 Payment Amounts Order, App. A, Table 22, line 4. The individual year amounts at line (c) for 2020 and 2021 are calculated as the year-over-year change in the forecast tax losses for the 2020-2021 period per EB-2016-0152 Payment Amounts Order, App. A, Table 22, line 4.

[++] The regulatory income taxes for regulatory ROE purposes shown above in 2020 and 2021 include minor corrections identified in the course of preparing this application.

4 For tax return reconciliation purposes, Taxable SR&ED Investment Tax Credits are shown at 100% recognition percentage for the historical years. For the bridge years, these amounts are shown at the accounting recognition percentage of 75% for consistency with the SR&ED ITCs in line 30.

Numbers may not add due to rounding.

Table 3b
Calculation of Regulatory Income Taxes - Regulated Hydroelectric ($M)
Years Ending December 31, 2027-2031

Line No.	Particulars	Note	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
			(a)	(b)	(c)	(d)	(e)
	Determination of Regulatory Taxable Income						
1	**Regulatory Earnings Before Tax**	1	470.2	539.4	610.0	645.0	679.5
	Additions for Regulatory Tax Purposes:						
2	**Depreciation and Amortization**		215.4	228.4	249.6	263.6	271.7
3	**Pension and OPEB Accrual**		44.2	45.6	45.6	45.6	45.7
4	**Regulatory Asset Amortization - Pension and OPEB Cash vs Accrual Differential Deferral Account**		(10.2)	(10.2)	(10.2)	0.0	0.0
5	**Regulatory Liability Amortization - Income and Other Taxes Variance Account**		(2.7)	(2.7)	(2.7)	0.0	0.0
6	**Restricted Net Interest and Financing Expenses**		0.0	0.0	0.0	0.0	0.0
7	**Taxable SR&ED Investment Tax Credits of Prior Periods & Current Provincial Portion**	4	3.3	3.3	3.3	3.3	3.3
8	**Other**		7.4	8.1	8.5	9.3	9.9
9	**Total Additions**		257.4	272.4	294.2	321.8	330.7
	Deductions for Regulatory Tax Purposes:						
10	**CCA**	2,3	537.7	448.3	468.7	473.6	477.8
11	**Pension Plan Contributions**		19.5	20.2	21.4	22.1	22.9
12	**OPEB Payments**		22.9	23.8	25.4	26.6	27.7
13	**Reversal of Return on Rate Base Recorded in Deferral and Variance Accounts**		0.0	0.0	0.0	0.0	0.0
14	**Deductible SR&ED Qualifying Expenditures**		25.0	25.0	25.0	25.0	25.0
15	**Other**		0.0	0.0	0.2	0.1	0.9
16	**Total Deductions**		605.1	517.3	540.6	547.4	554.3
17	**Regulatory Taxable Income Before Loss Carry-Over** (line 1 + line 9 - line 16)		122.5	294.5	363.6	419.5	455.8
18	**Tax Loss Carry-Over**		0.0	0.0	0.0	0.0	0.0
19	**Regulatory Taxable Income After Loss Carry-Over** (line 17 + line 18)		122.5	294.5	363.6	419.5	455.8
20	**Regulatory Income Taxes - Federal** (line 19 x line 25)		18.4	44.2	54.5	62.9	68.4
21	**Regulatory Income Taxes - Provincial** (line 19 x line 26)		12.2	29.4	36.4	41.9	45.6
22	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		(3.3)	(3.3)	(3.3)	(3.3)	(3.3)
23	**Total Regulatory Income Taxes** (line 20 + line 21 + line 22 + line 23)		27.3	70.3	87.6	101.6	110.7
	Income Tax Rate:						
24	**Federal Tax**		15.00%	15.00%	15.00%	15.00%	15.00%
25	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	10.00%	10.00%	10.00%	10.00%
26	**Total Income Tax Rate**		25.00%	25.00%	25.00%	25.00%	25.00%

For notes see Table 3c.

Numbers may not add due to rounding.

Table 3c
Notes to Table 3b
Calculation of Regulatory Income Taxes ($M) for Regulated Hydroelectric
Years Ending December 31, 2027-2031

Notes:
1 Regulatory Earnings Before Tax the regulated hydroelectrid facilities from 2027-2031 are calculated as follows :

Line No.	Item	Reference	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
			(a)	(b)	(c)	(d)	(e)
1a	After Tax Return on Equity - Regulated Hydroelectric	Col. (a): Ex. I1-1-1, Table 1, line 11 Col. (b) to (e): Ex. I1-2-1, Table 2, line 3, cols. (b) to (e)	432.8	458.9	512.3	543.4	568.8
2a	Additions for Regulatory Tax Purposes	line 9	257.4	272.4	294.2	321.8	330.7
3a	Less: Regulatory Asset Amort - Pension & OPEB Cash Vs Accrual Diff Def Act	Ex. H1-2-1, Table 1, lines 9-12	(10.2)	(10.2)	(10.2)	0.0	0.0
4a	Deductions for Regulatory Tax Purposes	line 16	605.1	517.3	540.6	547.4	554.3
5a		line 1a + line 2a - line 3a - line 4a	95.2	224.2	276.0	317.9	345.2
6a	Regulatory Income Taxes - Federal	(lines 5a + 12a + line 22) x line 24/ (1 - line 26)	18.4	44.2	54.5	62.9	68.4
7a	Regulatory Income Taxes - Provincial	(lines 5a + 12a + line 22) x line 25 / (1 - line 26)	12.2	29.4	36.4	41.9	45.6
8a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 22	(3.3)	(3.3)	(3.3)	(3.3)	(3.3)
9a	Total Regulatory Income Taxes Before Loss Carry-Over	line 6a + line 7a + line 8a	27.3	70.3	87.6	101.6	110.7
10a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	line 18 x line 24	0.0	0.0	0.0	0.0	0.0
11a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	line 18 x line 25	0.0	0.0	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	0.0	0.0
13a	Regulatory Income Taxes After Tax Loss Carry-Over - Federal	line 6a + line 10a	18.4	44.2	54.5	62.9	68.4
14a	Regulatory Income Taxes After Tax Loss Carry-Over - Provincial	line 7a + line 11a	12.2	29.4	36.4	41.9	45.6
15a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 22	(3.3)	(3.3)	(3.3)	(3.3)	(3.3)
16a	Total Regulatory Income Taxes After Tax Loss Carry-Over	line 13a + line 14a + line 15a	27.3	70.3	87.6	101.6	110.7
17a	After Tax Return on Equity	line 1a	432.8	458.9	512.3	543.4	568.8
18a	Less: Regulatory Asset Amort - Pension & OPEB Cash Vs Accrual Diff Def Act	line 3a	(10.2)	(10.2)	(10.2)	0.0	0.0
19a	Add: Total Regulatory Income Taxes After Tax Loss Carry-Over	line 16a	27.3	70.3	87.6	101.6	110.7
20a	Regulatory Earnings Before Tax	lines 17a - 18a + 19a	470.2	539.4	610.0	645.0	679.5

2 Amounts are from Ex. F4-2-1, Tables 16-20, col. (j) minus (i).
3 Includes total annual CCA for regulated hydroelectric project expenditures forming part of the proposed 2027-2031 capital-related revenue requirements that have been identified as eligible for the Capacity Refurbishment Variance Account (shown in Ex. H1-1-1, Att. 5) as follows: 2027 - $277.4M, 2028 - $212.0M, 2029 - $220.2M, 2030 - $231.0M, 2031 - $246.4M.
4 For tax return reconciliation purposes, Taxable SR&ED Investment Tax Credits are shown at 100% recognition percentage for the historical years. For the bridge years and IR term, these amounts are shown at the accounting recognition percentage of 75% for consistency with the SR&ED ITCs in line 23.

Numbers may not add due to rounding.

Updated: 2026-03-10
EB-2025-0297
Exhibit F4
Tab 2
Schedule 1
Table 3d

Table 3d
Calculation of Regulatory Income Taxes - OPG Nuclear Facilities ($M)
Years Ending December 31, 2027-2031

Line No.	Particulars	Note	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
			(a)	(b)	(c)	(d)	(e)
	Determination of Regulatory Taxable Income						
1	**Regulatory Earnings Before Tax**	1	728.7	741.4	769.5	772.9	1,115.8
	Additions for Regulatory Tax Purposes:						
2	**Depreciation and Amortization**		663.3	708.5	730.3	779.8	992.6
3	**Nuclear Waste Management Expenses**		30.4	47.2	58.9	72.9	79.1
4	**Receipts from Nuclear Segregated Funds**		498.2	420.1	347.2	326.7	342.0
5	**Pension and OPEB Accrual**		226.6	224.8	233.2	239.0	251.0
6	**Regulatory Asset Amortization - Bruce Lease Net Revenues Variance Account**		(34.5)	(34.5)	(34.5)	0.0	0.0
7	**Regulatory Asset Amortization - Pension and OPEB Cash Versus Accrual Differential Deferral Account**		0.0	0.0	0.0	0.0	0.0
8	**Regulatory Liability Amortization - Income and Other Taxes Variance Account**		(0.7)	(0.7)	(0.7)	0.0	0.0
9	**Adjustment Related to Financing Cost for Nuclear Liabilities**		4.7	1.1	0.0	0.0	0.0
10	**Restricted Net Interest and Financing Expenses**		0.0	0.0	0.0	0.0	0.0
11	**Taxable SR&ED Investment Tax Credits of Prior Periods & Current Provincial Portion**	5	16.6	16.6	16.6	16.6	16.6
12	**Nuclear Fuel Expense Half Charge Adjustment**		(35.9)	30.2	1.2	12.7	20.4
13	**Other**		95.1	85.9	87.4	95.3	109.0
14	**Total Additions**		1,463.9	1,499.2	1,439.6	1,543.1	1,810.7
	Deductions for Regulatory Tax Purposes:						
15	**CCA**	2,3	1,266.2	1,496.1	1,945.0	2,169.5	2,268.4
16	**Cash Expenditures for Nuclear Waste & Decommissioning**		637.4	539.1	437.9	443.3	472.1
17	**Contributions to Nuclear Segregated Funds**		0.0	0.0	0.0	0.0	0.0
18	**Pension Plan Contributions**		100.6	103.4	109.0	111.6	115.3
19	**OPEB Payments**		118.0	122.4	129.6	134.3	139.4
20	**Reversal of Return on Rate Base Recorded in Deferral and Variance Accounts**		0.0	0.0	0.0	0.0	0.0
21	**Deductible SR&ED Qualifying Expenditures**		81.4	81.4	81.4	81.4	81.4
22	**Other**		9.7	9.8	10.6	10.0	14.6
23	**Total Deductions**		2,213.3	2,352.2	2,713.5	2,950.1	3,091.2
24	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 14 - line 24)		(20.6)	(111.5)	(504.5)	(634.2)	(164.6)
25	**Tax Loss Carry-Over / (Applied)**	4	20.6	111.5	504.5	634.2	164.6
26	**Regulatory Taxable Income After Tax Loss Carry-Over** (line 25 + line 26)		0.0	0.0	0.0	0.0	0.0
27	**Regulatory Income Taxes - Federal** (line 27 x line 33)		0.0	0.0	0.0	0.0	0.0
28	**Regulatory Income Taxes - Provincial** (line 27 x line 34)		0.0	0.0	0.0	0.0	0.0
29	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		(16.6)	(16.6)	(16.6)	(16.6)	(16.6)
30	**Total Regulatory Income Taxes** (line 28 + line 29 + line 30 + line 31)		(16.6)	(16.6)	(16.6)	(16.6)	(16.6)
	Income Tax Rate:						
31	**Federal Tax**		15.00%	15.00%	15.00%	15.00%	15.00%
32	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	10.00%	10.00%	10.00%	10.00%
33	**Total Income Tax Rate**		25.00%	25.00%	25.00%	25.00%	25.00%

For notes see Table 3f.

Numbers may not add due to rounding.

Updated: 2026-03-10
EB-2025-0297
Exhibit F4
Tab 2
Schedule 1
Table 3e

Table 3e
2027 - 2031 Summary of OPG Nuclear Regulatory Losses ($M)

Line No.	Particulars	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
1	**Tax Loss Brought Forward**	1	(373.4)	(394.0)	(505.6)	(1,010.0)	(1,644.2)
2	**Income/(Loss) for the Year**	2	(20.6)	(111.5)	(504.5)	(634.2)	(164.6)
3	**Tax Loss Applied**		0.0	0.0	0.0	0.0	0.0
4	**Tax Loss Carried Forward** (Line 1 + Line 2 + Line 3)		(394.0)	(505.6)	(1,010.0)	(1,644.2)	(1,808.8)

Notes:
1 2027: Tax Loss Brought Forward per EB-2020-0290 PAO Appendix A, Table 22, line 4, col. (e).
2 Ex. F4-2-1, Table 3d, line 25.

Numbers may not add due to rounding.

Table 3f
Notes to Table 3d
Calculation of Regulatory Income Taxes ($M) for OPG Nuclear
Years Ending December 31, 2027-2031

Notes:

1 Regulatory Earnings Before Tax for the OPG nuclear facilities from 2027 - 2031 are calculated as follows :

Line No.	Item	Reference	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
			(a)	(b)	(c)	(d)	(e)
1a	After Tax Return on Equity - Presecribed Nuclear Facilities	Ex. I1-1-1, Table 2, line 12 plus line 12a	740.1	769.6	768.0	796.8	1,115.4
2a	Less: Bruce Lease Net Revenues	Ex. G2-2-1, Table 1, Line 3	(5.2)	11.5	(18.1)	7.3	(17.1)
3a		line 1a - line 2a	745.4	758.1	786.1	789.5	1,132.5
4a	Additions for Regulatory Tax Purposes	line 14	1,463.9	1,499.2	1,439.6	1,543.1	1,810.7
5a	Less: Regulatory Asset Amort - Pension & OPEB Cash Vs Accrual Diff Def Act	Ex. H1-2-1, Table 2, Lines 14-17	0.0	0.0	0.0	0.0	0.0
6a	Deductions for Regulatory Tax Purposes	line 23	2,213.3	2,352.2	2,713.5	2,950.1	3,091.2
7a		line 3a + line 4a - line 5a - line 6a	(4.0)	(94.9)	(487.8)	(617.6)	(148.0)
8a	Regulatory Income Taxes - Federal	(lines 7a + 14a + line 29) x line 31/ (1 - line 33)	(3.1)	(16.7)	(75.7)	(95.1)	(24.7)
9a	Regulatory Income Taxes - Provincial	(lines 7a + 15a + line 29) x line 32/ (1 - line 33)	(2.1)	(11.2)	(50.4)	(63.4)	(16.5)
10a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 29	(16.6)	(16.6)	(16.6)	(16.6)	(16.6)
11a	Total Regulatory Income Taxes Before Loss Carry-Over	line 8a + line 9a + line 10a	(21.8)	(44.5)	(142.7)	(175.2)	(57.8)
12a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	line 25 x line 31	3.1	16.7	75.7	95.1	24.7
13a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	line 25 x line 32	2.1	11.2	50.4	63.4	16.5
14a	Reduction in Total Regulatory Income Taxes Due to Loss Carry-Over	line 12a + line 13a	5.2	27.9	126.1	158.5	41.2
15a	Regulatory Income Taxes After Tax Loss Carry-Over - Federal	line 8a + line 12a	0.0	0.0	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	0.0	0.0
17a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 29	(16.6)	(16.6)	(16.6)	(16.6)	(16.6)
18a	Total Regulatory Income Taxes After Tax Loss Carry-Over	line 15a + line 16a + line 17a	(16.6)	(16.6)	(16.6)	(16.6)	(16.6)
19a	After Tax Return on Equity	line 1a	740.1	769.6	768.0	796.8	1,115.4
20a	Less: Bruce Lease Net Revenues	line 2a	(5.2)	11.5	(18.1)	7.3	(17.1)
21a	Less: Regulatory Asset Amort - Pension & OPEB Cash Vs Accrual Diff Def Act	line 5a	0.0	0.0	0.0	0.0	0.0
22a	Add: Total Regulatory Income Taxes After Tax Loss Carry-Over	line 18a	(16.6)	(16.6)	(16.6)	(16.6)	(16.6)
23a	Regulatory Earnings Before Tax	lines 19a - 20a - 21a + 22a	728.7	741.4	769.5	772.9	1,115.8

2 Amounts are from Ex. F4-2-1, Tables 28-32, col. (j) minus (i).

3 As discussed in Ex. F4-2-1, section 3.2.1, OPG has elected to claim "long-term project" CCA for the Pickering Refurbishment Program expenditures available under the Income Tax Act (Canada). Resulting total annual CCA for the Pickering Refurbishment Program expenditures is as follows: 2027 - $275.9M, 2028 - $572.1M, 2029 - $953.7M, 2030 - $1,169.4M, 2031 - $1,241.9M.

Consistent with EB-2016-0152 and EB-2020-0290, OPG continues to claim "long-term project" CCA for the Darlington Refurbishment Program expenditures available under the Income Tax Act (Canada) as well. Resulting total annual CCA for the Darlington Refurbishment Program expenditures, post disallowance applied to the D2O project, is as follows: 2027 - $484.4M, 2028 - $445.8M, 2029 - $410.4M, 2030 - $377.8M, 2031 - $348.0M.

Amounts also include total annual CCA for nuclear project expenditures, excluding the Pickering Refurbishment Program and Darlington Refurbishment Program, forming part of the proposed 2027-2031 capital-related revenue requirements that have been identified as eligible for the Capacity Refurbishment Variance Account (shown in Ex. H1-1-1, Att. 8) as follows: 2027 - $60.5M, 2028 - $89.8M, 2029 - $135.2M, 2030 - $164.9M, 2031 - $200.2M.

4 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 IR term, the loss is applied (carried back or carried forward) to reduce the nuclear business unit's taxable income in other years of the IR term, with any remaining tax losses carried forward to future IR terms.

5 For tax return reconciliation purposes, Taxable SR&ED Investment Tax Credits are shown at 100% recognition percentage for the historical years. For the bridge years and IR term, these amounts are shown at the accounting recognition percentage of 75% for consistency with the SR&ED ITCs in line 30.

Table 3g
Calculation of Regulatory Income Taxes - DNNP Facilities ($M)
Years Ending December 31, 2026-2031

Line No.	Particulars	Note	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
			(a)	(b)	(c)	(d)	(e)	(f)
	Determination of Regulatory Taxable Income							
1	**Regulatory Earnings Before Tax**	1	0.0	0.0	0.0	0.2	124.9	594.9
	Additions for Regulatory Tax Purposes:							
2	**Depreciation and Amortization**		0.0	0.0	0.0	0.0	22.6	109.7
3	**Pension and OPEB Accrual**	4	10.0	14.1	13.3	11.9	10.1	9.5
4	**Restricted Net Interest and Financing Expense**		0.0	0.0	0.0	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	0.0	0.0	0.0
6	**Other**		0.0	0.0	0.0	0.0	0.0	0.0
7	**Total Additions**		10.0	14.1	13.3	11.9	32.7	119.2
	Deductions for Regulatory Tax Purposes:							
8	**CCA**	2	0.0	195.5	311.1	345.0	365.6	377.3
9	**Pension Plan Contributions**	5	0.6	1.4	0.3	0.4	0.2	0.3
10	**OPEB Payments**	5	9.4	12.7	13.0	11.5	9.9	9.2
11	**Reversal of Return on Rate Base Recorded in Deferral and Variance Accounts**		0.0	0.0	0.0	0.0	0.0	0.0
12	**Deductible SR&ED Qualifying Expenditures**		0.0	0.0	0.0	0.0	0.0	0.0
13	**Other**		0.0	0.0	0.0	0.0	0.0	0.0
14	**Total Deductions**		10.0	209.6	324.4	356.9	375.7	386.8
15	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 7 - line 14)		0.0	(195.5)	(311.1)	(344.8)	(218.1)	327.3
16	**Tax Loss (Income) Attributable to Non-taxable Partners** (line 15 x 22.5%)	3	0.0	44.0	70.0	77.6	49.1	(73.7)
17	**Tax Loss (Income) Attributable to Taxable Partners** (line 15 x 77.5%)	5	0.0	151.5	241.1	267.2	169.0	(253.7)
18	**Regulatory Taxable Income After Tax Loss Carry-Over Subject to Tax** ([line 15 x 77.5%] + line 17)	5	0.0	0.0	0.0	0.0	0.0	0.0
19	**Regulatory Income Taxes - Federal** (line 18 x line 24)		0.0	0.0	0.0	0.0	0.0	0.0
20	**Regulatory Income Taxes - Provincial** (line 18 x line 25)		0.0	0.0	0.0	0.0	0.0	0.0
21	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		0.0	0.0	0.0	0.0	0.0	0.0
22	**Less: SR&ED Investment Tax Credits - Non-Controlling Partners** (line 21 x 22.5%)		0.0	0.0	0.0	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	0.0	0.0	0.0
	Income Tax Rate:							
24	**Federal Tax**		15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
25	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
26	**Total Income Tax Rate**		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%

For notes see Table 3i.

Numbers may not add due to rounding.

Table 3h

2027 - 2031 Summary of DNNP Facilities Regulatory Losses - Taxable Partners ($M)

Line No.	Particulars	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
1	**Tax Loss attributable to Taxable Partners Brought Forward**		0.0	(151.5)	(392.6)	(659.8)	(828.8)
2	**Income/(Loss) for the Year attributable to Taxable Partners**	1	(151.5)	(241.1)	(267.2)	(169.0)	0.0
3	**Tax Loss attributable to Taxable Partners Applied**	2	0.0	0.0	0.0	0.0	253.7
4	**Tax Loss attributable to Taxable Partners Carried Forward -** (Line 1 + Line 2 + Line 3)		(151.5)	(392.6)	(659.8)	(828.8)	(575.1)

Notes:

1 Ex. F4-2-1, Table 3g, line 17, col. (b) to (e), for 2027-2030.

2 Ex. F4-2-1, Table 3g, line 17, col. (f) for 2031.

Table 3i
Notes to Table 3g
Calculation of Regulatory Income Taxes ($M)
Years Ending December 31, 2027-2031

Notes:

1 Regulatory Earnings Before Tax for the Darlington New Nuclear Program from 2027 - 2031 are calculated as follows :

Line No.	Item	Reference	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
			(a)	(b)	(c)	(d)	(e)
1a	After Tax Return on Equity - Darlington New Nuclear Program	Ex. I1-1-1, Table 2a, line 11	0.0	0.0	0.2	124.9	594.9
2a	Additions for Regulatory Tax Purposes	line 7	14.7	16.3	17.1	40.7	129.9
3a	Deductions for Regulatory Tax Purposes	line 14	210.2	327.4	362.1	383.7	397.5
4a		line 1a + line 2a - line 3a	(195.5)	(311.1)	(344.8)	(218.1)	327.3
5a	Regulatory Income Taxes - Federal	(lines 4a + 11a + line 21) x line 24/ (1 - line 26)	(29.3)	(46.7)	(51.7)	(32.7)	49.1
6a	Regulatory Income Taxes - Provincial	(lines 4a + 11a + line 21) x line 25/ (1 - line 26)	(19.5)	(31.1)	(34.5)	(21.8)	32.7
7a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 21	0.0	0.0	0.0	0.0	0.0
8a	Total Regulatory Income Taxes Before Loss Carry-Over	line 5a + line 6a + line 7a	(48.9)	(77.8)	(86.2)	(54.5)	81.8
9a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	(line 16 + line 17) x line 24	29.3	46.7	51.7	32.7	(49.1)
10a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	(line 16 + line 17) x line 25	19.5	31.1	34.5	21.8	(32.7)
11a	Reduction in Total Regulatory Income Taxes Due to Loss Carry-Over	line 9a + line 10a	48.9	77.8	86.2	54.5	(81.8)
12a	Regulatory Income Taxes After Tax Loss Carry-Over - Federal	line 5a + line 9a	0.0	0.0	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	0.0	0.0
14a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 7a	0.0	0.0	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	0.0	0.0
16a	After Tax Return on Equity	line 1a	0.0	0.0	0.2	124.9	594.9
17a	Add: Total Regulatory Income Taxes After Tax Loss Carry-Over	line 15a	0.0	0.0	0.0	0.0	0.0
18a	Regulatory Earnings Before Tax	line 16a + line 17a	0.0	0.0	0.2	124.9	594.9

2 Amounts are from Ex. F4-2-1, Tables 33-37, col. (j) - (i).

3 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 IR term, the loss is applied (carried back or carried forward) to reduce the DNNP's taxable income in other years of the IR term, with any remaining tax losses carried forward to future IR terms.

4 The DNNP facilities will pay OPG its attributed portion of OPG's pension and OPEB accrual costs under the respective agreements. As a result, its pension plan contributions and OPEB payments are equivalent to its pension and OPEB accrual.

5 DNNP LP is a limited partnership in which non-controlling investors hold a stake of 22.5% and as a result, are entitled to utilize the corresponding proportion of the entity's tax loss carry-over each year. Thefore, the DNNP facilities' revenue requirement only reflects the impact of the remaining 77.5% of tax loss carry-over each year.

Numbers may not add due to rounding.

Table 4
Reconciliation of OPG's Tax Returns to Regulatory Income Tax Calculation for Prescribed Facilities ($M)
Year Ending December 31, 2024

Line No.	Particulars	2024 Tax Returns					Adjustments		(e) - (f) - (g)
		OPG Inc.	Subsidiaries	(a) + (b) Total[1]	Unregulated	(c) - (d) Regulated[2]	Bruce Lease[3]	Other Adjustments[4]	Regulatory Tax Calc'n[5]
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Determination of Taxable Income								
1	**Earnings Before Tax**	[redacted]				1,127.6	93.6	543.0	491.0
	Additions for Tax Purposes:								
2	**Depreciation and Amortization**					927.4	0.0	195.9	731.5
3	**Nuclear Waste Management Expenses (incl Accretion Expense)**					1,351.1	618.8	663.9	68.3
4	**Receipts from Nuclear Segregated Funds**					251.6	95.0	0.0	156.6
5	**Pension and OPEB Accrual**					240.3	0.0	(78.3)	318.6
6	**Regulatory Asset Amortization - Bruce Lease Net Revenues Variance Account**					28.4	0.0	0.0	28.4
7	**Regulatory Liability Amortization - Income and Other Taxes Variance Account**					(9.8)	0.0	0.0	(9.8)
8	**Regulatory Asset and Liability Amortization - Other Variance and Deferral Accounts**					164.4	0.0	(51.2)	215.6
9	**Adjustment Related to Financing Cost for Nuclear Liabilities**					0.0	0.0	(9.4)	9.4
10	**Nuclear fuel Expense Half Charge Adjustment**					3.0	0.0	0.0	3.0
11	**Taxable SR&ED Investment Tax Credits**					32.1	0.0	0.0	32.1
12	**Other**					101.8	9.74	18.16	73.9
13	**Total Additions**					3,090.1	723.6	739.0	1,627.6
	Deductions for Tax Purposes:								
14	**CCA**					1,109.6	5.6	6.59	1,097.3
15	**Cash Expenditures for Nuclear Waste Mngmt & Decommissioning and Facilities Removal**					691.3	249.2	0.0	442.2
16	**Contributions to and Earnings on Nuclear Segregated Funds**					1,100.8	273.7	627.1	200.1
17	**Pension Plan Contributions**					189.3	0.0	0.0	189.3
18	**OPEB/SPP Payments**					124.7	0.0	0.0	124.7
19	**Reversal of Nuclear Liability Deferral Account Additions**					159.2	0.0	159.2	0.0
20	**Reversal of Pension and OPEB Cost Variance Account Additions**					(129.880)	0.0	(129.9)	0.0
21	**Reversal of Regulatory Asset and Liability - Other Deferral and Variance Account Additions**					240.9	0.0	240.9	0.0
22	**Reversal of Return on Rate Base Recorded in Deferral and Variance Accounts**					0.0	0.0	(36.8)	36.8
23	**Deductible SR&ED Qualifying Expenditures**					150.9	0.0	0.0	150.9
24	**Construction In Progress Interest Capitalized**					121.5	0.0	121.5	0.0
25	**Other**					34.9	9.10	(3.65)	29.5
26	**Total Deductions**					3,793.3	537.6	984.9	2,270.8
27	**Taxable Income** (line 1 + line 13 - line 26)					424.4	279.6	297.0	(152.2)

Notes:

1 Represents the consolidated OPG amounts from its Canadian operations as reported in OPG's 2024 audited consolidated financial statements.

2 Represents amounts for OPG's "regulated" segments as reported in accordance with generally accepted accounting principles in OPG's audited consolidated financial statements.

3 Represents Bruce Lease net revenues included in col. (f). Bruce Lease earnings before tax at line 1 are as per Ex. G2-2-1 Table 7, col. (e), line 1 and taxable income at line 27 as per Ex. G2-2-1 Table 7, col. (e), line 16.

4 Represents items of income and expense reflected in OPG's income tax returns that do not form part of the regulatory income tax calculations as per OEB-approved methodology, and vice versa, as well as as line item presentation differences between the tax returns and the regulatory income tax calculation that do not impact taxable income.

5 Amounts are as shown in Ex. F4-2-1 Table 3, col. (e).

Numbers may not add due to rounding.

Table 5
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Hydroelectric Operations ($M)
Year Ending December 31, 2016

Line No.	Class	Undepreciated Capital Cost at Beginning of Year	Cost of Acquisitions	Cost of Acquisitions that are AIIP[1]	Net Adjustments[3]	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule or UCC adj for AIIP[2]	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	1,559.3	23.3	0.0	19.9	0.0	1,602.5	11.6	1,590.8	4%	0.0	63.6	1,538.8
2	**1-rolling start**	311.1	0.0	0.0	0.0	0.0	311.1	0.0	311.1	4%	0.0	12.4	298.6
3	**1.1**	19.7	4.8	0.0	0.0	0.0	24.5	2.4	22.1	6%	0.0	1.3	23.2
4	**2**	1,569.8	0.0	0.0	0.0	0.0	1,569.8	0.0	1,569.8	6%	0.0	94.2	1,475.6
5	**3**	0.3	0.0	0.0	0.0	0.0	0.3	0.0	0.3	5%	0.0	0.0	0.3
6	**6**	3.5	2.1	0.0	0.0	0.0	5.6	1.0	4.6	10%	0.0	0.5	5.1
7	**8**	32.4	5.4	0.0	0.0	0.2	37.6	2.6	35.0	20%	0.0	7.0	30.6
8	**10**	0.2	0.1	0.0	0.0	0.0	0.3	0.0	0.2	30%	0.0	0.1	0.2
9	**12**	0.3	5.8	0.0	0.0	0.0	6.1	2.9	3.2	100%	0.0	3.2	2.9
10	**13**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	n/a	0.0	0.0	0.0
11	**17**	284.9	18.1	0.0	0.0	0.0	303.0	9.0	293.9	8%	0.0	23.5	279.4
12	**42**	3.5	0.0	0.0	0.0	0.0	3.5	0.0	3.5	12%	0.0	0.4	3.1
13	**43.1**	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.1	30%	0.0	0.0	0.1
14	**43.2**	3.6	5.5	0.0	0.0	0.0	9.2	2.8	6.4	50%	0.0	3.2	6.0
15	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
16	**50**	0.4	0.7	0.0	0.0	0.0	1.1	0.4	0.8	55%	0.0	0.4	0.7
17	**Total**	3,789.3	65.7	0.0	19.9	0.2	3,874.8	32.8	3,842.0		0.0	209.9	3,664.8

Notes:

1 Represents Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and available for use before January 1, 2028. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

2 Half year rule was effective during this year as AIIP rules were not in place yet.

3 Net Adjustment in col. (c), line 1 is the undepreciated capital cost adjustment resulting from the difference between the original rate base addition disallowance ordered in EB-2013-0321 and the varied disallowance per EB-2014-0369 for the Niagara Tunnel Project.

Numbers may not add due to rounding.

Table 6
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Hydroelectric Operations ($M)
Year Ending December 31, 2017

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions	Cost of Acquisitions that are AIIP[2]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule or UCC adj for AIIP[3]	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	1,538.8	88.1	0.0	0.0	0.0	1,626.9	44.0	1,582.9	4%	0.0	63.3	1,563.6
2	**1-rolling start**	298.6	0.0	0.0	0.0	0.0	298.6	0.0	298.6	4%	0.0	11.9	286.7
3	**1.1**	23.2	3.2	0.0	0.0	0.0	26.4	1.6	24.8	6%	0.0	1.5	24.9
4	**2**	1,475.6	0.0	0.0	0.0	0.0	1,475.6	0.0	1,475.6	6%	0.0	88.5	1,387.1
5	**3**	0.3	0.0	0.0	0.0	0.0	0.3	0.0	0.3	5%	0.0	0.0	0.3
6	**6**	5.1	0.0	0.0	(0.0)	0.0	5.1	0.0	5.1	10%	0.0	0.5	4.6
7	**8**	30.6	14.9	0.0	0.0	0.2	45.3	7.4	37.9	20%	0.0	7.6	37.7
8	**10**	0.2	0.4	0.0	0.0	0.1	0.5	0.2	0.4	30%	0.0	0.1	0.4
9	**12**	2.9	1.6	0.0	0.0	0.0	4.5	0.8	3.7	100%	0.0	3.7	0.8
10	**13**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	n/a	0.0	0.0	0.0
11	**17**	279.4	49.8	0.0	0.0	0.0	329.2	24.9	304.3	8%	0.0	24.3	304.9
12	**42**	3.1	0.0	0.0	0.0	0.0	3.1	0.0	3.1	12%	0.0	0.4	2.7
13	**43.1**	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.1	30%	0.0	0.0	0.1
14	**43.2**	6.0	3.3	0.0	0.0	0.0	9.3	1.7	7.6	50%	0.0	3.8	5.5
15	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
16	**50**	0.7	1.1	0.0	0.0	0.0	1.8	0.6	1.3	55%	0.0	0.7	1.1
17	**Total**	3,664.8	162.4	0.0	(0.0)	0.3	3,827.0	81.1	3,745.9		0.0	206.5	3,620.5

Notes:

1 Amounts are from Ex. F4-2-1, Table 5, col. (k).

2 Represents Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and available for use before January 1, 2028. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 Half year rule was effective during this year as AIIP rules were not in place yet.

Numbers may not add due to rounding.

Table 7
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Hydroelectric Operations ($M)
Year Ending December 31, 2018

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions	Cost of Acquisitions that are AIIP[2]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule or UCC adj for AIIP[3]	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	1,563.6	71.5	4.6	0.0	0.0	1,635.1	31.2	1,603.9	4%	0.0	64.2	1,570.9
2	**1-rolling start**	286.7	0.0	0.0	0.0	0.0	286.7	0.0	286.7	4%	0.0	11.5	275.2
3	**1.1**	24.9	4.9	0.0	0.0	0.0	29.8	2.4	27.4	6%	0.0	1.6	28.2
4	**2**	1,387.1	0.0	0.0	0.0	0.0	1,387.1	0.0	1,387.1	6%	0.0	83.2	1,303.9
5	**3**	0.3	0.0	0.0	0.0	0.0	0.3	0.0	0.3	5%	0.0	0.0	0.3
6	**6**	4.6	0.0	0.0	0.0	0.0	4.6	0.0	4.6	10%	0.0	0.5	4.2
7	**8**	37.7	19.9	1.4	0.0	0.2	57.4	8.5	49.0	20%	0.0	9.8	47.6
8	**10**	0.4	0.4	0.0	0.0	0.2	0.6	0.1	0.5	30%	0.0	0.2	0.5
9	**12**	0.8	1.9	0.1	0.0	0.0	2.8	0.9	1.9	100%	0.0	1.9	0.9
10	**13**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	n/a	0.0	0.0	0.0
11	**14.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
12	**17**	304.9	44.2	2.0	0.0	0.0	349.1	20.1	329.0	8%	0.0	26.3	322.8
13	**42**	2.7	0.0	0.0	0.0	0.0	2.7	(0.0)	2.7	12%	0.0	0.3	2.4
14	**43.1**	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.1	30%	0.0	0.0	0.0
15	**43.2**	5.5	1.7	0.0	0.0	0.0	7.2	0.8	6.3	50%	0.0	3.2	4.0
16	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
17	**50**	1.1	1.0	0.0	0.0	0.0	2.1	0.5	1.6	55%	0.0	0.9	1.2
18	**Total**	3,620.5	145.5	8.1	0.0	0.4	3,765.6	64.6	3,701.0		0.0	203.5	3,562.1

Notes:

1 Amounts are from Ex. F4-2-1, Table 6, col. (k).

2 Represents Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and available for use before January 1, 2028. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 With AIIP rules effective for eligible property acquired after and available for use after November 20, 2018, the half year rule is suspended for AIIP until the former is phased out.

Numbers may not add due to rounding.

Table 8
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Hydroelectric Operations ($M)
Year Ending December 31, 2019

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions	Cost of Acquisitions that are AIIP[2]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule or UCC adj for AIIP[3]	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	1,570.9	71.8	35.8	0.0	0.0	1,642.7	0.1	1,642.6	4%	0.0	65.7	1,577.0
2	**1-rolling start**	275.2	0.0	0.0	0.0	0.0	275.2	0.0	275.2	4%	0.0	11.0	264.2
3	**1.1**	28.2	0.8	0.4	(3.4)	0.0	25.5	0.0	25.5	6%	0.0	1.5	24.0
4	**2**	1,303.9	0.0	0.0	0.0	0.0	1,303.9	0.0	1,303.9	6%	0.0	78.2	1,225.6
5	**3**	0.3	0.0	0.0	0.0	0.0	0.3	0.0	0.3	5%	0.0	0.0	0.3
6	**6**	4.2	3.2	2.5	3.4	0.0	10.8	(0.9)	11.7	10%	0.0	1.2	9.6
7	**8**	47.6	30.6	15.4	0.0	0.1	78.1	(0.2)	78.3	20%	0.0	15.7	62.5
8	**10**	0.5	0.5	0.3	0.0	0.0	0.9	(0.0)	1.0	30%	0.0	0.3	0.6
9	**12**	0.9	4.8	3.4	0.0	0.0	5.7	0.7	5.0	100%	0.0	5.0	0.7
10	**13**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	n/a	0.0	0.0	0.0
11	**14.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
12	**17**	322.8	41.0	24.7	0.0	0.0	363.7	(4.2)	368.0	8%	0.0	29.4	334.3
13	**42**	2.4	0.0	0.0	0.0	0.0	2.4	0.0	2.4	12%	0.0	0.3	2.1
14	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
15	**43.2**	4.0	58.3	26.8	0.0	0.0	62.3	(11.0)	73.3	50%	0.0	36.6	25.7
16	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
17	**50**	1.2	0.8	0.8	0.0	0.0	2.0	(0.4)	2.4	55%	0.0	1.3	0.7
18	**Total**	3,562.1	211.7	110.0	0.0	0.2	3,773.6	(15.9)	3,789.5		0.0	246.3	3,527.3

Notes:

1 Amounts are from Ex. F4-2-1, Table 7, col. (k).

2 Represents Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and available for use before January 1, 2028. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 With AIIP rules effective for eligible property acquired after and available for use after November 20, 2018, the half year rule is suspended for AIIP until the former is phased out.

Table 9
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Hydroelectric Operations ($M)
Year Ending December 31, 2020

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions	Cost of Acquisitions that are AIIP[2]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule or UCC adj for AIIP[3]	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	1,577.0	43.9	41.1	0.0	0.0	1,620.9	(19.2)	1,640.1	4%	0.0	65.6	1,555.3
2	**1-rolling start**	264.2	0.0	0.0	0.0	0.0	264.2	0.0	264.2	4%	0.0	10.6	253.6
3	**1.1**	24.0	4.8	4.7	0.0	0.0	28.7	(2.3)	31.0	6%	0.0	1.9	26.9
4	**2**	1,225.6	0.0	0.0	0.0	0.0	1,225.6	0.0	1,225.6	6%	0.0	73.5	1,152.1
5	**3**	0.3	0.0	0.0	0.0	0.0	0.3	0.0	0.3	5%	0.0	0.0	0.3
6	**6**	9.6	0.4	0.3	(0.6)	0.0	9.4	(0.2)	9.6	10%	0.0	1.0	8.5
7	**8**	62.5	25.4	24.0	0.0	0.1	87.7	(11.4)	99.1	20%	0.0	19.8	67.9
8	**10**	0.6	0.1	0.1	0.0	0.1	0.7	(0.1)	0.8	30%	0.0	0.2	0.4
9	**12**	0.7	8.8	8.4	0.0	0.0	9.5	0.2	9.3	100%	0.0	9.3	0.2
10	**13**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	n/a	0.0	0.0	0.0
11	**14.1**	0.0	4.7	4.7	0.0	0.0	4.7	(2.3)	7.0	5%	0.0	0.4	4.3
12	**17**	334.3	22.3	20.3	0.0	0.0	356.6	(9.1)	365.8	8%	0.0	29.3	327.4
13	**42**	2.1	0.0	0.0	0.0	0.0	2.1	0.0	2.1	12%	0.0	0.3	1.9
14	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
15	**43.2**	25.7	5.4	5.1	0.0	0.0	31.1	(4.9)	36.0	50%	0.0	18.0	13.1
16	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
17	**50**	0.7	1.0	1.0	0.0	0.0	1.7	(0.5)	2.2	55%	0.0	1.2	0.5
18	**Total**	3,527.3	116.8	109.8	(0.6)	0.2	3,643.4	(49.8)	3,693.2		0.0	231.0	3,412.4

Notes:

1 Amounts are from Ex. F4-2-1, Table 8, col. (k).

2 Represents Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and available for use before January 1, 2028. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 With AIIP rules effective for eligible property acquired after and available for use after November 20, 2018, the half year rule is suspended for AIIP until the former is phased out.

Numbers may not add due to rounding.

Table 10
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Hydroelectric Operations ($M)
Year Ending December 31, 2021

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions	Cost of Acquisitions that are AIIP[2]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule or UCC adj for AIIP[3]	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	1,555.3	117.2	108.8	(1.3)	0.0	1,671.3	(54.4)	1,725.7	4%	0.0	69.0	1,602.3
2	**1-rolling start**	253.6	0.0	0.0	0.0	0.0	253.6	0.0	253.6	4%	0.0	10.1	243.5
3	**1.1**	26.9	11.8	9.8	0.0	0.0	38.7	(3.9)	42.6	6%	0.0	2.6	36.1
4	**2**	1,152.1	0.0	0.0	0.0	0.0	1,152.1	0.0	1,152.1	6%	0.0	69.1	1,083.0
5	**3**	0.3	0.0	0.0	0.0	0.0	0.3	0.0	0.3	5%	0.0	0.0	0.2
6	**6**	8.5	0.0	0.0	(1.6)	0.0	6.9	(0.0)	6.9	10%	0.0	0.7	6.2
7	**8**	67.9	36.1	32.7	1.3	0.1	105.2	(14.7)	119.9	20%	0.0	24.0	81.2
8	**10**	0.4	0.6	0.6	0.0	0.1	1.0	(0.3)	1.3	30%	0.0	0.4	0.6
9	**12**	0.2	7.7	7.7	0.0	0.0	7.9	0.0	7.9	100%	0.0	7.9	0.0
10	**13**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	n/a	0.0	0.0	0.0
11	**14.1**	4.3	0.0	0.0	(4.8)	0.0	(0.5)	0.0	(0.5)	5%	0.0	(0.4)	(0.1)
12	**17**	327.4	32.2	13.4	0.0	0.0	359.6	2.8	356.8	8%	0.0	28.5	331.1
13	**42**	1.9	2.9	1.6	0.0	0.0	4.7	(0.1)	4.9	12%	0.0	0.6	4.2
14	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
15	**43.2**	13.1	5.7	5.7	0.0	0.0	18.8	(5.7)	24.5	50%	0.0	12.3	6.5
16	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
17	**50**	0.5	0.7	0.7	0.0	0.0	1.2	(0.4)	1.5	55%	0.0	0.8	0.3
18	**Total**	3,412.4	215.1	181.0	(6.4)	0.2	3,620.8	(76.8)	3,697.6		0.0	225.7	3,395.1

Notes:

1 Amounts are from Ex. F4-2-1, Table 9, col. (k).

2 Represents Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and available for use before January 1, 2028. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 With AIIP rules effective for eligible property acquired after and available for use after November 20, 2018, the half year rule is suspended for AIIP until the former is phased out.

Numbers may not add due to rounding.

Table 11
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Hydroelectric Operations ($M)
Year Ending December 31, 2022

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions	Cost of Acquisitions that are AIIP[2]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule or UCC adj for AIIP[3]	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	1,602.3	246.0	239.7	0.0	0.0	1,848.3	(116.7)	1,965.0	4%	0.0	78.6	1,769.7
2	**1-rolling start**	243.5	0.0	0.0	0.0	0.0	243.5	0.0	243.5	4%	0.0	9.7	233.7
3	**1.1**	36.1	16.8	16.4	0.0	0.0	52.9	(8.2)	61.0	6%	0.0	3.7	49.2
4	**2**	1,083.0	0.0	0.0	0.0	0.0	1,083.0	0.0	1,083.0	6%	0.0	65.0	1,018.0
5	**3**	0.2	0.0	0.0	0.0	0.0	0.2	0.0	0.2	5%	0.0	0.0	0.2
6	**6**	6.2	0.0	0.0	0.0	0.0	6.2	(0.0)	6.2	10%	0.0	0.6	5.6
7	**8**	81.2	52.6	57.8	12.4	0.2	146.1	(25.3)	171.4	20%	0.0	34.3	111.8
8	**10**	0.6	0.6	0.7	0.0	0.0	1.2	(0.3)	1.5	30%	0.0	0.5	0.8
9	**12**	0.0	11.0	11.0	0.0	0.0	11.0	0.0	11.0	100%	0.0	11.0	0.0
10	**13**	0.0					0.0	0.0	0.0	n/a	0.0	0.0	0.0
11	**14.1**	(0.1)	0.0	0.0	0.0	0.0	(0.1)	0.0	(0.1)	5%	0.0	(0.0)	(0.1)
12	**17**	331.1	143.6	131.2	(11.8)	0.0	462.9	(65.3)	528.2	8%	0.0	42.3	420.6
13	**42**	4.2	1.3	0.5	(1.3)	0.0	4.1	(0.5)	4.7	12%	0.0	0.6	3.6
14	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
15	**43.2**	6.5	24.9	24.9	(0.0)	0.0	31.5	(24.9)	56.4	50%	0.0	28.2	3.3
16	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
17	**50**	0.3	0.9	0.9	0.0	0.0	1.3	(0.5)	1.7	55%	0.0	0.9	0.3
18	**Total**	3,395.1	497.7	483.1	(0.7)	0.2	3,892.0	(241.7)	4,133.7		0.0	275.3	3,616.7

Notes:

1 Amounts are from Ex. F4-2-1, Table 10, col. (k).

2 Represents Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and available for use before January 1, 2028. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 With AIIP rules effective for eligible property acquired after and available for use after November 20, 2018, the half year rule is suspended for AIIP until the former is phased out.

Numbers may not add due to rounding.

Table 12
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Hydroelectric Operations ($M)
Year Ending December 31, 2023

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions	Cost of Acquisitions that are AIIP[2]	Net Adjustments[4]	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule or UCC adj for AIIP[3]	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	1,769.7	106.0	106.0	(84.6)	0.5	1,790.6	(52.8)	1,843.4	4%	0.0	73.7	1,716.9
2	**1-rolling start**	233.7	0.0	0.0	0.0	0.0	233.7	0.0	233.7	4%	0.0	9.3	224.4
3	**1.1**	49.2	25.0	25.0	(0.1)	0.0	74.1	(12.5)	86.6	6%	0.0	5.2	68.9
5	**2**	1,018.0	0.0	0.0	0.0	0.0	1,018.0	0.0	1,018.0	6%	0.0	61.1	956.9
6	**3**	0.2	0.0	0.0	0.0	0.0	0.2	0.0	0.2	5%	0.0	0.0	0.2
7	**6**	5.6	0.3	0.3	0.0	0.0	5.9	(0.1)	6.0	10%	0.0	0.6	5.3
8	**8**	111.8	37.7	37.7	(4.6)	0.2	144.7	(18.7)	163.4	20%	0.0	32.7	112.0
10	**10**	0.8	0.2	0.2	(0.0)	0.0	0.9	(0.1)	1.0	30%	0.0	0.3	0.6
11	**12**	0.0	10.1	10.1	0.1	0.0	10.1	0.0	10.1	100%	0.0	10.1	0.0
12	**13**	0.0	0.0	0.0	0.4	0.0	0.4	0.0	0.4	n/a	0.0	0.4	(0.0)
13	**14**	(0.1)	0.0	0.0	0.0	0.0	(0.1)	0.0	(0.1)	5%	0.0	(0.0)	(0.1)
14	**17**	420.6	35.1	35.1	(8.1)	0.0	447.7	(17.6)	465.2	8%	0.0	37.2	410.5
16	**42**	3.6	0.3	0.3	0.0	0.1	3.8	(0.1)	3.9	12%	0.0	0.5	3.3
17	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
18	**43.2**	3.3	145.6	145.6	(0.0)	0.0	148.9	(145.6)	294.5	50%	0.0	147.2	1.6
19	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
20	**50**	0.3	0.7	0.7	0.0	0.0	1.0	(0.3)	1.4	55%	0.0	0.7	0.3
21	**Total**	3,616.7	360.9	360.9	(96.9)	0.8	3,880.0	(247.9)	4,127.9		0.0	379.2	3,500.8

Notes:

1 Amounts are from Ex. F4-2-1, Table 11, col. (k).

2 Represents Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and available for use before January 1, 2028. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 With AIIP rules effective for eligible property acquired after and available for use after November 20, 2018, the half year rule is suspended for AIIP until the former is phased out.

4 Represents a reconciling adjustment related to prior years identified in the course of preparing the year's tax return.□

Numbers may not add due to rounding.

Table 13
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Hydroelectric Operations ($M)
Year Ending December 31, 2024

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions	Cost of Acquisitions that are AIIP[2]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule or UCC adj for AIIP[3]	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	1,716.9	217.5	217.5	0.0	0.0	1,934.4	0.0	1,934.4	4%	0.0	77.4	1,857.0
2	**1-rolling start**	224.4	0.0	0.0	0.0	0.0	224.4	0.0	224.4	4%	0.0	9.0	215.4
3	**1.1**	68.9	10.1	10.1	0.0	0.0	79.0	0.0	79.0	6%	0.0	4.7	74.2
4	**1.1-rolling start**	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**	956.9	0.0	0.0	0.0	0.0	956.9	0.0	956.9	6%	0.0	57.4	899.5
6	**3**	0.2	0.0	0.0	0.0	0.0	0.2	0.0	0.2	5%	0.0	0.0	0.2
7	**6**	5.3	1.7	1.7	0.0	0.0	6.9	0.0	6.9	10%	0.0	0.7	6.2
8	**8**	112.0	14.8	14.8	0.0	0.3	126.5	0.0	126.5	20%	0.0	25.3	101.2
9	**8-rolling start**	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**	0.6	0.2	0.2	0.0	0.0	0.8	0.0	0.8	30%	0.0	0.2	0.6
11	**12**	0.0	11.1	11.1	0.0	0.0	11.1	0.0	11.1	100%	0.0	11.1	0.0
12	**13**	(0.0)	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	n/a	0.0	0.0	(0.0)
13	**14.1**	(0.1)	0.0	0.0	0.0	0.0	(0.1)	0.0	(0.1)	5%	0.0	(0.0)	(0.1)
14	**17**	410.5	56.4	56.4	0.0	0.0	466.9	0.0	466.9	8%	0.0	37.3	429.5
15	**17-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
16	**42**	3.3	0.1	0.1	0.0	0.0	3.5	0.0	3.5	12%	0.0	0.4	3.1
17	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
18	**43.2**	1.6	24.6	24.6	0.0	0.0	26.2	(12.3)	38.5	50%	0.0	19.2	7.0
19	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
20	**50**	0.3	0.5	0.5	0.0	0.0	0.8	0.0	0.8	55%	0.0	0.4	0.4
21	**Total**	3,500.8	336.9	336.9	0.0	0.3	3,837.4	(12.3)	3,849.7		0.0	243.3	3,594.2

Notes:

1 Amounts are from Ex. F4-2-1, Table 12, col. (k).

2 Represents Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and available for use before January 1, 2028. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 With AIIP rules effective for eligible property acquired after and available for use after November 20, 2018, the half year rule is suspended for AIIP until the former is phased out.

Numbers may not add due to rounding.

Table 14
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Hydroelectric Operations ($M)
Year Ending December 31, 2025

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions	Cost of Acquisitions that are AIIP[2]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule or UCC adj for AIIP[3]	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	1,857.0	180.5	180.5	0.0	0.0	2,037.5	0.0	2,037.5	4%	0.0	81.5	1,956.0
2	**1-rolling start**	215.4	42.8	42.8	0.0	0.0	258.2	0.0	258.2	4%	0.0	10.3	247.9
3	**1.1**	74.2	19.3	19.3	0.0	0.0	93.5	0.0	93.5	6%	0.0	5.6	87.9
4	**1.1-rolling start**	0.0	4.4	4.4	0.0	0.0	4.4	0.0	4.4	6%	0.0	0.3	4.1
5	**2**	899.5	0.0	0.0	0.0	0.0	899.5	0.0	899.5	6%	0.0	54.0	845.5
6	**3**	0.2	0.0	0.0	0.0	0.0	0.2	0.0	0.2	5%	0.0	0.0	0.2
7	**6**	6.2	0.0	0.0	0.0	0.0	6.2	0.0	6.2	10%	0.0	0.6	5.6
8	**8**	101.2	43.3	43.3	0.0	0.0	144.5	0.0	144.5	20%	0.0	28.9	115.6
9	**8-rolling start**	0.0	10.4	10.4	0.0	0.0	10.4	0.0	10.4	20%	0.0	2.1	8.3
10	**10**	0.6	0.0	0.0	0.0	0.0	0.6	0.0	0.6	30%	0.0	0.2	0.4
11	**12**	0.0	14.8	14.8	0.0	0.0	14.8	0.0	14.8	100%	0.0	14.8	0.0
12	**12-rolling start**	0.0	3.1	3.1	0.0	0.0	3.1	0.0	3.1	100%	0.0	3.1	0.0
13	**13**	(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	0.0	0.0	0.0	(0.1)	0.0	(0.1)	5%	0.0	(0.0)	(0.1)
15	**17**	429.5	62.6	62.6	0.0	0.0	492.1	0.0	492.1	8%	0.0	39.4	452.7
16	**17-rolling start**	0.0	19.4	19.4	0.0	0.0	19.4	0.0	19.4	8%	0.0	1.5	17.8
17	**42**	3.1	0.0	0.0	0.0	0.0	3.1	0.0	3.1	12%	0.0	0.4	2.7
18	**43.1**	0.0	23.2	23.2	0.0	0.0	23.2	(34.8)	58.0	30%	0.0	17.4	5.8
19	**43.1-rolling start**	0.0	10.1	10.1	0.0	0.0	10.1	(15.1)	25.2	30%	0.0	7.5	2.5
20	**43.2**	7.0	0.0	0.0	0.0	0.0	7.0	0.0	7.0	50%	0.0	3.5	3.5
21	**45**	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**	0.4	0.3	0.3	0.0	0.0	0.7	0.0	0.7	55%	0.0	0.4	0.3
23	**Total**	3,594.2	434.2	434.2	0.0	0.0	4,028.3	(49.9)	4,078.2		0.0	271.4	3,756.9

Notes:

1 Amounts are from Ex. F4-2-1, Table 13, col. (k).

2 Represents Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and available for use before January 1, 2028. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 With AIIP rules effective for eligible property acquired after and available for use after November 20, 2018, the half year rule is suspended for AIIP until the former is phased out.

Numbers may not add due to rounding.

Table 15
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Hydroelectric Operations ($M)
Year Ending December 31, 2026

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions	Cost of Acquisitions that are AIIP[2]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule or UCC adj for AIIP[3]	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	1,956.0	193.9	193.9	0.0	0.0	2,150.0	0.0	2,150.0	4%	0.0	86.0	2,064.0
2	**1-rolling start**	247.9	30.0	30.0	0.0	0.0	277.9	0.0	277.9	4%	0.0	11.1	266.8
3	**1.1**	87.9	20.3	20.3	0.0	0.0	108.2	0.0	108.2	6%	0.0	6.5	101.8
4	**1.1-rolling start**	4.1	3.1	3.1	0.0	0.0	7.2	0.0	7.2	6%	0.0	0.4	6.7
5	**2**	845.5	0.0	0.0	0.0	0.0	845.5	0.0	845.5	6%	0.0	50.7	794.8
6	**3**	0.2	0.0	0.0	0.0	0.0	0.2	0.0	0.2	5%	0.0	0.0	0.2
7	**6**	5.6	0.0	0.0	0.0	0.0	5.6	0.0	5.6	10%	0.0	0.6	5.0
8	**8**	115.6	44.1	44.1	0.0	0.0	159.7	0.0	159.7	20%	0.0	31.9	127.8
9	**8-rolling start**	8.3	7.3	7.3	0.0	0.0	15.7	0.0	15.7	20%	0.0	3.1	12.5
10	**10**	0.4	0.0	0.0	0.0	0.0	0.4	0.0	0.4	30%	0.0	0.1	0.3
11	**12**	0.0	22.1	22.1	0.0	0.0	22.1	0.0	22.1	100%	0.0	22.1	0.0
12	**12-rolling start**	0.0	3.7	3.7	0.0	0.0	3.7	0.0	3.7	100%	0.0	3.7	0.0
13	**13**	(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	0.0	0.0	0.0	(0.1)	0.0	(0.1)	5%	0.0	(0.0)	(0.1)
15	**17**	452.7	69.8	69.8	0.0	0.0	522.5	0.0	522.5	8%	0.0	41.8	480.7
16	**17-rolling start**	17.8	13.6	13.6	0.0	0.0	31.4	0.0	31.4	8%	0.0	2.5	28.9
17	**42**	2.7	0.0	0.0	0.0	0.0	2.7	0.0	2.7	12%	0.0	0.3	2.4
18	**43.1**	5.8	163.1	163.1	0.0	0.0	168.9	(136.0)	304.9	30%	0.0	91.5	77.5
19	**43.1-rolling start**	2.5	51.2	51.2	0.0	0.0	53.7	(42.6)	96.3	30%	0.0	28.9	24.8
20	**43.2**	3.5	0.0	0.0	0.0	0.0	3.5	0.0	3.5	50%	0.0	1.7	1.7
21	**45**	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	0.3	0.3	0.0	0.0	0.6	0.0	0.6	55%	0.0	0.4	0.3
23	**Total**	3,756.9	622.8	622.8	0.0	0.0	4,379.6	(178.6)	4,558.2		0.0	383.5	3,996.1

Notes:

1 Amounts are from Ex. F4-2-1, Table 14, col. (k).

2 Represents Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and available for use before January 1, 2028. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 With AIIP rules effective for eligible property acquired after and available for use after November 20, 2018, the half year rule is suspended for AIIP until the former is phased out.

Numbers may not add due to rounding.

Table 16
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Hydroelectric Operations ($M)
Year Ending December 31, 2027

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions	Cost of Acquisitions that are AIIP[2]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule or UCC adj for AIIP[3]	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	2,064.0	266.5	266.5	0.0	0.0	2,330.5	0.0	2,330.5	4%	0.0	93.2	2,237.3
2	**1-rolling start**	266.8	162.4	162.4	0.0	0.0	429.2	0.0	429.2	4%	0.0	17.2	412.1
3	**1.1**	101.8	28.4	28.4	0.0	0.0	130.2	0.0	130.2	6%	0.0	7.8	122.4
4	**1.1-rolling start**	6.7	16.6	16.6	0.0	0.0	23.3	0.0	23.3	6%	0.0	1.4	21.9
5	**2**	794.8	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	0.0	0.0	0.0	0.2	0.0	0.2	5%	0.0	0.0	0.2
7	**6**	5.0	0.0	0.0	0.0	0.0	5.0	0.0	5.0	10%	0.0	0.5	4.5
8	**8**	127.8	63.5	63.5	0.0	0.0	191.2	0.0	191.2	20%	0.0	38.2	153.0
9	**8-rolling start**	12.5	39.6	39.6	0.0	0.0	52.1	0.0	52.1	20%	0.0	10.4	41.7
10	**10**	0.3	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	26.2	26.2	0.0	0.0	26.2	0.0	26.2	100%	0.0	26.2	0.0
12	**12-rolling start**	0.0	18.5	18.5	0.0	0.0	18.5	0.0	18.5	100%	0.0	18.5	0.0
13	**13**	(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	0.0	0.0	0.0	(0.1)	0.0	(0.1)	5%	0.0	(0.0)	(0.1)
15	**17**	480.7	100.0	100.0	0.0	0.0	580.8	0.0	580.8	8%	0.0	46.5	534.3
16	**17-rolling start**	28.9	73.5	73.5	0.0	0.0	102.4	0.0	102.4	8%	0.0	8.2	94.2
17	**42**	2.4	0.0	0.0	0.0	0.0	2.4	0.0	2.4	12%	0.0	0.3	2.1
18	**43.1**	77.5	116.7	116.7	0.0	0.0	194.1	(97.2)	291.4	30%	0.0	87.4	106.7
19	**43.1-rolling start**	24.8	227.9	227.9	0.0	0.0	252.7	(189.9)	442.7	30%	0.0	132.8	119.9
20	**43.2**	1.7	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	45%	0.0	0.0	0.0
22	**50**	0.3	0.4	0.4	0.0	0.0	0.7	0.0	0.7	55%	0.0	0.4	0.3
23	**Total**	3,996.1	1,140.3	1,140.3	0.0	0.0	5,136.4	(287.2)	5,423.6		0.0	537.7	4,598.7

Notes:

1 Amounts are from Ex. F4-2-1, Table 15, col. (k).

2 Represents Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and available for use before January 1, 2028. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 With AIIP rules effective for eligible property acquired after and available for use after November 20, 2018, the half year rule is suspended for AIIP until the former is phased out.

Numbers may not add due to rounding.

Table 17
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Hydroelectric Operations ($M)
Year Ending December 31, 2028

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions	Cost of Acquisitions that are AIIP[2]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule or UCC adj for AIIP[3]	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	2,237.3	336.9	0.0	0.0	0.0	2,574.2	168.5	2,405.7	4%	0.0	96.2	2,477.9
2	**1-rolling start**	412.1	122.7	0.0	0.0	0.0	534.7	0.0	534.7	4%	0.0	21.4	513.4
3	**1.1**	122.4	37.0	0.0	0.0	0.0	159.4	18.5	140.9	6%	0.0	8.5	151.0
4	**1.1-rolling start**	21.9	12.5	0.0	0.0	0.0	34.5	0.0	34.5	6%	0.0	2.1	32.4
5	**2**	747.1	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	0.0	0.0	0.0	0.2	0.0	0.2	5%	0.0	0.0	0.2
7	**6**	4.5	0.0	0.0	0.0	0.0	4.5	0.0	4.5	10%	0.0	0.5	4.1
8	**8**	153.0	84.0	0.0	0.0	0.0	237.0	42.0	195.0	20%	0.0	39.0	198.0
9	**8-rolling start**	41.7	29.9	0.0	0.0	0.0	71.6	0.0	71.6	20%	0.0	14.3	57.3
10	**10**	0.2	0.0	0.0	0.0	0.0	0.2	0.0	0.2	30%	0.0	0.1	0.2
11	**12**	0.0	28.7	0.0	0.0	0.0	28.7	14.4	14.4	100%	0.0	14.4	14.4
12	**12-rolling start**	0.0	15.1	0.0	0.0	0.0	15.1	0.0	15.1	100%	0.0	15.1	0.0
13	**13**	(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	0.0	0.0	0.0	(0.1)	0.0	(0.1)	5%	0.0	(0.0)	(0.1)
15	**17**	534.3	126.6	0.0	0.0	0.0	660.9	63.3	597.6	8%	0.0	47.8	613.1
16	**17-rolling start**	94.2	55.5	0.0	0.0	0.0	149.7	0.0	149.7	8%	0.0	12.0	137.7
17	**42**	2.1	0.0	0.0	0.0	0.0	2.1	0.0	2.1	12%	0.0	0.3	1.8
18	**43.1**	106.7	17.2	0.0	0.0	0.0	123.9	8.6	115.3	30%	0.0	34.6	89.3
19	**43.1-rolling start**	119.9	202.4	0.0	0.0	0.0	322.3	0.0	322.3	30%	0.0	96.7	225.6
20	**43.2**	0.9	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	45%	0.0	0.0	0.0
22	**50**	0.3	0.5	0.0	0.0	0.0	0.8	0.2	0.5	55%	0.0	0.3	0.5
23	**Total**	4,598.7	1,069.1	0.0	0.0	0.0	5,667.8	315.5	5,352.3		0.0	448.3	5,219.5

Notes:

1 Amounts are from Ex. F4-2-1, Table 16, col. (k).

2 Represents Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and available for use before January 1, 2028. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 With AIIP rules phased out after December 31, 2027, the half year rule is reinstated beginning January 1, 2028.

Numbers may not add due to rounding.

Table 18
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Hydroelectric Operations ($M)
Year Ending December 31, 2029

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions	Cost of Acquisitions that are AIIP[2]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule or UCC adj for AIIP[3]	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	2,477.9	473.9	0.0	0.0	0.0	2,951.8	236.9	2,714.9	4%	0.0	108.6	2,843.2
2	**1-rolling start**	513.4	129.7	0.0	0.0	0.0	643.1	0.0	643.1	4%	0.0	25.7	617.4
3	**1.1**	151.0	51.2	0.0	0.0	0.0	202.2	25.6	176.6	6%	0.0	10.6	191.6
4	**1.1-rolling start**	32.4	13.3	0.0	0.0	0.0	45.7	0.0	45.7	6%	0.0	2.7	42.9
5	**2**	702.3	0.0	0.0	0.0	0.0	702.3	0.0	702.3	6%	0.0	42.1	660.2
6	**3**	0.2	0.0	0.0	0.0	0.0	0.2	0.0	0.2	5%	0.0	0.0	0.2
7	**6**	4.1	0.0	0.0	0.0	0.0	4.1	0.0	4.1	10%	0.0	0.4	3.7
8	**8**	198.0	117.9	0.0	0.0	0.0	315.9	58.9	257.0	20%	0.0	51.4	264.5
9	**8-rolling start**	57.3	31.6	0.0	0.0	0.0	88.9	0.0	88.9	20%	0.0	17.8	71.1
10	**10**	0.2	0.0	0.0	0.0	0.0	0.2	0.0	0.2	30%	0.0	0.0	0.1
11	**12**	14.4	37.4	0.0	0.0	0.0	51.7	18.7	33.0	100%	0.0	33.0	18.7
12	**12-rolling start**	0.0	8.3	0.0	0.0	0.0	8.3	0.0	8.3	100%	0.0	8.3	0.0
13	**13**	(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	0.0	0.0	0.0	(0.1)	0.0	(0.1)	5%	0.0	(0.0)	(0.1)
15	**17**	613.1	188.0	0.0	0.0	0.0	801.1	94.0	707.1	8%	0.0	56.6	744.5
16	**17-rolling start**	137.7	58.7	0.0	0.0	0.0	196.4	0.0	196.4	8%	0.0	15.7	180.7
17	**42**	1.8	0.0	0.0	0.0	0.0	1.8	0.0	1.8	12%	0.0	0.2	1.6
18	**43.1**	89.3	0.2	0.0	0.0	0.0	89.6	0.1	89.5	30%	0.0	26.8	62.8
19	**43.1-rolling start**	225.6	0.7	0.0	0.0	0.0	226.3	0.0	226.3	30%	0.0	67.9	158.4
20	**43.2**	0.4	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	45%	0.0	0.0	0.0
22	**50**	0.5	0.5	0.0	0.0	0.0	1.0	0.3	0.7	55%	0.0	0.4	0.6
23	**Total**	5,219.5	1,111.4	0.0	0.0	0.0	6,330.9	434.5	5,896.4		0.0	468.7	5,862.2

Notes:

1 Amounts are from Ex. F4-2-1, Table 17, col. (k).

2 Represents Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and available for use before January 1, 2028. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 With AIIP rules phased out after December 31, 2027, the half year rule is reinstated beginning January 1, 2028.

Numbers may not add due to rounding.

Table 19
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Hydroelectric Operations ($M)
Year Ending December 31, 2030

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions	Cost of Acquisitions that are AIIP[2]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule or UCC adj for AIIP[3]	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	2,843.2	306.6	0.0	0.0	0.0	3,149.8	153.3	2,996.5	4%	0.0	119.9	3,029.9
2	**1-rolling start**	617.4	108.3	0.0	0.0	0.0	725.6	0.0	725.6	4%	0.0	29.0	696.6
3	**1.1**	191.6	34.0	0.0	0.0	0.0	225.6	17.0	208.6	6%	0.0	12.5	213.1
4	**1.1-rolling start**	42.9	11.1	0.0	0.0	0.0	54.0	0.0	54.0	6%	0.0	3.2	50.7
5	**2**	660.2	0.0	0.0	0.0	0.0	660.2	0.0	660.2	6%	0.0	39.6	620.5
6	**3**	0.2	0.0	0.0	0.0	0.0	0.2	0.0	0.2	5%	0.0	0.0	0.2
7	**6**	3.7	0.0	0.0	0.0	0.0	3.7	0.0	3.7	10%	0.0	0.4	3.3
8	**8**	264.5	76.9	0.0	0.0	0.0	341.4	38.5	303.0	20%	0.0	60.6	280.8
9	**8-rolling start**	71.1	26.4	0.0	0.0	0.0	97.5	0.0	97.5	20%	0.0	19.5	78.0
10	**10**	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.1	30%	0.0	0.0	0.1
11	**12**	18.7	27.4	0.0	0.0	0.0	46.1	13.7	32.4	100%	0.0	32.4	13.7
12	**12-rolling start**	0.0	6.9	0.0	0.0	0.0	6.9	0.0	6.9	100%	0.0	6.9	0.0
13	**13**	(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	0.0	0.0	0.0	(0.1)	0.0	(0.1)	5%	0.0	(0.0)	(0.1)
15	**17**	744.5	112.6	0.0	0.0	0.0	857.1	56.3	800.8	8%	0.0	64.1	793.0
16	**17-rolling start**	180.7	49.0	0.0	0.0	0.0	229.7	0.0	229.7	8%	0.0	18.4	211.3
17	**42**	1.6	0.0	0.0	0.0	0.0	1.6	0.0	1.6	12%	0.0	0.2	1.4
18	**43.1**	62.8	0.2	0.0	0.0	0.0	63.0	0.1	62.9	30%	0.0	18.9	44.1
19	**43.1-rolling start**	158.4	(0.2)	0.0	0.0	0.0	158.2	0.0	158.2	30%	0.0	47.5	110.7
20	**43.2**	0.2	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	45%	0.0	0.0	0.0
22	**50**	0.6	0.5	0.0	0.0	0.0	1.1	0.3	0.9	55%	0.0	0.5	0.7
23	**Total**	5,862.2	759.7	0.0	0.0	0.0	6,621.9	279.1	6,342.8		0.0	473.6	6,148.3

Notes:

1 Amounts are from Ex. F4-2-1, Table 18, col. (k).

2 Represents Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and available for use before January 1, 2028. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 With AIIP rules phased out after December 31, 2027, the half year rule is reinstated beginning January 1, 2028.

Numbers may not add due to rounding.

Table 20
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Hydroelectric Operations ($M)
Year Ending December 31, 2031

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions	Cost of Acquisitions that are AIIP[2]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule or UCC adj for AIIP[3]	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	3,029.9	353.8	0.0	0.0	0.0	3,383.7	176.9	3,206.8	4%	0.0	128.3	3,255.4
2	**1-rolling start**	696.6	125.4	0.0	0.0	0.0	822.1	0.0	822.1	4%	0.0	32.9	789.2
3	**1.1**	213.1	38.7	0.0	0.0	0.0	251.8	19.4	232.4	6%	0.0	13.9	237.9
4	**1.1-rolling start**	50.7	12.8	0.0	0.0	0.0	63.6	0.0	63.6	6%	0.0	3.8	59.7
5	**2**	620.5	0.0	0.0	0.0	0.0	620.5	0.0	620.5	6%	0.0	37.2	583.3
6	**3**	0.2	0.0	0.0	0.0	0.0	0.2	0.0	0.2	5%	0.0	0.0	0.1
7	**6**	3.3	0.0	0.0	0.0	0.0	3.3	0.0	3.3	10%	0.0	0.3	3.0
8	**8**	280.8	88.2	0.0	0.0	0.0	369.0	44.1	324.9	20%	0.0	65.0	304.0
9	**8-rolling start**	78.0	30.6	0.0	0.0	0.0	108.6	0.0	108.6	20%	0.0	21.7	86.9
10	**10**	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.1	30%	0.0	0.0	0.1
11	**12**	13.7	30.9	0.0	0.0	0.0	44.6	15.4	29.1	100%	0.0	29.1	15.4
12	**12-rolling start**	0.0	8.0	0.0	0.0	0.0	8.0	0.0	8.0	100%	0.0	8.0	0.0
13	**13**	(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	0.0	0.0	0.0	(0.1)	0.0	(0.1)	5%	0.0	(0.0)	(0.1)
15	**17**	793.0	134.4	0.0	0.0	0.0	927.4	67.2	860.2	8%	0.0	68.8	858.6
16	**17-rolling start**	211.3	56.8	0.0	0.0	0.0	268.1	0.0	268.1	8%	0.0	21.4	246.6
17	**42**	1.4	0.0	0.0	0.0	0.0	1.4	0.0	1.4	12%	0.0	0.2	1.3
18	**43.1**	44.1	(0.0)	0.0	0.0	0.0	44.1	0.0	44.1	30%	0.0	13.2	30.9
19	**43.1-rolling start**	110.7	0.0	0.0	0.0	0.0	110.7	0.0	110.7	30%	0.0	33.2	77.5
20	**43.2**	0.1	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	45%	0.0	0.0	0.0
22	**50**	0.7	0.5	0.0	0.0	0.0	1.2	0.3	0.9	55%	0.0	0.5	0.7
23	**Total**	6,148.3	880.1	0.0	0.0	0.0	7,028.4	323.3	6,705.2		0.0	477.8	6,550.6

Notes:

1 Amounts are from Ex. F4-2-1, Table 19, col. (k).

2 Represents Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and available for use before January 1, 2028. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 With AIIP rules phased out after December 31, 2027, the half year rule is reinstated beginning January 1, 2028.

Numbers may not add due to rounding.

Table 21
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Nuclear Operations ($M)
Year Ending December 31, 2020

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions	Cost of Acquisitions that are AIIP[2]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule or UCC adj for AIIP[3]	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	806.9	223.6	223.6	0.0	0.0	1,030.5	(111.8)	1,142.3	4%	0.0	45.7	984.8
2	**1-rolling start**	134.2	0.0	0.0	0.0	0.0	134.2	0.0	134.2	4%	0.0	5.4	128.9
3	**1.1**	407.8	50.4	50.4	(0.8)	0.0	457.5	(25.2)	482.7	6%	0.0	29.0	428.5
4	**1.1-rolling start**	265.9	0.0	0.0	0.0	0.0	265.9	0.0	265.9	6%	0.0	16.0	250.0
5	**2**	(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)	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	10%	0.0	0.0	0.0
8	**8**	242.2	71.7	71.7	0.0	0.2	313.7	(35.9)	349.6	20%	0.0	69.9	243.8
9	**8-rolling start**	51.6	0.0	0.0	(3.8)	0.0	47.8	0.0	47.8	20%	0.0	9.6	38.2
10	**10**	10.1	0.8	0.4	0.0	0.4	10.5	(0.2)	10.6	30%	0.0	3.2	7.3
11	**12**	5.6	27.9	27.9	0.0	0.0	33.5	0.0	33.5	100%	0.0	33.5	0.0
12	**13**	2.6	0.0	0.0	0.0	0.0	2.6	0.0	2.6	n/a	0.0	0.5	2.1
13	**14.1**	6.0	0.0	0.0	0.0	0.0	6.0	0.0	6.0	7%	0.0	0.4	5.6
14	**14.1**	14.9	0.0	0.0	0.0	0.0	14.9	0.0	14.9	5%	0.0	0.7	14.1
15	**17**	3,423.4	548.3	548.3	(0.2)	0.0	3,971.5	(274.2)	4,245.7	8%	0.0	339.7	3,631.9
16	**17-rolling start**	1,162.9	41.5	41.5	3.8	0.0	1,208.2	(20.7)	1,229.0	8%	0.0	98.3	1,109.9
17	**26**	0.0	0.4	0.4	0.0	0.0	0.4	(0.2)	0.6	5%	0.0	0.0	0.4
18	**42**	0.1	2.9	2.9	0.0	0.0	3.0	(1.4)	4.4	12%	0.0	0.5	2.5
19	**43.1**	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	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	45%	0.0	0.0	0.0
22	**50**	4.5	4.9	4.9	0.0	0.0	9.3	(2.4)	11.7	55%	0.0	6.5	2.9
23	**Total**	6,539.0	972.3	971.9	(1.0)	0.6	7,509.6	(472.1)	7,981.7		0.0	658.9	6,850.7

Notes:

1 Amounts are from EB-2020-0290, Ex. F4-2-1, Table 8, col. (k)

2 Represents Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and available for use before January 1, 2028. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 With AIIP rules effective for eligible property acquired after and available for use after November 20, 2018, the half year rule is suspended for AIIP until the former is phased out.

Numbers may not add due to rounding.

Table 22
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Nuclear Operations ($M)
Year Ending December 31, 2021

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions	Cost of Acquisitions that are AIIP[2]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule or UCC adj for AIIP[3]	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	984.8	70.6	70.6	0.0	0.0	1,055.4	(35.3)	1,090.7	4%	0.0	43.6	1,011.8
2	**1-rolling start**	128.9	0.0	0.0	0.0	0.0	128.9	0.0	128.9	4%	0.0	5.2	123.7
3	**1.1**	428.5	31.5	31.5	0.0	0.0	460.1	(15.8)	475.8	6%	0.0	28.6	431.5
4	**1.1-rolling start**	250.0	0.0	0.0	0.0	0.0	250.0	0.0	250.0	6%	0.0	15.0	235.0
5	**2**	(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)	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	10%	0.0	0.0	0.0
8	**8**	243.8	112.1	112.1	0.0	0.4	355.4	(56.3)	411.7	20%	0.0	82.3	273.1
9	**8-rolling start**	38.2	0.0	0.0	0.0	0.0	38.2	0.0	38.2	20%	0.0	7.6	30.6
10	**10**	7.3	2.5	2.3	0.0	0.2	9.6	(1.1)	10.7	30%	0.0	3.2	6.4
11	**12**	0.0	36.3	36.3	0.0	0.0	36.3	0.0	36.3	100%	0.0	36.3	0.0
12	**13**	2.1	0.0	0.0	0.0	0.0	2.1	0.0	2.1	n/a	0.0	0.5	1.5
13	**14.1**	5.6	0.0	0.0	0.0	0.0	5.6	0.0	5.6	7%	0.0	0.4	5.2
14	**14.1**	14.1	0.0	0.0	0.0	0.0	14.1	0.0	14.1	5%	0.0	0.7	13.4
15	**17**	3,631.9	843.8	843.8	0.0	0.0	4,475.7	(421.9)	4,897.6	8%	0.0	391.8	4,083.9
16	**17-rolling start**	1,109.9	4.7	4.7	0.0	0.0	1,114.6	(2.3)	1,116.9	8%	0.0	89.4	1,025.2
17	**26**	0.4	0.0	0.0	(0.0)	0.0	0.4	0.0	0.4	5%	0.0	0.0	0.4
18	**42**	2.5	15.6	15.6	0.0	0.0	18.1	(7.8)	25.9	12%	0.0	3.1	15.0
19	**43.1**	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	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	45%	0.0	0.0	0.0
22	**50**	2.9	4.3	4.3	0.0	0.0	7.1	(2.1)	9.3	55%	0.0	5.1	2.0
23	**Total**	6,850.7	1,121.3	1,121.1	0.0	0.6	7,971.5	(542.6)	8,514.1		0.0	712.8	7,258.6

Notes:

1 Amounts are from Ex. F4-2-1, Table 21, col. (k).

2 Represents Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and available for use before January 1, 2028. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 With AIIP rules effective for eligible property acquired after and available for use after November 20, 2018, the half year rule is suspended for AIIP until the former is phased out.

Numbers may not add due to rounding.

Filed: 2025-12-12
EB-2025-0297
Exhibit F4
Tab 2
Schedule 1
Table 23

Table 23
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Nuclear Operations ($M)
Year Ending December 31, 2022

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions	Cost of Acquisitions that are AIIP[2]	Net Adjustments[4]	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule or UCC adj for AIIP[3]	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	Capital Cost Allowance DIEP[5]	(j) + (k) Capital Cost Allowance	(e)+(i)-(l) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	**1**	1,011.8	51.7	51.7	3.2	0.0	1,066.7	(25.9)	1,092.5	4%	0.0	43.7	0.0	43.7	1,023.0
2	**1-rolling start**	123.7	0.0	0.0	(1.1)	0.0	122.6	0.0	122.6	4%	0.0	4.9	0.0	4.9	117.7
3	**1.1**	431.5	33.1	33.1	(0.2)	0.0	464.4	(16.6)	481.0	6%	0.0	28.9	0.0	28.9	435.6
4	**1.1-rolling start**	235.0	0.0	0.0	(0.2)	0.0	234.7	0.0	234.7	6%	0.0	14.1	0.0	14.1	220.6
5	**2**	(0.0)	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	6%	0.0	(0.0)	0.0	(0.0)	(0.0)
6	**3**	(0.0)	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	5%	0.0	(0.0)	0.0	(0.0)	(0.0)
7	**6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	0.0	0.0	0.0	0.0
8	**8**	273.1	87.6	87.4	0.0	0.3	360.3	(42.3)	402.6	20%	0.0	80.5	1.5	82.0	278.3
9	**8-rolling start**	30.6	0.0	0.0	0.0	0.0	30.6	0.0	30.6	20%	0.0	6.1	0.0	6.1	24.5
10	**10**	6.4	0.4	0.1	0.0	0.3	6.5	(0.1)	6.5	30%	0.0	2.0	0.0	2.0	4.5
11	**12**	0.0	47.7	47.7	0.0	0.0	47.7	0.0	47.7	100%	0.0	47.7	0.0	47.7	0.0
12	**13**	1.5	0.0	0.0	0.0	0.0	1.5	0.0	1.5	n/a	0.0	0.5	0.0	0.5	1.0
13	**14.1**	5.2	0.0	0.0	0.0	0.0	5.2	0.0	5.2	7%	0.0	0.4	0.0	0.4	4.9
14	**14.1**	13.4	0.0	0.0	0.0	0.0	13.4	0.0	13.4	5%	0.0	0.7	0.0	0.7	12.8
15	**17**	4,083.9	938.6	938.6	(26.0)	0.0	4,996.4	(469.3)	5,465.7	8%	0.0	437.3	0.0	437.3	4,559.2
16	**17-rolling start**	1,025.2	41.5	41.5	(27.0)	0.0	1,039.7	(20.7)	1,060.4	8%	0.0	84.8	0.0	84.8	954.8
17	**26**	0.4	0.0	0.0	0.0	0.0	0.4	0.0	0.4	5%	0.0	0.0	0.0	0.0	0.3
18	**42**	15.0	4.7	4.7	1.5	0.0	21.2	(2.3)	23.5	12%	0.0	2.8	0.0	2.8	18.4
19	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	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	50%	0.0	0.0	0.0	0.0	0.0
21	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0	0.0	0.0
22	**50**	2.0	4.3	4.3	0.0	0.0	6.3	(2.1)	8.4	55%	0.0	4.6	0.0	4.6	1.7
23	**Total**	7,258.6	1,209.5	1,209.1	(50.0)	0.6	8,417.5	(579.3)	8,996.8		0.0	759.0	1.5	760.4	7,657.1

Notes:

1 Amounts are from Ex. F4-2-1, Table 22, col. (k).

2 Represents Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and available for use before January 1, 2028. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 With AIIP rules effective for eligible property acquired after and available for use after November 20, 2018, the half year rule is suspended for AIIP until the former is phased out.

4 Net Adjustments in col. (c), lines 15 and 16 are the undepreciated capital cost adjustments resulting from the disallowance of the Heavy Water Storage and Drum Handling Facility ("D2O") Project per the EB-2020-0290 Decision and Order dated November 15, 2021.

5 Designated Immediate Expensing Property ("DIEP") refers to eligible property under AIIP rules that is acquired on or after April 19, 2021 and that becomes available for use before January 1, 2024. Eligible amounts, up to $1.5M per year, are expensed immediately; the half year rule is suspended for DIEP while AIIP rules are in effect.

Numbers may not add due to rounding.

Table 24
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Nuclear Operations ($M)
Year Ending December 31, 2023

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions	Cost of Acquisitions that are AIIP[2]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule or UCC adj for AIIP[3]	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	Capital Cost Allowance DIEP[4]	(j) + (k) Capital Cost Allowance	(e)+(i)-(l) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	**1**	1,023.0	86.6	86.6	0.2	0.0	1,109.7	(43.3)	1,153.0	4%	0.0	46.1	0.0	46.1	1,063.6
2	**1-rolling start**	117.7	0.0	0.0	0.0	0.0	117.7	0.0	117.7	4%	0.0	4.7	0.0	4.7	113.0
3	**1.1**	435.6	112.6	112.6	0.0	0.0	548.2	(56.3)	604.5	6%	0.0	36.3	0.0	36.3	511.9
4	**1.1-rolling start**	220.6	0.0	0.0	0.0	0.0	220.6	0.0	220.6	6%	0.0	13.2	0.0	13.2	207.4
5	**2**	(0.0)	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	6%	0.0	(0.0)	0.0	(0.0)	(0.0)
6	**3**	(0.0)	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	5%	0.0	(0.0)	0.0	(0.0)	(0.0)
7	**6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	0.0	0.0	0.0	0.0
8	**8**	278.3	149.7	149.7	0.3	0.4	428.0	(75.0)	503.0	20%	0.0	100.6	0.0	100.6	327.4
9	**8-rolling start**	24.5	0.0	0.0	0.0	0.0	24.5	0.0	24.5	20%	0.0	4.9	0.0	4.9	19.6
10	**10**	4.5	0.7	0.7	0.0	0.1	5.1	(0.4)	5.5	30%	0.0	1.6	0.0	1.6	3.5
11	**12**	0.0	52.7	52.7	0.1	0.0	52.8	0.0	52.8	100%	0.0	52.8	0.0	52.8	0.0
12	**13**	1.0	0.0	0.0	0.0	0.0	1.0	0.0	1.0	n/a	0.0	0.5	0.0	0.5	0.5
13	**14.1**	4.9	0.0	0.0	0.0	0.0	4.9	0.0	4.9	7%	0.0	0.3	0.0	0.3	4.5
14	**14.1**	12.8	0.0	0.0	0.0	0.0	12.8	0.0	12.8	5%	0.0	0.6	0.0	0.6	12.1
15	**17**	4,559.2	910.1	910.1	0.3	0.0	5,469.5	(455.0)	5,924.5	8%	0.0	474.0	0.0	474.0	4,995.5
16	**17-rolling start**	954.8	0.0	0.0	0.0	0.0	954.8	0.0	954.8	8%	0.0	76.4	0.0	76.4	878.4
17	**26**	0.3	0.3	0.3	0.0	0.0	0.7	0.1	0.5	5%	0.0	0.0	0.3	0.3	0.3
18	**42**	18.4	1.7	1.7	3.1	0.0	23.1	0.4	22.7	12%	0.0	2.7	1.2	3.9	19.2
19	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	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	50%	0.0	0.0	0.0	0.0	0.0
21	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0	0.0	0.0
22	**50**	1.7	0.0	0.0	0.0	0.0	1.7	(0.0)	1.7	55%	0.0	0.9	0.0	0.9	0.8
23	**Total**	7,657.1	1,314.4	1,314.4	3.8	0.4	8,974.9	(629.6)	9,604.5		0.0	815.8	1.5	817.0	8,157.7

Notes:

1 Amounts are from Ex. F4-2-1, Table 23, col. (m).

2 Represents Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and available for use before January 1, 2028. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 With AIIP rules effective for eligible property acquired after and available for use after November 20, 2018, the half year rule is suspended for AIIP until the former is phased out.

4 Designated Immediate Expensing Property ("DIEP") refers to eligible property under AIIP ruls that is acquired on or after April 19, 2021 and that becomes available for use before January 1, 2024. Eligible amounts, up to $1.5M per year, are expensed immediately; the half year rule is suspended for DIEP while AIIP rules are in effect.

Numbers may not add due to rounding.

Table 25
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Nuclear Operations ($M)
Year Ending December 31, 2024

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions	Cost of Acquisitions that are AIIP[2]	Net Adjustments[4]	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule or UCC adj for AIIP[3]	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	1,063.6	76.7	76.7	18.7	0.0	1,159.0	0.0	1,159.0	4%	0.0	46.4	1,112.6
2	**1-DNNP**	0.0	26.5	26.5	0.0	0.0	26.5	0.0	26.5	4%	0.0	1.1	25.4
3	**1-rolling start**	113.0	0.0	0.0	0.0	0.0	113.0	0.0	113.0	4%	0.0	4.5	108.4
4	**1-rolling start DNNP**	0.0	26.5	26.5	0.0	0.0	26.5	0.0	26.5	4%	0.0	1.1	25.4
5	**1.1**	511.9	62.7	62.7	0.0	0.0	574.6	0.0	574.6	6%	0.0	34.5	540.1
6	**1.1-rolling start**	207.4	0.0	0.0	0.0	0.0	207.4	0.0	207.4	6%	0.0	12.4	194.9
7	**2**	(0.0)	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	6%	0.0	(0.0)	(0.0)
8	**3**	(0.0)	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	5%	0.0	(0.0)	(0.0)
9	**6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	0.0	0.0
10	**8**	327.4	108.7	108.7	0.0	0.4	435.7	0.0	435.7	20%	0.0	87.1	348.6
11	**8-rolling start**	19.6	0.0	0.0	0.0	0.0	19.6	0.0	19.6	20%	0.0	3.9	15.7
12	**10**	3.5	4.2	4.2	0.0	0.1	7.5	0.0	7.5	30%	0.0	2.3	5.3
13	**12**	0.0	68.0	68.0	0.0	0.0	68.0	0.0	68.0	100%	0.0	68.0	0.0
14	**13**	0.5	0.0	0.0	0.0	0.0	0.5	0.0	0.5	n/a	0.0	0.3	0.3
15	**14.1**	4.5	0.0	0.0	0.0	0.0	4.5	0.0	4.5	7%	0.0	0.3	4.2
16	**14.1**	12.1	0.0	0.0	0.0	0.0	12.1	0.0	12.1	5%	0.0	0.6	11.5
17	**17**	4,995.5	1,127.3	1,127.3	45.4	0.0	6,168.2	0.0	6,168.2	8%	0.0	493.5	5,674.8
18	**17-DNNP**	0.0	114.9	114.9	0.0	0.0	114.9	0.0	114.9	8%	0.0	9.2	105.7
19	**17-rolling start**	878.4	41.5	41.5	0.0	0.0	919.9	0.0	919.9	8%	0.0	73.6	846.3
20	**17-rolling start DNNP**	0.0	114.9	114.9	0.0	0.0	114.9	0.0	114.9	8%	0.0	9.2	105.7
21	**26**	0.3	0.0	0.0	(0.4)	0.0	(0.1)	0.0	(0.1)	5%	0.1	(0.0)	0.0
22	**42**	19.2	8.2	8.2	0.0	0.0	27.4	0.0	27.4	12%	0.0	3.3	24.1
23	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
24	**43.2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50%	0.0	0.0	0.0
25	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
26	**50**	0.8	4.0	4.0	0.6	0.0	5.4	0.0	5.4	55%	0.0	2.9	2.4
27	**Total**	8,157.7	1,784.1	1,784.1	64.2	0.5	10,005.5	0.0	10,005.5		0.1	854.1	9,151.5

Notes:

1 Amounts are from Ex. F4-2-1, Table 24, col. (m).

2 Represents Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and available for use before January 1, 2028. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 With AIIP rules effective for eligible property acquired after and available for use after November 20, 2018, the half year rule is suspended for AIIP until the former is phased out.

4 Represents a reconciling adjustment related to prior years identified in the course of preparing the year's tax return.

Numbers may not add due to rounding.

Table 26
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Nuclear Operations ($M)
Year Ending December 31, 2025

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions	Cost of Acquisitions that are AIIP[2]	Net Adjustments	Proceeds of Dispositions[5]	(a)+(b)+(c)-(d) UCC1	50% Rule or UCC adj for AIIP[3]	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss[4]	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	1,112.6	30.1	30.1	0.0	0.0	1,142.8	0.0	1,142.8	4%	0.0	45.7	1,097.1
2	**1-DNNP**	25.4	0.0	0.0	0.0	26.5	(1.1)	0.0	(1.1)	4%	1.1	0.0	0.0
3	**1-rolling start**	108.4	35.4	35.4	0.0	0.0	143.8	0.0	143.8	4%	0.0	5.8	138.0
4	**1-rolling start DNNP**	25.4	0.0	0.0	0.0	26.5	(1.1)	0.0	(1.1)	4%	1.1	0.0	0.0
5	**1.1**	540.1	34.7	34.7	0.0	0.0	574.8	0.0	574.8	6%	0.0	34.5	540.4
6	**1.1-rolling start**	194.9	32.7	32.7	0.0	0.0	227.7	0.0	227.7	6%	0.0	13.7	214.0
7	**2**	(0.0)	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	6%	0.0	(0.0)	(0.0)
8	**3**	(0.0)	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	5%	0.0	(0.0)	(0.0)
9	**6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	0.0	0.0
10	**8**	348.6	78.5	78.5	0.0	0.0	427.0	0.0	427.0	20%	0.0	85.4	341.6
11	**8-rolling start**	15.7	66.1	66.1	0.0	0.0	81.8	0.0	81.8	20%	0.0	16.4	65.4
12	**10**	5.3	3.8	3.8	0.0	0.0	9.1	0.0	9.1	30%	0.0	2.7	6.3
13	**12**	0.0	77.7	77.7	0.0	0.0	77.7	0.0	77.7	100%	0.0	77.7	0.0
14	**12-rolling start**	0.0	32.7	32.7	0.0	0.0	32.7	0.0	32.7	100%	0.0	32.7	0.0
15	**13**	0.3	0.0	0.0	0.0	0.0	0.3	0.0	0.3	n/a	0.0	0.1	0.2
16	**14.1**	4.2	0.0	0.0	0.0	0.0	4.2	0.0	4.2	7%	0.0	0.3	3.9
17	**14.1**	11.5	0.0	0.0	0.0	0.0	11.5	0.0	11.5	5%	0.0	0.6	10.9
18	**17**	5,674.8	853.2	853.2	0.0	0.0	6,528.0	0.0	6,528.0	8%	0.0	522.2	6,005.8
19	**17-DNNP**	105.7	0.0	0.0	0.0	114.9	(9.2)	0.0	(9.2)	8%	9.2	0.0	0.0
20	**17-rolling start**	846.3	117.4	117.4	0.0	0.0	963.7	0.0	963.7	8%	0.0	77.1	886.6
21	**17-rolling start DNNP**	105.7	0.0	0.0	0.0	114.9	(9.2)	0.0	(9.2)	8%	9.2	0.0	0.0
22	**26**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
23	**42**	24.1	(0.1)	(0.1)	0.0	0.0	24.0	0.0	24.0	12%	0.0	2.9	21.2
24	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
25	**43.2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50%	0.0	0.0	0.0
26	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
27	**50**	2.4	1.7	1.7	0.0	0.0	4.1	0.0	4.1	55%	0.0	2.2	1.8
28	**Total**	9,151.5	1,363.9	1,363.9	0.0	282.7	10,232.7	0.0	10,232.7		20.5	919.9	9,333.3

Notes:

1 Amounts are from Ex. F4-2-1, Table 25, col. (k).

2 Represents Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and available for use before January 1, 2028. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 With AIIP rules effective for eligible property acquired after and available for use after November 20, 2018, the half year rule is suspended for AIIP until the former is phased out.

4 As discussed in Ex. A1-4-4, OPG expects to transfer assets related to the DNNP facilities to DNNP LP at the end of 2025. The transfer of these assets is forecasted to result in income in the form recapture of $20.5M to OPG for CCA claimed previously (and credited in the Nuclear Development Variance Account) for the DNNP facilities, which will be offset by higher CCA claims within DNNP LP.

5 Represents the capital cost of assets related to the DNNP facilities that OPG expects to transfer to DNNP LP by the end of 2025.

Numbers may not add due to rounding.

Table 27
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Nuclear Operations ($M)
Year Ending December 31, 2026

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions	Cost of Acquisitions that are AIIP[2]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule or UCC adj for AIIP[3]	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	1,097.1	128.1	128.1	0.0	0.0	1,225.1	0.0	1,225.1	4%	0.0	49.0	1,176.1
2	**1-DNNP**	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-rolling start**	138.0	40.5	40.5	0.0	0.0	178.6	0.0	178.6	4%	0.0	7.1	171.4
4	**1-rolling start DNNP**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4%	0.0	0.0	0.0
5	**1.1**	540.4	58.2	58.2	0.0	0.0	598.6	0.0	598.6	6%	0.0	35.9	562.7
6	**1.1-rolling start**	214.0	10.3	10.3	0.0	0.0	224.3	0.0	224.3	6%	0.0	13.5	210.8
7	**2**	(0.0)	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	6%	0.0	(0.0)	(0.0)
8	**3**	(0.0)	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	5%	0.0	(0.0)	(0.0)
9	**6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	0.0	0.0
10	**8**	341.6	117.8	117.8	0.0	0.0	459.5	0.0	459.5	20%	0.0	91.9	367.6
11	**8-rolling start**	65.4	24.1	24.1	0.0	0.0	89.5	0.0	89.5	20%	0.0	17.9	71.6
12	**10**	6.3	1.0	1.0	0.0	0.0	7.3	0.0	7.3	30%	0.0	2.2	5.1
13	**12**	0.0	113.0	113.0	0.0	0.0	113.0	0.0	113.0	100%	0.0	113.0	0.0
14	**12-rolling start**	0.0	10.3	10.3	0.0	0.0	10.3	0.0	10.3	100%	0.0	10.3	0.0
15	**13**	0.2	0.0	0.0	0.0	0.0	0.2	0.0	0.2	n/a	0.0	0.1	0.1
16	**14.1**	3.9	0.0	0.0	0.0	0.0	3.9	0.0	3.9	7%	0.0	0.3	3.6
17	**14.1**	10.9	0.0	0.0	0.0	0.0	10.9	0.0	10.9	5%	0.0	0.5	10.4
18	**17**	6,005.8	761.4	761.4	0.0	0.0	6,767.2	0.0	6,767.2	8%	0.0	541.4	6,225.8
19	**17-DNNP**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
20	**17-rolling start**	886.6	372.4	372.4	0.0	0.0	1,259.0	0.0	1,259.0	8%	0.0	100.7	1,158.3
21	**17-rolling start DNNP**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
22	**26**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
23	**42**	21.2	(0.1)	(0.1)	0.0	0.0	21.1	0.0	21.1	12%	0.0	2.5	18.6
24	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
25	**43.2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50%	0.0	0.0	0.0
26	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
27	**50**	1.8	1.3	1.3	0.0	0.0	3.1	0.0	3.1	55%	0.0	1.7	1.4
28	**Total**	9,333.3	1,638.2	1,638.2	0.0	0.0	10,971.5	0.0	10,971.5		0.0	988.0	9,983.5

Notes:

1 Amounts are from Ex. F4-2-1, Table 26, col. (k).

2 Represents Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and available for use before January 1, 2028. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 With AIIP rules effective for eligible property acquired after and available for use after November 20, 2018, the half year rule is suspended for AIIP until the former is phased out.

Numbers may not add due to rounding.

Table 28
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Nuclear Operations ($M)
Year Ending December 31, 2027

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions	Cost of Acquisitions that are AIIP[2]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule or UCC adj for AIIP[3]	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	1,176.1	232.6	232.6	0.0	0.0	1,408.7	0.0	1,408.7	4%	0.0	56.3	1,352.4
2	**1-DNNP**	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-rolling start**	171.4	152.5	152.5	0.0	0.0	323.9	0.0	323.9	4%	0.0	13.0	311.0
4	**1-rolling start DNNP**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4%	0.0	0.0	0.0
5	**1.1**	562.7	89.1	89.1	0.0	0.0	651.7	0.0	651.7	6%	0.0	39.1	612.6
6	**1.1-rolling start**	210.8	21.0	21.0	0.0	0.0	231.8	0.0	231.8	6%	0.0	13.9	217.9
7	**2**	(0.0)	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	6%	0.0	(0.0)	(0.0)
8	**3**	(0.0)	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	5%	0.0	(0.0)	(0.0)
9	**6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	0.0	0.0
10	**8**	367.6	189.5	189.5	0.0	0.0	557.1	0.0	557.1	20%	0.0	111.4	445.6
11	**8-rolling start**	71.6	56.8	56.8	0.0	0.0	128.4	0.0	128.4	20%	0.0	25.7	102.7
12	**10**	5.1	0.0	0.0	0.0	0.0	5.1	0.0	5.1	30%	0.0	1.5	3.6
13	**12**	0.0	147.7	147.7	0.0	0.0	147.7	0.0	147.7	100%	0.0	147.7	0.0
14	**12-rolling start**	0.0	21.0	21.0	0.0	0.0	21.0	0.0	21.0	100%	0.0	21.0	0.0
15	**13**	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.1	n/a	0.0	0.0	0.0
16	**14.1**	3.6	0.0	0.0	0.0	0.0	3.6	0.0	3.6	7%	0.0	0.3	3.4
17	**14.1**	10.4	0.0	0.0	0.0	0.0	10.4	0.0	10.4	5%	0.0	0.5	9.9
18	**17**	6,225.8	1,600.0	1,600.0	0.0	0.0	7,825.8	0.0	7,825.8	8%	0.0	626.1	7,199.7
19	**17-DNNP**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
20	**17-rolling start**	1,158.3	1,414.7	1,414.7	0.0	0.0	2,573.0	0.0	2,573.0	8%	0.0	205.8	2,367.2
21	**17-rolling start DNNP**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
22	**26**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
23	**42**	18.6	(0.1)	(0.1)	0.0	0.0	18.5	0.0	18.5	12%	0.0	2.2	16.3
24	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
25	**43.2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50%	0.0	0.0	0.0
26	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
27	**50**	1.4	1.6	1.6	0.0	0.0	3.0	0.0	3.0	55%	0.0	1.6	1.3
28	**Total**	9,983.5	3,926.4	3,926.4	0.0	0.0	13,909.9	0.0	13,909.9		0.0	1,266.2	12,643.7

Notes:

1 Amounts are from Ex. F4-2-1, Table 27, col. (k).

2 Represents Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and available for use before January 1, 2028. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 With AIIP rules effective for eligible property acquired after and available for use after November 20, 2018, the half year rule is suspended for AIIP until the former is phased out.

Numbers may not add due to rounding.

Table 29
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Nuclear Operations ($M)
Year Ending December 31, 2028

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions	Cost of Acquisitions that are AIIP[2]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule or UCC adj for AIIP[3]	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	1,352.4	345.6	0.0	0.0	0.0	1,698.0	172.8	1,525.2	4%	0.0	61.0	1,637.0
2	**1-DNNP**	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-rolling start**	311.0	273.0	0.0	0.0	0.0	583.9	0.0	583.9	4%	0.0	23.4	560.6
4	**1-rolling start DNNP**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4%	0.0	0.0	0.0
5	**1.1**	612.6	80.9	0.0	0.0	0.0	693.5	40.4	653.1	6%	0.0	39.2	654.3
6	**1.1-rolling start**	217.9	35.2	0.0	0.0	0.0	253.1	0.0	253.1	6%	0.0	15.2	237.9
7	**2**	(0.0)	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	6%	0.0	(0.0)	(0.0)
8	**3**	(0.0)	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	5%	0.0	(0.0)	(0.0)
9	**6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	0.0	0.0
10	**8**	445.6	185.0	0.0	0.0	0.0	630.6	92.5	538.1	20%	0.0	107.6	523.0
11	**8-rolling start**	102.7	97.4	0.0	0.0	0.0	200.1	0.0	200.1	20%	0.0	40.0	160.1
12	**10**	3.6	0.0	0.0	0.0	0.0	3.6	0.0	3.6	30%	0.0	1.1	2.5
13	**12**	0.0	144.3	0.0	0.0	0.0	144.3	72.1	72.1	100%	0.0	72.1	72.1
14	**12-rolling start**	0.0	35.2	0.0	0.0	0.0	35.2	0.0	35.2	100%	0.0	35.2	0.0
15	**13**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	n/a	0.0	0.0	0.0
16	**14.1**	3.4	0.0	0.0	0.0	0.0	3.4	0.0	3.4	7%	0.0	0.2	3.1
17	**14.1**	9.9	0.0	0.0	0.0	0.0	9.9	0.0	9.9	5%	0.0	0.5	9.4
18	**17**	7,199.7	3,032.1	0.0	0.0	0.0	10,231.8	1,516.0	8,715.8	8%	0.0	697.3	9,534.5
19	**17-DNNP**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
20	**17-rolling start**	2,367.2	2,632.9	0.0	0.0	0.0	5,000.1	0.0	5,000.1	8%	0.0	400.0	4,600.1
21	**17-rolling start DNNP**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
22	**26**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
23	**42**	16.3	(0.1)	0.0	0.0	0.0	16.2	(0.0)	16.3	12%	0.0	2.0	14.3
24	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
25	**43.2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50%	0.0	0.0	0.0
26	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
27	**50**	1.3	2.1	0.0	0.0	0.0	3.5	1.1	2.4	55%	0.0	1.3	2.1
28	**Total**	12,643.7	6,863.6	0.0	0.0	0.0	19,507.3	1,894.9	17,612.3		0.0	1,496.1	18,011.1

Notes:

1 Amounts are from Ex. F4-2-1, Table 28, col. (k).

2 Represents Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and available for use before January 1, 2028. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 With AIIP rules phased out after December 31, 2027, the half year rule is reinstated beginning January 1, 2028.

Numbers may not add due to rounding.

Table 30
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Nuclear Operations ($M)
Year Ending December 31, 2029

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions	Cost of Acquisitions that are AIIP[2]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule or UCC adj for AIIP[3]	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	1,637.0	383.3	0.0	0.0	0.0	2,020.3	191.7	1,828.6	4%	0.0	73.1	1,947.1
2	**1-DNNP**	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-rolling start**	560.6	222.6	0.0	0.0	0.0	783.2	0.0	783.2	4%	0.0	31.3	751.8
4	**1-rolling start DNNP**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4%	0.0	0.0	0.0
5	**1.1**	654.3	57.0	0.0	0.0	0.0	711.3	28.5	682.8	6%	0.0	41.0	670.4
6	**1.1-rolling start**	237.9	23.5	0.0	0.0	0.0	261.4	0.0	261.4	6%	0.0	15.7	245.8
7	**2**	(0.0)	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	6%	0.0	(0.0)	(0.0)
8	**3**	(0.0)	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	5%	0.0	(0.0)	(0.0)
9	**6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	0.0	0.0
10	**8**	523.0	137.5	0.0	0.0	0.0	660.5	68.8	591.8	20%	0.0	118.4	542.2
11	**8-rolling start**	160.1	69.5	0.0	0.0	0.0	229.6	0.0	229.6	20%	0.0	45.9	183.7
12	**10**	2.5	0.0	0.0	0.0	0.0	2.5	0.0	2.5	30%	0.0	0.8	1.8
13	**12**	72.1	125.8	0.0	0.0	0.0	198.0	62.9	135.1	100%	0.0	135.1	62.9
14	**12-rolling start**	0.0	23.5	0.0	0.0	0.0	23.5	0.0	23.5	100%	0.0	23.5	0.0
15	**13**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	n/a	0.0	0.0	0.0
16	**14.1**	3.1	0.0	0.0	0.0	0.0	3.1	0.0	3.1	7%	0.0	0.2	2.9
17	**14.1**	9.4	0.0	0.0	0.0	0.0	9.4	0.0	9.4	5%	0.0	0.5	8.9
18	**17**	9,534.5	3,659.4	0.0	0.0	0.0	13,193.9	1,829.7	11,364.2	8%	0.0	909.1	12,284.8
19	**17-DNNP**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
20	**17-rolling start**	4,600.1	2,234.9	0.0	0.0	0.0	6,835.0	0.0	6,835.0	8%	0.0	546.8	6,288.2
21	**17-rolling start DNNP**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
22	**26**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
23	**42**	14.3	(0.1)	0.0	0.0	0.0	14.2	(0.0)	14.2	12%	0.0	1.7	12.5
24	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
25	**43.2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50%	0.0	0.0	0.0
26	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
27	**50**	2.1	2.9	0.0	0.0	0.0	5.1	1.5	3.6	55%	0.0	2.0	3.1
28	**Total**	18,011.1	6,939.9	0.0	0.0	0.0	24,951.1	2,183.0	22,768.1		0.0	1,945.0	23,006.0

Notes:

1 Amounts are from Ex. F4-2-1, Table 29, col. (k).

2 Represents Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and available for use before January 1, 2028. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 With AIIP rules phased out after December 31, 2027, the half year rule is reinstated beginning January 1, 2028.

Numbers may not add due to rounding.

Table 31
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Nuclear Operations ($M)
Year Ending December 31, 2030

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions	Cost of Acquisitions that are AIIP[2]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule or UCC adj for AIIP[3]	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	1,947.1	306.2	0.0	0.0	0.0	2,253.3	153.1	2,100.2	4%	0.0	84.0	2,169.3
2	**1-DNNP**	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-rolling start**	751.8	79.4	0.0	0.0	0.0	831.3	0.0	831.3	4%	0.0	33.3	798.0
4	**1-rolling start DNNP**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6%	0.0	0.0	0.0
5	**1.1**	670.4	91.5	0.0	0.0	0.0	761.9	45.8	716.1	6%	0.0	43.0	718.9
6	**1.1-rolling start**	245.8	14.2	0.0	0.0	0.0	259.9	0.0	259.9	6%	0.0	15.6	244.3
7	**2**	(0.0)	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	6%	0.0	(0.0)	(0.0)
8	**3**	(0.0)	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	5%	0.0	(0.0)	(0.0)
9	**6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	0.0	0.0
10	**8**	542.2	200.9	0.0	0.0	0.0	743.1	100.4	642.6	20%	0.0	128.5	614.5
11	**8-rolling start**	183.7	35.8	0.0	0.0	0.0	219.4	0.0	219.4	20%	0.0	43.9	175.6
12	**10**	1.8	0.0	0.0	0.0	0.0	1.8	0.0	1.8	30%	0.0	0.5	1.2
13	**12**	62.9	167.4	0.0	0.0	0.0	230.3	83.7	146.6	100%	0.0	146.6	83.7
14	**12-rolling start**	0.0	14.2	0.0	0.0	0.0	14.2	0.0	14.2	100%	0.0	14.2	0.0
15	**13**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	n/a	0.0	0.0	0.0
16	**14.1**	2.9	0.0	0.0	0.0	0.0	2.9	0.0	2.9	7%	0.0	0.2	2.7
17	**14.1**	8.9	0.0	0.0	0.0	0.0	8.9	0.0	8.9	5%	0.0	0.4	8.5
18	**17**	12,284.8	2,589.9	0.0	0.0	0.0	14,874.7	1,294.9	13,579.7	8%	0.0	1,086.4	13,788.3
19	**17-DNNP**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
20	**17-rolling start**	6,288.2	822.8	0.0	0.0	0.0	7,111.0	0.0	7,111.0	8%	0.0	568.9	6,542.1
21	**17-rolling start DNNP**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
22	**26**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
23	**42**	12.5	(0.1)	0.0	0.0	0.0	12.4	(0.0)	12.5	12%	0.0	1.5	10.9
24	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
25	**43.2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50%	0.0	0.0	0.0
26	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
27	**50**	3.1	3.2	0.0	0.0	0.0	6.3	1.6	4.7	55%	0.0	2.6	3.7
28	**Total**	23,006.0	4,325.4	0.0	0.0	0.0	27,331.4	1,679.5	25,651.9		0.0	2,169.5	25,161.9

Notes:

1 Amounts are from Ex. F4-2-1, Table 30, col. (k).

2 Represents Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and available for use before January 1, 2028. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 With AIIP rules phased out after December 31, 2027, the half year rule is reinstated beginning January 1, 2028.

Numbers may not add due to rounding.

Table 32
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Nuclear Operations ($M)
Year Ending December 31, 2031

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions	Cost of Acquisitions that are AIIP[2]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule or UCC adj for AIIP[3]	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	2,169.3	215.3	0.0	0.0	0.0	2,384.6	107.6	2,277.0	4%	0.0	91.1	2,293.5
2	**1-DNNP**	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-rolling start**	798.0	13.3	0.0	0.0	0.0	811.3	0.0	811.3	4%	0.0	32.5	778.8
4	**1-rolling start DNNP**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6%	0.0	0.0	0.0
5	**1.1**	718.9	54.5	0.0	0.0	0.0	773.4	27.3	746.2	6%	0.0	44.8	728.7
6	**1.1-rolling start**	244.3	12.8	0.0	0.0	0.0	257.1	0.0	257.1	6%	0.0	15.4	241.7
7	**2**	(0.0)	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	6%	0.0	(0.0)	(0.0)
8	**3**	(0.0)	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	5%	0.0	(0.0)	(0.0)
9	**6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	0.0	0.0
10	**8**	614.5	117.4	0.0	0.0	0.0	731.9	58.7	673.2	20%	0.0	134.6	597.3
11	**8-rolling start**	175.6	25.8	0.0	0.0	0.0	201.3	0.0	201.3	20%	0.0	40.3	161.1
12	**10**	1.2	0.0	0.0	0.0	0.0	1.2	0.0	1.2	30%	0.0	0.4	0.9
13	**12**	83.7	141.4	0.0	0.0	0.0	225.1	70.7	154.4	100%	0.0	154.4	70.7
14	**12-rolling start**	0.0	12.8	0.0	0.0	0.0	12.8	0.0	12.8	100%	0.0	12.8	0.0
15	**13**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	n/a	0.0	0.0	0.0
16	**14.1**	2.7	0.0	0.0	0.0	0.0	2.7	0.0	2.7	7%	0.0	0.2	2.5
17	**14.1**	8.5	0.0	0.0	0.0	0.0	8.5	0.0	8.5	5%	0.0	0.4	8.0
18	**17**	13,788.3	2,181.0	0.0	0.0	0.0	15,969.3	1,090.5	14,878.8	8%	0.0	1,190.3	14,779.0
19	**17-DNNP**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
20	**17-rolling start**	6,542.1	291.3	0.0	0.0	0.0	6,833.4	0.0	6,833.4	8%	0.0	546.7	6,286.7
21	**17-rolling start DNNP**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
22	**26**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
23	**42**	10.9	(0.1)	0.0	0.0	0.0	10.9	(0.0)	10.9	12%	0.0	1.3	9.6
24	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
25	**43.2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50%	0.0	0.0	0.0
26	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
27	**50**	3.7	4.4	0.0	0.0	0.0	8.1	2.2	5.9	55%	0.0	3.2	4.8
28	**Total**	25,161.9	3,069.8	0.0	0.0	0.0	28,231.7	1,357.0	26,874.8		0.0	2,268.4	25,963.4

Notes:

1 Amounts are from Ex. F4-2-1, Table 31, col. (k).

2 Represents Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and available for use before January 1, 2028. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 With AIIP rules phased out after December 31, 2027, the half year rule is reinstated beginning January 1, 2028.

Table 33
Undepreciated Capital Cost and Capital Cost Allowance Schedule for DNNP Facilities ($M)
Year Ending December 31, 2027

Line No.	Class	Undepreciated Capital Cost at Beginning of Year	Cost of Acquisitions	Cost of Acquisitions that are AIIP[1]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule or UCC adj for AIIP[2]	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	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	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	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	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	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	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	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	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	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	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	100%	0.0	0.0	0.0
12	**13**	0.0	1,620.7	1,620.7	0.0	0.0	1,620.7	0.0	1,620.7	n/a	0.0	85.3	1,535.4
13	**13-rolling start**	0.0	2,093.2	2,093.2	0.0	0.0	2,093.2	0.0	2,093.2	n/a	0.0	110.2	1,983.0
14	**14.1**	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	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	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	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	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	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	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	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	55%	0.0	0.0	0.0
23	**50R**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	55%	0.0	0.0	0.0
24	**Total**	0.0	3,713.8	3,713.8	0.0	0.0	3,713.8	0.0	3,713.8		0.0	195.5	3,518.4

Notes:

1 Represents Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and available for use before January 1, 2028. For further discussion of AIIP, refer to EB-2020-

2 With AIIP rules effective for eligible property acquired after and available for use after November 20, 2018, the half year rule is suspended for AIIP until the former is phased out.

3 There is no CCA prior to 2027 because tax additions to undepreciated capital cost starts in 2027 under the long-term project rule.

Numbers may not add due to rounding.

Table 34
Undepreciated Capital Cost and Capital Cost Allowance Schedule for DNNP Facilities ($M)
Year Ending December 31, 2028

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions	Cost of Acquisitions that are AIIP[2]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule or UCC adj for AIIP[3]	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	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	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	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	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	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	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	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	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	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	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	100%	0.0	0.0	0.0
12	**13**	1,535.4	896.7	0.0	0.0	0.0	2,432.1	24.9	2,407.1	n/a	0.0	110.2	2,321.9
13	**13-rolling start**	1,983.0	1,633.4	0.0	0.0	0.0	3,616.4	0.0	3,616.4	n/a	0.0	200.9	3,415.5
14	**14.1**	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	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	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	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	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	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	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	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	55%	0.0	0.0	0.0
23	**50R**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	55%	0.0	0.0	0.0
24	**Total**	3,518.4	2,530.1	0.0	0.0	0.0	6,048.5	24.9	6,023.6		0.0	311.1	5,737.4

Notes:

1 Amounts are from Ex. F4-2-1, Table 33, col. (k).

2 Represents Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and available for use before January 1, 2028. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 With AIIP rules phased out after December 31, 2027, the half year rule is reinstated beginning January 1, 2028.

Numbers may not add due to rounding.

Table 35
Undepreciated Capital Cost and Capital Cost Allowance Schedule for DNNP Facilities ($M)
Year Ending December 31, 2029

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions	Cost of Acquisitions that are AIIP[2]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule or UCC adj for AIIP[3]	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	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	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	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	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	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	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	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	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	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	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	100%	0.0	0.0	0.0
12	**13**	2,321.9	304.7	0.0	0.0	0.0	2,626.6	9.0	2,617.6	n/a	0.0	144.1	2,482.5
13	**13-rolling start**	3,415.5	0.0	0.0	0.0	0.0	3,415.5	0.0	3,415.5	n/a	0.0	200.9	3,214.6
14	**14.1**	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	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	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	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	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	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	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	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	55%	0.0	0.0	0.0
23	**50R**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	55%	0.0	0.0	0.0
24	**Total**	5,737.4	304.7	0.0	0.0	0.0	6,042.1	9.0	6,033.1		0.0	345.0	5,697.1

Notes:

1 Amounts are from Ex. F4-2-1, Table 34, col. (k).

2 Represents Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and available for use before January 1, 2028. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 With AIIP rules phased out after December 31, 2027, the half year rule is reinstated beginning January 1, 2028.

Numbers may not add due to rounding.

Table 36
Undepreciated Capital Cost and Capital Cost Allowance Schedule for DNNP Facilities ($M)
Year Ending December 31, 2030

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions	Cost of Acquisitions that are AIIP[2]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule or UCC adj for AIIP[3]	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	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	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	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	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	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	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	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	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	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	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	100%	0.0	0.0	0.0
12	**13**	2,482.5	373.2	0.0	0.0	0.0	2,855.7	11.7	2,844.1	n/a	0.0	164.7	2,691.0
13	**13-rolling start**	3,214.6	0.0	0.0	0.0	0.0	3,214.6	0.0	3,214.6	n/a	0.0	200.9	3,013.7
14	**14.1**	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	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	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	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	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	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	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	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	55%	0.0	0.0	0.0
23	**50R**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	55%	0.0	0.0	0.0
24	**Total**	5,697.1	373.2	0.0	0.0	0.0	6,070.3	11.7	6,058.7		0.0	365.6	5,704.7

Notes:

1 Amounts are from Ex. F4-2-1, Table 35, col. (k).

2 Represents Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and available for use before January 1, 2028. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 With AIIP rules phased out after December 31, 2027, the half year rule is reinstated beginning January 1, 2028.

Numbers may not add due to rounding.

Table 37
Undepreciated Capital Cost and Capital Cost Allowance Schedule for DNNP Facilities ($M)
Year Ending December 31, 2031

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions	Cost of Acquisitions that are AIIP[2]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule or UCC adj for AIIP[3]	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	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	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	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	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	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	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	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	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	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	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	100%	0.0	0.0	0.0
12	**13**	2,691.0	0.0	0.0	0.0	0.0	2,691.0	0.0	2,691.0	n/a	0.0	176.4	2,514.7
13	**13-rolling start**	3,013.7	0.0	0.0	0.0	0.0	3,013.7	0.0	3,013.7	n/a	0.0	200.9	2,812.8
14	**14.1**	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	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	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	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	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	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	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	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	55%	0.0	0.0	0.0
23	**50R**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	55%	0.0	0.0	0.0
24	**Total**	5,704.7	0.0	0.0	0.0	0.0	5,704.7	0.0	5,704.7		0.0	377.3	5,327.5

Notes:

1 Amounts are from Ex. F4-2-1, Table 36, col. (k).

2 Represents Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and available for use before January 1, 2028. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 With AIIP rules phased out after December 31, 2027, the half year rule is reinstated beginning January 1, 2028.

COMPENSATION AND BENEFITS

1.0 PURPOSE

The purpose of this exhibit is to:

- Describe the nature of OPG's workforce and the changes to this workforce as a result of extending operations and moving forward with the refurbishment of Units 5-8 at the Pickering Nuclear Generating Station ("Pickering"), the Darlington New Nuclear Program ("DNNP"), and the hydroelectric refurbishment and redevelopment projects;
- Describe key developments in OPG's workforce strategy and collective bargaining since EB-2020-0290;
- Provide 2020-2031 compensation information for employees working at and supporting OPG's regulated facilities and the DNNP facilities; and
- Present the results of the independent compensation study conducted by Willis Towers Watson ("WTW").

2.0 OVERVIEW

OPG's ability to deliver safe, reliable, and cost-effective electricity for Ontario is closely tied to its workforce. The Company's employees provide the technical and management expertise required to operate nuclear and regulated hydroelectric facilities and to plan, design and execute complex projects such as refurbishments, redevelopments and new builds. As such, compensation and benefits are an inherent component of the cost of the electricity generated by OPG. This section outlines how OPG's workforce and associated strategies will continue to enable OPG to fulfill its mandate during a period of significant transition, including key workforce strategy and collective bargaining developments since EB-2020-0290.

For the period 2027-2031, forecast compensation costs are $11,116M for OPG's nuclear operations, $2,140M for OPG's regulated hydroelectric operations and $550M for the DNNP facilities, reflecting the significant role OPG's employees play in producing electricity for Ontario. These costs are detailed in Attachment 1

As discussed in Ex. A1-4-4, Darlington New Nuclear Program Limited Partnership Inc. ("DNNP LP") is expected to be a newly prescribed generator under O. Reg. 53/05 and is entering into a lease for the DNNP facilities with OPG. DNNP LP will undertake the development, construction, and operation of the DNNP facilities, with OPG contracted to act as the project manager and operator of the facilities. The Application assumes that DNNP LP enters into the lease and associated agreements and that the DNNP asset transfer from OPG all occur at the end of 2025. DNNP LP will not have its own workforce and will contract for all applicable services with OPG and will therefore reimburse OPG for its fully allocated costs of providing the services. This includes the applicable labour costs of OPG's workforce. As such, the evidence regarding OPG's workforce and compensation costs supports both OPG and DNNP LP's proposed revenue requirements.

OPG has a wide variety of employees, including skilled trades who operate and maintain the generation facilities, professional staff who provide expertise related to projects and generation facilities, management who direct work functions, and executives who lead the organization. OPG employees work at generating stations, offices and other facilities across the province and are predominantly unionized. Additional details on OPG's workforce, including the extent of unionization, work locations, and demographics are presented in Section 3.0.

With the significant change in the energy landscape, OPG's organizational and workforce strategies have undergone important changes since EB-2020-0290. In addition to continuing to reliably and cost effectively operate its facilities, OPG has expanded priorities from the Province of Ontario ("Province") to invest in existing and new assets to help meet future electricity needs. As discussed elsewhere in the Application, to help meet these objectives, OPG is executing on the DNNP, planning for the execution of the Pickering Refurbishment Program ("PRP") and Pickering's "second life" operations, completing the DRP while addressing emergent equipment reliability needs at the station, and advancing a turbine-generator refurbishment program and other projects to renew an aging hydroelectric fleet.

To meet this mandate, OPG must ensure it has the necessary skilled workforce and is able to effectively manage the organization through this period of change, while operating within

complex collective agreements. In line with these needs, OPG's full-time equivalents ("FTE") are projected to increase by approximately 11% from 2021-2027. This is in contrast to the landscape presented in EB-2020-0290 where the Company was preparing to downsize as a result of the then planned end of Pickering commercial operations in 2025. Instead, OPG is now operating Pickering Units 5-8 until September 2026, prior to refurbishing them for another 30-plus years of useful life. The growth and composition of OPG's workforce reflects this change in direction and aligns to the current and upcoming operations and project demands. As OPG progresses through PRP execution, regular headcount is projected to stabilize over the IR term.

In response to decisions to progress the PRP and other initiatives, OPG has established dedicated strategies to help secure the necessary talent during this period of transition, and for the longer-term future. Through cross functional teams and focused human resources programs, OPG aims to secure and maintain an engaged and capable workforce to deliver on project commitments, ensure an operationally strong fleet, and support continuous improvement. An essential area of focus is skilled trades and science, technology, engineering and math ("STEM") expertise. There is a growing demand for these skillsets locally and in some cases globally, including in the electricity sector. Combined with a shrinking pool of candidates in certain skill areas, this is driving increased competition for talent at a time when OPG's own resourcing needs are increasing. This requires the Company to proactively identify and address current and anticipated skill gaps using a variety of externally and internally focused strategies. These actions are implemented with consideration of labour market conditions, collective bargaining outcomes, financial impacts and risk management, and are further discussed in Section 5.0.

Given the extent of unionization at OPG, collective bargaining plays a significant role in determining both ongoing compensation costs and workforce and resourcing strategies. Collective agreements prescribe wages, incentives, pension and benefits for unionized employees, and other provisions including contracting out, scheduling, redeployment and downsizing. Since EB-2020-0290, the broader organized labour landscape has become increasingly volatile, with recovery from the COVID-19 pandemic, extraordinary inflation levels,

the repeal of *Protecting a Sustainable Public Sector for Future Generations Act, 2019* ("Bill 124") and increased labour action among the factors shaping the collective bargaining environment. While inflation peaks have since then moderated, unions generally continue to seek significant wage increases and other compensatory improvements to help offset the workers' cost of living and perceived erosion of purchasing power. These demands are considered by arbitrators as part of arbitration awards. For the energy sector, the above developments have coincided with an increasing demand for skilled labour and qualified professionals to help meet energy policy objectives.

Since non-unionized (i.e., management) compensation is directly managed by OPG rather than collectively negotiated, it allows for greater cost control. This has enabled OPG to maintain compensation for this group below the target market range. In contrast, compensation for unionized roles is subject to bargaining processes where there is inherently less control and predictability over wage outcomes and where such outcomes continue to be influenced by the principle of replication. Under this principle, an arbitrator aims to "replicate" the wage increase outcomes of the bargaining process using patterns in other arbitration awards and settlements in the same or similar sector or industry. This often results in other unionized organizations' outcomes, overall wage trends in the sector and labour actions across the industry influencing the arbitration outcome to a greater extent than an entity's specific circumstances. This patterning effect creates an upward pressure on OPG's compensation levels.

In addition, the compensation established in collective agreements can affect management employees by creating wage compression relative to their represented direct reports. This can result in challenges with internal equity, impede career development and make it more difficult to attract experienced employees into management positions. Management compensation is further discussed in Section 6.0.

Since EB-2020-0290, OPG engaged in two rounds of collective bargaining with the Power Workers' Union ("PWU"), in 2022 and 2024, and two rounds with the Society of United Professionals ("Society"), in 2021 and 2023. OPG and the PWU reached a two-party

agreement in both rounds of bargaining, following extensive negotiations and a failed ratification by the employees in each round. The current collective agreement with the PWU expires on March 31, 2027.

OPG and the Society were unable to reach a full two-party voluntary agreement in each of the two rounds of bargaining. Pursuant to a binding dispute resolution process in place between the parties, both collective agreements were completed through an arbitrator's award. OPG and the Society have also engaged in bargaining for a new collective agreement effective January 1, 2026, and subsequently proceeded to an arbitration that is taking place in December 2025.

The above collective bargaining processes spanned the period during which OPG's business and workforce needs evolved from preparing for the Pickering downsizing to resourcing for upcoming projects and anticipated Pickering "second life" operations. OPG's planning for the Pickering downsizing focused on addressing significant workforce challenges and uncertainties, including employee transitions and attrition, while mitigating the substantial cost impacts of reducing the workforce. OPG sought to manage these issues by investing in workforce planning, labour relations, skills retention and targeted recruitment. These efforts are further discussed in Section 4.0.

Chief among the strategies to manage the Pickering downsizing was negotiating jointly agreed changes to collective agreement provisions that would lessen the operational disruption, timelines and costs of downsizing processes. Notwithstanding the complex labour environment, OPG was able to reach agreements with both the PWU and the Society on more efficient downsizing provisions for a partial or total Pickering closure during the first rounds of bargaining after EB-2020-0290.[1] OPG also succeeded in maintaining the ability to use PWU-represented term-based employees ("Term Employees") and Society-represented extended

[1] These provisions also cover a potential downsizing related to the completion of the Darlington Refurbishment Program.

temporary employees ("ETEs"),[2] a critical strategy in mitigating the impacts of a Pickering shutdown.[3] While the Company's focus then shifted toward the possibility of refurbishing Pickering Units 5-8, these negotiated agreements, along with the various workforce planning tools and strategies developed to help manage staff transitions, are contributing to better workforce planning and greater resource flexibility across the organization. Additional details on Term Employees and ETEs are provided in Section 5.1.

OPG is now focused on ensuring a smooth workforce transition through the Pickering refurbishment period. Critical to this is ensuring a minimally disruptive, cost effective and timely redeployment of employees from Pickering operations to the PRP and other parts of the organization. In addition to benefiting the PRP execution by utilizing skilled and experienced resources, this transition will support effective business continuity by retaining employees who will be needed to operate and maintain the station once Unit 5 is refurbished. To enable this strategy, OPG successfully negotiated agreements with the PWU and the Society (discussed below), as well with the Building Trades Unions ("BTU") to permit PWU-represented employees to perform certain refurbishment work. These efforts support optimizing labour resources and help to mitigate any potential risk of skilled trade shortages and are incorporated in the PRP's release quality estimate cost and schedule commitments.

In addition to the BTU agreement, OPG successfully secured provisions with the PWU and the Society that allow employees to move between positions and locations without triggering disruptive displacement processes. Under the PWU agreement, OPG has increased flexibility to deploy PWU-represented employees across the fleet and in a wider span of jobs. Under the Society agreement, staff redeployment provisions have been modified to allow OPG to more effectively reassign Society-represented employees within the Durham region, where Pickering, Darlington and many of the supporting functions are located, and where OPG has

[2] ETEs are used to refer to Society-represented classifications of employees that could be hired to avoid adding regular staff in circumstances where additional regular employees were likely to be laid off as a result of the planned shutdown of Pickering.
[3] EB-2020-0290 Ex. F4-3-1, Section 4.0.

a sustained need for qualified and skilled professionals.[4] OPG's workforce redeployment strategy is discussed further in Section 5.1.

OPG was also able to negotiate broadened job classifications for PWU-represented roles, and greater resourcing flexibility in support of maintenance outages for DNNP operations. This agreement will support an optimized staffing structure and streamlined operating model for which these small modular reactors are designed. These provisions underpin the forecast operating cost assumptions for the DNNP facilities in this Application (Ex. F2-2-1). Finally, OPG also achieved permanent collective agreement provisions with the Society that allow for contracting out of professional services, securing increased agility and the option to manage temporary or peaking resource needs more cost effectively.

OPG secured the collective bargaining outcomes above while navigating a complex period of extraordinary inflation and broader labour action which, together with the repeal of Bill 124, resulted in elevated wage increases since 2021. The specific wage increases under the PWU and Society collective agreements are discussed in Section 6.2.1, which also shows that these increases broadly aligned with inflation, remain below those of Bruce Power LP ("Bruce Power") and are comparable to those of Hydro One.

Section 6.0 provides an overview of OPG's compensation elements for both unionized and non-unionized positions and includes a discussion of OPG's actions to manage compensation costs, including a summary of pension and benefit changes that became effective in 2025. This section also includes a summary of compensation costs for employees operating and supporting the prescribed nuclear and regulated hydroelectric facilities, with additional details available in Attachment 1 ("Appendix 2k").

OPG continues to undertake compensation benchmarking to ensure compensation costs are competitive, cost-effective, and aligned with OPG's business strategy and the environment in

[4] Under previous provisions, Society-represented employees within the Durham region had the option to elect to terminate their employment and access a severance package, despite the ongoing work demands.

which OPG operates. In response to changes in the energy sector, OPG engaged Southlea Group ("Southlea"), a third-party compensation consulting firm with expertise in the energy sector, to conduct an independent review of the company's compensation philosophy (Attachment 2). Based on Southlea's recommendations, OPG revised its compensation philosophy to more closely align with its evolving role in meeting Ontario's energy demand and its evolution into a more complex, growing organization. The results of the WTW compensation benchmarking study demonstrate that, overall, OPG's Total Remuneration[5] is within the target market range.[6] Section 8.0 provides an overview of the compensation benchmarking performed by WTW and the full WTW Report is included in Attachment 3.

WTW also undertook a comparison of OPG's wages to those provided by Bruce Power (Attachment 4). Bruce Power is OPG's closest comparator, operating in the same energy industry, with a workforce represented by the same unions in the same provincial labour market. The nuclear operations industry is a niche labour market in Ontario, with comparable roles requiring extensive nuclear knowledge or training not readily found in the province, other than at Bruce Power and OPG. OPG's compensation levels remain lower compared to Bruce Power. Additionally, WTW provided OPG with an analysis of the tenure of its workforce relative to the energy sector, the results of which demonstrate that OPG generally has a more tenured unionized workforce compared to its peer group (Attachment 5).

3.0 OPG's WORKFORCE

At the end of 2024, OPG employed 10,332 regular, Term and ETE employees.[7]

3.1 Unionization

OPG's employees work in a predominantly unionized environment, with approximately 87% of employees represented by the PWU or the Society. The PWU represents 56% of OPG's unionized employees and the Society represents the remainder. The proportion of unionization

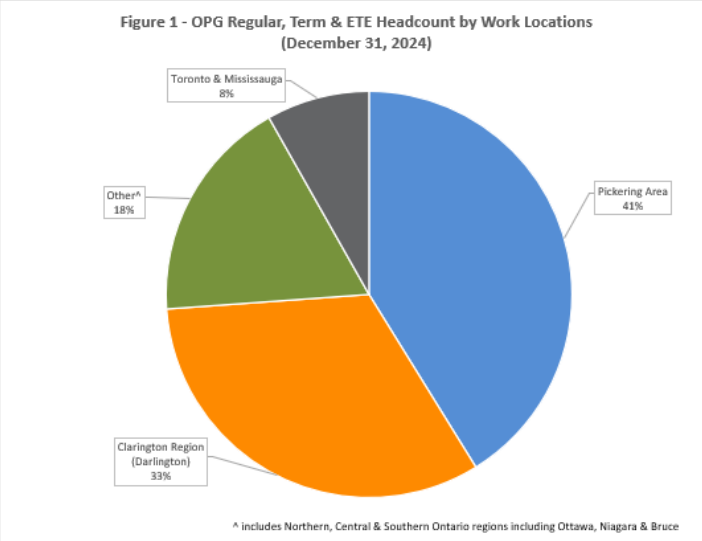
[5] Total Remuneration reflects the total direct compensation, pension and benefits, and paid time off for eligible employees as a percentage of base salary (Attachment 2, p. 7).
[6] Target market range is defined by WTW as +/- 10% of the peer group median or "P50".
[7] All total OPG employee statistics are provided excluding OPG's operating subsidiaries.

and the mix of PWU-represented, Society-represented, management (managers/supervisors) and non-unionized individual contributors has generally remained stable over the past several years. The current collective agreement with the PWU is for a three-year term, from April 1, 2024-March 31, 2027. The current collective agreement with the Society is for a two-year term, from January 1, 2024-December 31, 2025.

3.2 Work Locations and Employees

OPG's employees work in generating stations and other facilities across the province as shown in Figure 1.

Figure 1 – OPG Regular, Term and ETE Headcount by Work Locations

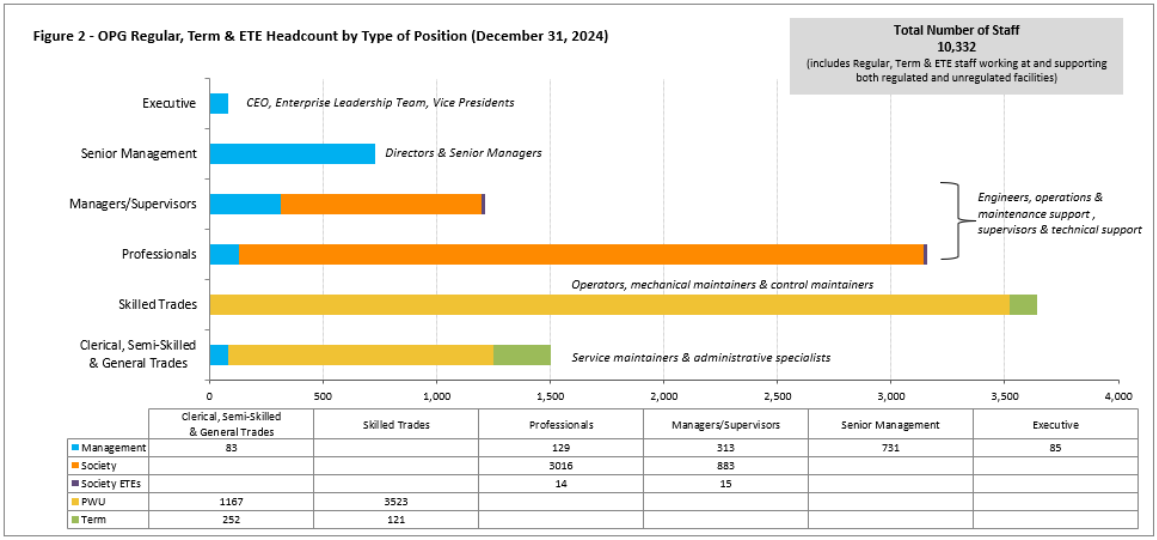


OPG employs individuals from a variety of disciplines, many of which are specialized technical roles. This includes engineers, and operations and maintenance staff that operate and maintain the nuclear and hydroelectric facilities in a safe and reliable manner. To support the refurbishment and new build programs for generating assets, OPG's demand for qualified project and engineering professionals, which are largely Society-represented roles at OPG, is expected to surpass historical levels. In order for OPG to successfully deliver key projects and initiatives on time, on budget and with the required quality, it is essential to attract and retain project and engineering professionals critical to planning and executing this work. OPG seeks to offer opportunities for professional growth and a strong organizational culture to help attract

and retain this talent, which is especially important given that such professionals are often attracted to opportunities outside of Ontario. These efforts are required to ensure a robust pipeline of candidates in support of OPG's mandate and are further discussed in Section 6.2.2.

Figure 2 shows an overview of OPG's headcount (regular, Term Employees and ETEs) by type of positions as of December 31, 2024. This includes employees supporting OPG's regulated and unregulated facilities. As noted in Section 2.0, the increase in the number of managers and professionals is largely due to employees required to support the advancement and execution of key projects and initiatives including the PRP, the DNNP and the refurbishment of the hydroelectric fleet in alignment with the Province's vision for the future of energy. This includes engineers, project management professionals, information technology professionals, including respective trainees.

Figure 2 – OPG Regular and Term Headcount by Type of Position



	Clerical, Semi-Skilled & General Trades	Skilled Trades	Professionals	Managers/Supervisors	Senior Management	Executive
Management	83		129	313	731	85
Society			3016	883		
Society ETEs			14	15		
PWU	1167	3523				
Term	252	121				

In addition to Term Employees and ETEs, OPG employs other forms of non-regular labour, where employees are hired for a fixed period with an end date.

3.3 Demographics

OPG has a mature and experienced workforce. By year-end 2025, approximately 11% of active regular employees (~1,065) will be eligible to retire with an undiscounted pension, with an additional 15% becoming eligible to retire between 2026-2031. Compared to EB-2020-0290, the lower number of employees eligible for fully undiscounted retirement in 2025 reflects changes in the retirement eligibility formula negotiated in 2015 that have now taken effect (see Section 7.0.2 below), and the shift in OPG's overall demographics.

4.0 PLANNED PICKERING CLOSURE

As noted in Section 2.0, the planning for the end of commercial operation at Pickering and the associated reduction in the workforce has been marked by significant uncertainty since EB-2020-0290, requiring OPG to navigate evolving business imperatives.

As discussed in EB-2020-0290, OPG had begun preparing for a large-scale workforce reduction of over 3,000 positions following the then anticipated end of commercial operation of the six Pickering units at the end of 2025. Acknowledging the profound nature that such a downsizing would have on the company, the employees and the local communities, OPG continued to advance these preparations subsequent to EB-2020-0290, with a focus on ensuring continued availability of a skilled workforce while mitigating the material cost impacts of the downsizing. The downsizing costs were expected to include severance obligations, as well as post-station shutdown transition costs for the movement of employees within the organization under complex redeployment and displacement provisions of the collective agreements that would be triggered by a downsizing.

OPG's key strategies to mitigate the organizational and financial impacts of the downsizing included the hiring of Term Employees and ETEs pursuant to agreements with the unions, facilitating the transfer of regular employees from Pickering to Darlington ahead of the Pickering closure within operational constraints, and leveraging attrition-based headcount reductions, where feasible. Additional details regarding Term Employees and ETEs are provided in Section 5.1.1 below.

Another key strategy was negotiating changes to downsizing provisions within the collective agreements, which OPG successfully pursued in the first rounds of collective bargaining that followed EB-2020-0290. These jointly agreed changes related to the planned Pickering closure provided for a more defined and efficient downsizing process that would significantly lessen operational disruption and transition impacts, decreasing the overall cost of a workforce reduction.

To effectively plan for the Pickering closure, OPG focused on key areas including knowledge management, workforce planning, recruitment, and labour relations. Among others, these preparations included analyzing employee attrition patterns, operationalizing the negotiated collective agreement redeployment provisions, developing tools, processes and the required training programs to manage employee transitions, upgrading workforce modeling capability, implementing programs to address increased staff turnover and mitigate the risk of losing critical resources, and managing labour relations issues. Through these actions, OPG sought to ensure a reasonable and fair transition for both employees and the organization, minimizing operational risks and supporting business continuity throughout the process.

In parallel with preparing for the Pickering closure, as discussed in Ex. D2-3-1, the Province asked OPG to update its feasibility assessment for refurbishing Pickering Units 5-8 in September 2022, while also expressing its support for OPG's plan to operate Pickering Units 5-8 until September 2026, rather than the end of 2025. In August 2023, OPG's Board of Directors approved OPG's updated refurbishment feasibility assessment and in January 2024, the Province announced its support for OPG to proceed with the initiation phase of the project. With the Province's support, OPG continued to advance the PRP through decision gates leading up to the approval to proceed into execution as announced by the Province in November 2025. As the Company increasingly shifted toward the possibility of the refurbishment, OPG began refocusing strategic workforce planning to ensure preparedness for the project, alongside the DNNP and other major work programs, while continuing to manage the risks of a potential downsizing should the refurbishment ultimately not proceed. While a major downsizing is no longer anticipated, many of the tools and strategies developed in preparation for the station's full closure are enabling workforce planning and a more efficient

redeployment of employees as they transition from normal operations to the refurbishment and back. These efforts also assisted in mitigating the impacts of Pickering Units 1 and 4 ending commercial operation in the fourth quarter of 2024, as planned.

As outlined in Ex. H1-1-1, Section 5.21, OPG is seeking recovery of $7.6M in costs incurred as of December 31, 2024 in connection with the preparations for the Pickering closure through the Pickering Closure Costs Deferral Account.

5.0 PLANNING FOR THE FUTURE

In 2020, OPG undertook an organizational realignment with the goal of driving efficiencies and increasing cross-functional synergies and collaboration. These changes resulted in a consolidation of certain functions and incremental cost savings, including a 10% reduction in the number of management positions, marking an important step towards preparing for post-Pickering operations. The reduction in management positions was maintained until 2023, at which point the planning efforts for the potential Pickering refurbishment, the progression of the DNNP and the ramping up of the hydroelectric work program necessitated the addition of management and other positions to facilitate the building out of these major investments. OPG continues to leverage the centralization of functions implemented in 2020, including Support Services, to more effectively scale up (or down) project teams using existing organizational structures.

Skilled professionals at OPG are responsible for areas such as designing and maintaining infrastructure, ensuring safety and environmental compliance, and advancing digital capabilities such as data systems and cyber security. According to external studies, rapid technological change and a limited supply of STEM graduates have created a skills gap, particularly in the electricity sector, where there have been challenges in attracting and retaining roles, particularly within engineering.[8] At the same time, the demand for this talent in the energy and other sectors has been increasing.

[8] Electricity Human Resources Canada Employer Survey in 2023, Labour Market Insights Report, p 49.

With growing labour market pressures and a shrinking pool of skilled workers, competition for key talent, particularly energy project professionals, has increased since EB-2020-0290. Compounded by the demand for major infrastructure projects and the success of the DRP, OPG must proactively identify and address any skill gaps in order to secure and retain the workforce needed to deliver on its commitments. Since 2023, OPG has hired approximately 500 project managers and engineers and expects to continue hiring to ensure the appropriate resourcing through the IR term. Recruiting for these roles in advance of the PRP execution has helped OPG to continue achieving strong DRP performance (Ex. D2-2-1), progress the DNNP, and meet operational needs while allowing new hires sufficient time to build proficiency and engage in project planning activities.

Skilled labour employed by OPG is represented by the PWU and is essential for successful execution of OPG's projects, which are inherently time and capital-intensive. According to Electricity Human Resources Canada, while the electricity sector has experienced significant employment growth, the progressive decline in new apprenticeships could lead to a gradual reduction in the pool of skilled trades workers available to the sector.[9] OPG will continue to focus on strategies to develop employees and ensure they have the right skills in place to meet future workforce needs. This is being accomplished by identifying the necessary skills for OPG's future workforce, strengthening and expanding the skilled trade talent pipeline, expanding early career and career progression opportunities, and strengthening partnerships with educational institutions and programs in the utility and energy industry.

OPG must navigate these labour market risks at the same time as it moves through the PRP. A comprehensive, risk-based workforce planning strategy is essential to maintaining stability in these circumstances while ensuring the PRP's success and preparing for the future. OPG's workforce transition plans are designed to enable the appropriate staffing for executing current work programs, enabling major projects, and ensuring operational continuity and critical skill retention leading into Pickering's "second life" operations.

[9] Electricity Human Resources Canada Employer Survey in 2023 Labour Market Insights Report, p 80.

5.1 Workforce Planning and Redeployments

OPG's central strategy to meeting its staffing objectives over the next several years is ensuring the ability to effectively and efficiently redeploy its existing unionized workforce from Pickering operations to the PRP, Darlington operations and the DNNP. This enables two significant benefits. First, it supports optimal resourcing for the PRP, helping to secure sufficient and proficient labour to meet project schedules and creating opportunities to utilize employees familiar with the station to support more efficient, safe execution of certain work. The benefits of this strategy to the PRP are further discussed in Ex. D2-3-4. Redeployment also preserves critical skills and specialized knowledge, mitigates operational disruption and avoids severance and the eventual recruitment costs that would arise in the absence of redeployment. This helps to ensure that Pickering will have the right workforce skillsets and competencies for post-refurbishment operations.

OPG needed to negotiate union agreements in order to enable the redeployment strategy. As discussed in Section 2.0, OPG successfully secured such agreements with the PWU and the Society that allow employees to move between locations and perform the same or similar work where there is demand. OPG also reached an agreement with the BTU to allow PWU-represented employees to perform certain refurbishment work.

The BTU agreement was reached in 2023 after it was identified, in anticipation of a potential Pickering refurbishment, that there was an opportunity to optimize value for OPG by proactively addressing union labour jurisdiction restrictions that prevented OPG's PWU-represented employees from performing certain refurbishment work. OPG proactively engaged in negotiations with the BTU. The PWU agreement was reached in 2023, in parallel with OPG's decision to hire a number of Term Employees to regular positions to mitigate attrition and labour market supply risks, subject to a positive decision regarding the Pickering refurbishment (see Section 5.1.1 below).

In total, OPG anticipates redeploying about 1,300 employees from the Pickering station to the PRP, Darlington, the DNNP and other parts of the organization. As DRP nears completion, about 200 employees will be redeployed primarily to Darlington and the PRP. These transitions

are expected to be completed by the end of 2026. The benefits of these measures are reflected in OPG's 2025-2031 Business Plan and in the PRP's release quality estimate, and form part of the cost and staffing plans reflected in the Application.

A certain portion of the workforce will continue to support Pickering during the refurbishment period. OPG will maintain these necessary resources to ensure compliance with regulatory requirements, perform ongoing and cyclical maintenance, and preserve readiness to re-enter service following the four-unit refurbishment window. Support functions not directly tied to the refurbishment in such areas as security, emergency preparedness, engineering, fleet management, nuclear oversight, and training will continue to sustain the necessary critical operational capabilities of the station. Station requirements during the four-unit refurbishment window are discussed further in Ex. F2-2-1.

In addition to enabling redeployment flexibility, key strategies OPG has undertaken in workforce planning include:

- Establishing an enterprise staffing strategy and a hiring oversight committee to ensure that staffing levels and decisions support ongoing operational and project needs, while optimizing the workforce and managing risks for high-demand roles in the market.
- Developing transition plans to efficiently and effectively manage staff deployment during the completion of the DRP and Pickering Units 5-8 operations in 2026, and the subsequent transition to PRP execution.
- Implementing targeted training initiatives for developing proficiency in the workforce for the hydroelectric operations. These training and development activities will be critical as Renewable Generation looks to hire additional staff to support the increased work program. described in Ex. F1-1-1, primarily for the regulated hydroelectric refurbishment projects.
- Increasing local external hiring to Renewable Generation roles in order to reduce regional turnover, and a focus on critical knowledge areas, including water resources, dam safety, and hydroelectric operating technicians.
- Reintroducing early career programs to better attract talent and ensure continuity in talent pipelines for ongoing operations and key projects.

- Succession planning to ensure leadership development enables a diverse and robust talent pipeline for the long term.
- Expanding outreach programs to academic institutions and career fairs to support increased supply in the market for skilled trades and STEM roles.
- Supporting various skilled trades initiatives to increase a diverse supply, creating an industry wide resource demand profile, and other efforts to balance supply and demand.

5.1.1 PWU and Society-represented Term-Based Employees

To assist in mitigating the anticipated impacts associated with the Pickering closure, as discussed in EB-2020-0290, OPG had negotiated the category of Term Employees with the PWU in the 2015-2018 collective agreement and successfully extended the availability of this classification in subsequent rounds of collective bargaining. In general, Term Employees could be hired instead of regular staff in circumstances where employees were likely to be laid off as a result of the planned shutdown of Pickering. These employees have been hired with the understanding that there is no expectation of ongoing employment after Pickering commercial operations cease (and shut down units' transition through certain safe storage preparation activities), and they are entitled to less severance than PWU-represented regular employees upon layoff.

Since EB-2020-0290, OPG began to experience noticeably higher attrition among certain Term Employee job classifications. Through continued hiring, the number of Term Employees had peaked close to 1,000.[10] In 2024, with the Province's announcement supporting next steps toward the refurbishment of Pickering Units 5-8 and the progression of the DNNP, and faced with the increased attrition of Term Employees and a tightening labour market supply for these skillsets, OPG made a decision to hire approximately 60% of Term Employees to regular positions, within operations and maintenance areas. As discussed above, OPG made this decision in parallel to securing more flexible redeployment provisions for its PWU-represented employees within the Nuclear business. Pursuant to collective agreement provisions, OPG will have substantially no Term Employees or ETEs in its workforce after 2026.

[10] FTE is calculated at an employee level as labour hours divided by scheduled hours.

6.0 COMPENSATION COSTS AND STAFFING LEVEL TRENDS

Compensation costs for OPG's regulated nuclear operations and regulated hydroelectric operations, and the DNNP facilities, are comprised of the following elements:

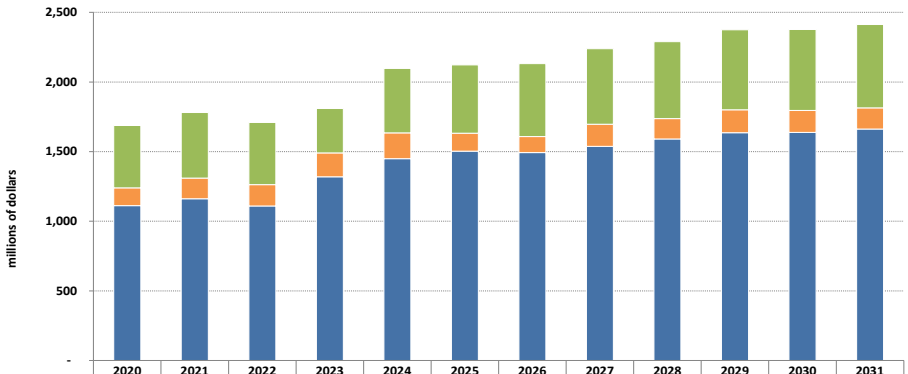
- Base Salaries and Incentives
- Pension and Benefits
- Overtime

Each of these elements is discussed below, as are FTEs.

Figure 3a summarizes the compensation costs in respect of OPG's nuclear facilities and the DNNP facilities, as applicable, for 2020-2031. Figure 3b summarizes the compensation costs for OPG's regulated hydroelectric facilities for 2020-2031. The increases in the costs over time primarily reflect the higher collective agreement wage increases over the last several years as well as wage escalation assumptions over the IR term. The increases in FTEs in the near term also contribute to the higher compensation costs.

Figure 3a – Compensation Costs for Nuclear*

Figure 3a - Compensation Costs for Nuclear (including DNNP LP)

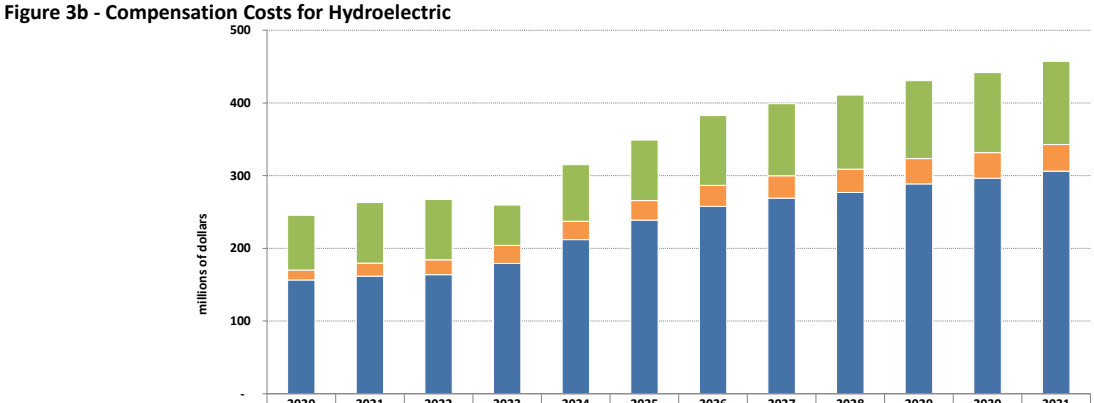


	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Pensions & Benefits (M$)*	448	470	447	318	462	491	524	542	553	575	581	598
Overtime (M$)	128	149	153	172	186	129	115	160	147	165	158	151
Base Salaries & Incentives (M$)	1,112	1,161	1,110	1,320	1,449	1,503	1,493	1,538	1,591	1,635	1,638	1,663
Total Compensation (M$)	1,688	1,781	1,709	1,809	2,098	2,123	2,132	2,239	2,290	2,376	2,377	2,413
Rate of Change (Total Compensation)	2%	6%	-4%	6%	16%	1%	0%	5%	2%	4%	0%	1%
Full Time Equivalents**	8,396	8,334	8,035	8,621	9,073	9,938	9,589	9,368	9,398	9,249	9,038	8,909

*Pension and benefits include current service costs only and are shown on an accrual basis.
** FTE includes both regular and non-regular FTEs

*Includes DNNP facilities

Figure 3b – Compensation Costs for Regulated Hydroelectric



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Pensions & Benefits (M$)*	75	83	83	56	78	83	96	99	102	107	110	114
Overtime (M$)	14	18	21	25	25	27	29	31	32	35	35	37
Base Salaries & Incentives (M$)	156	162	164	179	212	239	258	269	277	289	296	306
Total Compensation (M$)	245	263	267	260	315	349	383	399	411	431	442	457
Rate of Change (Total Compensation)	7%	7%	2%	-3%	21%	11%	10%	4%	3%	5%	3%	3%
Full Time Equivalents**	1,229	1,218	1,251	1,303	1,416	1,626	1,696	1,712	1,712	1,716	1,713	1,711

*Pension and benefits include current service costs only and are shown on an accrual basis.
** FTE includes both regular and non-regular FTEs

6.1 Staffing Levels

Figure 4a shows the FTEs (2020-2024 actual and 2025-2031 planned) for OPG's nuclear facilities and the DNNP facilities (including allocation of corporate Support Services), broken down by management (managers/supervisors vs individual contributors), Society-represented, and PWU-represented regular and non-regular employees, Term Employees, ETEs, and EPSCA Trades.

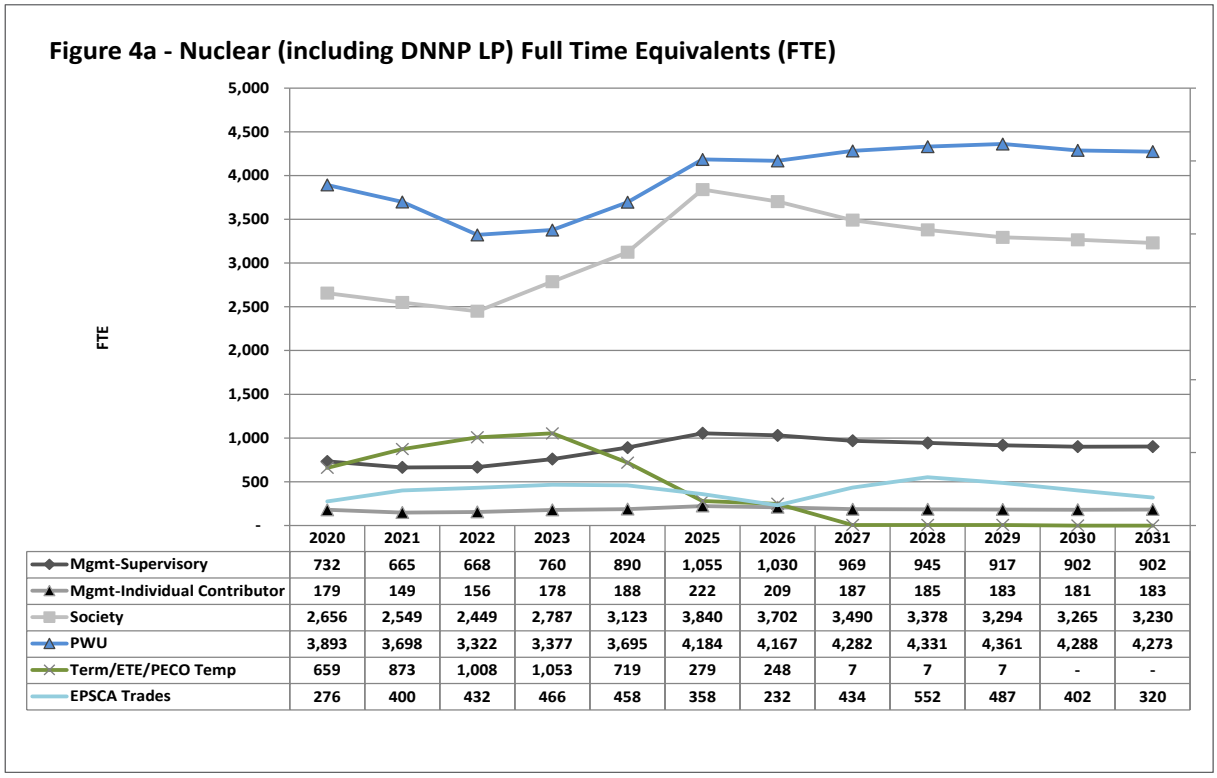
At the time of EB-2020-0290, OPG was expecting a declining trend in the FTEs for the nuclear facilities due to the anticipated Pickering closure, taking into account the various workforce strategies discussed in Section 4.0. During the period from 2022-2024, the Company shifted from planning for Pickering shutdown by the end of 2025 to enabling extended operations to September 2026 and assessing the feasibility and beginning to plan for refurbishing Pickering Units 5-8 thereafter. This shift required a responsive workforce plan to meet these changing business needs, while anticipating an increased risk of attrition over the remaining life of the station.

As of 2022, Nuclear base OM&A full-time equivalents ("FTEs") were beginning to attrite to levels lower than those planned in EB-2020-0290, which if left unaddressed, would lead to inadequate staffing levels to meet operational needs. With the implementation of a responsive workforce plan, by 2023, FTE levels aligned more closely to the original planned resourcing requirements established in EB-2020-0290. By 2024, FTE levels increased to enable the extension of Pickering operations to 2026, to maintain site continuity through the Pickering refurbishment outage, and to meet ongoing operational and regulatory requirements. Excluding the increase in the FTEs as a result of the repatriation of New Horizon Systems Solutions employees in 2022 (further discussed in Ex. F3-1-1), the FTEs increased by 6% in 2023 and 5% in 2024.

With the PRP progressing into the definition phase in 2025 while the Pickering station is operating, the FTEs for the nuclear facilities are forecasted to temporarily increase by a further 10%. The forecasted FTEs then decline by 7% over 2026-2029 with the completion of the DRP in 2026 and the completion of preparations for the safe storage of Pickering Units 1 and 4 in 2028, and are largely stable thereafter. The execution phase of the PRP will not result in a material change in the FTEs, as necessary resources will be redeployed from Pickering station operations to support the project during the four-unit refurbishment window (see Section 5.0).

The decrease in Term Employee FTEs over the 2023-2025 period is largely offset by an increase in PWU-represented regular FTEs, reflecting OPG's decision to hire a number of Term Employees into regular positions (see Section 5.1.1). The increase in Society-represented and management regular FTEs is primarily driven by the ramp up in work for the PRP and the DNNP, as discussed above, the repatriation of New Horizons System Solutions IT resources to OPG (about 250 employees) and an increase in Pickering staffing to restore capacity to enable continued operations and planning for the PRP.

Figure 4a – Nuclear Full Time Equivalents

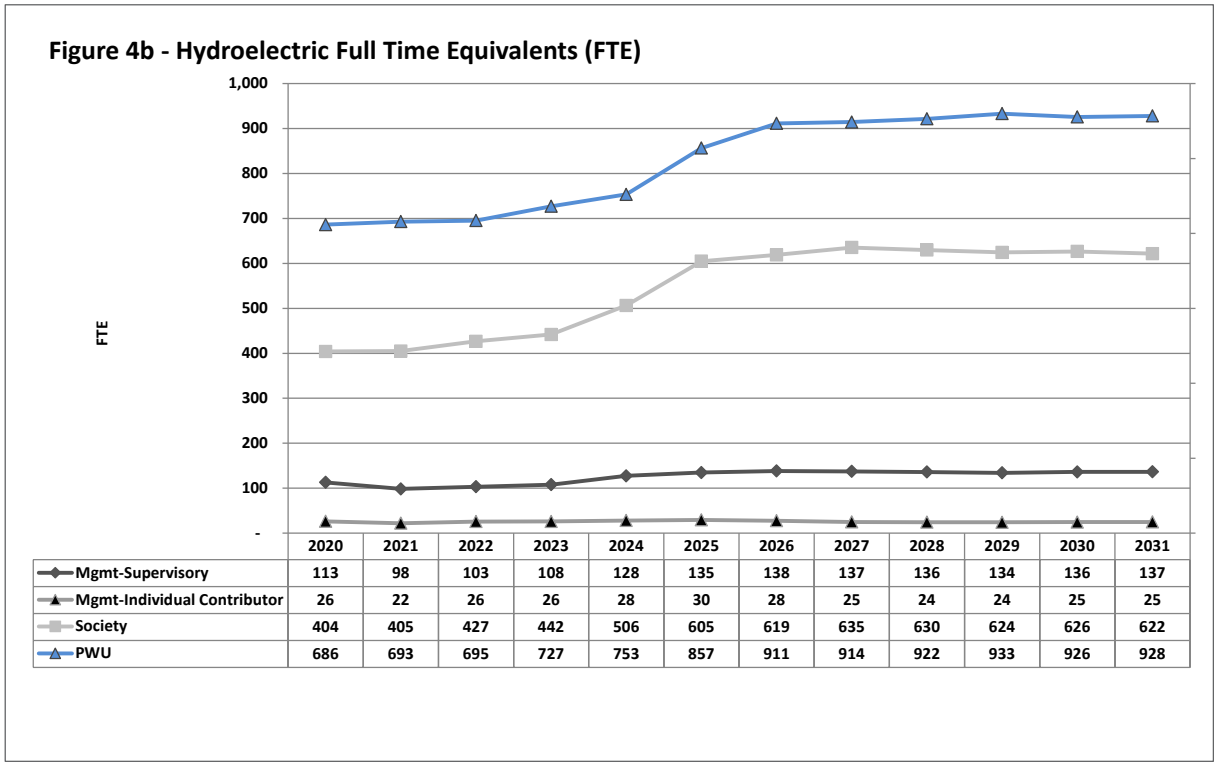


	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Mgmt-Supervisory	732	665	668	760	890	1,055	1,030	969	945	917	902	902
Mgmt-Individual Contributor	179	149	156	178	188	222	209	187	185	183	181	183
Society	2,656	2,549	2,449	2,787	3,123	3,840	3,702	3,490	3,378	3,294	3,265	3,230
PWU	3,893	3,698	3,322	3,377	3,695	4,184	4,167	4,282	4,331	4,361	4,288	4,273
Term/ETE/PECO Temp	659	873	1,008	1,053	719	279	248	7	7	7	-	-
EPSCA Trades	276	400	432	466	458	358	232	434	552	487	402	320

Figure 4b shows the FTEs (2020-2024 actual and 2025-2031 planned) for the regulated hydroelectric facilities (including allocation of corporate Support Services), broken down by management (managers/supervisors vs individual contributors), Society represented, and PWU-represented regular and non-regular employees for regulated hydroelectric facilities (including allocation of Corporate Support Services).

The FTEs for the regulated hydroelectric facilities are largely stable over the 2020-2023 period, before increasing by 9% in 2024 and 15% in 2025, mainly to support major capital projects including the turbine-generator refurbishment program taking place across the fleet, as described in Ex. F1-1-1. The FTEs are generally stable over the IR term.

Figure 4b – Regulated Hydroelectric Full Time Equivalents



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Mgmt-Supervisory	113	98	103	108	128	135	138	137	136	134	136	137
Mgmt-Individual Contributor	26	22	26	26	28	30	28	25	24	24	25	25
Society	404	405	427	442	506	605	619	635	630	624	626	622
PWU	686	693	695	727	753	857	911	914	922	933	926	928

6.2 Base Salaries and Incentives

Base salaries and incentives represent about 69% of OPG's total compensation costs related to the regulated facilities over the IR term.

Base salaries and incentives continue to be impacted by certain legislative and regulatory constraints. The following legislative and regulatory restrictions are applicable to OPG's compensation or have been in effect since EB-2020-0290:

a) On August 13, 2018, the Ontario government implemented the Compensation Framework Regulation ("O. Reg. 406/18") issued under the *Broader Public Sector Executive Compensation Act, 2014*, which imposed a cap on base salaries and pay at risk envelopes, at the prior pay year. As a result of this regulation, OPG has not provided base salary increases greater than prescribed legislative caps to its executive management employees

(generally Vice President level and above) since the implementation of O. Reg. 406/18, and pay for performance envelopes have been maintained based on 2017 amounts which were paid in 2018.

b) *Protecting a Sustainable Public Sector for Future Generations Act, 2019* ("Bill 124"), which came into effect on November 8, 2019, previously limited salary and total compensation increases to a maximum of 1% annually for the duration of the applicable three-year moderation period. On November 29, 2022, the Ontario Superior Court ("Superior Court") concluded that Bill 124 was unconstitutional and of no force and effect. On February 12, 2024, the Ontario Court of Appeal upheld, in part, the decision of the Superior Court. On February 23, 2024, the Ontario government formally repealed Bill 124 in its entirety.[11]

c) On August 31, 2021, the *Federal Pay Equity Act* came into force with the purpose of achieving pay equity for employees in jobs that are commonly held by women. OPG has established a Pay Equity Committee with representation across employee groups, in compliance with the requirements of the act. Compensation data collected through this process will be reviewed independently to facilitate comparisons between predominantly female and male job classes performing work of equal value and determine the need for any remediation.

The details of salaries and incentives are discussed below.

6.2.1 Unionized Salaries

OPG's compensation costs are largely a function of the collective agreements that cover approximately 87% of the company's employees. OPG is legally bound by its collective agreements, which establish salary rates and govern salary increases, any cost-of-living adjustments, and progressions through established salary ranges, among other elements of compensation.

[11] On March 1, 2023 OPG applied to the OEB for an accounting order proposing a new variance account be approved to record the impact of the overturning of Bill 124 on its nuclear revenue requirement, effective March 1, 2023 and until the effective date of the OEB's next nuclear payment amounts order. On June 27, 2023, the OEB issued its Decision and Order denying OPG's accounting order application.

Over the last five years, the backdrop of extraordinary inflation and broader labour unrest, combined with the repeal of Bill 124, contributed to significantly more challenging collective bargaining and negotiations. While inflation has begun to abate, it has contributed to higher-than-normal wage increases starting in 2021, as shown in Figure 5. Notwithstanding the challenging landscape, OPG was able to secure the continued suspension of the cost of living allowance/adjustment[12] provisions of the collective agreements with both unions during this period, in addition to securing outcomes related to the streamlined downsizing provisions, continued use of Term Employees and ETEs, broadened job classifications for the DNNP SMRs, more flexible redeployment provisions, and permanent purchased services agreement provisions, as discussed above.

In EB-2020-0290, OPG projected wage increases for unionized employees to be restricted to an annual increase of 1% for the respective three-year moderation period in accordance with Bill 124. The moderation period began on April 1, 2021 for OPG's PWU bargaining unit and January 1, 2022 for OPG's Society bargaining unit, tied to the expiration of the then-current collective agreements. As a result of Bill 124 being overturned and subsequently repealed, the following wage adjustments occurred to reverse the previous limit on the wage increases in respect of the moderation periods served:[13]

- On May 8, 2023, an arbitrator awarded Society-represented employees additional wage increases for 2022 (for a total increase of 4%) and 2023 (for a total increase of 3.25%) pursuant to an existing provision in that collective agreement, also awarded by an arbitrator, that provided for a reopening of the wage increases if Bill 124 became of no force and effect; and
- During the 2024 round of bargaining, OPG and the PWU negotiated an adjustment representing an additional 2.5% wage increase, compounded from 2021, effective April 1,

[12] A Cost-of-Living Allowance (PWU) or a Cost-of-Living Adjustment (Society) are clauses in the collective agreements which may result in an incremental wage adjustment should the negotiated wage increase for a given year fall below that of inflation, as measured by the Consumer Price Index.

[13] This evidence presents OPG's wage adjustments arising as a result of the overturning of Bill 124 in the applicable retrospective years, for comparative purposes. The actual cost impact of the adjustments was incurred in the years they were awarded or negotiated; the cost information in the Application is presented on this basis.

2024 on account for the period from April 1, 2021-March 31, 2022 (for a total increase of 3.5%).

The bargaining process for the 2023-2024 collective agreement with the PWU concluded subsequent to the overturning of Bill 124 and therefore was not subject to a legislated wage increase restriction at a time of significant market pressure on negotiated wages.

Chart 1 below shows OPG's actual yearly wage increases for the 2021-2026 collective agreement period(s) compared to those assumed in EB-2020-0290, for each of PWU and Society-represented employees, as well Ontario's general inflation rate. The actual figures are inclusive of the wage adjustments resulting from the overturning of Bill 124 and, in total, approximate overall inflation over the period.

Chart 1 - 2021-2026 Collective Agreement Wage Increases[14]

	Actual		EB-2020-2090		CPI (Ontario)
	PWU	**Society**	**PWU**	**Society**	
2021	3.50%[15]	2.80%	1.00%	2.80%	3.5%
2022	4.75%	4.00%	1.00%	1.00%	6.8%
2023	3.50%	3.25%	1.00%	1.00%	3.8%
2024	3.75%	4.75%[16]	2.00%	1.00%	2.4%
2025	3.75%	3.25%	2.00%	2.00%	1.9%
2026	2.50%	2.00%	2.00%[17]	2.00%	2.0%
Simple Total	**21.75%**	**20.05%**	**9.00%**	**9.80%**	**20.40%**

[14] For PWU-represented employees, increases are effective April 1 of each year shown. For Society-represented employees, increases are effective January 1.
[15] Includes a 2.5% compounded wage increase compounded from 2021, effective January 1, 2024.
[16] Includes a 1% one-time adjustment to salary schedules awarded by the arbitrator contemporaneous with the general wage increase.
[17] The actual 2026 wage increase for Society-represented employees is illustratively shown at the EB-2020-0290 forecast value, as the actual value is not yet known due to an ongoing arbitration process.

Both the 2022-2024 and the 2024-2027 collective agreements were reached with the PWU following extensive negotiations and a failed ratification by employees in the most recent round of collective bargaining. The 2022-2024 agreement was reached after the PWU members voted in favour of a strike, which was averted as a second tentative agreement was subsequently ratified. The 2024-2027 agreement was reached after the PWU requested a conciliator to assist with negotiations.

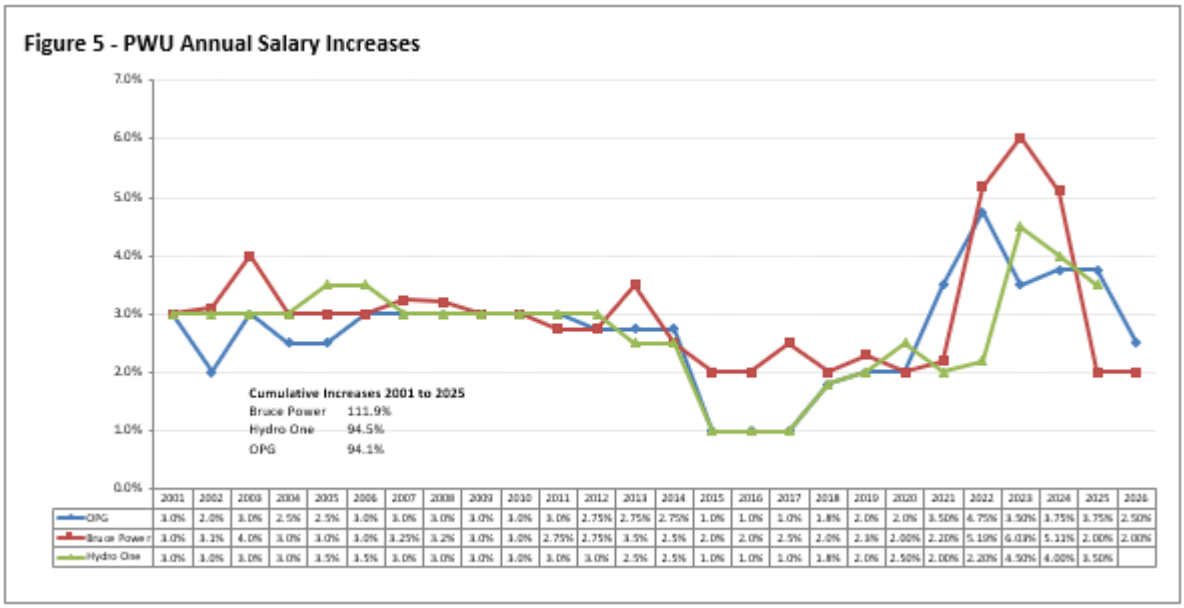
The two recent collective agreements with the Society, the first for 2022-2023 and the second for 2024-2025, were awarded through interest arbitration pursuant to a binding dispute resolution process in place between the parties.[18]

Taking into account the recent developments, historical union salary increases for OPG and other large companies within the electricity sector in Ontario are shown in Figures 5-8 below.[19] This information shows that, for both PWU and Society-represented employees, OPG's cumulative salary increases continue to fall below those of Bruce Power, and are comparable to those at Hydro One. It also demonstrates that other large utilities have been similarly impacted by the higher wage environment over the last several years.

[18] During interest arbitration, a neutral third-party hears submissions and evidence from the union and the employer on matters that the parties have not been able to settle in their negotiations and issues a decision. The decision of an arbitrator or arbitration board is final and binding.

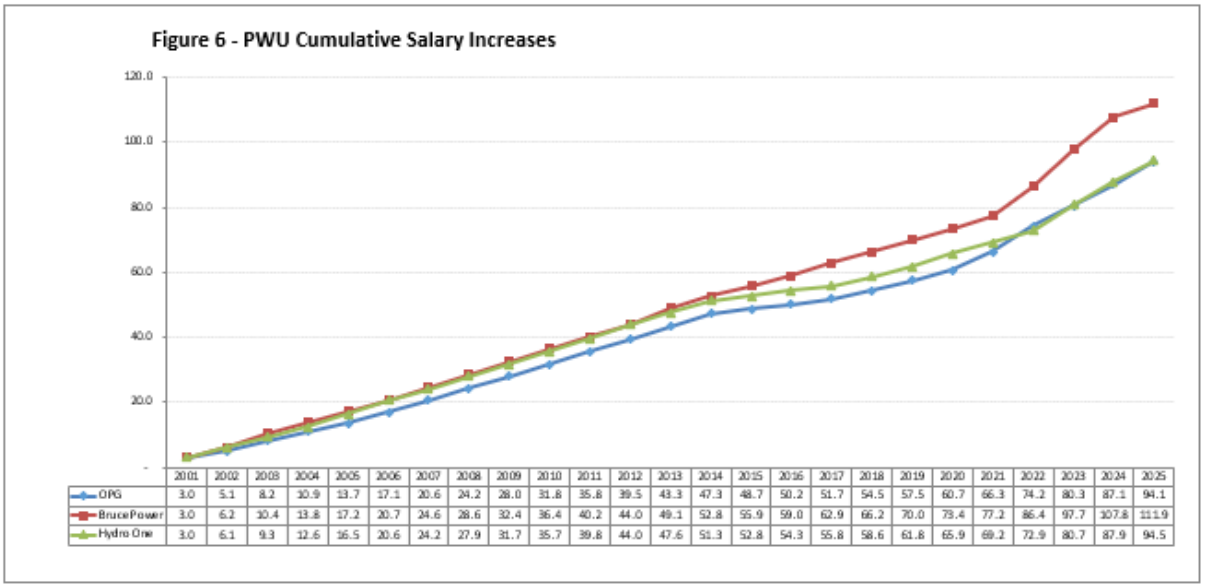
[19] Figures reflect annual increases per negotiated collective agreements. Where there are two economic increases in one calendar year, they have been added to provide an overall total for the year.

Figure 5 – PWU Annual Salary Increases



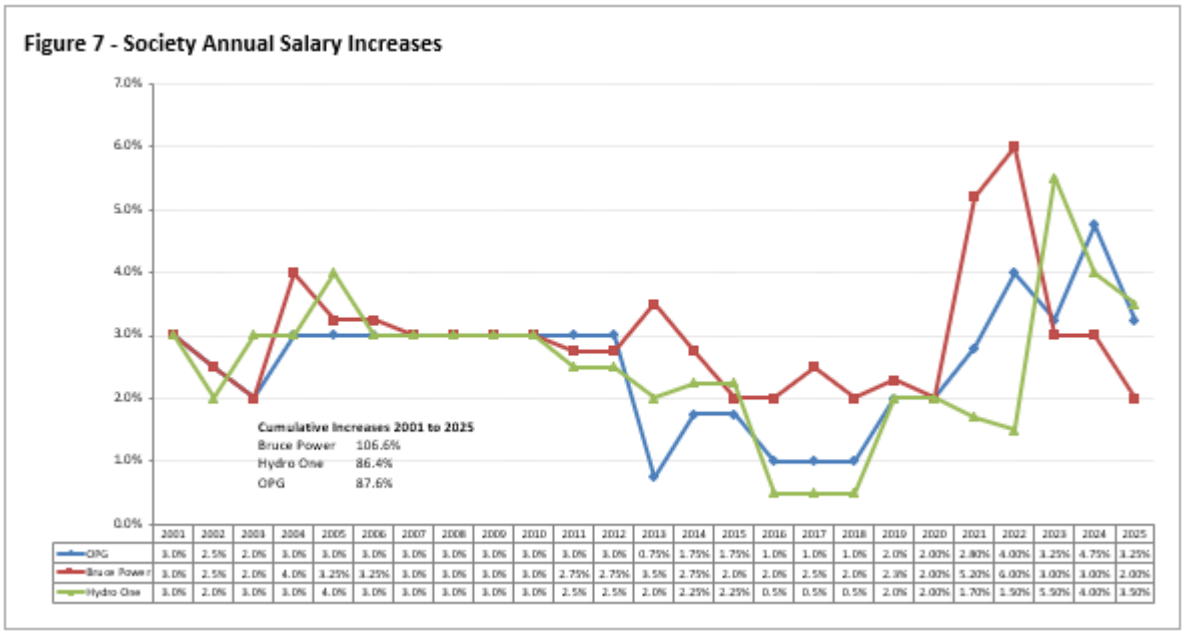
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
OPG	3.0%	2.0%	3.0%	2.5%	2.5%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	2.75%	2.75%	2.75%	1.0%	1.0%	1.0%	1.8%	2.0%	2.0%	3.50%	4.75%	3.50%	3.75%	3.75%	2.50%
Bruce Power	3.0%	3.1%	4.0%	3.0%	3.0%	3.0%	3.25%	3.2%	3.0%	3.0%	2.75%	2.75%	3.5%	2.5%	2.0%	2.0%	2.5%	2.0%	2.3%	2.00%	2.20%	5.19%	6.03%	5.11%	2.00%	2.00%
Hydro One	3.0%	3.0%	3.0%	3.0%	3.5%	3.5%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	2.5%	2.5%	1.0%	1.0%	1.0%	1.8%	2.0%	2.50%	2.00%	2.20%	4.50%	4.00%	3.50%	

Figure 6 – PWU Cumulative Salary Increases



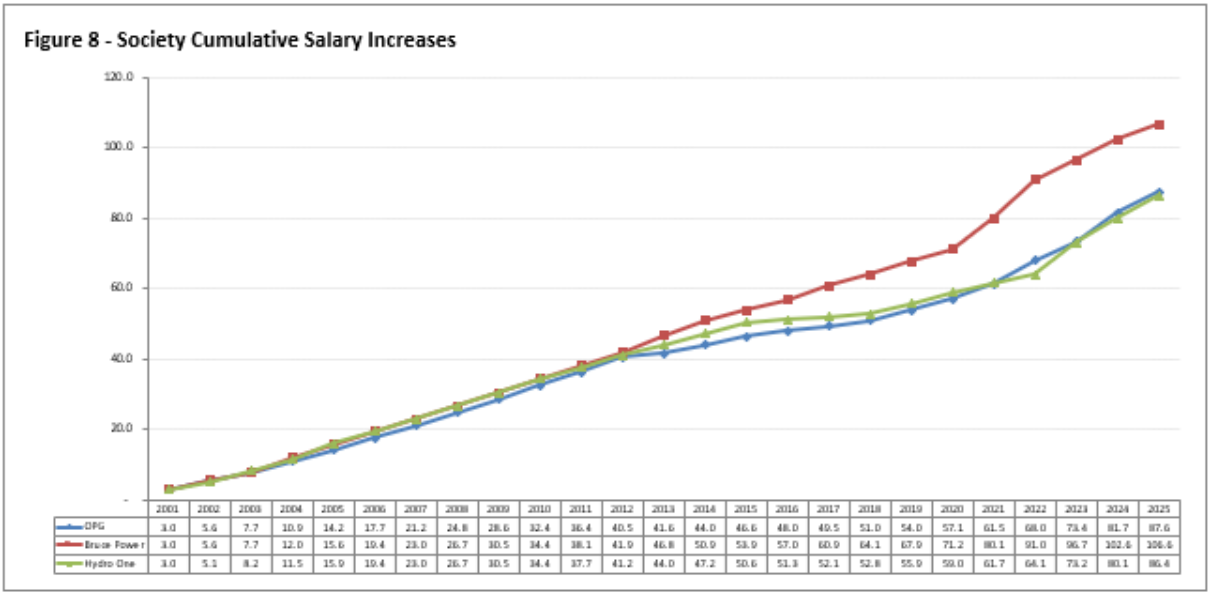
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
OPG	3.0	5.1	8.2	10.9	13.7	17.1	20.6	24.2	28.0	31.8	35.8	39.5	43.3	47.3	48.7	50.2	51.7	54.5	57.5	60.7	66.3	74.2	80.3	87.1	94.1
BrucePower	3.0	6.2	10.4	13.8	17.2	20.7	24.6	28.6	32.4	36.4	40.2	44.0	49.1	52.8	55.9	59.0	62.9	66.2	70.0	73.4	77.2	86.4	97.7	107.8	111.9
Hydro One	3.0	6.1	9.3	12.6	16.5	20.6	24.2	27.9	31.7	35.7	39.8	44.0	47.6	51.3	52.8	54.3	55.8	58.6	61.8	65.9	69.2	72.9	80.7	87.9	94.5

Figure 7 – Society Annual Salary Increases



	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
OPG	3.0%	2.5%	2.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	0.75%	1.75%	1.75%	1.0%	1.0%	1.0%	2.0%	2.00%	2.80%	4.00%	3.25%	4.75%	3.25%
Bruce Power	3.0%	2.5%	2.0%	4.0%	3.25%	3.25%	3.0%	3.0%	3.0%	3.0%	2.75%	2.75%	3.5%	2.75%	2.0%	2.0%	2.5%	2.0%	2.3%	2.00%	5.20%	6.00%	3.00%	3.00%	2.00%
Hydro One	3.0%	2.0%	3.0%	3.0%	4.0%	3.0%	3.0%	3.0%	3.0%	3.0%	2.5%	2.5%	2.0%	2.25%	2.25%	0.5%	0.5%	0.5%	2.0%	2.00%	1.70%	1.50%	5.50%	4.00%	3.50%

Figure 8 – Society Cumulative Salary Increases



	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
OPG	3.0	5.6	7.7	10.9	14.2	17.7	21.2	24.8	28.6	32.4	36.4	40.5	41.6	44.0	46.6	48.0	49.5	51.0	54.0	57.1	61.5	68.0	73.4	81.7	87.6
Bruce Power	3.0	5.6	7.7	12.0	15.6	19.4	23.0	26.7	30.5	34.4	38.1	41.9	46.8	50.9	53.9	57.0	60.9	64.1	67.9	71.2	80.1	91.0	96.7	102.6	106.6
Hydro One	3.0	5.1	8.2	11.5	15.9	19.4	23.0	26.7	30.5	34.4	37.7	41.2	44.0	47.2	50.6	51.3	52.1	52.8	55.9	59.0	61.7	64.1	73.2	80.1	86.4

6.2.2 Management Salaries

As of December 31, 2024, management represented 13% (~1,340) of OPG employees whose salaries are not prescribed by collective agreements, and whose base salary ranges and pay for performance programs are approved by OPG's Board of Directors. Within OPG's management group, 16% of employees are individual contributors while the remaining 84% are supervisors and managers.

OPG's ability to successfully deliver on its mandate will depend heavily on the attraction and retention of management talent in a significantly competitive labour market. The demand for skilled leadership talent in the energy sector remains high, posing ongoing risks to OPG's ability to retain and attract talent into management positions. The specialized skillsets required within the nuclear sector and geographical dispersion of OPG's hydroelectric assets further complicate recruitment efforts, posing a risk of leadership availability in critical operational and project areas. In particular, the number of experienced nuclear leaders available in the market is very limited. The nuclear operations industry is a niche market in Canada with similar roles existing only at Bruce Power and, at a smaller scale, at New Brunswick Power. It takes an average of 20 years to develop a senior Nuclear Executive due to the extensive training and experience required. OPG must continue to focus on building its own talent by hiring more junior employees and developing them internally in order to mitigate these risks.

Increasingly and in large part due to the increased demand for specialized skills, OPG competes for management talent with utilities across Canada, including primarily private companies and several large US utilities for specific nuclear skillsets, the majority of whom are not subject to legislative restrictions to the same extent as OPG. As further discussed in Section 8.0 below, OPG's management compensation continues to benchmark below the target market range. Underscoring this competitive dynamic, as of the end of 2024, attrition among leaders at the director level was higher than benchmark,[20] exceeding historical levels. Additionally, although OPG has a robust succession planning program, by 2031, approximately

[20] Conference Board of Canada's *HR Metrics Benchmarking 2023: Year in Review* report indicates that voluntary attrition rates among Management and Executives was 5.9% and 1.1% respectively. In 2024, OPG's voluntary attrition for Directors and Executives was 6.5% and 2.6% respectively.

30% of OPG's executive and 15% of senior management employees will be eligible to retire. OPG directors and managers play a key role in achieving the company's operations, project and general business objectives and comprise the pool of succession candidates for executive roles.

In response to these pressures, OPG has implemented both non-compensation and compensation initiatives aimed at maintaining a competitive market position for management roles, recruiting and retaining talent, and encouraging union represented employees to transition into management roles, including:

1. Increased focus on training, career development, and succession planning to empower management employees and provide a roadmap for their professional growth.
2. Emphasis on a values-based culture centered on safety, integrity, excellence, inclusion and innovation, aimed at enhancing engagement and strengthening work environment.
3. Formal and day-to-day employee recognition programs and tools, including a digital platform and enhanced leadership focus on recognition.
4. Formal commitments to societal imperatives through development and commitment to actions such as the Reconciliation Action Plan.
5. Well-being and mental health support through benefit offerings and resources.
6. Salary adjustments through Board of Directors' approval, performance-based merit increases.
7. Board of Directors' approved salary band adjustments to more closely align OPG's midpoint salaries with its peers, with the aim of gradually closing the gap to the 50th percentile.

6.2.3 Management Stakeholder Return Program

The Stakeholder Return Program ("SRP") is a short-term (i.e., single year) pay for performance incentive plan for eligible management employees, intended to deliver a portion of total compensation on a pay for performance basis. The goal of the program is to motivate and reward employee performance that promotes successful business outcomes. Assessment of performance is based on individual and corporate objectives set for the applicable program year.

Since 2021, OPG has used a financial results model for deriving the SRP amounts based on a percentage applied to forecast corporate earnings before tax. The setting of this percentage for a given year takes into consideration the underlying business objectives for that year, is limited to a range based on practices among industry peers,[21] and contemplates any other established limits, including legislative constraints discussed above. This amount is then multiplied by OPG's corporate score (assumed at target or 1.0 in the forecast period) and further adjusted to account for the distribution of individual performance scores. A limited amount may be added, at the discretion of the CEO, to recognize specific performance aligned with organizational business imperatives. The percentage to be applied to earnings before tax, the corporate score results and the incentive payouts are subject to OPG's Board of Directors' approval. Forecast performance incentives costs under the SRP for every year within the IR term are estimated based on projected financial results, using the above principles.

As in OPG's previous proceedings, the costs of these incentives are shown separately as a centrally held cost in Ex. F4-4-1, Tables 1 and 3, and are included in Attachment 1.

6.3 Pension and Benefits

Pension and benefits represent approximately 24% of the regulated compensation costs (including the DNNP facilities) over the IR term and include current employee benefits and current service costs for pension and other post-employment benefits ("OPEB"). Pension and benefit plan provisions for represented employees are established in collective bargaining, while the pension and benefits offered to management employees are determined by OPG's Board of Directors.

6.3.1 Current Employee Benefits

OPG's current employee benefits include health, dental and group life insurance benefits for employees while on payroll, as well as statutory requirements such as the Employer Health Tax, Employment Insurance and Workers Compensation. Health, dental and life insurance benefits for PWU and Society-represented employees are negotiated during collective bargaining, whereas OPG's Board of Directors approves the benefit programs for

[21] Willis Towers Watson indicates that annual incentive pools range from 2-7% of EBT/EBITDA.

management. In addition to forming part of the compensation package, these programs provide an opportunity to support a healthy, engaged and productive workforce.

OPG outsources claims administration to Sun Life Financial and has plan management and adjudication mechanisms in place to control benefit costs. These include a frequency limit on prescription drug refills, mandatory substitution of lowest cost equivalent drugs, maximizing coordination of benefit opportunities, and a requirement for prior approval for certain drug and treatment therapies.

6.3.2 Pension and Other Post Employment Benefits ("OPEB")

Pension and OPEB costs include the employer paid costs of providing a pension along with OPEB such as life insurance, and health and dental care for pensioners and their dependants, as well as long-term disability benefits for current employees. Additional information on OPG's pension plan can be found in Ex. F4-3-2, including the most recently filed actuarial valuation (Ex. F4-3-2, Attachment 4).

Pension and OPEB amounts are included in the proposed revenue requirements on an accrual basis, consistent with the OEB's policy on pension and OPEB cost recovery set out in the OEB's Report: *Regulatory Treatment of Pension and Other Post-employment Benefits Costs* issued in EB-2015-0040. The amount and basis of forecast pension and OPEB accrual costs for the IR term are described in Ex. F4-3-2.

Pension and OPEB accrual costs are actuarially determined to reflect the present value of the benefits earned by today's employees for service they have rendered in support of the company's operations. Generally, the variability in the pension and OPEB current service costs over the 2020-2031 period is driven by changes in discount rates, changes in regular headcount levels, increases in salaries translating into pension obligations, and the impact of the passage of time on the present value calculations. For example, the decrease in pension and OPEB current service costs in 2023 was due to higher discount rates reflecting the interest rate environment at the time. Ex. F4-3-2, Section 4.3 discusses the major drivers of year-over-year trends in the current service cost components of pension and OPEB costs.

OPG makes employer contributions to its registered pension plan ("RPP") as required by the *Pension Benefits Act* (Ontario) ("PBA"). The PBA permits the sponsor to reduce employer contributions below the otherwise required levels when the plan is in a funding surplus position (as defined under the PBA for this purpose and known as Available Actuarial Surplus ("AAS")) and the associated requirements are met. OPG's RPP has AAS. In March 2025, OPG's Board of Directors approved such a reduction in OPG's contributions to match the level of employee contributions over the 2025-2027 period, effective March 2025, subject to meeting the legislative requirements. OPG has implemented the approved reduction in employer contributions. Based on the January 1, 2025 actuarial valuation of the RPP and future projections, the AAS is forecasted to continue throughout the IR term; accordingly, OPG's 2025-2031 Business Plan and the Application assume that OPG's employer contributions will continue to match employee contributions over this period, subject to future approval by OPG's Board of Directors. Additional details are provided in Ex. F4-3-2, Section 5.0.

As discussed in Ex. H1-1-1, Section 5.12, OPG will continue to record interest, asymmetrically in favour of ratepayers, on the difference between pension and OPEB accrual costs and actual cash amounts over the IR term through the use of the Pension and OPEB Forecast Accrual versus Actual Cash Differential Deferral Variance Account. As shown in Ex. F4-3-2, Charts 6 and 7, forecast pension and OPEB accrual costs attributed to OPG's regulated facilities are very close to the forecast cash amounts for the IR term, in aggregate. For the RPP, accrual costs continue to be lower than the cash amounts, after taking into account the reduction in employer contributions due to the availability of the AAS.

7.0 Changes to Pension and Benefits

Changes to employee contribution rates and pension plan design were negotiated with both the PWU and the Society in 2015, as described below. As discussed in EB-2016-0152, a broader approach to collective bargaining was taken in 2015, involving both Hydro One and the Province, in recognition of the impact that unionization has on sector-wide compensation. The resulting changes to contribution rates became effective during the 2015-2017 period, and a number of pension reform measures aimed at reducing pension costs came into effect in 2025, as discussed in Sections 7.0.1 and 7.0.2 below. Additionally, since EB-2020-0290, OPG

has made changes to management group health benefits with the goal of better aligning to those available to represented employees, in order to positively impact attraction and retention to management positions. All of the above changes are reflected in the IR term cost forecasts presented in the Application and included in the proposed revenue requirements.

7.0.1 Pension Reform Measures – Employee Contribution Increases and Employee / Employer Contribution Ratio

Through negotiations with the unions in 2015, OPG was able to increase employee pension contributions beginning April 1, 2015 for PWU-represented employees, and January 1, 2016 for Society-represented employees. Comparable changes were made to contributions for management employees beginning January 1, 2016. In addition, the pension provision changes that took effect in 2025 (discussed below) will now also work to decrease the overall current service cost (also known as normal cost) and funding requirements, thereby decreasing OPG's employer contributions. Figure 9 provides an overview of the changes in employee contribution rates and the employee-to-employer contribution ratio, inclusive of the impact of OPG's decision to reduce contributions as a result of the availability of the funding surplus (discussed above) beginning in 2025. As OPG's RPP is a defined benefit, single employer pension plan, the employer covers the residual balance of the total contribution requirements after employee contributions.

Figure 9 – Employee Contributions and Employee/Employer Contribution Ratio

Figure 9 – Overview of Employee Contributions

Employee Pension Contributions [1]	above Earnings Limit)			Contribution Ratio (Employee/Employer)
	MG	PWU	Society	
2014	7 / 7	5 / 7	7	24% / 76%
2015	7 / 7	6 / 8	7	24% / 76%
2016	7.3 / 8.25 / 2	7 / 9	8	29% / 71%
2017	7.6 / 9.5 / 4.5	7.5 / 10	9	32% / 68%
2018	7.6 / 9.5 / 4.5	7.5 / 10	9	33% / 67%
2019	7.6 / 9.5 / 4.5	7.5 / 10	9	34% / 66%
2020	7.6 / 9.5 / 4.5	7.5 / 10	9	32% / 68%
2021	7.6 / 9.5 / 4.5	7.5 / 10	9	33% / 67%
2022	7.6 / 9.5 / 4.5	7.5 / 10	9	31% / 69%
2023	7.6 / 9.5 / 4.5	7.5 / 10	9	38% / 62%
2024	7.6 / 9.5 / 4.5	7.5 / 10	9	36% / 64%
2025 [2]	7.6 / 9.5 / 4.5	7.5 / 10	9	47% / 53%
2026 [3]	7.6 / 9.5 / 4.5	7.5 / 10	9	50% / 50%

[1]Employee pension contributions are tiered for PWU and Management employees based on Canada Pension Plan Yearly Maximum Pensionable Earnings (YMPE) limit. Society-represented employees are not subject to tiered contributions. CRA will not allow individual member contributions to exceed the annual *Income Tax Act* dollar limit.

[2]Effective March 1, 2025, OPG elected to utilize the Available Actuarial Surplus to reduce employer contributions to match contributions remitted by employees. Projected Contribution Ratio at 47%/53%.

[3]Projected Contribution Ratio at 50%/50%

As in EB-2020-0290, the contribution ratio shown above is calculated as the ratio between: (i) the current service cost funding contributions made by OPG to its RPP pursuant to actuarial valuations filed with the Financial Services Regulatory Authority in accordance with the PBA (as reduced by the utilization of AAS), and (ii) the total amount of contributions made by OPG's employees to the plan. Funding for special payments toward a pension plan deficit, if any, and OPEB payments are excluded from this calculation.[22] This treatment is consistent with the approach outlined in the *Report on the Sustainability of Electricity Sector Pension Plans* (the "Leech Report").[23]

The negotiated increases to employee contributions from 2016 and the use of AAS to lower employer contributions beginning have helped OPG to achieve the target ratio of 50/50 of employee-to-employer contributions. As illustrated in Figure 9, the employee-to-employer contribution ratio has markedly shifted from 24:76 in 2014 to 50:50 in 2026. Given the AAS is

[22] OPG has not made any such special payments toward a pension plan deficit since 2017.
[23] Leech Report, p. 2 (the term used is "ongoing contributions").

projected to continue throughout the IR term, OPG expects to continue to match the level of contributions remitted by employees.

7.0.2 Pension Reform Measures – Earnings Basis for Pension and Retirement Eligibility for an Undiscounted Pension

OPG negotiated changes in 2015 to the basis for determining pension benefits for represented employees. Previously, the calculation basis was an employee's highest three consecutive years of pensionable earnings. This was changed to the highest five consecutive years for future service beginning March 31, 2025 for both PWU and Society represented employees. This change applies to both current employees and new hires.

OPG also successfully negotiated with the unions a change in the retirement eligibility formula in 2015. For service prior to March 31, 2025, PWU and Society-represented employees could retire with an undiscounted pension when their age plus service equals 82; this is referred to as the Rule of 82. For service after March 31, 2025, the eligibility for an undiscounted pension changed to the Rule of 85. The retirement eligibility formula of age plus service was also changed for management employees from Rule of 84 to Rule of 90, effective July 1, 2014 for new management employees, and effective for future service beginning January 1, 2025 for existing employees.

In exchange for the pension reforms negotiated in 2015, PWU and Society-represented employees who were contributing to the pension plan on April 1, 2015 (PWU) and January 1, 2016 (Society) and had less than 35 years of pensionable service as of those dates were granted Hydro One Limited shares awards at the start of the third year of the applicable contract term (April 1, 2017 for PWU and January 1, 2018 for Society). Eligible employees continue to receive shares annually for up to 15 years subject to certain conditions, which are unchanged from prior payment amounts applications.[24] As of 2025, the number of employees entitled to shares since the beginning of the program has decreased by about 40%. This number is expected to decrease further until the program ends in 2032. As in EB-2020-0290,

[24] EB-2016-0152, Ex. F4-3-2, pp. 17-18.

the cost associated with the share performance plan over the IR term is less than the cost savings from the pension reforms that apply to all employees (existing and new), and the pension savings will continue to grow over time.[25]

7.0.3 Health Benefit Coverage Changes

In 2018, OPG negotiated changes to the health benefit plan, with both the PWU and the Society, to control benefit costs and has maintained these cost control measures through subsequent rounds of collective bargaining. The changes included a cap on the frequency of dispensing fees for maintenance level drugs and mandated the use of the lowest price equivalent drug (generic or brand name). These measures were also implemented for management employees. These changes were significant because prescription drugs account for approximately 50% of OPG's health benefit spending. In exchange, OPG provided for modest benefit improvements to both PWU and Society-represented employees. Certain modest benefit improvements for both represented groups were also negotiated through subsequent rounds of collective bargaining.

Since EB-2020-0290, OPG also updated health benefits coverage for management employees. These enhancements have been aimed at promoting equity in benefits within the entire management group and, with some exceptions, better aligning the coverage to those of represented employees to promote equity in benefits and provide more comprehensive support to management employees. Promoting equity in benefits helps the organization to improve internal mobility from union-represented roles into management, strengthens succession planning efforts and reinforces a commitment to internal talent development during a period of increased demand for talent. The impact of these changes has been considered in the WTW Report (Attachment 2, p. 18).

7.1 Overtime

Overtime is available to represented employees for work performed outside their normal working hours. Management employees are not eligible to receive overtime payments. Provisions relating to the payment of overtime are established through collective bargaining.

[25] The cost impact of the Hydro One share performance plan is included in total compensation cost presented in Attachment 1.

The control and approval of overtime hours worked rests with OPG.

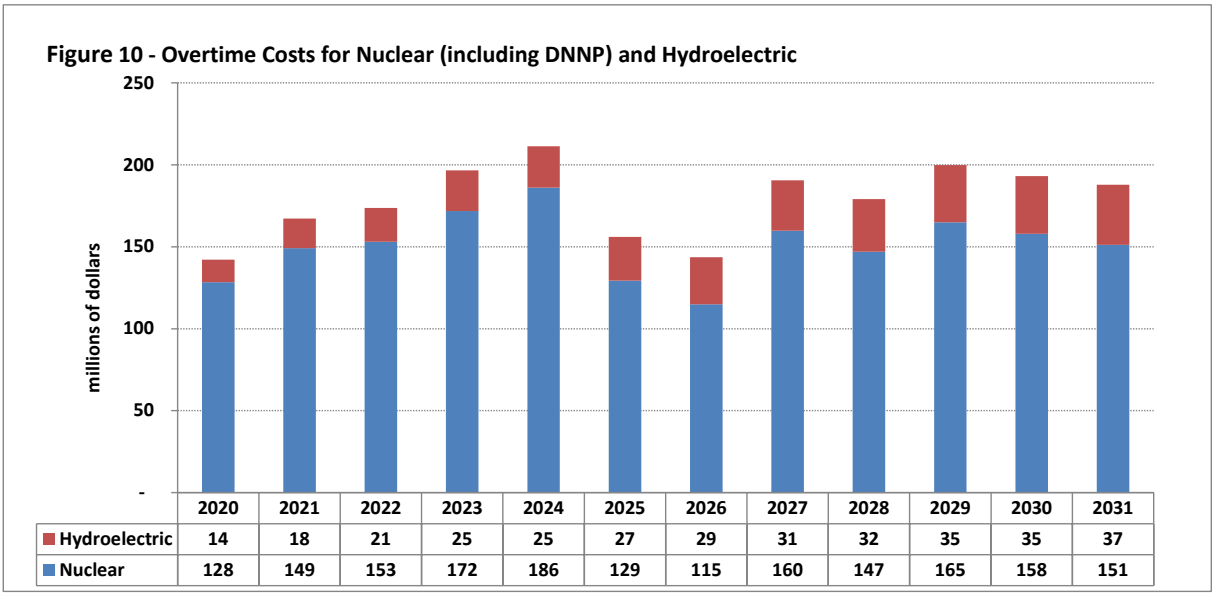
Over the IR term, overtime costs account for about 7% on average of the total forecast compensation costs for the regulated facilities, which is consistent with the EB-2020-0290 forecasts. Overtime rates are paid on a premium basis at a rate of two times the wage rate. As set out in Attachment 2, OPG's overtime elements are generally aligned with the range in energy sector market practice.[26]

OPG uses overtime to meet peak work demands and as a cost-effective alternative to other options for accomplishing work, while also ensuring crew coverage according to collective agreement obligations. Overtime requirements fluctuate with key work programs and are typically driven by planned outage cycles, plant refurbishments, additional effort required in support of project activities and work required to maintain unit reliability. OPG's use of incremental short-term labour resources for its regulated facilities, including overtime and non-regular labour, is discussed in Ex. F2-2-1 and Ex. F1-2-1.

Overtime costs for OPG's regulated facilities are planned to be relatively stable during the IR term, as shown in Figure 10 below. Annual overtime temporarily declines in 2025 and 2026 due to fewer planned outages across the nuclear stations, reduced support at Pickering, and the conclusion of the DRP in 2026. From 2027-2031, the levels of overtime costs are primarily driven by support of critical path for planned outages at Darlington, the PRP and hydroelectric capital projects. See Attachment 1 for additional details.

[26] Attachment 2, p. 17.

Figure 10 – Overtime Costs for Nuclear* and Hydroelectric



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Hydroelectric	14	18	21	25	25	27	29	31	32	35	35	37
Nuclear	128	149	153	172	186	129	115	160	147	165	158	151

*Includes DNNP LP

8.0 COMPENSATION BENCHMARKING STUDY

8.1 Overview

OPG seeks to manage its labour costs while ensuring its total compensation is positioned competitively relative to the external labour markets in which it competes to attract and retain employees.

Since OPG's last review of its compensation philosophy in 2020, the energy sector landscape has evolved, with OPG playing a critical role in helping Ontario meet its growing energy demands. To address these changes, OPG engaged Southlea to conduct an independent study to review its compensation philosophy to determine whether its compensation strategy aligns with the company's evolving role in meeting the province's energy demand and enables OPG to prepare the organization to successfully deliver on its business objectives (Attachment 2). Based on Southlea's recommendations, OPG's Board of Directors approved a revision to OPG's compensation philosophy to include changes to guiding principles, and a refinement in the existing peer group selection criteria and associated weighting. These updates allow OPG to more accurately assess its market competitiveness through more relevant and robust

comparisons to the market in which it competes for talent. This is essential to attracting and retaining employees for the long term, particularly for the operations and project roles that demand specialized skills and require substantial time to achieve full proficiency.

As noted above, OPG retained WTW to undertake compensation benchmarking (Attachment 3). WTW conducted the benchmarking, taking into account the updates in OPG's compensation philosophy. The results of the study indicate that OPG's Total Direct Compensation ("TDC") and Total Remuneration ("TR") are within target market range of market peers, defined in the WTW Report as +/- 10% of the midpoint of the peers. The benchmarking was conducted using the same two-segment approach as in EB-2020-0290, in compliance with the OEB-approved settlement proposal in EB-2020-0290. An overview of the approach taken, comparator groups used, and summarized results is provided below. The assessment by WTW included OPG's Base Salaries, TDC and TR, including the value of Pension and Benefits, as defined below.

OPG's target market positioning for purposes of talent attraction and retention continues to be the 50th percentile for positions in the Standard segment, and 75th percentile for the Nuclear Authorized segment.[27] Based on the OEB's Decision and Order in EB-2016-0152,[28] and as provided in EB-2020-0290,[29] the WTW Report also shows all Nuclear Authorized positions benchmarked to the 50th percentile. This is the basis for the benchmarking results summarized below.

8.2 Benchmarking Approach and Results

This section provides an overview of WTW's benchmarking approach and results. The WTW Report benchmarked approximately 94% of OPG positions and indicates that OPG's TDC and

[27] Nuclear Authorized positions in senior executive positions (Bands A-D) continue to be benchmarked at the 50th percentile. This is a correction from EB-2020-0290, Ex. F4-3-1, where it was stated that Bands A-E Nuclear Authorized are benchmarked at 50th percentile. For clarity, Band E (Vice President) and below are benchmarked at the 75th percentile.

[28] EB-2016-0152 Decision and Order, December 28, 2027, p. 80.

[29] EB-2020-0290, Ex. F4-3-1, Section 6.

TR are 7.2% and 8.9% above the midpoint of market peers, respectively, which are within target market range as defined in the WTW Report (i.e. within +/- 10% of the midpoint).

In assessing OPG's compensation relative to external labour markets, as in EB-2020-0290, OPG's positions were categorized into the following segments: Nuclear Authorized and Standard. OPG's compensation in each of these segments was compared to other companies that employ similar positions. This assessment included reviewing OPG's Base Salaries, TDC, Pensions and Benefits, as well as TR. TDC reflects the cash compensation paid to employees, excluding overtime. It includes base salary and pay-at-risk incentives. TR reflects TDC paid to employees, and for eligible employees, Pension & Benefits and paid time off.

The benchmarking analysis includes Term Employees as part of the PWU incumbents. As discussed above, Term Employees were hired to perform work of regular employees in anticipation of the cessation of commercial operation at Pickering and do not participate in OPG's pension and benefit plans.

As noted earlier, a Hydro One share performance plan was negotiated as part of the 2015 collective bargaining process, in exchange for changes to pension plan provisions. In its Decision and Order in EB-2016-0152, the OEB indicated that share performance plan should be included in the compensation benchmarked by WTW as the plan forms part of the compensation received by employees.[30] As in EB-2020-0290, the WTW Report separately presents OPG incumbent information including the impact of the share performance plan.

OPG continues to believe that the results excluding the impact of share performance plan are more representative of its positioning against the market, as the share performance plan is only available for a defined group of eligible employees, and all new employees are not eligible. As noted, as of 2025, the total number of eligible employees have declined by 40% since the start of the program and are expected to continue to decline through to the end of the IR term.

[30] EB-2016-0152 Decision and Order, December 28, 2017, p. 81.

In addition, as noted at page 15 of the WTW Report, annual share grants similar to OPG's, while relatively uncommon, are included in TDC, but other types of lump sum payments are not, as WTW does not routinely include this information in its compensation database. Without directly inquiring with each comparator company, it is not possible for WTW to determine which companies have provided similar lump sum payments (whether cash or shares) or the amount of such payments. As such, including the share performance plan grant for OPG, without also including information on lump sum payments by comparators, potentially overstates OPG's TDC relative to the market. On this basis, the analysis below refers to the benchmarking results excluding the share performance plan grants.

The Nuclear Authorized segment captures only those positions that require the incumbent to be, or have been, licensed by federal regulators, and continues to represent a very small portion of OPG's employee population (about 3%). All other positions fall under the Standard segment.

In determining the appropriate comparator group or companies, WTW continued to focus on the following types of organizations as the main selection criteria of OPG's peer comparators:

a) organizations from which OPG recruits;
b) organizations to which OPG loses staff;
c) organizations which operate in the same or similar industry sectors;
d) organizations that reflect the complexity and size of OPG;
e) organizations with similar geographic scope; and
f) organizations with both public and private ownership structure.

Taking into account the updated compensation philosophy, WTW updated the benchmarking methodology to align with market practices. Consistent with the approval by OPG's Board of Directors and with practices of other regulated companies, and consistent with the benchmarking of the Utility and Nuclear Authorized segments in EB-2016-0152, [31] the benchmarking methodology utilizes an unweighted, single peer group that more accurately

[31] EB-2016-0152, Ex. F3-1-4, Section 5 and Attachment 2

reflects the talent market for each role, no longer utilizing a forced 50/50 weighting between public and private peers to roles below the executive level.

The following hypothetical example illustrates the difference between the two approaches. The market data for an Engineering role includes matches from 50 organizations: five from the public sector and 45 from the private sector. Using a forced weighting methodology, equal weighting is assigned to both public and private sectors. This means that even though there are only five public sector companies matches, they would represent 50% of the market data, while the 45 private sector companies would make up the remaining 50%. In contrast, an unweighted, single peer group approach assigns equal weighting to each organization, regardless of sector, resulting in the five public sector companies making up 10% of the data and remaining 90% of data reflecting the proportionate number of matches in the private sector companies. This approach provides more robust benchmarking data that more accurately reflects the market compensation for each role.

The shift to an unweighted, single peer group also provides a better representation of where talent is available for OPG to source (and conversely where talent is more likely lost). Specifically, for jobs that are more common in the public sector, the market data will primarily reflect the public sector, while for roles more prevalent in the private sector, the data will primarily reflect the private sector. This approach also results in more robust market data for benchmarking, as evidenced by a higher percentage of positions matched to the market (94% versus 84% in EB-2020-0290).[32] As a measure of ongoing restraint regarding executive compensation, OPG will continue to apply the 50/50 public sector/private sector forced weighting to executive roles.

[32] Under the previous 50/50 weighted approach, as shown in EB-2020-0290, benchmarks required sufficient representation from both public and private sectors to be included, limiting job match coverage. For example, a job with insufficient (less than five companies) or no matches in one sector could not be included in the benchmarking as the result could not be weighted.

Figures 11 and 12 depict the results of the compensation benchmarking conducted by WTW. These results are shown for TDC and TR by applicable segment and representation. The benchmarking was conducted based on 2024 employee and compensation data.

Figure 11 – Total Direct Compensation

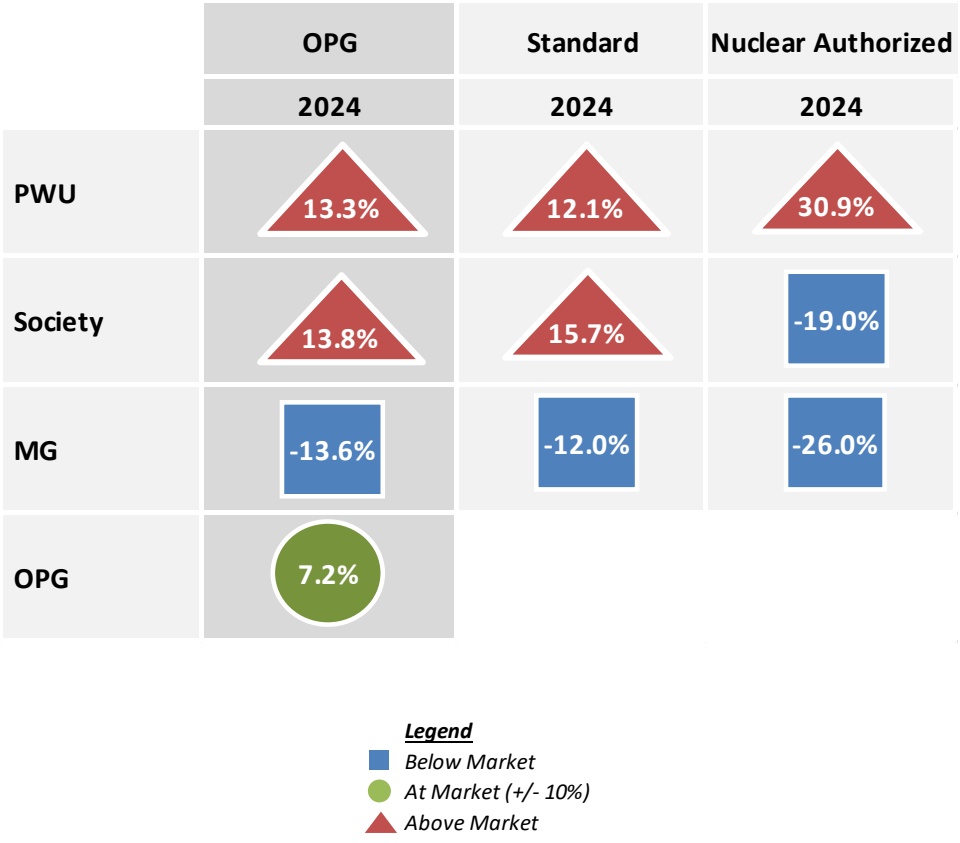
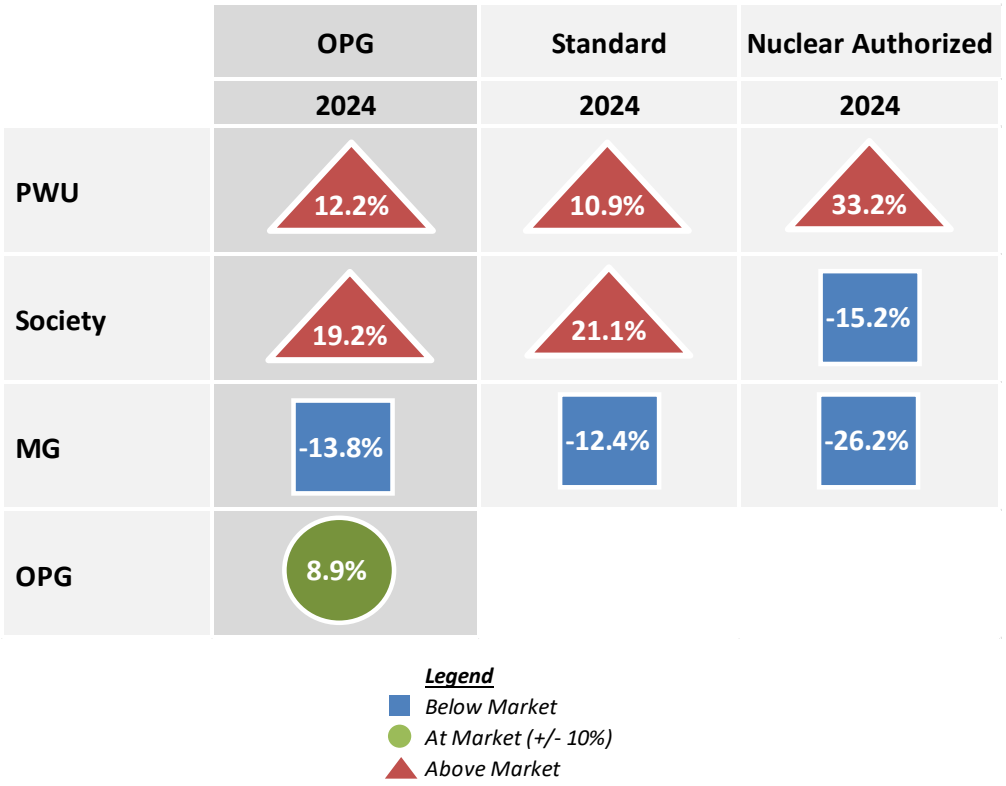


Figure 12 - Total Remuneration



Compared to overall benchmarking results in EB-2020-0290, OPG's overall TR has increased slightly from 8.6%[33] above peer median. On a TR basis, the Society group is further from peer median, the PWU group has remained about the same and Management has moved further below the median. The overall benchmarking results vary as follows by representation and between segments for each of TDC and TR:

a) PWU-represented employees' TDC and TR, in the Standard segment, benchmark above target market range. PWU-represented employees' TDC and TR, in the Nuclear Authorized segment, benchmark above target market range.

[33] For a consistent basis of comparison and as explained on pp. 14-17 in the WTW Report, 2019 results were recalculated to include the remittances paid by OPG to the union on behalf of PWU Term Employees for union-administered benefit programs as base salary.

b) Society-represented employees' TDC and TR benchmark above target market range for the Standard segment. Society-represented employees' TDC and TR benchmark below target market range for the Nuclear Authorized segment.
c) Management's TDC and TR in the Standard segment benchmark below the target market range. Management's TDC and TR benchmark below target market range for the Nuclear Authorized segment.

In addition to the benchmarking based on April 2024 data, OPG requested WTW to complete a comparative analysis to illustrate the impact of certain discrete changes in OPG's compensation programs and employee type composition since that time. Specifically, this comparative analysis included the following three items, holding constant all other inputs and variables into the benchmarking:

- A reduction of the Term Employee population of approximately 60% compared to the number of Term Employees that were in role as of April 1, 2024, as discussed in Section 5.1.1 above;
- The implementation of pension reform measures for PWU and Society-represented employees, discussed in Section 7.0.1 above;[34] and
- Health benefit changes for management employees discussed in Section 7.0. above.

With these changes, OPG's TDC and TR are 6.2% and 8.3% above the midpoint of market peers, respectively, which remains within the target market range and moves OPG's benchmarking position closer to P50. The following outline the differences compared to the main benchmarking results:

- 0.6% decrease in overall TR positioning (8.9% to 8.3%)
- 0.8% decrease in TR positioning for the PWU group (12.2% to 11.4%)
- 0.8% decrease in TR positioning for the Society group (19.2% to 18.4%)
- 0.2% increase in TR positioning for Management (-13.8% to -13.6%).

[34] OPG's decision to reduce its contributions to the RPP by utilizing the AAS as permitted under the PBA does not impact compensation benchmarking results, as it does not affect the value of the pension benefits provided under the plan.

The market median in the compensation benchmarking study reflects a blend of compensation levels across a wide range of experience and tenure (years of service with a company) found in the market. As of April 1, 2024, 60% of PWU-represented employees and 41% of Society-represented employees were at the top of their respective pay scale due to their tenure with OPG. To help better interpret the benchmarking results, OPG asked WTW to provide an analysis of the average tenure of its workforce compared to its peer comparators. According to the WTW analysis (Attachment 5), 56% of OPG's unionized employees have tenure at the 75th percentile of the market, indicating that OPG's compensation reflects a more tenured workforce than the market.

OPG continues to take actions to ensure its compensation and benefit programs reflect the changing needs of the company within the context of the labour market and within the requirements of labour negotiations. As part of these efforts and in line with the results of the benchmarking, the actions being taken include:

a) Compensation benchmarking results and pension and benefit information continue to be shared with union representatives to inform and set context for the collective bargaining processes.

b) Management salary ranges continue to be regularly reviewed to assess the midpoint of the salary range with the target market position. OPG's target market for base salaries is set at the 50th percentile for the Standard segment and 75th percentile for the Nuclear Authorized segment.[35]

c) Targeted groups continue to receive education on OPG's compensation philosophy, including achieving affordability through targeting market 50th percentile (75th percentile for Nuclear Authorized) while remaining competitive to attract and retain the required talent. Additionally, efforts continue to ensure a culture that encourages staff retention and enables leader development.

[35] Nuclear Authorized positions in senior executive positions (Bands A-D) continue to be benchmarked at the 50th percentile.

d) "Get the Facts" sessions on compensation programs are held to ensure employees have a good understanding of all elements of remuneration. Additionally, management employees are provided with a total compensation statement that sets out a comprehensive overview of compensation value after the annual performance review.

9.0 WAGES AND THE GENERATION OF ELECTRICITY IN ONTARIO

Bruce Power remains OPG's closest competitor for attracting and retaining talent. Both Bruce Power and OPG generate electricity in the same energy market, operate similar nuclear technology, have a workforce comprised of similar roles, and have employees represented by the same unions.

WTW undertook a comparison of OPG's wages to those provided by Bruce Power.[36] The results of this comparison are captured in Attachment 4, and a summary is provided below in Figure 13. The analysis shows that Bruce Power's unionized wages are 24% higher for PWU-represented positions and 9% higher for Society-represented positions. For licensed nuclear roles, such as the Control Room Shift Supervisor (Society), Bruce Power's unionized wages are up to 20% higher.

Figure 13 - Comparison of OPG and Bruce PWU and Society Base Salary

Annual Base Salary Comparison	OPG k$	Bruce Power k$	Difference (OPG-Bruce Power) k$	Difference (OPG-Bruce Power) %
PWU	130.8	160.5	(29.7)	(24.0)
Society	159.7	174.7	(15.0)	(9.0)

[36] Comparison of 2024 wage schedules.

10.0 CONCLUSION

The Province is embarking on a transformative period for Ontario's energy sector, with OPG being a key contributor to the Province's plans for an energy system that is affordable, secure, reliable, and clean. OPG's regulated facilities and the DNNP facilities constitute critical infrastructure for Ontario's electricity supply. In order to execute on the Province's Integrated Energy Plan, OPG must maintain a highly skilled and experienced workforce across the province. OPG's compensation and benefits are largely the product of its collective agreements. OPG operates within a complex labour environment, where the essential nature of its services affects its bargaining leverage and arbitration dynamics drive upward pressure on wage trends. Despite this, OPG's overall TR and TDC are positioned within the target market range compared to peers. When compared to EB-2020-0290, OPG has been able to achieve additional resource flexibility and efficiencies in redeployment and downsizing provisions in its labour agreements. The ability to resource to meet peaks in demand and to reassign existing staff where there is a sustained need will enable OPG to more effectively and efficiently execute the Pickering Refurbishment Program, maintain an engaged workforce, and avoid costs and operational disruption through the IR term, all of which is reflected in the payment amounts sought in this Application.

LIST OF ATTACHMENTS

Attachment 1:	FTE, Compensation and Benefit Information for OPG's Nuclear Regulated Facilities ("Appendix 2k")
Attachment 2:	Southlea Report and Recommendations on OPG Compensation Philosophy
Attachment 3:	Total Compensation Benchmarking Study prepared by Willis Towers Watson
Attachment 4:	Comparison of Salary Schedules for Society and PWU Roles prepared by Willis Towers Watson
Attachment 5:	Benchmarking Tenure Analysis prepared by Willis Towers Watson

FTE, Compensation and Benefit Information for OPG's Nuclear Regulated Facilities ("Appendix 2k")

Numbers may not add due to rounding

EB-2025-0297 (2027-2031 Custom IR term)

Line No.	Nuclear Facilities (excluding DNNP LP)	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Staff (Regular and Non-Regular)	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**
	Nuclear - Direct												
1	Management	642.7	545.9	549.8	623.0	737.4	873.3	751.5	694.7	685.2	671.9	665.0	682.0
2	Society	2,270.6	2,163.8	2,032.2	2,222.6	2,479.0	3,085.4	2,783.5	2,569.3	2,514.8	2,476.7	2,457.2	2,436.7
3	PWU	3,458.6	3,293.0	2,873.1	2,887.0	3,206.2	3,686.0	3,640.2	3,651.3	3,646.4	3,678.9	3,640.5	3,623.2
4	Term/ETE/PECO Temporary	598.9	794.9	928.0	988.6	657.5	240.2	215.2	7.0	7.0	7.0		
5	EPSCA	234.3	355.7	401.3	434.7	427.2	321.2	194.9	396.9	515.0	450.4	365.1	281.9
6	Subtotal	7,205.1	7,153.3	6,784.4	7,155.9	7,507.3	8,206.1	7,585.4	7,319.2	7,368.4	7,284.9	7,127.7	7,023.8
	Nuclear - Allocated												
7	Management	268.9	267.4	273.5	314.9	341.3	403.6	387.1	347.4	343.7	344.3	342.4	336.7
8	Society	385.6	385.2	417.1	564.5	643.7	754.3	690.0	681.6	669.2	664.9	662.9	650.8
9	PWU	434.2	405.0	448.8	490.0	488.3	498.2	456.3	489.9	485.4	485.1	489.3	493.8
10	Term/ETE/PECO Temporary	60.6	78.5	80.3	64.6	61.6	39.0	33.3					
11	EPSCA	42.1	44.4	30.9	31.6	30.8	37.0	37.0	37.0	37.0	37.0	36.9	38.2
12	Subtotal	1,191.3	1,180.5	1,250.8	1,465.6	1,565.7	1,732.2	1,603.6	1,555.9	1,535.2	1,531.3	1,531.5	1,519.4
	Nuclear Facilities												
13	Management	911.5	813.3	823.3	937.9	1,078.6	1,276.9	1,138.6	1,042.2	1,028.9	1,016.2	1,007.4	1,018.7
14	Society	2,656.2	2,549.0	2,449.4	2,787.1	3,122.7	3,839.7	3,473.6	3,250.9	3,184.1	3,141.7	3,120.1	3,087.5
15	PWU	3,892.7	3,698.1	3,321.9	3,377.1	3,694.6	4,184.3	4,096.5	4,141.2	4,131.8	4,164.0	4,129.8	4,116.9
16	Term/ETE/PECO Temporary	659.4	873.4	1,008.4	1,053.2	719.1	279.2	248.5	7.0	7.0	7.0		
17	EPSCA	276.4	400.0	432.2	466.3	458.0	358.2	231.8	433.9	551.9	487.3	402.0	320.0
18	Total	8,396.4	8,333.8	8,035.2	8,621.5	9,073.0	9,938.3	9,189.0	8,875.1	8,903.6	8,816.2	8,659.2	8,543.2
	Salary & Incentive Pay (including Fiscal Adjustment)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
19	Management	165.2	151.6	159.1	183.1	209.3	251.9	229.6	220.8	225.0	231.5	234.1	243.5
20	Society	352.5	366.5	342.7	430.4	482.6	600.3	555.0	547.6	553.3	571.4	584.1	599.7
21	PWU[2]	462.5	479.8	417.8	486.0	579.7	560.3	571.3	599.6	616.3	650.4	661.2	674.0
22	Term[2]/ETE/PECO Temporary	70.7	98.7	120.0	139.2	93.6	32.2	30.0	1.2	1.2	1.3		
23	EPSCA[2]	41.1	64.8	70.0	80.9	84.0	58.5	39.1	79.8	102.1	94.8	80.1	65.5
24	Unallocated[3]	19.5											
25	Total	1,111.6	1,161.3	1,109.6	1,319.6	1,449.2	1,503.3	1,425.0	1,448.9	1,498.0	1,549.3	1,559.5	1,582.8
	Overtime	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
	Management		0.0	0.0	0.0	(0.0)							
26	Society	39.4	44.3	46.1	49.4	56.0	43.0	37.7	42.2	39.3	43.5	41.8	40.5
27	PWU	75.5	80.9	71.3	79.3	93.9	71.8	68.4	96.2	87.4	101.6	96.0	91.5
28	Term/ETE/PECO Temporary	8.8	11.7	16.4	21.0	12.3	3.2	2.5					
29	EPSCA	4.7	12.2	19.2	22.0	23.8	11.2	5.0	19.8	18.5	18.3	18.6	15.3
	Unallocated[3]												
30	Total	128.4	149.1	153.0	171.8	186.0	129.3	113.6	158.2	145.2	163.4	156.5	147.3
	Benefits (Current Benefits and Pension & OPEB)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
31	Management	67.5	68.7	69.3	48.1	68.4	77.3	76.1	72.3	72.9	75.6	76.0	79.3
32	Society	166.0	182.2	176.2	130.8	188.3	218.0	213.4	212.3	215.8	225.6	229.8	237.0
33	PWU	198.9	210.2	188.2	125.0	192.9	190.1	206.4	220.6	226.6	239.9	245.2	253.5
34	Term/ETE/PECO Temporary	5.1	6.0	8.4	9.4	7.8	2.0	1.8	0.1	0.1	0.1		
35	EPSCA	2.8	3.3	4.7	4.7	5.1	3.3	2.0	4.8	5.7	5.4	4.7	3.8
36	Unallocated[3]	7.4											
37	Total	447.7	470.5	446.7	318.0	462.4	490.5	499.7	510.1	521.1	546.5	555.7	573.7
38	Current Benefits (Statutory)	68.4	65.8	69.0	77.3	91.3	102.8	96.8	99.6	101.7	107.1	106.6	108.3
39	Current Benefits (Non-Statutory)	40.8	46.3	45.6	50.1	54.8	70.1	65.7	68.0	69.9	73.3	74.2	76.6
40	Pension & OPEB (Current Service)[1]	338.5	358.3	332.0	190.6	316.3	317.7	337.2	342.6	349.5	366.2	375.0	388.8
	TOTAL COMPENSATION	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
41	Management	232.8	220.3	228.5	231.2	277.7	329.2	305.7	293.1	297.9	307.0	310.1	322.8
42	Society	557.8	592.9	564.9	610.6	726.9	861.3	806.1	802.1	808.5	840.5	855.8	877.2
43	PWU	736.9	770.9	677.2	690.3	866.5	822.2	846.0	916.4	930.3	991.9	1,002.4	1,019.0
44	Term/ETE/PECO Temporary	84.6	116.5	144.8	169.6	113.7	37.4	34.4	1.2	1.3	1.3		
45	EPSCA	48.7	80.3	93.9	107.6	112.9	73.0	46.1	104.4	126.4	118.4	103.4	84.7
46	Unallocated[3]	26.9											
47	Total	1,687.7	1,780.9	1,709.3	1,809.4	2,097.7	2,123.1	2,038.3	2,117.2	2,164.3	2,259.2	2,271.7	2,303.7

[1]Presented on an accrual basis

[2]Includes employee remittances for purpose of union-administered benefit programs

[3]Refer to Nuclear EB-2020-0290 L-F4-03-Society-018 part a)

FTE, Compensation and Benefit Information for
OPG's DNNP LP Regulated Facilities ("Appendix 2k")

Numbers may not add due to rounding — EB-2025-0297 (2027-2031 Custom IR term)

Line No.	DNNP LP	2026 Plan	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	Staff (Regular and Non-Regular)	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**
	DNNP LP - Direct						
1	Management	68.4	75.0	58.8	45.4	32.5	26.8
2	Society	177.1	178.4	129.7	96.2	84.7	78.2
3	PWU	50.9	116.4	174.5	172.0	139.6	133.6
4	EPSCA						
5	Subtotal	296.4	369.9	363.1	313.6	256.8	238.5
	DNNP LP - Allocated						
6	Management	29.9	35.3	37.3	29.9	29.1	19.1
7	Society	50.5	58.3	60.3	47.2	46.4	44.1
8	PWU	19.5	23.5	23.3	22.4	15.0	18.0
9	EPSCA	0.0	0.0	0.0	0.0	0.1	0.2
10	Subtotal	99.8	117.2	120.9	99.5	90.5	81.4
	DNNP LP Facilities						
11	Management	98.3	110.3	96.1	75.3	61.6	45.9
12	Society	227.6	236.7	190.0	143.4	131.2	122.3
13	PWU	70.3	140.0	197.8	194.3	154.6	151.6
14	EPSCA	0.0	0.0	0.0	0.0	0.1	0.2
15	Total	396.2	487.1	484.0	413.1	347.3	319.9
	Salary & Incentive Pay (including Fiscal Adjustment)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
16	Management	20.9	25.3	24.7	21.5	19.5	16.2
17	Society	36.2	39.4	33.6	27.2	26.0	25.8
18	PWU[2]	10.1	23.2	32.8	33.9	27.7	29.7
19	EPSCA[2]	0.0	0.0	0.0	0.0	0.0	0.0
20	Total	67.3	87.8	91.2	82.6	73.2	71.7
	Overtime	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
21	Society	1.0	1.0	0.9	0.7	0.7	0.7
22	PWU	0.2	0.6	0.8	0.8	0.6	3.0
23	EPSCA						
24	Total	1.2	1.6	1.7	1.5	1.3	3.7
	Benefits (Current Benefits and Pension & OPEB)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
25	Management	7.1	8.3	7.4	6.0	4.9	3.7
26	Society	14.1	15.1	12.5	9.9	9.3	8.8
27	PWU	3.0	7.6	10.8	11.4	8.9	8.8
28	EPSCA	0.0	0.0	0.0	0.0	0.0	0.0
29	Total	24.2	31.0	30.8	27.3	23.1	21.3
30	Current Benefits (Statutory)	4.2	5.5	5.4	4.8	4.0	3.8
31	Current Benefits (Non-Statutory)	3.3	4.2	4.2	3.8	3.2	2.9
32	Pension & OPEB (Current Service)[1]	16.7	21.3	21.1	18.7	15.9	14.5
	TOTAL COMPENSATION	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
33	Management	28.0	33.6	32.1	27.5	24.4	19.9
34	Society	51.3	55.5	47.0	37.8	35.9	35.3
35	PWU	13.4	31.4	44.5	46.1	37.2	41.5
36	EPSCA	0.0	0.0	0.0	0.0	0.0	0.0
37	Total	92.7	120.4	123.6	111.4	97.6	96.7

[1]Presented on an accrual basis

[2]Includes employee remittances for purpose of union-administered benefit programs

[3]Refer to Nuclear EB-2020-0290 L-F4-03-Society-018 part a)

FTE, Compensation and Benefit Information for OPG's Hydroelectric Regulated Facilities ("Appendix 2k")

Numbers may not add due to rounding

EB-2025-0297 (2027-2031 Custom IR term)

Line No.	Hydroelectric Facilities	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
	Staff (Regular and Non-Regular)	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**
	Hydroelectric - Direct																
1	Management	84.6	86.5	87.4	84.1	82.5	69.8	73.1	74.9	85.7	93.6	96.2	96.6	96.1	95.0	96.7	95.7
2	Society	265.7	282.4	320.8	324.5	341.2	346.7	364.6	370.6	423.5	508.0	522.5	536.3	531.2	528.1	531.1	527.3
3	PWU	665.1	639.0	670.4	664.6	667.7	676.5	670.3	701.9	727.3	826.7	883.7	888.6	896.1	908.7	901.2	902.7
4	Subtotal	1,015.4	1,008.0	1,078.6	1,073.1	1,091.4	1,093.0	1,108.0	1,147.4	1,236.6	1,428.3	1,502.4	1,521.5	1,523.4	1,531.8	1,529.0	1,525.6
	Hydroelectric - Allocated																
5	Management	67.7	62.3	59.7	60.7	56.6	50.6	56.0	58.8	69.9	70.9	69.7	65.5	64.3	63.4	64.0	65.7
6	Society	74.0	69.7	77.2	81.5	62.8	58.4	62.1	71.3	83.0	96.8	96.5	98.9	98.6	96.3	95.3	94.4
7	PWU	37.3	38.8	39.4	34.1	18.4	16.4	24.9	25.1	26.2	29.8	27.7	25.9	25.5	24.5	24.6	25.3
8	Subtotal	179.0	170.8	176.2	176.3	137.9	125.4	143.0	155.1	179.0	197.5	193.9	190.3	188.5	184.2	183.9	185.4
	Hydroelectric Facilities																
9	Management	152.2	148.8	147.1	144.8	139.1	120.3	129.1	133.7	155.6	164.5	165.9	162.1	160.4	158.4	160.7	161.3
10	Society	339.8	352.1	398.0	405.9	404.0	405.1	426.7	441.9	506.5	604.8	619.0	635.3	629.8	624.4	626.4	621.7
11	PWU	702.3	677.8	709.8	698.7	686.1	692.9	695.2	726.9	753.5	856.6	911.4	914.5	921.6	933.2	925.8	928.1
12	Total	1,194.4	1,178.8	1,254.9	1,249.4	1,229.3	1,218.4	1,251.0	1,302.6	1,415.6	1,625.8	1,696.3	1,711.9	1,711.9	1,716.0	1,712.9	1,711.1
	Salary & Incentive Pay (including Fiscal Adjustment)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
13	Management	24.8	25.8	25.9	25.7	25.2	21.0	23.5	27.5	31.8	34.3	35.7	36.5	37.3	38.1	39.5	40.7
14	Society	41.4	44.4	50.4	51.7	52.4	55.5	59.1	60.6	73.1	91.6	96.6	102.9	105.0	108.7	112.6	116.0
15	PWU[2]	75.8	73.4	76.6	77.2	78.3	85.1	81.1	91.0	107.1	113.0	125.5	129.7	134.6	141.8	144.4	149.6
16	Unallocated[3]	(3.3)	(2.3)	(8.0)	(6.6)	0.4											
17	Total	138.7	141.4	144.9	148.1	156.4	161.7	163.7	179.2	211.9	238.9	257.8	269.0	276.9	288.7	296.4	306.2
	Overtime	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
18	Society	2.3	3.0	3.4	4.2	4.2	4.4	6.1	7.1	6.6	7.1	7.8	8.3	8.5	9.0	9.3	9.8
19	PWU	5.9	8.5	9.1	10.1	9.4	13.6	14.5	17.7	18.7	19.7	21.0	22.4	23.6	25.8	25.9	26.9
20	Total	8.2	11.5	12.5	14.4	13.7	18.0	20.6	24.8	25.3	26.8	28.8	30.7	32.2	34.8	35.2	36.7
	Benefits (Current Benefits and Pension & OPEB)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
21	Management	9.4	9.3	10.8	10.3	10.3	10.1	11.5	6.3	10.3	10.2	11.6	11.6	11.7	12.1	12.5	12.9
22	Society	18.0	18.7	24.1	23.9	26.5	29.5	31.5	18.8	28.5	33.9	39.3	41.2	42.3	44.5	45.8	47.3
23	PWU	31.9	30.9	35.9	34.4	36.9	43.8	40.1	30.5	39.1	39.3	45.3	46.3	47.8	50.7	51.9	54.0
24	Unallocated[3]	(0.8)	(1.1)	(2.6)	(1.3)	1.7											
25	Total	58.5	57.8	68.1	67.2	75.4	83.3	83.0	55.7	77.8	83.4	96.2	99.2	101.8	107.3	110.2	114.3
26	Current Benefits (Statutory)	8.7	9.0	9.1	9.2	9.2	8.0	11.0	11.9	13.9	17.2	18.5	19.3	20.0	21.2	21.5	22.2
27	Current Benefits (Non-Statutory)	6.1	7.1	6.6	6.8	7.0	9.2	8.9	9.4	9.8	12.0	12.7	13.2	13.6	14.4	14.6	15.2
28	Pension & OPEB (Current Service)[1]	43.7	41.7	52.4	51.2	59.2	66.1	63.1	34.3	54.1	54.2	65.0	66.7	68.2	71.8	74.0	77.0
	TOTAL COMPENSATION	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
29	Management	34.1	35.2	36.7	36.0	35.5	31.1	34.9	33.8	42.0	44.4	47.2	48.1	49.1	50.2	51.9	53.6
30	Society	61.7	66.1	77.9	79.8	83.1	89.4	96.8	86.5	108.2	132.6	143.7	152.4	155.8	162.3	167.7	173.1
31	PWU	113.6	112.8	121.6	121.8	124.7	142.5	135.7	139.3	164.8	172.0	191.8	198.4	206.0	218.3	222.1	230.5
32	Unallocated[3]	(4.1)	(3.4)	(10.6)	(8.0)	2.1											
33	Total	205.4	210.7	225.6	229.7	245.5	263.0	267.4	259.6	315.1	349.0	382.7	399.0	410.9	430.8	441.8	457.2

[1]Presented on an accrual basis

[2]Includes employee remittances for purpose of union-administered benefit programs

[3]Refer to Nuclear EB-2020-0290 L-F4-03-Society-018 part a)

Ontario Power Generation

Compensation Philosophy & Peer Groups

September 29, 2025

SOUTHLEA GROUP

Background

- Ontario Power Generation ("OPG") is reviewing the compensation philosophy and peer group approach to support the continued attraction and retention of talent required to deliver upon its mandate
- As requested by OPG, Southlea Group ("Southlea") conducted an independent review to determine whether any changes should be made to the compensation philosophy and peer group approach
- The compensation philosophy and peer group approach addresses all employees in OPG, both represented and non-represented employees. The purpose is to inform the compensation structure and design for non-represented employees and to support the bargaining mandate for represented employees
- In this review, Southlea performed an environmental scan to gather information about OPG's business strategy, talent objectives, workforce profile, and the external labour market in which OPG currently operates and will compete for talent to fulfill its mandate

SOUTHLEA a GECN GROUP company
© 2025 Southlea Group LP.
Proprietary and Confidential.

Compensation Philosophy Development

Framework needs to consider both internal and external factors

Internal Factors
Business strategy
ESG strategy
Talent strategy

External Factors
Market practices
Governance considerations
Stakeholder preferences

Compensation Philosophy

Comparator group / talent market (i.e., the companies you recruit from and lose talent to)

Role of each compensation element

Pay mix (e.g., fixed v. variable, short v. long-term, cash v. equity)

Desired pay positioning relative to peers

Pay-for-Performance Strategy

Definition of performance

Key objectives in the short-, mid- and long-terms

Risk and reward relationship

Mix between performance and retention

Degree of variability

SOUTHLEA a GECN GROUP company
© 2025 Southlea Group LP.
Proprietary and Confidential.

Compensation Philosophy Development



Industry Drivers

- Electricity demand is expected to increase by 75% in Ontario over next 25 years due to increased electrification (offset by greater efficiency / conservation efforts)
- Ontario's growth is consistent with broader expected growth in demand across Canada and globally
- Significant increase in demand is expected to be met with mixed energy sources, including nuclear, hydroelectric and gas
- Overall growth of the industry will put increased pressure on financial, capital and labour resources associated with electricity generation and transmission / distribution
- Increasing number of nuclear plants as well as new forms of nuclear power generation will lead to more competition for limited skilled labour in Canada over a longer period of time

SOUTHLEA a GECN GROUP company
© 2025 Southlea Group LP.
Proprietary and Confidential.

Compensation Philosophy Development



OPG's Business Objectives and Mandate

- Company is transitioning from a primarily operationally-focused power generator to a full-cycle power producer:
  - Source (finding projects; evaluating feasibility; developing initial plans)
  - Develop (securing permits and financing; detailed planning)
  - Construct (building plant; efficient project management)
  - Operate and Maintain (safe, efficient and reliable performance; cost management)
- Requirement to maintain safe, reliable and cost-efficient operations while successfully executing on large scale project developments
- Potential opportunities to provide services outside of Ontario in a competitive marketplace

OPG's Scope and Complexity

- ~$7B in revenue and increasing
- ~$70B in assets, with $5 to $7B in annual capex forecast over next seven years across the business, including:
  - Constructing first of a kind nuclear reactors
  - Nuclear refurbishments and developments
  - Increasing gas and energy storage capacity
  - Advancing potential hydroelectric projects
- More than 11,000 employees
- Pure-play multi-generation utility with 18,000 MW generating capacity (nuclear 26%, regulated hydroelectric 36%, contracted hydroelectric 23% and other, Atura Power 15%)
- Increasing commercial orientation / mindset
  - Greater financing complexity
  - Focus on long-term shareholder value
  - Still responsive to public policy demands
- Production of medical isotopes; energy-related services

SOUTHLEA a GECN GROUP company
© 2025 Southlea Group LP.
Proprietary and Confidential.

Compensation Philosophy Development



OPG's Talent Objectives	Value Proposition / Employee Experience
• Strong competition for nuclear talent will continue supporting the need to build talent from within and to encourage retention • Increasing focus on the acquisition and retention of project / engineering talent that may come from more non-traditional sources (particularly new nuclear; technology investors) • Complexity and long development timelines put more pressure on retention • Ability to build talent across organization while recognizing differences in compensation (particularly in nuclear authorized) • Ensuring a high-performance, business-oriented workforce that will drive sustainable success to lead the energy transition • Operations-oriented organization requiring employees to work in person (on location or in office) • Managing compression to sufficiently differentiate compensation relative to level	• Part of fast growing and complex organization that provides great learning and development opportunities • Strong focus on leadership development, business orientation and accountability • Market competitive compensation with a strong performance orientation and pay-for-performance incentive programs • Grow with us over time and develop your career for the long-term • Work environment orientation supports teamwork, collaboration and innovation

SOUTHLEA a GECN GROUP company
© 2025 Southlea Group LP.
Proprietary and Confidential.

OPG's Risk and Accountability Framework

Shifting to a more private-sector orientation over time with continued recognition of public ownership and mandate

Lower ← Market Compensation Levels → Higher

	Government	Crown Corporation	OPG →	Privately-held	Publicly-traded
Goals	Mission effectiveness	Mission / competitive Efficiency	Expanding into more competitive markets Greater focus on growing financial returns to support reinvestment and meet energy demand needs	Competitiveness Financial returns	Competitiveness Profit / growth > value
Risk	Low risk	Low - medium risk	Increasing risk profile with large-scale refurbishment projects Pursuing first-of-a-kind technologies, including being the first G7 nation to construct SMRs Targeting other higher-return growth through various ventures	Medium – high risk	High risk
Capital	From income streams such as taxes (backstopped by the government)	From revenue-generating activities (sometimes externally raised through public debt; limited/no external equity)	Significant portion of funding through internal core operations Reliance on external financing has grown through public debt and green bond issuances; incremental provincial funding remains limited Growth emphasis on alternative funding, new partnerships and global bond program	Internally generated and externally raised (primarily debt)	Internally generated and externally raised (equity and debt)
Strategy	Primary focus on needs of government and citizens	Primary focus on needs of key stakeholders (including financial self-sufficiency)	Continuing pursuit of profitability based of a commercial mandate which is heavily weighted in incentives Oriented to continued profit growth and value creation over long-term	Primary focus on growing profits (typically a longer-term orientation)	Equity market value creation
Account-ability	Large group of stakeholders	Medium group of stakeholders (primarily customers)	Expanding group of stakeholders, investors and partners In addition to a continuing focus on shareholder and ratepayers	Owners / investors (tend to be more limited)	Shareholders (retail and institutional)
Compe-titive	Likely no competition	Mixed (some are monopolies / others are in competitive environments)	Increasing focus on competing for projects based on cost, managing levelized cost of energy and expanding energy generation with recognition that core industry remains stable and not highly competitive New business ventures that are inherently more competitive	Competitive environment	Competitive environment

SOUTHLEA a GECN GROUP company
© 2025 Southlea Group LP.
Proprietary and Confidential.

OPG's Workforce Profile - Breakdown

OPG's workforce is heavily operationally-oriented

- The majority of OPG's workforce is related to the utility operations, engineering and project development

Utility Jobs					Corporate Jobs
Operations	Engineering	Nuclear Operations	Projects	Renewable Generation	
9%	17%	30%	11%	14%	18%

- The workforce primarily consists of represented employees

Management Group (MG) / Non-represented	Represented
14%	86%

- And the workforce has a strong emphasis on nuclear operations and development

Nuclear	Other / Non-Nuclear
~75%	~25%

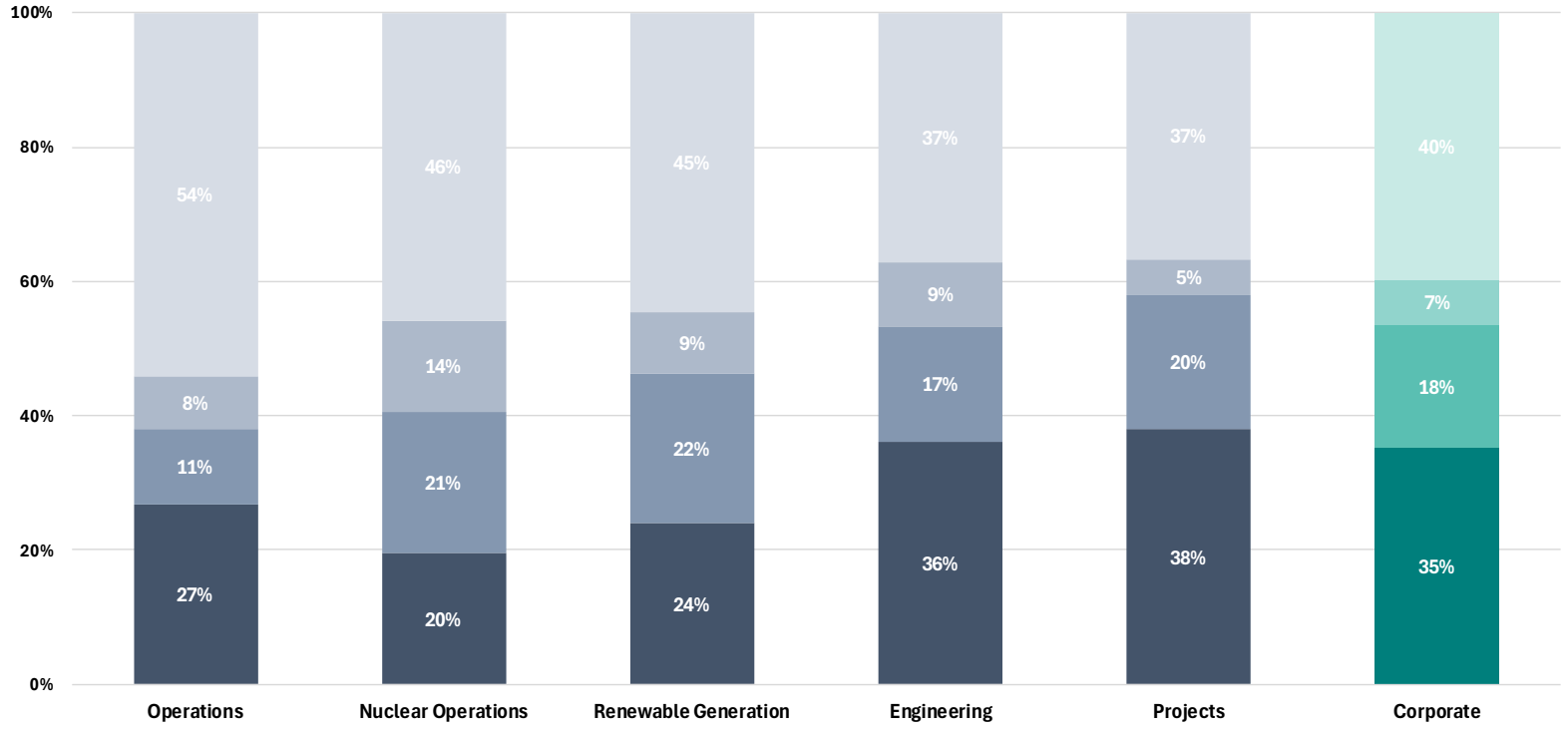
Note: Based on full time employees as of June 2025. Nuclear allocation based on OM&A by segment as reported in 2024

SOUTHLEA a GECN GROUP company
© 2025 Southlea Group LP.
Proprietary and Confidential.

OPG's Workforce Profile – Years of Service

OPG has a combination of new hires and long-tenured employees

- OPG has a bifurcated workforce profile with lots of new hires (less than 5 years experience) and those with significant experience (more than 16 years) which creates a gap in experience



Note: Based on full time employees as of June 2025

SOUTHLEA GECN GROUP company
© 2025 Southlea Group LP.
Proprietary and Confidential.

OPG's Workforce Profile - Turnover

Employees are primarily leaving for private sector with better opportunities and compensation

Band A-G Turnover (2019 to 2024) – n=139

	Industry (%)
General Industry	35%
Energy	65%

	Sector (%)
Private Sector	80%
Public Sector	20%

Note: Based on those in Band A-G leaving OPG (except retirees) that went to another identifiable organization

Exit Interview Findings (2025 YTD) – n=163

Years of Service	Prevalence
< 5 years	45%
5 to 10 years	26%
10 to 15 years	5%
15 to 20 years	14%
20 to 25 years	7%
> 25 years	4%

Primary Reasons for Leaving	Prevalence
Better External Opport. | Comp / Benefits	32%
Personal / Family	15%
Ltd. Dev't / Advancement	7%
Company Culture	7%
Work-life Balance	6%

SOUTHLEA a GECN GROUP company
© 2025 Southlea Group LP.
Proprietary and Confidential.

OPG's Workforce Profile - Hiring

Hiring is increasingly coming from engineering and project roles. The hiring talent market is private-sector oriented and from a variety of industries

External Hiring Data (2024 to 2025 YTD) – n=538

Sector (%)	Overall	Non-represented	Represented
Private Sector	64%	69%	62%
Public Sector	36%	31%	38%

Industry (%)	Overall	Non-represented	Represented
General Industry	60%	61%	59%
Energy	40%	39%	41%

Key hiring challenges cited:

- Hiring less experienced candidates
- Increasingly difficult to pay above middle of internal pay band for external talent
- Finding talent with needed specialized skills and in right location(s)

External Hiring Functions

- OPG has hired more engineering, project and renewable generation talent over past 18 months (relative to size of unit)

Utility Jobs					Corporate Jobs
Operations	Engineering	Nuclear Operations	Projects	Renewable Generation	
8%	21%	8%	20%	23%	20%

SOUTHLEA a GECN GROUP company
© 2025 Southlea Group LP.
Proprietary and Confidential.

Peer Group Selection Criteria

Design principles are used to capture the market for labour talent in terms of companies which you recruit from or lose talent to

Design principles	Considerations
Ownership	• Compensation levels are impacted by ownership structure • Private sector companies generally pay more than public sector organizations (although this may vary by level)
Industry	• Given the limited size of the Canadian market, it is common to look to other comparable industries • Some roles might be more industry agnostic with transferable skills
Size	• Company size is typically correlated with compensation levels, particularly at the executive level. Company size is still relevant below-executive as company size can inform the approach to compensation design • Size is typically defined by revenue, although other factors can also be used to gauge company scope
Geography	• Canadian companies carefully consider the geographic mix between Canadian and US headquartered companies given higher US pay levels • References are increasingly being made on a national basis given mobility of talent
Complexity	• Other factors can impact the scope and complexity of a company including geographic span of operations, number of business units, capital complexity, employee representation, etc.

SOUTHLEA a GECN GROUP company
© 2025 Southlea Group LP.
Proprietary and Confidential.

Peer Group Selection Criteria

Market practices vary across the utility sector with differences depending on unique business characteristics and historical practices

Design principles	General market practices	Specific Ontario Regulated Utility Practices		
		Hydro One	Toronto Hydro	IESO
Ownership	• Utilities: practices vary as many will focus more specifically on industry comparisons • Crowns: weighting on public sector varies based on degree of commercialization	• No specific mix • Non-exec: 75% public • Exec: 75% private	• No specific mix • Non-exec: varies • Exec: no more than 1/3rd priv.	• No specific mix • Exec: 50% public
Industry	• Utilities: benchmark primarily against other energy/utility companies. In some cases, they may expand the peer group to include other related industries (for all or some roles)	• 100% Energy/Utilities • OEB requested that it be broader	• Two separate groups: Energy & General Industry (100% priv.)	• Three groups: Energy, Public & Private • Energy included across all three
Size	• Utilities: primary focus on revenue with other scope factors	• Revenue	• Revenue, FTE & operations	• Energy: revenue and operations
Geography	• Utilities: broader focus on Canadian/national data with some recognition of local market	• Canada and Ontario	• Canadian	• Canadian with emphasis on Ontario/GTA
Complexity	• Utilities: consideration of other factors (regulated v. non-regulated, capital intensity)	• Not considered	• Comparable operations	• Private: focus on financial services and engineering orgs

1. Sourced from recent OEB rate applications and other public disclosures

SOUTHLEA a GECN GROUP company
© 2025 Southlea Group LP.
Proprietary and Confidential.

Peer Group Selection Criteria

Various other considerations in defining peer groups and pay positioning

- Most companies will position target compensation at the 50th percentile allowing for actual pay to vary above/below based on performance
  - In some cases, pay will be targeted higher (e.g., 75th percentile) for certain critical skills / roles
  - Each of the specific Ontario regulated utilities target the 50th percentile
- The Arnett Report (2007) outlined several executive compensation-related considerations for Ontario-based utilities:
  - The report indicated that while utilities have a commercial orientation, they still serve a public interest with broad policies outlined by the government
  - Recommended that utilities target their executive total compensation at the market 50th percentile of a peer group consisting of an equal mix of private and public sector organizations of similar size, scope and complexity
  - No specific reference to industry composition of peer group
- Other shareholder advisory bodies (e.g., ISS / Glass Lewis) define peer groups primarily based on industry and size (e.g., revenue and market capitalization)

© 2025 Southlea Group LP.
Proprietary and Confidential.

Recommendations

Updated compensation philosophy guiding principles (1 of 2)

Current	Recommended
Market Competitive – Drive organization results with a performance orientation that aligns with our business strategy and risk tolerance while taking into consideration affordability, market competitiveness as well as the context and environment in which OPG operates	**Market Competitive –** We operate in an increasingly competitive industry for specialized roles with relevant experience. We provide a market competitive total compensation package to attract and retain talent required to deliver upon our strategic priorities. On a selective basis, we also tailor our compensation programs to address specific areas where needed
Affordable – Demonstrate fiscal conservatism through sustainability, sound financial management and defensibility while supporting the attraction and retention of top talent	**Value Driven –** We optimize the design of our compensation programs for fiscal responsibility and value for our shareholder and ratepayers so that the value of our total compensation package enables OPG to meet its commitments
Performance Oriented – Have a strong performance orientation linked to OPG's value creation and results while allowing individual compensation to be meaningfully differentiated based on performance, where appropriate.	**Performance Oriented -** We have a high-performance orientation that rewards for overall success as well as individual contributions to our success. We hold each other accountable for making business-oriented decisions that support safe and reliable operations, and successful delivery of projects. Our compensation will vary based on the success of the organization in delivering short- and long-term value for our shareholder and ratepayers

© 2025 Southlea Group LP.
Proprietary and Confidential.

Recommendations

Updated compensation philosophy guiding principles (2 of 2)

Current	Recommended
Focus on Purpose and Operations – Recognize OPG's role as a significant Ontario employer; encourage long-term employment and development, a culture of trust and respect, and a seamless integration with talent and succession management objectives	**Agile and Flexible** – The labour markets are rapidly evolving, and we prioritize flexibility and agility in our compensation programs. We regularly monitor the environment in which we operate (e.g., market changes, talent shortages, regulatory shifts, etc.) so that we can adjust our compensation programs as needed
	Risk Management – Our compensation programs reinforce effective stewardship and risk management of our resources to demonstrate our commitment to our shareholder and ratepayers
	Long-term Orientation – We operate a complex business with long-term investments that stretch over decades. Our compensation programs support a career with the organization so that our employees can fully develop and apply their knowledge over time
Simple and Transparent – Be simple to understand and administer, sustainable and scalable; communicated in a way that is integrated with messages about other monetary and non-monetary rewards such that the perceived value of all programs meet or exceed program costs **Fair and Equitable** – Internal equity ensures equal pay for work of equal value and is free from discrimination	**Fair and Transparent** – We provide fair and equitable compensation programs and practices. We support transparent communication of our compensation programs and the overall total rewards package

SOUTHLEA a GECN GROUP company
© 2025 Southlea Group LP.
Proprietary and Confidential.

Recommendations

Updated peer group selection criteria (excluding Nuclear Authorized)

Element	Current	Recommended	Rationale
Ownership	• 50% public sector and 50% private sector • Includes all corporate structures	• Put a greater emphasis on private sector organizations within a single peer group • If required to maintain separate peer groups, adopt a 25% public sector and 75% private sector weighting • Include only autonomous organizations	• Lack of comparable public sector peers • Provides more robust data • Better balances talent market with accountability profile
Industry	• 75% energy/utility and 25% general industry	• 75% energy/utility and 25% other adjacent industries with similar complexity (as per below), such as: mining, industrial, telecom, financial	• Reflects need for energy industry experience • Balanced by need for broader representation
Size	• Revenue: $3B to $15B (executives) • Not used for non-executives	• Revenue: $3B to $24B, plus assets and employees (executives) • Not used for non-executives, but typically apply minimum threshold ($1B in revenue)	• Captures operating revenue and capital expenditures ($7B + $5B = $12B+) • Approx. 1/2x to 2.0x range
Geography	• Canada	• Canada with a focus on Ontario-based employers outside of energy	• Better aligns with broader talent market
Other		• Organizations with similar complexity (considering factors such as: regulatory environment, engineering, represented employee base, capital orientation, multi-business lines)	• Better reflects OPG's organizational complexity and OPG's talent market

Refer to **Appendix** for further details on current practices

SOUTHLEA a GECN GROUP company
© 2025 Southlea Group LP.
Proprietary and Confidential.

Recommendations

The impact of the proposed changes to be paced accordingly and aligned with attraction/retention needs

- The intent of the proposed changes to the compensation philosophy and peer group are to reflect the go-forward orientation of OPG in terms of its growth and transition
- The impact of the proposed changes to be tested relative to market compensation data to better understand the potential impact of OPG's current compensation structure and actual compensation
- Any changes to the compensation structure to be considered in terms of its impact on OPG's overall costs and various stakeholder interests and may need to be phased in overtime, and subject to Board of Directors approval as necessary
- Changes to the compensation structure may also be considered for specific employee groups depending on internal and external talent needs, e.g., critical skills, pivotal roles, etc.
  - It is anticipated that there might be special consideration for project roles (at certain levels and in specific areas) to address more challenging attraction/retention challenges in new nuclear given the market evolution in terms of new industry entrants (e.g., newer nuclear firms; technology investors)
- In addition, the implementation of some of the proposed changes may need to be considered when supported by regulatory / legal updates (e.g., Broader Public Service Executive Compensation Act)
- Actual compensation changes within a revised compensation structure will also be monitored with sufficient controls to manage the pacing of changes overtime aligned with business and talent needs

SOUTHLEA a GECN GROUP company
© 2025 Southlea Group LP.
Proprietary and Confidential.

Appendix

OPG's current compensation philosophy and peer group selection criteria (for reference)

© 2025 Southlea Group LP.
Proprietary and Confidential.

Appendix

Peer Group

Current philosophy / peer group approach

OPG's Market Position

Standard	Authorized
• **Market position: P50** • Peer group reflects 75% utilities and 25% in general industry, with emphasis on large Ontario employers • 50% of data is weighted to public sector and 50% to private sector	• **Market position: P75** • Includes roles that require licensing, specific education and in-depth knowledge of theories, principles, and methods associated with nuclear energy • Comparable roles are not readily found in Canada. Peer group reflects large nuclear organizations in Canada and US based nuclear organizations

The reason why OPG targets P75 for Authorized segment is to account for the additional scope in responsibilities and complexity relative to external market.

Individuals in OPG's nuclear control rooms:

- Are responsible for the safe operation of four nuclear units (compared to two in the US),
- Oversee more equipment and systems,
- Carry out more functions than their US counterparts (e.g., Candu has online fuel handling & heavy water handling), and as a result,
- Have more staff and responsibilities than international comparator nuclear operating units.

Non-authorized nuclear roles are also benchmarked against market data with a nuclear-related premium

OPG

SOUTHLEA a GECN GROUP company
© 2025 Southlea Group LP.
Proprietary and Confidential.

Appendix

Peer Group

Current selection criteria

Areas with recommendations

Comparator Group Criteria

Total Sample (Excluding Nuclear Authorized) - Weighted 50% Public Sector / 50% Private Sector

Criteria	Private Sector		Public Sector	
	Executives	Non-Executives	Executives	Non-Executives
Size	• Restrict to organizations with revenue between $3 and $15 billion	• No revenue restriction	• Restrict to organizations with revenue between $3 and $15 billion	• No revenue restriction
Corporate structure	• Include: – Publicly-traded – Privately-held – Subsidiaries – Joint ventures – Mutuals	• Include: – Publicly-traded – Privately-held – Subsidiaries – Joint ventures – Mutuals	• Include government-owned, crown corporations only	• Include government-owned, crown corporations only
Industry	• Blend of 75% utility and energy companies and 25% general industry organizations	• Blend of 75% utility and energy companies and 25% general industry organizations	• Blend of 75% utility and energy companies and 25% general industry organizations	• Blend of 75% utility and energy companies and 25% general industry organizations
Geography	• Canadian (national)	• Canadian (national)	• Canadian (national)	• Canadian (national)

wtwco.com
© 2024 WTW. Proprietary and confidential. For WTW and WTW client use only.

wtw 2

© 2025 Southlea Group LP.
Proprietary and Confidential.

Appendix

Peer Group

Current selection criteria

Areas with recommendations

Comparator Group Criteria

Nuclear Authorized

Criteria	Executives & Non-Executives
Size	• Restrict to organizations with more than 1000 MW in nuclear power generation • Nine organizations in the U.S. plus Bruce Power in Canada
Corporate structure	• Include: – Publicly-traded – Privately-held – Subsidiaries – Joint ventures – Government owned – Mutuals
Industry	• Nuclear generating organizations (Energy industry)
Geography	• North America

While talent market is broader for nuclear talent (including Europe and Middle East), the North American market remains relevant as the primary benchmarking reference

wtwco.com
© 2024 WTW. Proprietary and confidential. For WTW and WTW client use only.

wtw 6

© 2025 Southlea Group LP.
Proprietary and Confidential.

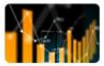
Appendix

Compensation Philosophy

OPG's current guiding principles can be updated

OPG Compensation Philosophy – Guiding Principles

OPG's compensation philosophy utilizes the following guiding principles to design and implement compensation programs that align with the organization's overall strategy and business objectives:



Market Competitive – Drive organization results with a performance orientation that aligns with our business strategy and risk tolerance while taking into consideration affordability, market competitiveness as well as the context and environment in which OPG operates.



Affordable – Demonstrate fiscal conservatism through sustainability, sound financial management and defensibility while supporting the attraction and retention of top talent.



Performance Oriented – Have a strong performance orientation linked to OPG's value creation and results while allowing individual compensation to be meaningfully differentiated based on performance, where appropriate.



Focus on Purpose and Operations – Recognize OPG's role as a significant Ontario employer; encourage long-term employment and development, a culture of trust and respect, and a seamless integration with talent and succession management objectives.



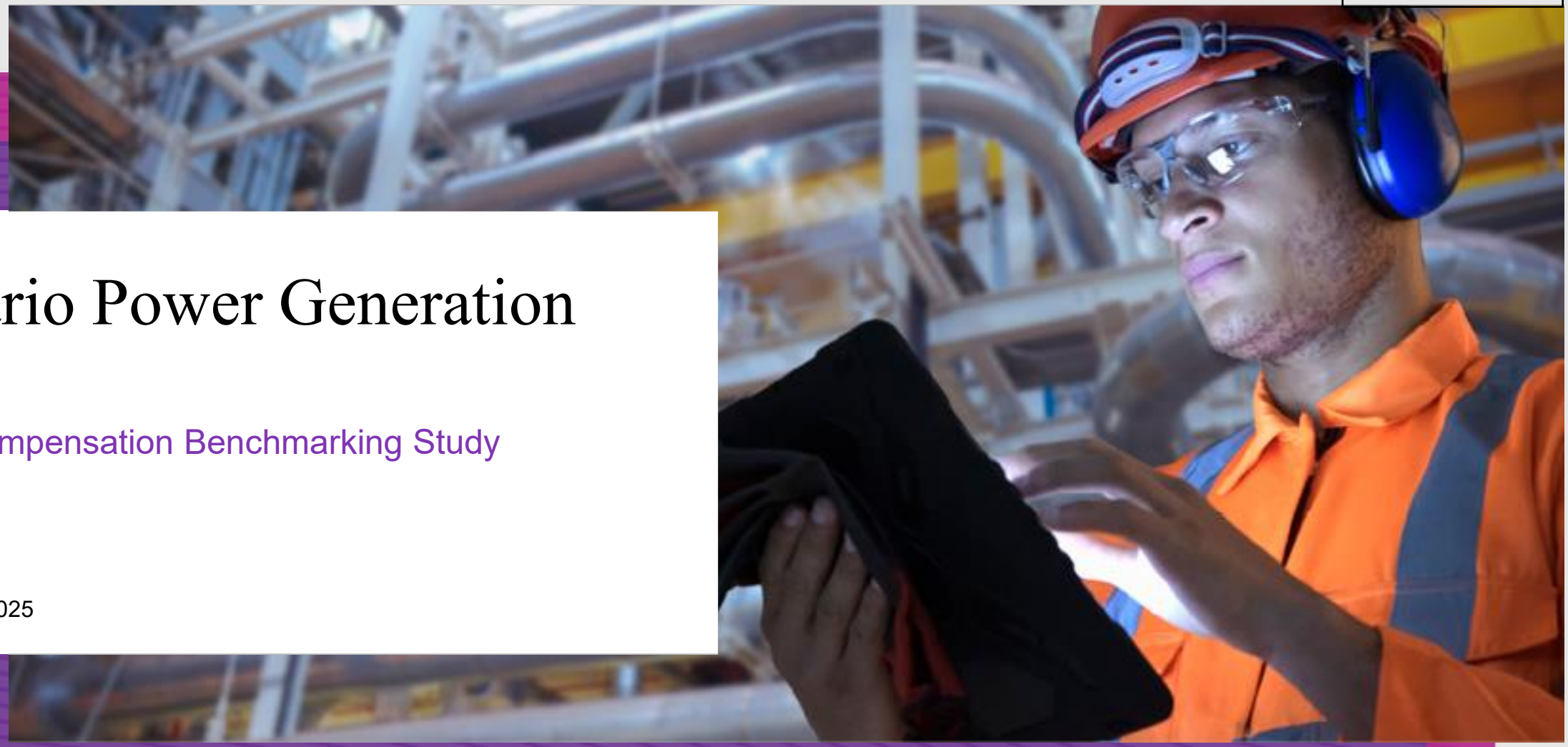
Simple and Transparent – Be simple to understand and administer, sustainable and scalable; communicated in a way that is integrated with messages about other monetary and non-monetary rewards such that the perceived value of all programs meet or exceed program costs.



Fair and Equitable – Internal equity ensures equal pay for work of equal value and is free from discrimination.

OPG

SOUTHLEA a GECN GROUP company
© 2025 Southlea Group LP.
Proprietary and Confidential.



Ontario Power Generation

Total Compensation Benchmarking Study

November 2025

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

Table of Contents

Introduction	**p. 3**
Methodology	p. 4
Comparator Groups	p. 5
Benchmark Selection	p. 6
Total Remuneration Elements	p. 7
Market Statistics	p. 8
Competitive Total Remuneration Benchmarking	p. 9
Total Remuneration Benchmark Results Presentation	p. 10
Overview	**p. 11**
Overview by OPG Group	p. 12
Total Remuneration Analysis Results by Job Family	p. 21
Total Excluding Nuclear Authorized	p. 22
Nuclear Authorized	p. 26
Appendices	**p. 30**
I. Comparator Organizations	p. 31
II. Non-Authorized Nuclear Operations Market Analysis	p. 35
III. Pension and Benefits Valuation	p. 36

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

Introduction

- WTW has provided market total remuneration benchmark results for roles across Ontario Power Generation's (OPG) Management, PWU and Society employee groups
- Roles have been matched to survey benchmarks and comparator groups based on the underlying skills and responsibilities
  - The majority of roles are compared to a broad comparator group of utility and general industry organizations ("Total Excluding Nuclear Authorized")
  - A small percentage of roles are compared to a select comparator group reflecting large Nuclear organizations across North America ("Nuclear Authorized")

# of incumbents benchmarked

	Total OPG Count	Total Benchmarked	Total Excluding Nuclear Authorized	Nuclear Authorized	*% of OPG Population*
PWU	5,407	4,885	4,694	191	*51%*
Society	3,866	3,737	3,647	90	*36%*
Mgmt Group	1,328	1,299	1,239	60	*13%*
OPG Total	10,601	9,921	9,580	341	
% of OPG Population			*97%*	*3%*	

% of incumbents benchmarked

	Total OPG Count	Total Excluding Nuclear Authorized	Nuclear Authorized	*% of OPG Population*
PWU	90%	90%	100%	*51%*
Society	97%	97%	100%	*36%*
Mgmt Group	98%	98%	98%	*13%*
OPG Total	94%	93%	100%	
% of OPG Population		*97%*	*3%*	

WTW generally considers benchmarking samples of 60% to be highly representative in the utility industry. 94% of OPG incumbents are in roles covered by this benchmark review

Note: OPG incumbent information as of April 2024

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

Methodology

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

Methodology (1/6)

Comparator Groups

- Compensation data have been sourced from WTW's 2024 Compensation Databases for the following comparator groups:
  - ***Total Excluding Nuclear Authorized*** – 97% of OPG's benchmarked jobs
    - A single comparator group of private and public sector organizations reflecting approximately 75% utility and 25% organizations in adjacent industries with similar complexity and an emphasis on large Ontario employers
    - For Executive positions, the data have been weighted 50% public sector and 50% private sector among the companies in the comparator group
    - The single comparator group approach is common among regulated utilities
  - ***Nuclear Authorized*** – 3% of OPG's benchmarked jobs
    - Comparator group reflects a sample of 10 large nuclear organizations of a comparable size to OPG, including Bruce Power (Canada) and nine U.S.-based nuclear organizations
    - These roles require federal licensing, specific education and in-depth knowledge in a unique discipline related to the theories, principles and methods associated with nuclear energy including generation, regulation or training. The requirement to apply this professional body of knowledge represents a significant portion of the job and comparable roles are not readily found in Canada
- Pension and benefits data have been sourced from WTW's Benefits Data Source (Canada) for a sample of 17 companies reflecting approximately 75% utility and 25% organizations in adjacent industries, and weighted 50% public sector and 50% private sector organizations for executive positions
  - A single comparator group has been used for executives and non-executives as organizations typically offer common pension and benefit plans across all roles and skill sets
- Companies included in each comparator group are listed in Appendix I
- Further details regarding the pension and benefits benchmarking approach are included in Appendix III

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

Methodology (2/6)

Benchmark Selection

- Based on job information and profiles from OPG, each OPG role has been matched to a benchmark with a similar level of functional specialty and accountability within WTW's 2024 Compensation Databases where a suitable match was available
  - For nuclear operations roles that are non-authorized (do not have the same federal licensing requirements), no direct matches were available in the Canadian market. However, it is recognized that comparable skill sets reside within energy, utility and other general industry organizations. As such, these jobs were matched to Total Excluding Nuclear Authorized comparators based on similar skills and level of accountability. Based on a supplemental US analysis (details in Appendix II), a +7.5% adjustment was made to the Canadian market statistics for these select roles, reflecting the premium observed in the US market where a critical mass of these skills reside

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

Methodology (3/6)

Total Remuneration Elements

- Market statistics are reported for the following elements of Total Remuneration (TR):

TR Element	OPG Definition	Market Data Definition
Base Salary	Actual annual salary (annualized for wage-based employees) as of April 2024	Actual annual salary (annualized for wage-based employees) as of April 2024
Total Direct Compensation (TDC)	Salary (as of April 2024) + target bonus (if applicable) + nuclear and/or other applicable allowances of incumbents in benchmark roles + long-term incentives at target for eligible roles	2024 actual reported annual salary + target bonus + nuclear allowances + long-term incentives (if applicable) of incumbents in benchmark roles
Total Remuneration (TR)	Total direct compensation + pension & benefits for eligible employees + paid time off for eligible employees as a % of base salary • Pension & benefits values reflect employer paid values of pension and benefits as a % of base salary, and are also provided separately • Paid time off consists of vacation days and all regular employer-scheduled holidays and employee-scheduled days	Total direct compensation + pension & benefits for eligible employees + paid time off for eligible employees as a % of base salary • Pension & benefits values reflect employer paid values of pension and benefits as a % of base salary, and are also provided separately • Paid time off consists of vacation days and all regular employer-scheduled holidays and employee scheduled days

- WTW's standard approach is to exclude paid time off (PTO) values from Total Remuneration (defined in this report as Total Remuneration Excluding PTO). To illustrate the impact of PTO on OPG's market positioning given the impact on employee experience and as part of the overall offering to employees, Total Remuneration including PTO is the primary reference of total remuneration in this report (defined in this report as Total Remuneration)

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

Methodology (4/6)

Market Statistics

- Market statistics reported reflect the 50th and 75th percentiles of the benchmark sample for the data elements included in Total Remuneration:
  - 50th percentile represents the mid-point of the sample, 50% of the data points are positioned below and above this level
  - 75th percentile represents the level where 75% of the data points are positioned below and 25% are positioned above this level. For survey confidentiality purposes, the 75th percentile can only be shown if there are a minimum of five data points in the sample
- For internal compensation management purposes, OPG compares most roles against the 50th percentile of the market
  - However, given the size and complexity of OPG's site operations relative to the comparator group, OPG compares Nuclear Authorized roles against the 75th percentile, except for senior executive roles which target the 50th percentile
- In its decision in EB-2016-0152, the Ontario Energy Board (OEB) found that "the appropriate comparator for the nuclear authorized group should be the 50th percentile"
  - OPG continues to believe that the 75th percentile is the appropriate market reference for Nuclear Authorized roles below the executive level; therefore, tables included in this report summarize OPG's positioning against both the 50th percentile and the 75th percentile
- US market data for the Nuclear Authorized comparator group were converted to CAD, consistent with WTW's practice, using an average annual exchange rate to April 2024 of $1 USD to $1.3487 CAD to moderate fluctuations

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

Methodology (5/6)

Competitive Total Remuneration Benchmarking

- Total remuneration benchmarking focuses on assessing the competitive positioning and not the costs of the programs relative to the market. The cost and value of different elements of remuneration can vary significantly
- Compensation decisions are incumbent / role specific and can be adjusted to take account of the competitive market, whereas benefit programs are designed to cover broad groups of employees rather than individual specific incumbents / roles
  - Total direct compensation (salary + target incentives) values are based on the roles and responsibilities of the employee and represent the cost of the employer of providing the target compensation
  - For pension and benefit values, the individual role is not the primary driver. The design of the benefit programs is company rather than incumbent specific, and both the design and the employer costs will reflect the characteristics and demographics of the particular organization's workforce
    - For example, defined benefit pension values are determined at a plan level and depend on factors such as age, service, actual retirement ages, etc., of the plan members as a whole
    - Unlike annual base salary or a target incentive opportunity, benefit programs cannot be readily adjusted year-over-year
- Given the potential differences between the value provided by programs relative to the cost, the total remuneration values in this report should be interpreted with care and to establish OPG's relative competitiveness against its comparator groups rather than to assess the competitiveness of OPG's costs. It is also important to consider the costs of OPG's total direct compensation and the relative value of its pension & benefit programs separately

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

Methodology (6/6)

Total Remuneration Benchmark Results Presentation

- The benchmark results are reported by market sample and OPG employee group and are summarized by job family
- All benchmarked OPG roles have been aligned to one of the following job families based on the underlying skill set and benchmarked function:

Job Families	
1. Administration	6. Human Resources
2. Corporate Services	7. Information Technology
3. Engineering	8. Maintenance
4. Enviroment, Health & Safety	9. Operations
5. Finance	10. Supply Chain

- OPG and market findings reflect the average pay and market statistics for all incumbents benchmarked
- The percentage (%) above or below the market reflects the variance between the sum of OPG's compensation and the sum of market results (i.e., 50th percentile or 75th percentile) for all incumbents benchmarked within the respective job family, OPG Group and comparator group for the data element reported where market data are available

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

Overview

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

Overview (1/9)

Observations

- When the nuclear authorized roles are compared to the 50th percentile of the market, OPG's total remuneration is 8.9% above market median and total remuneration excluding PTO is 9.4% above market median
  - Including OPG's Hydro One share grants, OPG's total remuneration is 10.1% above market median and total remuneration excluding PTO is 10.8% above market median
- When the nuclear authorized roles are compared to the 75th percentile of the market, consistent with OPG's compensation philosophy, OPG's total remuneration is 8.1% above the market reference and total remuneration excluding PTO is 8.7% above the market reference
  - Including OPG's Hydro One share grants, OPG's total remuneration is 9.3% above the market reference and total remuneration excluding PTO is 10% above the market reference
- WTW, consistent with standard methodologies, defines competitive market positioning as +/-10% of the target market position
  - This market range reflects the natural variability in market data and allows organizations to manage total remuneration on a competitive basis over time
  - We note that it is common for individual benchmark data to vary from year to year based on factors such as sample size and individual compensation program changes
  - Across most analyses, OPG's overall positioning of total direct compensation and total remuneration are within the competitive range (+/-10%) of the market median

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

Overview (2/9)

Observations

- There is variation by employee group. OPG's PWU and Society groups within the Total Excluding Nuclear Authorized sample are positioned above the 50th percentile; this potentially reflects the limited ability to negotiate differentiated compensation arrangements by job family with represented employees in order to preserve internal relativity across the represented workforce
  - It is important to assess competitiveness on an overall basis, allowing organizations to manage the trade-offs between different employee groups
  - OPG's total remuneration (which reflects a mix of total direct compensation costs and pension & benefits values) is positioned higher relative to market median than total direct compensation. Total direct compensation at 7.2% above market median (and 8.7% above market median with Hydro One shares) should be considered when assessing cost competitiveness

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

Overview (3/9)

Total Remuneration Analysis Results (Nuclear Authorized compared to 50th percentile)

- In the summary table below, Nuclear Authorized roles are compared to the 50th percentile of the market
- OPG is positioned relative to market median as follows:
  - Total direct compensation at 7.2% above
  - Total remuneration excluding PTO at 9.4% above
  - Total remuneration at 8.9% above

Segment	# of OPG Matched Incumbents	Base Salary	Total Direct Compensation	Total Remuneration Excluding PTO	Total Remuneration
		% above / below	% above / below	% above / below	% above / below
PWU	4,885	20.5%	13.3%	13.7%	12.2%
Total Exc. Nuc. Auth	4,694	20.3%	12.1%	12.4%	10.9%
Nuclear Authorized	191	23.5%	30.9%	33.5%	33.2%
Society	3,737	26.2%	13.8%	18.7%	19.2%
Total Exc. Nuc. Auth	3,647	28.2%	15.7%	20.6%	21.1%
Nuclear Authorized	90	-13.2%	-19.0%	-15.9%	-15.2%
Management	1,299	-11.5%	-13.6%	-12.9%	-13.8%
Total Exc. Nuc. Auth	1,239	-10.0%	-12.0%	-11.4%	-12.4%
Nuclear Authorized	60	-27.7%	-26.0%	-25.2%	-26.2%
OPG Total	**9,921**	**16.4%**	**7.2%**	**9.4%**	**8.9%**

***Note:** In conducting the current review, the definition of compensation provided to PWU Term employees has been revised to include the remittances for union-administered benefit programs provided to the Term employees. WTW revisited the 2020 benchmarking report and recalculated the results to reflect the corrected definition so that a comparison between the two benchmarking reports may be done on a consistent basis. OPG's recalculated total remuneration ("TR") in 2020 is 8.6% above market median ("P50") and recalculated TR excluding PTO is 11.1% above P50. For the PWU segment, recalculated TR is 12.9% above P50 and recalculated TR excluding PTO is 16.9% above P50.

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

Overview (4/9)

Total Remuneration Analysis Results Including Hydro One Share Grants
(Nuclear Authorized compared to 50th percentile)

- Including OPG's Hydro One share grants, OPG is positioned relative to market median as follows:
  - Total direct compensation at 8.7% above
  - Total remuneration excluding PTO at 10.8% above
  - Total remuneration at 10.1% above
- Annual share grants similar to OPG's Hydro One share grant are relatively uncommon in the market but have been captured in Total Direct Compensation where provided in the market. Other one-time lump-sum awards (whether in cash or shares) are not captured in WTW's compensation surveys which could potentially understate the market results

Segment	# of OPG Matched Incumbents	Base Salary	Total Direct Compensation	Total Remuneration Excluding PTO	Total Remuneration
		% above / below	% above / below	% above / below	% above / below
PWU	4,885	20.5%	15.5%	15.7%	14.0%
Total Exc. Nuc. Auth	4,694	20.3%	14.3%	14.3%	12.6%
Nuclear Authorized	191	23.5%	34.5%	36.6%	36.0%
Society	3,737	26.2%	15.4%	20.1%	20.5%
Total Exc. Nuc. Auth	3,647	28.2%	17.3%	22.1%	22.4%
Nuclear Authorized	90	-13.2%	-17.4%	-14.5%	-13.9%
Management	1,299	-11.5%	-13.5%	-12.8%	-13.8%
Total Exc. Nuc. Auth	1,239	-10.0%	-11.9%	-11.4%	-12.3%
Nuclear Authorized	60	-27.7%	-26.0%	-25.1%	-26.1%
OPG Total	**9,921**	**16.4%**	**8.7%**	**10.8%**	**10.1%**

***Note:** OPG's recalculated TR in 2020 is 9.9% above P50 and recalculated TR excluding PTO is 12.5% above P50. For the PWU segment, recalculated TR is 14.7% above P50 and recalculated TR excluding PTO is 18.9% above P50.

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

Overview (5/9)

Total Remuneration Analysis Results (Nuclear Authorized compared to 75th percentile)

- In the summary table below, Nuclear Authorized roles are compared to the 75th percentile of the market, consistent with OPG's compensation philosophy. OPG's market positioning is as follows:
  - Total direct compensation at 6.4% above
  - Total remuneration excluding PTO at 8.7% above
  - Total remuneration at 8.1% above

Segment	# of OPG Matched Incumbents	Base Salary	Total Direct Compensation	Total Remuneration Excluding PTO	Total Remuneration
		% above / below	% above / below	% above / below	% above / below
PWU	4,885	19.2%	12.2%	12.7%	11.3%
Total Exc. Nuc. Auth	4,694	20.3%	12.1%	12.4%	10.9%
Nuclear Authorized	191	4.2%	13.2%	16.6%	16.6%
Society	3,737	25.9%	13.1%	18.0%	18.6%
Total Exc. Nuc. Auth	3,647	28.2%	15.7%	20.6%	21.1%
Nuclear Authorized	90	-17.2%	-26.7%	-23.6%	-23.1%
Management	1,299	-11.9%	-14.2%	-13.6%	-14.4%
Total Exc. Nuc. Auth	1,239	-10.0%	-12.0%	-11.4%	-12.4%
Nuclear Authorized	60	-31.6%	-30.5%	-30.0%	-30.5%
OPG Total	**9,921**	**15.7%**	**6.4%**	**8.7%**	**8.1%**

***Note:** OPG's recalculated TR in 2020 is 7.6% above the market reference and recalculated TR excluding PTO is 10.1% above the market reference. For the PWU segment, recalculated TR is 11.4% above the market reference and recalculated TR excluding PTO is 15.4% above the market reference.

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

Overview (6/9)

Total Remuneration Analysis Results Including Hydro One Share Grants (Nuclear Authorized compared to 75th percentile)

- Including OPG's Hydro One share grants and comparing Nuclear Authorized roles to the 75th percentile of the market, OPG is positioned relative to market as follows:
  - Total direct compensation at 7.9% above
  - Total remuneration excluding PTO at 10.0% above
  - Total remuneration at 9.3% above

Segment	# of OPG Matched Incumbents	Base Salary	Total Direct Compensation	Total Remuneration Excluding PTO	Total Remuneration
		% above / below	% above / below	% above / below	% above / below
PWU	4,885	19.2%	14.4%	14.7%	13.0%
Total Exc. Nuc. Auth	4,694	20.3%	14.3%	14.3%	12.6%
Nuclear Authorized	191	4.2%	16.4%	19.3%	19.1%
Society	3,737	25.9%	14.8%	19.4%	19.8%
Total Exc. Nuc. Auth	3,647	28.2%	17.3%	22.1%	22.4%
Nuclear Authorized	90	-17.2%	-25.2%	-22.3%	-22.0%
Management	1,299	-11.9%	-14.1%	-13.5%	-14.3%
Total Exc. Nuc. Auth	1,239	-10.0%	-11.9%	-11.4%	-12.3%
Nuclear Authorized	60	-31.6%	-30.4%	-29.9%	-30.4%
OPG Total	**9,921**	**15.7%**	**7.9%**	**10.0%**	**9.3%**

***Note:** OPG's recalculated TR in 2020 is 8.9% above the market reference and recalculated TR excluding PTO is 11.5% above the market reference. For the PWU segment, recalculated TR is 13.1% above the market reference and recalculated TR excluding PTO is 17.3% above the market reference.

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

Overview (7/9)

Impact of Pension, Benefits & PWU Terms Incumbent Changes since April 2024

- OPG implemented changes to the pension plans for PWU and Society employees and to the benefits plans for management employees
  - Pension plan changes include increasing the required service and age for unreduced pension to 85 points (from 82 points) and averaging pensionable earnings over 5 years instead of 3 years
  - Benefits plan changes for management employees to align more closely to the benefits provided to represented employees
- In 2024, OPG hired approximately two-thirds of PWU Term employees into full-time positions (decreased PWU Terms from 986 to 323)
- The table below summarizes OPG's total remuneration competitive positioning reflecting these changes
  - These changes reduce Total Remuneration excluding PTO positioning from 9.4% to 8.7% above market median and Total Remuneration positioning reduces from 8.9% to 8.3% above market median
  - When the nuclear authorized roles are compared to the 75th percentile of the market, OPG's Total Remuneration excluding PTO reduces from 8.7% to 7.9% above the market reference and Total Remuneration positioning reduces from 8.1% to 7.5% above the market reference

Segment	# of OPG Matched Incumbents	Base Salary	Total Direct Compensation	Total Remuneration Excluding PTO	Total Remuneration
		% above / below	% above / below	% above / below	% above / below
PWU	4,885	18.0%	11.0%	12.5%	11.4%
Total Exc. Nuc. Auth	4,694	17.7%	9.7%	11.2%	10.1%
Nuclear Authorized	191	23.5%	30.9%	32.6%	32.4%
Society	3,737	26.2%	13.8%	17.7%	18.4%
Total Exc. Nuc. Auth	3,647	28.2%	15.7%	19.7%	20.3%
Nuclear Authorized	90	-13.2%	-19.0%	-16.5%	-15.8%
Management	1,299	-11.5%	-13.6%	-12.7%	-13.6%
Total Exc. Nuc. Auth	1,239	-10.0%	-12.0%	-11.2%	-12.1%
Nuclear Authorized	60	-27.7%	-26.0%	-25.0%	-26.0%
OPG Total	**9,921**	**15.3%**	**6.2%**	**8.7%**	**8.3%**

Note: Projected impact results exclude OPG's Hydro One share grants. Nuclear Authorized employees compared to the 50th percentile

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

Overview (8/9)

Benefits, Pension and Paid Time Off

- The table below illustrates the weighted average employer-provided values (expressed as a % of base salary) of pension and benefits, paid time off and entire benefits (includes combined pension and benefits and paid time off values) at OPG and compares these values to the 50th percentile of the market, recognizing that values vary across demographic, tenure and age profiles
- The employer-provided value of OPG's entire benefits is positioned below the 50th percentile of market for the Management group and above the 50th percentile for Society and PWU groups
  - The employer-provided value of OPG's pension and benefits is positioned above the 50th percentile for all employee groups
  - The employer-provided value of OPG's paid time off is positioned below the 50th percentile for all employee groups

OPG Group	Pension & Benefits (% of base salary)		Paid Time Off (% of base salary)		Entire Benefits (% of base salary)	
	OPG	Market P50	OPG	Market P50	OPG	Market P50
PWU	17.9%	15.5%	13.6%	14.5%	31.5%	30.9%
Society	20.1%	17.2%	14.3%	14.7%	34.4%	32.0%
Management	16.4%	15.9%	13.4%	14.3%	29.8%	31.5%

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

Overview (9/9)

Overtime Analysis

- Overtime is not captured in total remuneration benchmarking as overtime costs are a factor of overtime usage, and usage is not generally captured in compensation surveys. The typical benchmarking approach is to focus on overtime design (e.g., rate, when applied and the form)
- WTW's 2024 General Industry Compensation Policies and Practices Survey captures overtime policies and practices which are summarized in the table below
- OPG's overtime elements are generally aligned with energy sector market practice
  - As energy and utility organizations comprise the majority of OPG's comparators, the energy sector was seen to be the most appropriate market reference for overtime practices and policies

Element	PWU	Society	Market
Rate	Typically 2x	Typically 2x	• Energy Services market is split between 1.5x and 2.0x overtime rate across all time conditions • 1.5x is the most common rate in the General Industry market
When applied	On a daily basis, beyond scheduled hours*	On a daily basis, beyond scheduled hours*	• Typically applied on a weekly basis • Most prevalent minimum hours worked before overtime is applied is 40 hours

*as provided by OPG

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

Total Remuneration Analysis Results by Job Family

Note: Total Results by Job Family exclude OPG's Hydro One share grants

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

Total Results by Job Family (Excluding Nuclear Authorized) (1/4)

Overview

Job Family Distribution

- Benchmarked incumbents within PWU are primarily within the Maintenance (54%) and Operations (32%) job families
- Benchmarked incumbents span all ten job families within the Society Group with the majority within Engineering (47%) and Operations (17%)
- Benchmarked incumbents also span ten job families within the Management Group with the majority in Engineering (23%) and Operations (19%)

Market Positioning against the 50th percentile

- Total Direct Compensation positioning varies by OPG Group and Job Family:
  - The PWU and Society Groups are above the competitive market range
  - The Management Group is below the competitive market range
- Total Remuneration positioning varies by OPG Group and Job Family:
  - The PWU and Society Groups are above the competitive market range
  - The Management Group is below the competitive market range

Note: Total Results by Job Family exclude OPG's Hydro One share grants

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

Total Results by Job Family (Excluding Nuclear Authorized) (2/4)

PWU

Total Excluding Nuclear Authorized
OPG Group: PWU

Job Family	# OPG Matched Incumbents	Base Salary					Total Direct Compensation					Total Remuneration				
		Avg. OPG	Avg. P50	P50 (% +/-)	Avg. P75	P75 (% +/-)	Avg. OPG	Avg. P50	P50 (% +/-)	Avg. P75	P75 (% +/-)	Avg. OPG	Avg. P50	P50 (% +/-)	Avg. P75	P75 (% +/-)
Administration	261	$79	$68	16.4%	$80	-1.3%	$79	$71	12.3%	$85	-6.6%	$99	$91	8.9%	$107	-7.3%
Corporate Services	18	$111	$78	41.8%	$85	31.0%	$111	$84	31.9%	$91	22.2%	$144	$108	33.7%	$116	24.1%
Engineering	0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Environmental Health and Safety	167	$115	$95	21.2%	$118	-2.4%	$115	$103	12.2%	$123	-6.3%	$147	$131	11.9%	$154	-4.3%
Finance	77	$92	$68	36.5%	$86	7.4%	$92	$72	27.6%	$87	5.5%	$116	$92	25.4%	$109	6.4%
Human Resources	0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Information Technology	80	$109	$80	35.8%	$102	6.9%	$109	$86	25.9%	$111	-2.5%	$141	$111	27.6%	$137	2.6%
Maintenance	2517	$126	$107	17.3%	$122	2.5%	$126	$113	10.9%	$130	-3.6%	$159	$146	9.0%	$166	-3.8%
Operations	1508	$128	$104	23.2%	$120	6.2%	$128	$114	11.8%	$126	1.3%	$163	$146	11.6%	$161	1.6%
Supply Chain	66	$111	$69	60.8%	$83	34.6%	$111	$72	53.7%	$86	28.8%	$143	$93	53.3%	$109	31.5%
Average Positioning				***20.3%***		***3.9%***			***12.1%***		***-1.7%***			***10.9%***		***-1.5%***

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

Total Results by Job Family (Excluding Nuclear Authorized) (3/4)

Society

Total Excluding Nuclear Authorized
OPG Group: Society

Job Family	# OPG Matched Incumbents	Base Salary					Total Direct Compensation					Total Remuneration				
		Avg. OPG	Avg. P50	P50 (% +/-)	Avg. P75	P75 (% +/-)	Avg. OPG	Avg. P50	P50 (% +/-)	Avg. P75	P75 (% +/-)	Avg. OPG	Avg. P50	P50 (% +/-)	Avg. P75	P75 (% +/-)
Administration	33	$127	$85	49.3%	$97	30.5%	$127	$93	35.9%	$105	20.5%	$168	$120	40.0%	$134	25.3%
Corporate Services	92	$141	$103	36.3%	$116	21.7%	$141	$115	22.8%	$127	11.1%	$189	$147	28.5%	$162	16.7%
Engineering	1577	$134	$113	18.2%	$122	9.1%	$134	$124	7.5%	$138	-3.1%	$179	$160	12.0%	$177	1.4%
Environmental Health and Safety	206	$146	$116	25.6%	$126	15.1%	$146	$129	12.9%	$140	4.1%	$197	$166	18.4%	$180	9.1%
Finance	275	$147	$107	36.7%	$117	25.1%	$147	$123	19.3%	$137	7.2%	$199	$158	26.2%	$175	13.9%
Human Resources	70	$115	$81	42.2%	$89	29.6%	$115	$89	29.2%	$99	15.9%	$150	$114	31.7%	$126	19.1%
Information Technology	297	$145	$110	32.1%	$121	19.2%	$145	$122	18.2%	$137	5.7%	$197	$158	24.6%	$175	12.0%
Maintenance	345	$165	$117	41.4%	$125	32.5%	$165	$130	27.2%	$143	15.3%	$226	$168	34.3%	$185	21.9%
Operations	614	$150	$110	36.9%	$119	25.8%	$150	$122	23.2%	$134	12.2%	$204	$157	29.6%	$172	18.2%
Supply Chain	138	$138	$100	38.1%	$110	25.7%	$138	$110	25.9%	$120	15.2%	$186	$142	31.0%	$155	20.0%
Average Positioning				***28.2%***		***17.9%***			***15.7%***		***4.6%***			***21.1%***		***9.9%***

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

Total Results by Job Family (Excluding Nuclear Authorized) (4/4)

Management

Total Excluding Nuclear Authorized
OPG Group: Management

Job Family	# OPG Matched Incumbents	Base Salary					Total Direct Compensation					Total Remuneration				
		Avg. OPG	Avg. P50	P50 (% +/-)	Avg. P75	P75 (% +/-)	Avg. OPG	Avg. P50	P50 (% +/-)	Avg. P75	P75 (% +/-)	Avg. OPG	Avg. P50	P50 (% +/-)	Avg. P75	P75 (% +/-)
Administration	83	$63	$78	-19.1%	$85	-26.1%	$67	$84	-20.4%	$92	-27.3%	$86	$111	-22.5%	$120	-28.4%
Corporate Services	128	$164	$179	-8.8%	$197	-17.1%	$224	$249	-10.2%	$299	-25.1%	$274	$306	-10.5%	$360	-23.9%
Engineering	287	$156	$183	-14.3%	$200	-22.0%	$203	$245	-17.2%	$292	-30.6%	$249	$301	-17.4%	$352	-29.3%
Environmental Health and Safety	94	$145	$156	-6.7%	$173	-15.9%	$186	$201	-7.3%	$238	-21.8%	$229	$249	-8.1%	$290	-20.9%
Finance	105	$163	$168	-2.8%	$192	-15.2%	$222	$233	-4.7%	$285	-22.3%	$272	$286	-4.8%	$342	-20.6%
Human Resources	151	$111	$126	-11.5%	$138	-19.5%	$139	$154	-9.8%	$177	-21.8%	$171	$193	-11.6%	$219	-22.1%
Information Technology	28	$160	$171	-6.5%	$186	-14.2%	$214	$234	-8.4%	$276	-22.5%	$262	$287	-8.6%	$333	-21.3%
Maintenance	93	$159	$185	-14.0%	$202	-21.2%	$209	$254	-17.8%	$295	-29.3%	$256	$311	-17.8%	$356	-28.1%
Operations	241	$171	$183	-6.5%	$206	-17.2%	$234	$259	-9.6%	$316	-25.8%	$287	$316	-9.5%	$378	-24.1%
Supply Chain	29	$162	$177	-8.5%	$198	-18.4%	$214	$242	-11.6%	$286	-25.1%	$262	$297	-11.7%	$344	-23.8%
Average Positioning				***-10.0%***		***-18.9%***			***-12.0%***		***-26.3%***			***-12.4%***		***-25.0%***

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

Nuclear Authorized Results by Job Family (1/4)

Overview

Job Family Distribution

- The Operations job family represents 100% of benchmarked roles within all nuclear authorized benchmarked roles

Market Positioning against the 50th percentile

- Relative to the Nuclear Authorized sample, Total Direct Compensation and Total Remuneration positioning relative to market varies by OPG Group:
  - The PWU Group is positioned above the competitive range
  - The Society and Management Groups are positioned below the competitive range

Note: Total Results by Job Family exclude OPG's Hydro One share grants and includes PTO

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

Nuclear Authorized Results by Job Family (2/4)

PWU

Total Nuclear Authorized
OPG Group: PWU

		Base Salary					Total Direct Compensation					Total Remuneration				
Job Family	**# OPG Matched Incumbents**	**Avg. OPG**	**Avg. P50**	**P50 (% +/-)**	**Avg. P75**	**P75 (% +/-)**	**Avg. OPG**	**Avg. P50**	**P50 (% +/-)**	**Avg. P75**	**P75 (% +/-)**	**Avg. OPG**	**Avg. P50**	**P50 (% +/-)**	**Avg. P75**	**P75 (% +/-)**
Administration	0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Corporate Services	0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Engineering	0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Environmental Health and Safety	0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Finance	0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Human Resources	0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Information Technology	0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Maintenance	0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Operations	191	$190	$154	23.5%	$183	4.2%	$225	$172	30.9%	$198	13.2%	$297	$223	33.2%	$254	16.6%
Supply Chain	0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Average Positioning				***23.5%***		***4.2%***			***30.9%***		***13.2%***			***33.2%***		***16.6%***

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

Nuclear Authorized Results by Job Family (3/4)

Society

Total Nuclear Authorized
OPG Group: Society

Job Family	# OPG Matched Incumbents	Base Salary					Total Direct Compensation					Total Remuneration				
		Avg. OPG	Avg. P50	P50 (% +/-)	Avg. P75	P75 (% +/-)	Avg. OPG	Avg. P50	P50 (% +/-)	Avg. P75	P75 (% +/-)	Avg. OPG	Avg. P50	P50 (% +/-)	Avg. P75	P75 (% +/-)
Administration	0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Corporate Services	0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Engineering	0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Environmental Health and Safety	0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Finance	0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Human Resources	0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Information Technology	0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Maintenance	0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Operations	90	$199	$229	-13.2%	$240	-17.2%	$231	$285	-19.0%	$315	-26.7%	$306	$360	-15.2%	$397	-23.1%
Supply Chain	0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Average Positioning				***-13.2%***		***-17.2%***			***-19.0%***		***-26.7%***			***-15.2%***		***-23.1%***

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

Nuclear Authorized Results by Job Family (4/4)

Management

Total Nuclear Authorized
OPG Group: Management

Job Family	# OPG Matched Incumbents	Base Salary					Total Direct Compensation					Total Remuneration				
		Avg. OPG	Avg. P50	P50 (% +/-)	Avg. P75	P75 (% +/-)	Avg. OPG	Avg. P50	P50 (% +/-)	Avg. P75	P75 (% +/-)	Avg. OPG	Avg. P50	P50 (% +/-)	Avg. P75	P75 (% +/-)
Administration	0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Corporate Services	0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Engineering	0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Environmental Health and Safety	0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Finance	0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Human Resources	0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Information Technology	0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Maintenance	0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Operations	60	$222	$307	-27.7%	$333	-33.4%	$423	$572	-26.0%	$663	-36.1%	$497	$673	-26.2%	$775	-35.9%
Supply Chain	0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Average Positioning				***-27.7%***		***-33.4%***			***-26.0%***		***-36.1%***			***-26.2%***		***-35.9%***

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

Appendices

I. Comparator Organizations
II. Non-Authorized Nuclear Operations Market Analysis
III. Pension and Benefits Valuation

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

Filed: 2025-12-12
EB-2025-0297, Exhibit F4-3-1
Attachment 3, Page 31 of 38

Comparator Organizations (1/4)

Executives (Excluding Nuclear Authorized)

Comparator Organizations Executives (n = 41)		
Private Sector | n= 30		
Air Canada	Canfor Corporation	MEG Energy
Alcoa	Capital Power	NOVA Chemicals
Algonquin Power & Utilities	Cascades	Ovintiv
AltaGas	Emera	Pembina Pipeline
ARC Resources	Fortis	Secure Energy Services
Barrick Gold	Gibson Energy	Strathcona Resources
Bombardier	Hydro One	TC Energy
Bruce Power	Irving Oil	Teck Resources
Canadian National Railway	Keyera Corp.	Veren Inc.
Canadian Pacific Kansas City	Kinross Gold	WSP
Public Sector | n= 11		
Alberta Electric System Operator	EPCOR Utilities	Ontario Teachers' Pension Plan Board
British Columbia Hydro and Power Authority	Hydro-Québec	Trans Mountain
Canadian Nuclear Laboratories	Independent Electricity System Operator	Workplace Safety and Insurance Board
Enmax Corporation	Investment Management Corporation of Ontario	

Percentile Statistics	**Revenue ($CAD)**
75th Percentile	$12,776,000,000
50th Percentile	$5,741,232,152
25th Percentile	$3,905,500,000
Ontario Power Generation	**$7,434,000,000**
Percent Rank	***54P***

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

Filed: 2025-12-12
EB-2025-0297, Exhibit F4-3-1
Attachment 3, Page 32 of 38

Comparator Organizations (2/4)

Non-Executives (Excluding Nuclear Authorized)

Comparator Organizations Non-executives (n = 55)		
Private Sector | n= 40		
Air Canada	Capital Power	Ovintiv
Alcoa	Cenovus Energy	Parkland Corporation
Algonquin Power & Utilities	Emera	Pembina Pipeline
AltaGas	Enbridge	Precision Drilling
ARC Resources	Fortis	Secure Energy Services
AtkinsRéalis	Gibson Energy	Strathcona Resources
Barrick Gold	Hydro One	Suncor Energy
Bell Canada	Imperial Oil	TC Energy
Bombardier	Innergex Renewable Energy	Teck Resources
Boralex	Irving Oil	TransAlta Corporation
Bruce Power	Keyera Corp.	Veren Inc.
Canadian National Railway	Kinross Gold	WSP
Canadian Natural Resources	MEG Energy	
Canadian Pacific Kansas City	NOVA Chemicals	
Public Sector | n= 15		
Alberta Electric System Operator	EPCOR Utilities	OMERS
British Columbia Hydro and Power Authority	Export Development Canada	Ontario Teachers' Pension Plan Board
Business Development Bank of Canada	Hydro-Québec	OPSEU Pension Trust
Canadian Nuclear Laboratories	Independent Electricity System Operator	Trans Mountain
Enmax Corporation	Investment Management Corporation of Ontario	Workplace Safety and Insurance Board

Percentile Statistics	**Revenue ($CAD)**
75th Percentile	$14,737,323,280
50th Percentile	$7,053,126,000
25th Percentile	$3,355,000,000
Ontario Power Generation	**$7,434,000,000**
Percent Rank	***51P***

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

Filed: 2025-12-12
EB-2025-0297, Exhibit F4-3-1
Attachment 3, Page 33 of 38

Comparator Organizations (3/4)

Nuclear Authorized – Executives and Non-Executives

Comparator Organizations Nuclear Authorized - Executives and Non-Executives (n = 10)	
Bruce Power	FirstEnergy
Dominion Energy	NextEra Energy Inc.
Duke Energy	Public Service Enterprise Group
Entergy	Southern Company Services
Exelon	Tennessee Valley Authority

Percentile Statistics	**Revenue ($USD)**
75th Percentile	$26,683,500,000
50th Percentile	$14,393,000,000
25th Percentile	$11,692,206,000
Ontario Power Generation	**$7,434,000,000**
Percent Rank	***4P***

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

Filed: 2025-12-12
EB-2025-0297, Exhibit F4-3-1
Attachment 3, Page 34 of 38

Comparator Organizations (4/4)

Pension & Benefits Analysis

Pension and Benefits Comparator Organizations (n=17)			
#	Private Sector Organizations	#	Public Sector Organizations
1	Bruce Power	9	British Columbia Hydro and Power Authority
2	Candu Energy	10	ENMAX Corporation
3	Hydro One	11	EPCOR Utilities
4	Kinross Gold	12	Hydro-Québec
5	Northland Power	13	Independent Electricity System Operator
6	Scotiabank	14	Ontario Public Service
7	TC Energy	15	SaskPower
8	TransAlta Corporation	16	Toronto Hydro Electric Systems
		17	Workplace Safety and Insurance Board

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

Filed: 2025-12-12
EB-2025-0297, Exhibit F4-3-1
Attachment 3, Page 35 of 38

Non-Authorized Nuclear Operations Market Analysis

- To assess whether base salaries in the Total Sample (excluding Nuclear Authorized) are different relative to the Nuclear Authorized Sample for similar skills sets and levels of accountability, the following analysis was performed:
  - Comparison of relative job rates between select US utilities and nuclear organizations to understand whether nuclear roles within the US are paid differently than utility roles in the US (for roles reflecting comparable skills and level of accountability)
  - Comparison of relative job rates between the Canadian Total Sample (excluding Nuclear Authorized) comparator group (used for the benchmark review) and the US nuclear comparator group to assess whether there is any differentiation between these two markets (for roles reflecting comparable skills and level of accountability)
- The analysis indicated that for many roles and levels of work, salaries are comparable between these sectors. However, for nuclear operations roles at select career levels (e.g., technician, supervisory), base salaries are observed to carry an average premium of 7.5% relative to their non-nuclear counterparts. As such, where comparisons for non-authorized roles in nuclear facilities have been made to the Canadian Total Sample (excluding Nuclear Authorized), market data for these levels is adjusted by 7.5% to reflect this identified premium for such roles

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

Filed: 2025-12-12
EB-2025-0297, Exhibit F4-3-1
Attachment 3, Page 36 of 38

Pension and Benefits Valuation (1/3)

Methodology

- Pension and benefits information was obtained from WTW's Benefits Data Source (Canada) based on a comparator group of public and private sector organizations and is weighted 50%/50% for executive positions
  - The same comparator group has been used for executives and non-executives as organizations typically offer common pension and benefit plans across all roles and skill sets
- Comparator organizations are selected based on data availability
- Across participating organizations, plan provisions valued apply to newly hired salaried non-union employees; benefits no longer available to new hires are not considered
- Results are based on the benefits data and information provided to WTW by participating organizations, including: defined benefit pension, defined contribution pension, savings (including stock purchase, group RRSP, DPSP), active and retiree health care, active dental care, short-term disability, long-term disability and active death benefits
  - This information was supplemented by publicly available information such as management proxy circulars for the purpose of valuing the pension plans of executive profiles
  - To benchmark the PWU and Society incumbents, only organizations with hourly-non-union employees or those who offer their hourly-union employees with the same or similar pension & benefit plans as their non-unionized plans were considered
- WTW determines a value for these benefits by applying the same methodology and a common set of assumptions to each employee profile applicable to Executives, non-executive Management, PWU, and Society

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

Filed: 2025-12-12
EB-2025-0297, Exhibit F4-3-1
Attachment 3, Page 37 of 38

Pension and Benefits Valuation (2/3)

Pension Plans

- The methodology quantifies the provisions offered by each peer organization to determine the value to employees of each organization's benefits program
  - Values are not intended to represent actual plan costs
- The employer-provided pension and savings plan values are determined as follows:

A. Defined Benefit (DB) Plans

- The following elements are considered in determining comparative values for DB pension plans: normal and early retirement benefits, post-retirement death benefits, termination benefits, post-retirement pension adjustments and employee contributions
- Plans are valued in terms of anticipated prospective benefit payments being allocated over the employee's entire working history (the service prorate method to determined projected unit credit)
- For executives, bridge benefits were not considered since these benefits are relatively low in comparison with the total pension benefit of high earners and information available on these benefits is limited

B. Defined Contribution (DC) and Savings Plans

- Plans are valued by determining employee and employer contributions made during the year of valuation (term cost method)
- Employees are deemed to contribute in such a way that reflects their savings opportunity and ability to contribute; contributions will be different depending on available income, on the level of contributions permitted in the plan, and on the level of employer matching

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

Filed: 2025-12-12
EB-2025-0297, Exhibit F4-3-1
Attachment 3, Page 38 of 38

Pension and Benefits Valuation (3/3)

Benefit Plans

- The employer-provided benefit plan values are determined as follows:
  - **A. Health Care and Dental Plans**
    - Health care values are generated for pre-retirement and post-retirement coverage and dental care is generated for pre-retirement coverage (using the projected unit credit with service prorate method). Postretirement values and retiree contributions have been increased to reflect future inflation; however, deductibles under post-retirement health care plans are assumed to remain at the current level in the future
    - Values are determined using recent claims experience for large organizations taking into account plan deductibles, co-insurance and maximums as well as eligibility requirements
  - **B. Disability Plans**
    - Short-term disability benefits (including salary continuance and sickness plans) and long-term disability benefits have been valued
    - Values are determined according to specific plan provisions, including waiting periods and benefits co-ordination
  - **C. Death Benefit Plans**
    - Values for the following benefits have been calculated: pre-retirement group life insurance, and accidental death and dismemberment benefits
  - **D. Flexible Benefits (other than Pension)**
    - Values are determined based on the highest enrolled option for each plans

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.



Ontario Power Generation

Comparison of 2024 Salary Schedules for PWU and Society roles (OPG vs Bruce Power)

April, 2025

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

2024 Base Salary Comparison | Power Worker's Union Roles (PWU)

OPG Band	Job Titles	April 2024 Headcount	Hourly				Yearly			
			OPG (As of April 1, 2024)	Bruce Power (As of Jan 1, 2024)	Difference (OPG - Bruce Power)		OPG 2024	Bruce Power 2024	Difference (OPG - Bruce Power)	
					$ Per Hour	% Per Hour			$ Per Year	% Per Year
Authorized	Authorized Nuclear Operator (including Trainees, excluding supervisors)	172	$87.16	$95.64	-$8.48	***-10%***	$181,791	$199,478	-$17,687	***-10%***
	Certified Unit 0 Control Room Operator (including Trainees)	19	$78.42	$86.07	-$7.65	***-10%***	$163,562	$179,517	-$15,956	***-10%***
Band 3	Nuclear Operator (including Trainees)	603	$65.88	$81.25	-$15.37	***-23%***	$137,407	$169,464	-$32,057	***-23%***
	Electrical & Control Techn & Technologists / Shift Control Technician	839	$65.88	$79.82	-$13.94	***-21%***	$137,407	$166,478	-$29,071	***-21%***
	Mechanical Technician & Technologist / Mechanical Maintainer	768	$65.88	$79.58	-$13.70	***-21%***	$137,407	$165,981	-$28,574	***-21%***
	Chemical Technician / Chemical Technologist	83	$65.88	$72.47	-$6.59	***-10%***	$137,407	$151,151	-$13,744	***-10%***
	Planning & Cost Control Technician / Cost & Scheduling Technician	45	$65.88	$73.35	-$7.47	***-11%***	$127,101	$133,868	-$6,767	***-5%***
	Quality Technician I E&C [1]	29	$65.88	$71.56	-$5.68	***-9%***	$130,537	$149,248	-$18,711	***-14%***
Band 2	Civil & Service Trades Maintainers / Civil Maintainer I	481	$51.24	$72.99	-$21.75	***-42%***	$106,872	$152,236	-$45,364	***-42%***
	Civil & Service Trades Maintainers / Civil Maintainer II		$51.24	$68.36	-$17.12	***-33%***	$106,872	$142,579	-$35,707	***-33%***
	Nuclear Security Officer	n/a	$51.24	$56.97	-$5.73	***-11%***	$106,872	$118,823	-$11,951	***-11%***
	Emergency Response Maintainer / Emergency Services Maintainer	106	$51.24	$65.76	-$14.52	***-28%***	$106,872	$137,157	-$30,285	***-28%***
	Office Support Representative II / Administrative Assistant - Clerk I (Admin)	204	$51.24	$67.16	-$15.92	***-31%***	$93,513	$122,569	-$29,056	***-31%***
	Finance Clerk / Payroll & Accounting Services Specialist	58	$51.24	$69.66	-$18.42	***-36%***	$93,513	$127,138	-$33,625	***-36%***
Band 1	Office Support Representative I / Clerk II	8	$42.10	$50.84	-$8.74	***-21%***	$76,833	$92,787	-$15,955	***-21%***
Totals & Simple Average		***3,415***	***$60.69***	***$72.77***	***-$12.07***	***-21%***	***$122,931***	***$147,232***	***-$24,301***	***-21%***
Totals & Weighted Average		***3,415***	***$63.33***	***$77.79***	***-$14.47***	***-24%***	***$130,836***	***$160,620***	***-$29,784***	***-24%***

Notes:

1. Project Technician - E&C / Project Tech II - E&C has been updated to Quality Technician I E&C

- *OPG collective agreement provides salary schedules by band, whereas the Bruce Power agreement is on a role basis. Prior to the introduction of skill broadening, OPG utilized a salary schedule that was structured 365.25-day Bruce Power. Therefore, comparisons are on a best effort basis by matching jobs at Bruce Power to those previously used by OPG and which continue to be used today in a broader capacity*
- *Annualized salary is calculated based on a 365.25-day year*
- *n/a = not available due to security reasons*

Sources:

- *Bruce Power and PWU wage schedules as of September 4, 2024 | Revised on October 31, 2024*
- *OPG and PWU wage schedules as of April 1, 2024 | Revised on November 29, 2024*

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

2024 Base Salary Comparison | Society of United Professionals

OPG Band	Sample Job Titles	April 2024 Headcount	Weekly				Yearly			
			OPG (As of Jan 1, 2024)	Bruce Power (As of Jan 1, 2024)	Difference (OPG - Bruce Power)		OPG 2024	Bruce Power 2024	Difference (OPG - Bruce Power)	
					$ Per Week	% Per Week			$ Per Year	% Per Year
Authorized	Shift Supervisor In Training	27	$3,728.91	$4,108.00	-$379.09	***-10%***	$194,436	$214,203	-$19,767	***-10%***
	Control Room Shift Supervisor, Training Supervisor	35	$4,169.28	$5,015.00	-$845.72	***-20%***	$217,398	$261,496	-$44,098	***-20%***
MP6 - 40 Hr	Section Manager Outage, Real Time Markets Supv (Shift)	9	$3,772.92	$4,103.00	-$330.08	*-9%*	$196,731	$213,942	-$17,211	*-9%*
MP5 - 40 Hr	Project Site Supervisor, Real Time Markets Specialist (Shift)	23	$3,539.07	$3,849.00	-$309.93	*-9%*	$184,537	$200,698	-$16,161	*-9%*
MP4 - 40 Hr	FLM, Control/Mechanical / Trades Mgmt Supv, Hydroelectric	197	$3,319.59	$3,609.00	-$289.41	*-9%*	$173,093	$188,184	-$15,091	*-9%*
MP3 - 40 Hr	FLM, Civil Maintenance	19	$3,112.79	$3,384.00	-$271.21	*-9%*	$162,310	$176,451	-$14,142	*-9%*
MP6 - 35 Hr	Section Head Information Systems, Senior Performance Improvement Officer	31	$3,220.98	$3,503.00	-$282.02	***-9%***	$167,951	$182,656	-$14,705	***-9%***
MP5 - 35 Hr	Sr Engineer/Scientist - Specialist	63	$3,020.55	$3,286.00	-$265.45	***-9%***	$157,500	$171,341	-$13,841	***-9%***
MP4 - 35 Hr	Senior Technical Engineer/Officer , Eng/Applied Science Trainee	495	$2,832.86	$3,081.00	-$248.14	***-9%***	$147,713	$160,652	-$12,939	***-9%***
MP3 - 35 Hr	Assistant Proceurement Specialist, Financial Analyst	16	$2,657.88	$2,890.00	-$232.12	***-9%***	$138,589	$150,693	-$12,103	***-9%***
MP2 - 35 Hr	Materials Co-Ordinator, Support Specialist	14	$2,492.48	$2,711.00	-$218.52	***-9%***	$129,965	$141,359	-$11,394	***-9%***
Totals & Simple Average		***929***	***$3,260.66***	***$3,594.45***	***-$333.79***	***-10%***	***$170,020***	***$187,425***	***-$17,405***	***-10%***
Totals & Weighted Average		***929***	***$3,062.32***	***$3,349.91***	***-$287.59***	***-9%***	***$159,678***	***$174,674***	***-$14,996***	***-9%***

Sources:
- *Bruce Power and Society as of January 1, 2024*
- *OPG and Society as of January 1, 2024 | Revised on December 18, 2023*

© 2025 WTW. Proprietary and confidential. For WTW and WTW client use only.

Ontario Power Generation

OEB benchmarking – Tenure analysis

November, 2025

Ontario Power Generation ("OPG") requested WTW's support in assessing how its employees' average tenure compares to the average tenure in the market as of April 1, 2024*.

OPG data reflect full-time employees in OPG's PWU and Society groups in roles matched to the Total excluding Nuclear Authorized Sample where there are sufficient tenure market data to report.

Market data have been sourced from WTW's proprietary compensation data base and reflect the average of median tenure data reported by benchmark. Data are summarized for each group.

Findings and Observations

OPG's average tenure is higher than the market. The majority of OPG's employees have longer tenure than observed in the market (above the 75th percentile). We observe some variability by job family and salary level within each group.

Table 1 – Tenure summary by Employee Group

OPG Band	#Ees	Average Tenure		% of Employees						
		OPG	Market**	Below P25	P25	Between P25 and P50	P50	Between P50 and P75	P75	Above P75
Society	2,097	10	5	29%	4%	3%	4%	5%	3%	52%
PWU	2,358	14	8	15%	5%	14%	2%	3%	1%	60%
Total	**4,455**	**12**	**7**	**22%**	**4%**	**9%**	**3%**	**4%**	**2%**	**56%**

* WTW was not asked to assess the relationship between tenure and compensation levels.

** Average market tenure reflects the average of median tenure data reported for each benchmark included in the analysis.

PENSION AND OTHER POST-EMPLOYMENT BENEFIT COSTS

1.0 PURPOSE

The purpose of this exhibit is to:

- Detail the forecast IR term pension and other post-employment benefit ("OPEB") costs for OPG's regulated facilities and the DNNP facilities determined in accordance with US GAAP ("accrual costs") included in the proposed revenue requirements and set out supporting evidence for these amounts;
- Present the forecast IR term pension contributions and OPEB benefit payments ("cash amounts") as well as the differential between the accrual costs and cash amounts. These amounts are provided for reference and continuity with past proceedings;
- Present the historical and bridge period pension and OPEB accrual costs and cash amounts for OPG's regulated facilities; and
- Support the request for disposition of balances in the Pension and OPEB Cost Variance Account, Pension & OPEB Cash versus Accrual Differential Deferral Account, the Pension & OPEB Cash Payment Variance Account, and the Pension and OPEB Forecast Accrual versus Actual Cash Differential Variance Account, as set out in Ex. H1-1-1.

2.0 OVERVIEW

OPG's pension and OPEB programs applicable to the prescribed facilities consist of a registered pension plan ("RPP"), a supplementary pension plan, other post-retirement benefits such as group life insurance and health and dental care for pensioners and their dependants, as well as long-term disability ("LTD") benefits for current employees.[1] This includes the DNNP facilities, for which DNNP LP is entering into a lease with OPG. DNNP LP will undertake the development, construction, and operation of the DNNP facilities, with OPG contracted to act as the project manager and operator of the facilities. As such, OPG is expected to charge DNNP LP for the corresponding portion of the costs of the pension and OPEB plans under the

[1] The term "other post-retirement benefits" is used to refer to post-employment benefit plans other than the RPP and LTD benefits. Unless otherwise noted, OPEB is used to refer to all post-employment benefits other than the RPP benefits.

terms of the associated agreements. As discussed in Ex. A1-4-4, DNNP LP will not have its own workforce and will contract all applicable services with OPG.

Consistent with the OEB's policy on pension and OPEB cost recovery set out in the OEB's Report: *Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs* (the "Pension & OPEB Report"),[2] the pension and OPEB costs in the proposed revenue requirements have been calculated on an accrual basis.[3]

For OPG's regulated nuclear facilities, this methodology represents a continuation of the treatment reflected in the OEB-approved settlement proposal in EB-2020-0290 and the resulting payment amounts and attendant deferral and variance accounts. The same treatment has been applied to the DNNP facilities in this Application. As the regulated hydroelectric payment amounts have been underpinned by the revenue requirements approved in EB-2013-0321, they do not yet reflect pension and OPEB accrual costs and instead reflect the then forecasted pension and OPEB cash amounts. Upon being rebased in this Application as proposed, the regulated hydroelectric payment amounts will reflect the same treatment for pension and OPEB costs as OPG's regulated nuclear facilities.

The operation of deferral and variance accounts related to pension and OPEB costs is discussed in Ex. H1-1-1, including the continued application of the Pension and OPEB Forecast Accrual versus Actual Cash Differential Variance Account that records interest, at the OEB's prescribed Construction Work In Progress rate, on the difference between pension and OPEB accrual costs and cash amounts, asymmetrically in favour of ratepayers.

The nature of pension and OPEB accrual costs and cash amounts presented in this evidence and the methodologies used to derive them are unchanged from those reflected in EB-2020-

[2] The Pension & OPEB Report was issued in the OEB's generic consultation on the issue (EB-2015-0040).
[3] As the OEB stated in EB-2018-0243, Decision and Payments Amounts Order, February 21, 2019, p.4: In accepting the settlement proposal, the OEB notes the following:

- The parties agreed the accrual method is the appropriate regulatory accounting and recovery basis for pensions and other post-employment benefits for OPG consistent with the Report of the Ontario Energy Board: Regulatory Treatment of Pension and Other Post-Employment Benefits (OPEBs) Costs (Report), issued in EB-2015-0040.

0290. This includes the DNNP facilities, for which amounts chargeable by OPG under the respective agreements are expected to be determined in the same manner as the amounts attributed to OPG's regulated facilities.

Forecast pension and OPEB accrual costs attributed to the nuclear facilities for the IR term are $226.6M in 2027, $224.8M in 2028, $233.2M in 2029, $239.0M in 2030, and $251.0M in 2031 (see Chart 1). Forecast pension and OPEB accrual costs attributed to the regulated hydroelectric facilities for the IR term are $44.2M in 2027, $43.9M in 2028, $45.7M in 2029, $47.2M in 2030, and $49.6M in 2031 (see Chart 2). Overall pension and OPEB accrual costs attributed to OPG's regulated facilities are very close to the approximate cash amounts for the IR term (for Nuclear see Chart 4 and for regulated hydroelectric see Chart 5). Pension accrual costs continue to be lower than the pension cash amounts, while OPEB accrual costs continue to be higher than the OPEB cash amounts.

Forecast pension and OPEB accrual costs attributed to the DNNP facilities for the IR term are $14.1M in 2027, $13.3M in 2028, $11.9M in 2029, $10.2M in 2030, and $9.5M in 2031 (see Chart 3). The DNNP facilities will not experience a difference between pension and OPEB accrual costs and cash amounts, as, once charged to DNNP LP by OPG, any pension and OPEB costs become cash expenditures of DNNP LP by virtue of being payable to OPG under the respective agreements.

Section 3.0 summarizes OPG's pension and OPEB costs for the regulated facilities for the historical and bridge years, and the IR term. For reference and continuity with past proceedings, this evidence shows both the accrual costs and cash amounts for pension and OPEB. Sections 4.0 and 5.0, respectively, set out how the accrual costs and cash amounts presented in Section 3.0 were developed and discuss related trends and variances.

As part of this exhibit, the list of attachments includes Aon's reports on the pension and OPEB costs for 2020-2031 (Attachment 1-3), Aon's report on the latest actuarial valuation as at January 1, 2025 (Attachment 4) and summary appendices 1-3 of the pension and OPEB

accrual costs compared to the OEB approved amounts, and pension contributions and OPEB cash payments for the historical, bridge period and IR term (Attachment 5).

3.0 SUMMARY OF PENSION AND OPEB COSTS

Charts 1, 2, 2A, and 3 set out pension and OPEB accrual costs attributed to the regulated facilities in the historical and bridge years, and the IR term. OPG's total accrual costs for these periods were determined by Aon, an independent actuary, in accordance with US GAAP, as set out in Attachment 1 for the 2025-2031 forecast amounts, Attachment 2 for the 2023-2024 actual amounts, and Attachment 3 for the 2020-2022 actual amounts.[4,5]

After increasing in 2027 following the expected adoption of a new mortality improvement scale actuarial assumption recommended by Aon (see Section 4.1), pension accrual costs are projected to generally decrease over the IR term reflecting earnings on the pension asset, at the expected rate of return, that are increasing faster than the interest cost on the benefit obligation, at the current discount rate. OPEB accrual costs are projected to generally increase over the IR term reflecting increasing interest cost on the benefit obligation over time.

Chart 1 – Total Pension and OPEB Accrual Costs – OPG Nuclear (2020 to 2031)[6] ($M)

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan	2027-2031 Total
Pension	124.0	154.9	65.7	(27.9)	47.2	(12.0)	10.0	22.6	13.8	11.2	7.8	9.3	64.7
OPEB	179.0	165.0	151.1	153.5	158.0	186.8	190.5	204.0	211.0	222.0	231.2	241.7	1,109.9
Total	**303.0**	**319.9**	**216.8**	**125.6**	**205.2**	**174.8**	**200.5**	**226.6**	**224.8**	**233.2**	**239.0**	**251.0**	**1,174.6**

[4] Aon's reports in support of the 2016 and 2017 actual amounts were provided in EB-2018-0243, Ex. H1-1-1 Attachment 3. Aon's reports in support of the 2018 and 2019 actual amounts were provided in EB-2020-0290, Ex. F4-3-2 Attachment 2. Aon's reports in support of the 2020-2022 actual amounts were provided in EB-2023-0336, Ex. H1-1-1, Attachment 5.

[5] Actual amounts for years prior to 2023 are those reflected in the previously approved balances of the Pension and OPEB Cost Variance, Pension & OPEB Cash versus Accrual Differential Deferral Account, and Pension & OPEB Cash Payment Variance Account, as applicable.

[6] OPG's nuclear pension and OPEB amounts presented in this exhibit exclude amounts related to the Nuclear Waste Management Organization, which is consolidated into OPG's financial statements.

Chart 2 – Total Pension and OPEB Accrual Costs – OPG Regulated Hydroelectric (2020-2031) ($M)

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan	2027-2031 Total
Pension	23.0	28.4	12.4	(5.0)	8.1	(2.0)	1.7	4.6	2.7	2.2	1.5	1.6	12.6
OPEB	30.3	30.7	28.6	27.7	26.9	31.9	36.8	39.6	41.2	43.5	45.7	48.0	218.0
Total	**53.3**	**59.1**	**41.0**	**22.7**	**35.0**	**29.9**	**38.5**	**44.2**	**43.9**	**45.7**	**47.2**	**49.6**	**230.6**

Chart 2A – Total Pension and OPEB Accrual Costs – OPG Regulated Hydroelectric (2016-2019) ($M)

	2016 Actual	2017 Actual	2018 Actual	2019 Actual
Pension	46.6	28.8	34.6	33.2
OPEB	24.1	25.5	27.8	27.7
Total	**70.7**	**54.3**	**62.4**	**60.9**

Chart 3 – Total Pension and OPEB Costs – DNNP Facilities (2026-2031) ($M)

	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan	2027-2031 Total
Pension	0.6	1.4	0.3	0.4	0.2	0.3	2.6
OPEB	9.4	12.7	13.0	11.5	10.0	9.2	56.4
Total	**10.0**	**14.1**	**13.3**	**11.9**	**10.2**	**9.5**	**59.0**

Charts 4 and 5 below sets out pension and OPEB cash amounts attributed to OPG's regulated facilities in the historical and bridge years, and the IR term. The cash amounts consist of contributions to the RPP and benefit payments to retirees and dependents under the OPEB plans. OPG's total forecast cash amounts for pension and OPEB for 2025-2031 were calculated by Aon, as shown in Attachment 1. Beginning in 2025, pension contributions have been set to equal projected employee contributions to reflect a permissible reduction in OPG's contributions under the *Pension Benefits Act* (Ontario) ("PBA") due to the available surplus in the plan and are projected to increase during the IR term as total employee contributions

increase (see Sections 5.0 and 5.1). Increasing OPEB benefit payments over the period reflect the growing retiree population and expected increases in per capita health and dental costs due to inflation.

Cash amounts are not shown for the DNNP facilities as DNNP LP will not make RPP contributions or make benefit payments under OPG's plans. Instead, it is expected to pay OPG its attributed portion of OPG's pension and OPEB accrual costs under the respective agreements.

Chart 4 – Pension and OPEB Cash Amounts – OPG Nuclear

(2020-2031) ($M)

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan	2027-2031 Total
Pension	148.3	137.7	147.0	128.2	161.7	99.1	100.4	100.6	103.4	109.0	111.6	115.3	539.9
OPEB	83.1	89.2	87.5	106.8	106.6	117.6	114.1	118.0	122.4	129.6	134.3	139.4	643.7
Total	**231.4**	**226.9**	**234.5**	**235.0**	**268.3**	**216.7**	**214.5**	**218.6**	**225.8**	**238.6**	**245.9**	**254.7**	**1,183.6**

Chart 5 – Pension and OPEB Cash Amounts – Regulated Hydroelectric

(2020-2031) ($M)

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan	2027-2031 Total
Pension	24.6	25.7	27.9	23.1	27.6	16.9	19.5	19.5	20.2	21.4	22.1	22.9	106.1
OPEB	13.8	16.6	16.6	19.3	18.2	20.1	22.1	22.9	23.8	25.4	26.6	27.7	126.4
Total	**38.4**	**42.3**	**44.5**	**42.4**	**45.8**	**37.0**	**41.6**	**42.4**	**44.0**	**46.8**	**48.7**	**50.6**	**232.5**

Chart 5A – Pension and OPEB Cash Amounts – OPG Regulated Hydroelectric (2016-2019) ($M)

	2016 Actual	2017 Actual	2018 Actual	2019 Actual
Pension	32.5	26.3	25.3	24.1
OPEB	13.7	13.5	14.4	15.4
Total	**46.2**	**39.8**	**39.7**	**39.5**

Charts 6 and 7 below set out the difference between pension and OPEB accrual costs and cash amounts attributed to OPG's regulated facilities for the historical and bridge years, and the IR term (i.e., the difference between the amounts in Charts 1 to 2 and the amounts in Charts 4 to 5). In aggregate, pension and OPEB accrual costs attributed to OPG's regulated facilities are very close to the cash amounts for the IR term and are lower than the cash amounts over the historical and bridge years.

Chart 6 – Pension and OPEB Accrual-Cash Differential Amounts – OPG Nuclear (2020-2031)[7] ($M)

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan	2027-2031 Total
Pension	(24.3)	17.2	(81.3)	(156.1)	(114.5)	(111.1)	(90.4)	(78.0)	(89.6)	(97.8)	(103.8)	(106.0)	(475.2)
OPEB	95.9	75.8	63.6	46.7	51.4	69.2	76.4	86.0	88.6	92.4	96.9	102.3	466.2
Total	**71.6**	**93.0**	**(17.7)**	**(109.4)**	**(63.1)**	**(41.9)**	**(14.0)**	**8.0**	**(1.0)**	**(5.4)**	**(6.9)**	**(3.7)**	**(9.0)**

Chart 7 – Pension and OPEB Accrual-Cash Differential Amounts – Regulated Hydroelectric (2020-2031)[7] ($M)

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan	2027-2031 Total
Pension	(1.6)	2.7	(15.5)	(28.1)	(19.5)	(18.9)	(17.8)	(14.9)	(17.5)	(19.2)	(20.6)	(21.3)	(93.5)
OPEB	16.5	14.1	12.0	8.4	8.7	11.8	14.7	16.7	17.4	18.1	19.1	20.3	91.6
Total	**14.9**	**16.8**	**(3.5)**	**(19.7)**	**(10.8)**	**(7.1)**	**(3.1)**	**1.8**	**(0.1)**	**(1.1)**	**(1.5)**	**(1.0)**	**(1.9)**

[7] Positive amounts represent excess of accrual costs over cash amounts.

Chart 7A – Pension and OPEB Accrual-Cash Differential Amounts – Regulated Hydroelectric (2016-2019)[7] ($M)

	2016 Actual	2017 Actual	2018 Actual	2019 Actual
Pension	14.1	2.5	9.3	9.1
OPEB	10.4	12.0	13.4	12.3
Total	**24.5**	**14.5**	**22.7**	**21.4**

As set out in Ex. H1-1-1, this Application requests the disposition of balances recorded as at December 31, 2024, less amortization amounts previously approved by the OEB for the 2025-2026 period, in the following pension and OPEB related deferral and variance accounts: the Pension and OPEB Cost Variance Account, Pension & OPEB Cash versus Accrual Differential Deferral Account, the Pension & OPEB Cash Payment Variance Account, and the Pension & OPEB Forecast Accrual versus Actual Cash Differential Variance Account.

4.0 ACCRUAL COSTS FOR PENSION AND OPEB

As in prior applications, OPG's accrual costs for pension and OPEB continue to be determined in accordance with US GAAP and include several components. These components are: current service cost (net of required employee contributions for funded plans), interest cost on the benefit obligations at the appropriate discount rate, the expected return on RPP fund assets using an assumed long-term rate of return, amounts for past service costs arising from plan amendments, and amounts for actuarial gains or losses. Actuarial gains or losses consist of experience gains or losses, which arise because actual experience differs from that assumed (e.g., investment returns higher than assumed), and adjustments for changes in assumptions (e.g., discount rates).

In accordance with US GAAP, OPG's pension and other post-retirement benefit accrual costs for a given year are based on the measurement of benefit obligations and RPP fund assets at the end of the previous year. As discussed below, the full impact of certain events arising during a year is not charged to pension and OPEB costs for that year; rather, certain amounts are accumulated and amortized over future periods. OPG's LTD costs for the current year are based on the measurement of the benefit obligation at the end of both the current and the

previous year, in accordance with US GAAP. The full impact of events arising during a year related to LTD benefits is charged to OPEB costs for that year.

The accounting obligations for pension and other post-retirement benefits continue to be determined using the projected benefit method pro-rated on service. Under this method, an equal portion of the total estimated benefit liability is attributed to each year of service until the date the plan participant would be entitled to the full benefit. The obligation at a particular date is the actuarial present value of the benefits attributed to the service rendered up to that date. The LTD obligation continues to be determined using the projected benefit method on a terminal basis. Under this method, the total estimated future benefit is attributed to the year of service in which a disability occurs.

OPG's pension and OPEB costs and obligations continue to be determined annually by an independent actuary using management's best estimate assumptions, both economic (e.g., inflation, salary escalation and health care cost trends) and demographic (e.g., mortality rates and improvement scale, termination rates and retirement rates). The long-term inflation assumption is based on a long-term outlook view of the consumer price index, informed by economic forecasts and the Bank of Canada's target range of inflation. It also takes into consideration the spreads between nominal and real interest rates. The salary escalation rate builds on the long-term inflation assumption, subject to adjustments in the near term for known short-term salary expectations based on collective agreement provisions and other expectations of salary growth. Determined in consultation with Aon, the longer-term salary escalation rate is equal to the long-term inflation rate plus 0.75%, an increase from plus 0.50% used prior to December 31, 2023. Expected per capita health and dental costs and trends rates underpinning the OPEB costs are developed by Aon based on OPG's actual historical experience and the health care trend assumption model published by the Canadian Institute of Actuaries (the "CIA"). Many of the pension assumptions used for accounting purposes are the same as those used in the actuarial valuations for funding purposes discussed in Section 5.0.

OPG uses the Full Yield Curve Approach to determine the current service and interest cost components of pension and OPEB costs. This approach involves calculating the current service cost by applying individual spot interest rates based on a representative AA corporate bond yield curve to discount each future year's underlying projected benefit payments, and interest cost by multiplying individual spot rates from the yield curve by each year's present values of future projected benefit payments.[8] There has been no new educational notes or articles issued by the CIA since OPG's last major rate application in 2020 pertaining to methods for determining such accounting discount rates, nor has there been new guidance from CPA Canada on approaches to selecting such discount rates.[9]

For purposes of determining pension costs, RPP fund assets continue to be valued using a market-related value of assets. The market-related value used in determining OPG's pension costs recognizes gains and losses on equity assets relative to a 6% assumed real return over a five-year period. This contributes to the smoothing of impacts from equity market volatility over time. Gains and losses on other than equity assets continue to be recognized in the market-related value of assets immediately.

The expected long-term rate of return on the RPP fund assets continues to be calculated by Aon based on the pension fund asset mix and capital market expectations of future risk and return for each asset class within the fund portfolio.

Actuarial gains and losses for pension and other post-retirement benefits are generally amortized over future periods. In accordance with US GAAP, OPG amortizes the net cumulative unamortized gain or loss for each of these plans in excess of 10% of the greater of the benefit obligation and the market-related value of the plan assets over the expected average remaining service life of the employees (i.e., the "corridor approach"). Past service

[8] Tied to financial market conditions, discount rates are often a main driver of variability in accrual costs. Changes in discount rates affect accrual costs in several different ways: 1) they directly decrease or increase current service cost component, which is determined on a present value basis; 2) they decrease or increase the benefit obligation, which is determined on a present value basis, giving rise to an actuarial gain or loss that, in turn, is subject to amortization under the corridor approach (other than for LTD); and 3) they change the interest rates applied to the benefit obligation cash flows to determine the interest cost component.

[9] Detailed discussions on discount rates were provided in prior applications: EB-2013-0321, Ex. F4-3-1, Section 6.3.3 and EB-2016-0152, Ex. N1-1-1, Section 3.1.2.

costs or credits for pension and other post-retirement benefits continue to be amortized over the expected average remaining service period to full eligibility of the affected employee groups. All actuarial gains and losses and past service costs related to LTD benefits continue to be recognized in the year they arise, in accordance with US GAAP.

Comprehensive accounting valuations of the pension and OPRB benefit obligations are conducted periodically to incorporate current demographics of plan membership, and update applicable assumptions to represent the current best estimate based on plan experience and current expectations. Since EB-2016-0152, OPG has conducted a comprehensive accounting valuation at each year-end, as triggered by the availability of more current information as a result of performing annual pension funding valuations discussed in Section 5.0. Performing comprehensive accounting valuations ensures that OPG's accounting obligations continue to be fairly stated in accordance with US GAAP.

4.1 Forecasting Pension and OPEB Accrual Costs

Forecasting pension and OPEB accrual costs requires estimating the values of the benefit obligations and pension fund asset value at the end of the year preceding the forecast year. Developing these estimates requires projections of the actual pension fund performance as well as projections of assumptions that will be used to determine the actual obligations. Forecasting LTD costs also requires estimating the value of the benefit obligation at the end of the last year in the forecast period.

OPG's total projected pension and OPEB accrual costs for 2027-2031 underpinning this Application were determined by Aon. The forecast 2025 costs were determined using actual December 31, 2024 values of the benefit obligations and pension fund assets, and the final assumptions as of December 31, 2024.[10] The forecast 2026-2031 costs reflect projections of benefit obligations and pension fund assets at the end of each year in the 2025-2030 period using the assumptions determined as of the end of December 2024, as updated, effective

[10] As the final December 31, 2024 assumptions were used in the projection, the 2025 pension and OPEB costs are expected to be close to the actual costs for the year with the exception of LTD costs. The 2025 LTD cost projections are less definitive because the actual costs will be calculated using information as of year-end 2025.

December 31, 2026, to reflect the 2024 Mortality Improvement Scale ("MI-2024") released by the CIA, as recommended by Aon.[11] Prior to the end of 2026, OPG's pension and OPEB valuations continue to reflect the CIA's 2017 Mortality Improvement Scale, being the last mortality improvement scale issued prior to MI-2024. Aon advised that the CIA has communicated that MI-2024 will help inform the valuation and reporting of Canadian pension plans and determine commuted values, after the CIA completes the review and endorsement process in early 2026, and as such that MI-2024 is expected to be widely adopted by pension plan sponsors in Canada starting in 2026.[12]

Additionally, the forecast 2025-2031 costs reflect the previously negotiated pension reform measures for unionized employees that became effective in 2025, related to the earnings basis and retirement eligibility provisions. These cost saving measures are discussed further in Ex. F4-3-1, Sections 7.0.1 and 7.0.2.

Chart 8 below presents the assumptions used to determine OPG's 2020-2024 actual and 2025-2031 projected pension and OPEB accrual costs in accordance with US GAAP.[13]

Chart 8 – Key Assumptions for Pension and OPEB Accrual Costs

	2020 Actual[14]	**2021 Actual[14]**	**2022 Actual[14]**	**2023 Actual[15]**	**2024 Actual[15]**	**2025-2031 Plan[16]**
Discount rate for pension[17,18]	Current service cost – 3.19% Interest cost – 2.91%	Current service cost – 2.86% Interest cost – 2.10%	Current service cost – 3.38% Interest cost – 2.79%	Current service cost - 5.25% Interest cost – 5.23%	Current service cost – 4.62% Interest cost – 4.63%	Current service cost – 4.80% Interest cost – 4.39%

[11] A mortality improvement scale is a standard actuarial input into pension and OPEB valuations and refers to a set of factors that measures the expected percentage decrease in mortality rates over time.
[12] For further details on the MI-2024 mortality improvement scale, refer to Aon's report in Attachment 1, p. 6.
[13] The assumptions used to determine OPG's 2016-2019 actual pension and OPEB accrual costs in accordance with US GAAP can be found in EB-2020-0290, Ex. F4-3-2, Chart 4.
[14] These are the same assumptions used to develop the final 2020, 2021, and 2022 pension and OPEB costs presented in EB-2023-0336 (see EB-2023-0336, Ex. H1-1-1, Chart 3, p.31). They can also be found at pp. 6-8 of Aon's report in Attachment 3.
[15] The assumptions for 2023-2024 can also be found at pp. 6-8 of Aon's report in Attachment 2.
[16] The assumptions for 2025-2031 can also be found at pp. 5-8 of Aon's report in Attachment 1.
[17] The rate for current service cost shown represents the single equivalent discount rate implicit in the current service cost calculations under the Full Yield Curve Approach.
[18] The rates for interest cost shown apply to the projected benefit obligations at the beginning of the year under the

	2020 Actual[14]	2021 Actual[14]	2022 Actual[14]	2023 Actual[15]	2024 Actual[15]	2025-2031 Plan[16]
Discount rate for other post-retirement benefit[17,18]	Current service cost – 3.21% Interest cost – 3.00%	Current service cost – 2.93% Interest cost – 2.29%	Current service cost - 3.43% Interest cost – 2.91%	Current service cost – 5.25% Interest cost – 5.24%	Current service cost - 4.61% Interest cost – 4.63%	Current service cost – 4.81% Interest cost – 4.47%
Discount rate for long-term disability[17,18,19]	Current service cost – 2.83% Interest cost – 2.55%	Current service cost – 1.89% Interest cost – 1.28%	Current service cost – 2.69% Interest cost – 2.16%	Current service cost - 5.21% Interest cost – 5.19%	Current service cost - 4.61% Interest cost – 4.63%	Current service cost – 4.37% Interest cost – 3.98%
Expected long-term rate of return on pension fund assets	6.00%	5.75%	5.75%	6.25%	6.25%	6.25%
Inflation rate	1.75%	1.75%	2.00%	2.00%	2.00%	2.00%
Weighted average salary schedule escalation rate[20]	1.7% from Jan 1, 2020 to Dec 31, 2026; 2.25% thereafter	1.6% from Jan 1, 2021 to Dec 31, 2026 and 2.25% thereafter	1.6% from Jan 1, 2022 to Dec 31, 2026 and 2.50% thereafter	1.7% from Jan 1, 2023 to Dec 31, 2026 and 2.50% thereafter	3.25% from Jan 1, 2024 to Dec 31, 2025; 2.75% thereafter	3.0% from Jan 1, 2025 to Dec 31, 2026; 2.75% thereafter
Rate of return used to project year-end pension fund asset values[21]	N/A	N/A	N/A	N/A	N/A	6.25% in 2025 to 2031

The actual returns on pension fund assets were 7.10% for 2020, 11.71% for 2021, -2.13% for 2022, 7.90% for 2023, and 10.29% for 2024.

Full Yield Curve Approach. Under this approach, a separate rate is used to calculate the interest cost on the current service cost recognized during the year. For 2020-2022, this rate can be found at pp. 6-7 of Attachment 3. For 2023 and 2024, this rate can be found at pp. 6-7 of Attachment 2. For 2025-2031, this rate can be found at pp. 5 of Attachment 1.

[19] As the LTD costs for the year are based on the re-measurement of the benefit obligation at the end of the year in accordance with US GAAP, the total LTD costs inclusive of any actuarial gains or losses due to the re-measurement continue to reflect the discount rate used to determine the year-end benefit obligations, notwithstanding the adoption of the Full Yield Curve Approach. This discount rate was 1.89% for December 31, 2020, 2.69% for December 31, 2021, 5.21% for December 31, 2022, 4.61% for December 31, 2023, and 4.37% for December 31, 2024.

[20] Where applicable, the weighted average salary schedule escalation rates reflect assumptions based on existing collective agreements and, prior to its repeal, the requirements of *Protecting a Sustainable Public Sector for Future Generations Act, 2019* ("Bill 124") that limited public sector salary and total compensation increases (see Ex. F4-3-1, Section 6.2). The longer-term salary schedule escalation (currently after 2026) is set at the assumed inflation rate plus 0.75% (plus 0.5% prior to 2024).

[21] Projections of rates of return to determine year-end pension fund asset values are not required for the calculation of the 2020-2024 costs because the actual prior year-end asset values are known.

4.2 Pension and OPEB Accrual Cost Distribution

A portion of OPG's total pension and OPEB accrual costs continues to be charged to OPG businesses and functions as part of standard labour rates, based on an estimate of the accrual current service cost for pension and OPEB. The remainder of the accrual costs, which include interest costs on the obligations, the expected return on pension plan assets, amounts for past service costs and actuarial gains and losses, and any current service cost variance from the estimate reflected in standard labour rates, continues to be recorded as a centrally-held cost (line 1 of Ex. F4-4-1, Tables 1-3).

The centrally held portion of pension and OPEB costs continues to be directly assigned and allocated to the operating businesses, in proportion to amounts of pension and OPEB costs charged directly to each of the businesses (including amounts assigned and allocated as part of corporate Support Services costs). This methodology has been reviewed by an independent expert as part of OPG's overall cost allocation methodology and is unchanged from prior OPG applications.[22]

The above methodologies will also be used by OPG to distribute pension and OPEB costs to the DNNP facilities and, as is expected, to charge DNNP LP such costs under the terms of the respective agreements (line 1 of Ex. F4-4-1, Table 4).

4.3 Comparison of Pension and OPEB Accrual Costs

4.3.1 Historical, Bridge Period and IR Term Pension and OPEB Accrual Costs

Chart 9 below provides a breakdown of the pension and OPEB accrual costs shown in Chart 1 for OPG's regulated nuclear facilities for the years 2020-2031 between amounts charged to OPG businesses/functions and those recorded in centrally held costs. Charts 10 and 10A provide such breakdown of the pension and OPEB accrual costs shown in Charts 2 and 2A for the regulated hydroelectric facilities for the years 2016-2031. Chart 11 provides such breakdown of the pension and OPEB accrual costs shown in Chart 3 for the DNNP facilities for the years 2026-2031. As noted above, OPG is providing independent actuarial reports in

[22] Refer to Ex. F3-1-4, Attachment 1 for an independent expert's report on OPG's cost allocation methodology.

support of the total OPG forecast 2025-2031 costs (Attachment 1), the actual 2023 and 2024 costs (Attachment 2), and the actual 2020-2022 costs (Attachment 3).

Chart 9 – Total Pension and OPEB Accrual Costs – OPG Nuclear (2020-2031) ($M)*

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
Pension – Business Unit Charge	235.3	232.9	232.5	255.9	198.6	272.0	274.2	283.5	291.5	305.7	309.4	319.5
Pension – Centrally Held	(111.2)	(78.0)	(166.8)	(283.8)	(151.4)	(284.0)	(264.1)	(260.9)	(277.7)	(294.4)	(301.6)	(310.2)
Total Pension Cost	**124.0**	**154.9**	**65.7**	**(27.9)**	**47.2**	**(12.0)**	**10.0**	**22.6**	**13.8**	**11.2**	**7.8**	**9.3**
OPEB – Business Unit Charge	57.6	56.6	55.3	64.3	65.8	83.4	83.9	86.8	89.2	93.6	94.7	97.8
OPEB – Centrally Held	121.4	108.4	95.8	89.2	92.2	103.4	106.6	117.3	121.7	128.4	136.5	143.8
Total OPEB Cost	**179.0**	**165.0**	**151.1**	**153.5**	**158.0**	**186.8**	**190.5**	**204.0**	**211.0**	**222.0**	**231.2**	**241.7**
Total Pension and OPEB Costs	**303.0**	**319.9**	**216.8**	**125.6**	**205.2**	**174.8**	**200.5**	**226.6**	**224.8**	**233.2**	**239.0**	**251.0**

* Numbers may not add due to rounding.

Chart 10 – Total Pension and OPEB Accrual Costs – Regulated Hydroelectric (2020-2031)[23] ($M)*

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
Pension – Business Unit Charge	41.4	43.6	45.1	46.0	33.7	46.4	52.9	55.2	56.9	59.9	61.1	63.3
Pension – Centrally Held	(18.5)	(15.3)	(32.6)	(51.1)	(25.6)	(48.4)	(51.1)	(50.5)	(54.2)	(57.7)	(59.6)	(61.7)
Total Pension Cost	**23.0**	**28.4**	**12.4**	**(5.0)**	**8.1**	**(2.0)**	**1.7**	**4.6**	**2.7**	**2.2**	**1.5**	**1.6**
OPEB – Business Unit Charge	10.1	9.6	9.9	11.5	11.4	14.2	16.2	16.9	17.4	18.3	18.7	19.4
OPEB – Centrally Held	20.2	21.1	18.7	16.2	15.6	17.6	20.6	22.7	23.8	25.2	27.0	28.6
Total OPEB Cost	**30.3**	**30.7**	**28.6**	**27.7**	**26.9**	**31.9**	**36.8**	**39.6**	**41.2**	**43.5**	**45.7**	**48.0**
Total Pension and OPEB Costs	**53.3**	**59.1**	**41.0**	**22.7**	**35.0**	**29.9**	**38.5**	**44.2**	**43.9**	**45.7**	**47.2**	**49.6**

* Numbers may not add due to rounding.

Chart 10A – Total Pension and OPEB Accrual Costs – Regulated Hydroelectric (2016-2019) ($M)*

	2016 Actual	2017 Actual	2018 Actual	2019 Actual
Pension – Business Unit Charge	34.9	33.3	32.9	35.1
Pension – Centrally Held	11.7	(4.5)	1.7	(1.9)
Total Pension Cost	**46.6**	**28.8**	**34.6**	**33.2**
OPEB – Business Unit Charge	9.4	9.3	9.5	9.8
OPEB – Centrally Held	14.7	16.3	18.3	17.9
Total OPEB Cost	**24.1**	**25.5**	**27.8**	**27.7**
Total Pension and OPEB Costs	**70.7**	**54.3**	**62.4**	**60.9**

* Numbers may not add due to rounding.

[23] See footnote 5.

Chart 11 – Total Pension and OPEB Costs – DNNP Facilities

(2026-2031) ($M)*

	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
Pension – Business Unit Charge	13.6	17.7	17.7	15.7	13.2	12.2
Pension – Centrally Held	(12.9)	(16.2)	(17.4)	(15.3)	(13.0)	(11.9)
Total Pension Cost	**0.6**	**1.4**	**0.3**	**0.4**	**0.2**	**0.3**
OPEB – Business Unit Charge	4.2	5.4	5.4	4.8	4.1	3.7
OPEB – Centrally Held	5.2	7.3	7.6	6.7	5.9	5.5
Total OPEB Cost	**9.4**	**12.7**	**13.0**	**11.5**	**10.0**	**9.2**
Total Pension and OPEB Costs	**10.0**	**14.1**	**13.3**	**11.9**	**10.2**	**9.5**

* Numbers may not add due to rounding.

Pension costs increased from 2020 to 2021, primarily due to the impact of lower discount rates, and a reduction in the expected return on pension plan assets from 6.00% to 5.75%, partially offset by the impact of the negative expected net growth in cost components.[24]

Pension costs deceased from 2021 to 2022, primarily due to the impact of higher discount rates and a higher-than-expected year-end 2021 pension fund asset value, partially offset by the impact of an increase in the inflation assumption from 1.75% to 2.00%.

Pension costs decreased from 2022 to 2023, primary due to the impact of higher discount rates, and an increase in the expected return on pension plan assets from 5.75% to 6.25%, partially offset by a lower-than-expected year-end 2022 pension fund asset value.

[24] As in previous proceedings, “expected net growth” (i.e., change) in cost components is used to refer to the net impact of the following: increases in current service costs due to the passage of time in the present value calculation, higher interest costs on a higher benefit obligation due to the passage of time, changes in the pension asset value due to expected earnings and expected unwinding of the market-related value, and related changes in amortization of historical actuarial gains or losses under the corridor approach. “Expected net growth” can be negative if, for example, earnings on the pension assets, at the expected rate of return, are increasing faster than the interest cost on the benefit obligation, at the current discount rate.

Pension costs increased from 2023 to 2024, primarily due to the impact of lower discount rates, updated salary increase assumptions reflecting new collective agreements for unionized employees and an updated long-term salary escalation rate, and higher regular headcount. Collective bargaining outcomes are discussed in Ex. F4-3-1.

Pension costs are projected to decrease from 2024 to 2025, primary due to the impact of lower discount rates for the interest cost on benefit obligations and the previously achieved pension plan reform measures which came into effect in 2025 (i.e. earnings basis for pension and retirement eligibility for an undiscounted pension) as discussed in Ex. F4-3-1, Section 7.0.2, partially offset higher regular headcount. OPEB costs are projected to increase from 2024 to 2025, primary due to the impact of higher regular headcount and an LTD actuarial gain in 2024, partially offset by the impact of lower discount rates.

Pension and OPEB costs are forecasted to increase from 2025 to 2026, mainly due to the impact of higher regular headcount, and from 2026 to 2027, due to the expected adoption of the MI-2024 mortality improvement scale effective December 31, 2026. Over the remainder of the 2027-2031 forecast period for the nuclear and regulated hydroelectric facilities, pension costs are forecasted to generally decrease reflecting negative expected net growth in cost components, and OPEB costs are forecasted to generally increase reflecting expected net growth in cost components. The forecasted DNNP facilities pension and OPEB costs decrease over the remainder of the 2027-2031 forecast period mainly due to the completion of Unit 1 execution by 2030.

Charts 12, 13, 13A, and 14 present the current service cost component of the pension and OPEB accrual costs shown in Charts 9, 10, 10A, and 11. As discussed in Section 5.2, total current service cost is comprised of estimated amounts charged to the business units through standard labour rates as well as variances from these estimated amounts, which are included in centrally held costs. The total of pension and OPEB current service cost shown in Charts 12, 13, 13A, and 14 is presented as part of the respective total compensation details in Ex. F4-3-1, Attachment 1.

Chart 12 – Pension and OPEB Accrual Current Service Cost – OPG Nuclear (2020-2031) ($M)*

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
Pension – Direct Charge	235.3	232.9	232.5	255.9	198.6	272.0	274.2	283.5	291.5	305.7	309.4	319.5
Pension – Centrally Held	28.3	47.5	27.6	(116.9)	35.8	(41.9)	(27.2)	(32.9)	(36.2)	(38.4)	(36.7)	(37.4)
Total Pension Current Service Cost	**263.6**	**280.4**	**260.1**	**139.0**	**234.4**	**230.1**	**247.0**	**250.6**	**255.3**	**267.3**	**272.7**	**282.1**
OPEB – Direct Charge	57.6	56.6	55.3	64.3	65.8	83.4	83.9	86.8	89.2	93.6	94.7	97.8
OPEB – Centrally Held	17.3	21.3	16.6	(12.7)	16.1	4.2	6.3	5.2	5.0	5.3	7.6	8.9
Total OPEB Current Service Cost	**74.9**	**77.9**	**71.9**	**51.6**	**81.9**	**87.6**	**90.2**	**92.0**	**94.2**	**98.9**	**102.3**	**106.7**
Total Pension and OPEB Current Service Cost	**338.5**	**358.3**	**332.0**	**190.6**	**316.3**	**317.7**	**337.2**	**342.6**	**349.5**	**366.2**	**375.0**	**388.8**

* Numbers may not add due to rounding.

Chart 13 – Pension and OPEB Accrual Current Service Cost – Regulated Hydroelectric (2020-2031) ($M)*

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
Pension – Direct Charge	41.4	43.6	45.1	46.0	33.7	46.4	52.9	55.2	56.9	59.9	61.1	63.3
Pension – Centrally Held	4.8	8.1	4.4	(20.9)	6.4	(7.2)	(5.3)	(6.4)	(7.1)	(7.5)	(7.3)	(7.5)
Total Pension Current Service Cost	**46.2**	**51.7**	**49.4**	**25.1**	**40.1**	**39.2**	**47.6**	**48.8**	**49.8**	**52.4**	**53.8**	**55.8**
OPEB – Direct Charge	10.1	9.6	9.9	11.5	11.4	14.2	16.2	16.9	17.4	18.3	18.7	19.4
OPEB – Centrally Held	2.9	4.8	3.7	(2.2)	2.6	0.7	1.2	1.0	1.0	1.1	1.5	1.8
Total OPEB Current Service Cost	**13.0**	**14.4**	**13.6**	**9.3**	**14.0**	**14.9**	**17.4**	**17.9**	**18.4**	**19.4**	**20.2**	**21.2**
Total Pension and OPEB Current Service Cost	**59.2**	**66.1**	**63.1**	**34.4**	**54.1**	**54.1**	**65.0**	**66.7**	**68.2**	**71.8**	**74.0**	**77.0**

* Numbers may not add due to rounding.

Chart 13A – Pension and OPEB Accrual Service Cost – Regulated Hydroelectric (2016-2019) ($M)*

	2016 Actual	2017 Actual	2018 Actual	2019 Actual
Pension – Direct Charge	34.9	33.3	32.9	35.1
Pension – Centrally Held	(0.3)	(0.5)	8.5	5.9
Total Pension Current Service Cost	**34.6**	**32.8**	**41.4**	**41.0**
OPEB – Direct Charge	9.4	9.3	9.5	9.8
OPEB – Centrally Held	(0.3)	(0.4)	1.5	0.4
Total OPEB Current Service Cost	**9.1**	**8.9**	**11.0**	**10.2**
Total Pension and OPEB Current Service Cost	**43.7**	**41.7**	**52.4**	**51.2**

* Numbers may not add due to rounding.

Chart 14 – Pension and OPEB Current Service Cost – DNNP Facilities (2026-2031) ($M)*

	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
Pension – Direct Charge	13.6	17.7	17.7	15.7	13.2	12.2
Pension – Centrally Held	(1.4)	(2.1)	(2.3)	(2.1)	(1.7)	(1.6)
Total Pension Current Service Cost	**12.2**	**15.6**	**15.4**	**13.6**	**11.5**	**10.6**
OPEB – Direct Charge	4.2	5.4	5.4	4.8	4.1	3.7
OPEB – Centrally Held	0.3	0.3	0.3	0.3	0.3	0.2
Total OPEB Current Service Cost	**4.5**	**5.7**	**5.7**	**5.1**	**4.4**	**3.9**
Pension and OPEB Current Service Cost	**16.7**	**21.3**	**21.1**	**18.7**	**15.9**	**14.5**

* Numbers may not add due to rounding.

Pension accrual current service cost increased from 2020-2021, primarily due to the impact of lower discount rates. Pension current service cost decreased from 2021 to 2022, primarily due to the impact of higher discount rates, partially offset by the impact of an increase in the inflation assumption from 1.75% to 2.00%. OPEB accrual current service cost decreased from 2021 to 2022, mainly due to the impact of higher discount rates.

Both pension and OPEB accrual current service costs decreased from 2022 to 2023, primarily due to the impact of higher discount rates.

Pension accrual current service cost increased from 2023 to 2024, primarily due to the impact of lower discount rates, updated salary increase assumptions reflecting new collective agreements for unionized employees, and increased regular headcount. OPEB accrual current service cost increased from 2023 to 2024, mainly due to the impact of lower discount rates and increased regular headcount.

Pension accrual current service cost is projected to decrease from 2024 to 2025, primary due to the impact of higher discount rates and the previously achieved pension plan reform measures which came into effect in 2025 (i.e. earnings basis for pension and retirement

eligibility for an undiscounted pension) as discussed in Ex. F4-3-1 Section 7.0.2, largely offset by the impact of increased regular headcount.

Forecast accrual current service costs for both pension and OPEB increase from 2025 to 2026, primarily due to the impact of higher regular headcount. Forecast current service costs for both pension and OPEB are generally stable between 2026 and 2027 for OPG's nuclear and regulated hydroelectric facilities. Forecast current service costs for both pension and OPEB increase from 2026 to 2027 for the DNNP facilities due to increased regular headcount. Over the remainder of the 2027-2031 forecast period, the nuclear and regulated hydroelectric facilities current service costs for both pension and OPEB are forecasted to generally increase, mainly reflecting expected pensionable earnings and expected increases in per capita health and dental costs. The forecasted DNNP facilities current service costs for both pension and OPEB decrease over the remainder of the 2027-2031 forecast period mainly due to the completion of Unit 1 execution by 2030.

The split of each year's accrual current service cost between direct charges and centrally held costs primarily varies with differences between actual and budgeted current service cost amounts, and differences between total estimated payroll for regular employees used to develop standard labour rates and the company's actual payroll.

Main drivers of year-over-year changes in pension and OPEB accrual costs for the regulated hydroelectric facilities for years 2016-2020 are the same as provided for the nuclear facilities in EB-2020-0290, Ex. F4-3-2, pp. 11-12.

4.3.1 Historical and Bridge Period to OEB Approved Pension and OPEB Accrual Costs

Chart 15 below presents the EB-2020-0290 projected (2020 and 2021) and OEB-approved (2022-2026) pension and OPEB accrual costs for the nuclear facilities.

Chart 15 – EB-2020-0290 Forecasted Pension and OPEB Accrual Costs – OPG Nuclear ($M)

	2020	2021	2022	2023	2024	2025	2026
Pension – Business Unit Charge	246.4	243.1	243.3	243.9	245.3	217.3	193.8
Pension – Centrally Held	(122.0)	(72.0)	(89.3)	(109.7)	(133.6)	(146.0)	(157.2)
Total Pension Cost	**124.4**	**171.1**	**154.0**	**134.2**	**111.7**	**71.3**	**36.6**
OPEB – Business Unit Charge	60.3	57.8	56.5	56.1	56.5	51.1	45.9
OPEB – Centrally Held	110.2	97.0	101.2	103.8	104.6	105.8	101.0
Total OPEB Cost	**170.5**	**154.8**	**157.7**	**159.9**	**161.1**	**156.9**	**146.9**
Total Pension and OPEB Costs	**294.9**	**325.9**	**311.7**	**294.1**	**272.8**	**228.2**	**183.5**

As anticipated, with the exception of the long-term disability costs that were calculated using information as of December 31, 2020, the 2020 actual accrual costs for pension and OPEB were very close or equal to the 2020 projected costs provided in EB-2020-0290, as the projection was determined using actual December 31, 2019 values of the benefit obligations and pension fund assets, and the final assumptions as of December 31, 2019.

The 2021 actual pension accrual costs were lower than projected in EB-2020-0290. This was primarily due to the impact of a higher-than-expected year-end 2020 pension fund asset value, partially offset by the impact of lower discount rates and a reduction in the expected return on pension plan assets from 6.00% to 5.75%.

Actual pension accrual costs for 2022 were lower than the forecast amounts underpinning the EB-2020-0290 nuclear revenue requirements, primarily due to the impact of higher discount rates and higher than expected year-end 2020 and 2021 pension fund asset values, partially offset by the impact of a higher inflation rate assumption of 2.00% compared to 1.75% and a lower expected return on pension plan assets of 5.75% compared to 6.00%.

The 2023 actual pension accrual costs were lower than the forecast amounts underpinning the EB-2020-0290 nuclear revenue requirements, primary due to the impact of higher discount rates, a higher than expected year-end 2022 pension fund asset value and an increase in the expected return on the pension plan assets of 6.25% compared to 6.00%, partially offset by the impact of a higher inflation rate assumption of 2.00% compared to 1.75% and a higher long-term salary scale assumption of 2.50% compared to 2.25%.

The 2024 actual, 2025 estimated and 2026 forecast pension accrual costs are lower than the corresponding forecast amounts underpinning the EB-2020-0290 revenue requirements, primarily due to the impact of higher discount rates, a higher than expected preceding year-end pension fund asset value and a higher expected return on the pension plan assets of 6.25% compared to 6.00%, partially offset the impact of a higher inflation rate assumption of 2.00% compared to 1.75%, a higher long-term salary scale assumption of 2.75% compared to 2.25% and higher than planned regular headcount.

The 2025 estimated and 2026 forecast OPEB accrual costs are higher than the forecast amounts underpinning the EB-2020-0290 revenue requirements, primary due to higher planned headcount and higher LTD benefit payments, partially offset by the impact of higher discount rates. The forecast pension and OPEB costs underpinning the EB-2020-0290 revenue requirements reflected anticipated declines in headcount in 2025 and 2026 due to the then-planned Pickering end of commercial operations and associated reduction in the workforce.

5.0 CASH AMOUNTS FOR PENSION AND OPEB

OPG's pension plans are defined benefit pension plans that provide members with a pension amount based on years of service and salary at retirement. The RPP is funded by member (i.e., employee) and OPG (i.e., employer) contributions.[25] The PBA sets the minimum funding requirements for registered pension plans to ensure that plans have sufficient assets in place to meet existing and future obligations. Contributions must be made to fund the plan's current

[25] The supplementary pension plan is not funded but is secured by letters of credit.

service cost (also known as normal cost), as well as deficiencies (i.e., deficits), if any, through defined special payments over a period of time.

The PBA requires actuarial valuations on both going concern and solvency bases to be performed at least once every three years to determine the funded status of a registered pension plan (i.e., the difference between the value of pension fund assets and the actuarial present value of the accrued liability[26] as of the valuation date) and required future contributions. The going concern valuation measures the financial position of the pension plan assuming that the plan continues indefinitely into the future. The solvency valuation measures the financial position of the pension plan, as defined pursuant to the PBA, assuming that the plan is wound-up on the valuation date and all benefits are settled by either lump sum payments or annuity purchases.[27]

Going concern special payments are required to be made over a 10-year period. To the extent that going concern special payments will not eliminate 85% of the solvency deficit over a five-year period beginning no later than 12 months from the date of the valuation in which the solvency deficiency is determined, additional payments towards the solvency deficit (i.e., solvency special payments) are required over the five-year period. Valuations are prepared and certified by an independent actuary and must be filed with the Financial Services Regulatory Authority of Ontario ("FSRA") and the Canada Revenue Agency ("CRA").

In determining the going concern accrued liability and current service cost, an actuary attributes the present value of future expected benefits over each plan member's projected service. The obligation at a particular date is the actuarial present value of the benefits attributed to each member's service rendered up to that date. Employer's current service cost represents the actuarial present value of benefits earned in respect of each additional year of employee service, less any required employee contributions to the pension plan.

[26] The term "accrued liability" and "benefit obligation" may be used interchangeably in this exhibit.

[27] Contingent benefits such as indexation are excluded from the solvency liabilities as permitted by the PBA. The PBA also requires actuarial valuations on a hypothetical wind-up basis to be performed as part of the actuarial valuation. This hypothetical wind-up valuation is similar to the solvency valuation except that contingent benefits are included in the liabilities. The wind-up deficit is not required to be funded except on actual plan wind up.

In order to establish funding requirements, economic and demographic assumptions are required to determine the plan's accrued liability as of the valuation date and to project current service cost for future years. Examples of economic assumptions include discount rates, inflation rate, and salary escalation rate. Examples of demographic assumptions include mortality rates and improvement scale, termination rates, and retirement rates. As discussed below, certain assumptions differ between going concern valuations and solvency valuations. Many of the assumptions used in the going concern funding valuations are also applied in accounting valuations for determining the pension obligation and accrual costs, as discussed in Section 4.0.

Going concern valuation assumptions and methods are determined by the actuary preparing the valuation, in accordance with accepted actuarial practice and taking into account regulatory and legislative constraints and guidance issued by the CIA, with input from plan sponsors. As prescribed by the PBA, key assumptions used in the solvency valuation are required to be set in accordance with specific CIA standards of practice.

The going concern benefit obligation and funding requirements are determined using a discount rate based on the expected long-term rate of return on pension plan assets. This long-term rate of return is based on the pension fund asset mix and capital market expectations of future risk and return for each asset class within the fund portfolio, net of passive investment management fees.[28] A provision for adverse deviation ("PfAD") is required to be included in the non-indexed going concern benefit obligation and total current service cost, which serves to increase funding requirements.[29] The PfAD is determined based on the plan's target asset allocation at the valuation date and is tested against an overall benchmark discount rate that varies with government of Canada bonds yields.[30]

[28] The long-term expected rate of return used for US GAAP accrual accounting purposes is determined in a similar way to the going concern discount rate, with the main differences being that the accounting rate does not take into account an allowance for passive investment management fees.
[29] There is no equivalent to PfAD in the accrual accounting calculations under US GAAP.
[30] The PfAD is also determined by whether the plan is "open" or "closed" to new entrants.

For the solvency valuation, the discount rates used to determine the benefit obligation are required to be determined in accordance with specific standards of practice issued by the CIA and with reference to government of Canada bonds.[31]

Under the PBA, a registered pension plan sponsor is allowed to reduce employer contributions from the otherwise required levels when the plan has what is referred to as available actuarial surplus ("AAS") and meets the associated requirements. A public sector registered pension plan has AAS that can be used to reduce employer contributions when: (i) no special payments are required; (ii) it is fully funded on a going concern basis (including the PfAD); and (iii) its solvency ratio, which measures the funded status on a solvency basis, is not less than 105%.

The most recently filed actuarial valuation of OPG's RPP is as at January 1, 2025. That valuation showed that the pension fund was in a surplus position. Funding requirements pursuant to the valuation are therefore for the employer's portion of current service cost only, with no going concern or solvency special payments and before any application of the AAS. The January 1, 2025 valuation is filed in Attachment 4. The next actuarial valuation of the OPG RPP is assumed to be completed in 2028, on a triennial cycle, using data and assumptions as of January 1, 2028, and must be filed with FSRA and CRA by September 30, 2028. A subsequent valuation is similarly assumed to be completed as of January 1, 2031.

OPG's RPP has AAS and therefore OPG is permitted to reduce employer contributions to the plan. As discussed in Ex. F4-3-1, in March 2025, OPG's Board of Directors approved such a reduction in OPG's contributions to match the level of employee contributions over the 2025-2027 period, effective March 1, 2025, subject to meeting the legislative requirements. OPG has implemented the approved reduction in employer contributions.

Aon has determined that AAS is projected to continue throughout the IR term. Consistent with OPG's 2025-2031 Business Plan, the forecast RPP contributions for the 2027-2031 period

[31] The solvency discount rates are typically lower than the going concern discount rates, as the solvency rates reflect current government bond yields and annuity purchase rates determined using information provided by insurance companies rather than the rate of return expected to be earned on pension fund assets.

have therefore been set equal to the projected employee contributions as determined by Aon, which will be subject to future approvals by OPG's Board of Directors for years after 2027. As discussed further in Section 5.1, Aon prepared this projection based on information available as of December 31, 2024.

Cash amounts for OPEB reflect OPG's benefit payments to retirees and dependants in accordance with the provisions of the plans. Forecast OPEB payments for the 2027-2031 period represent the total estimated future cash flows used by Aon to project OPEB benefit obligations over this period, as attributed to the regulated facilities.

5.1 Forecasting Pension and OPEB Cash Amounts

Projecting the availability of the AAS and forecasting the RPP contributions requires estimating the funded status of the plan during the forecast period. Aon has estimated the going concern and solvency funded status of the plan as of January 1 each year from 2026 to 2031, which confirmed a sufficient forecast AAS to meet the requirements for the ongoing contribution reduction. Developing these estimates of funded status required expectations of assumptions that will be used to determine the accrued liability as of these dates, and projections of the actual pension fund performance to those dates. In order to project the January 1 benefit obligations, Aon applied the January 1, 2025 funding valuation assumptions, as updated for the MI-2024 mortality improvement scale for the estimated going concern position for January 1, 2028 and onwards. The January 1 pension asset values were projected by Aon based on the end of December 2024 actual value, at the expected long-term rate of return of 6.25% per annum. OPG's total projected required RPP contributions for the 2026-2031 period, set to match the projected level of contributions remitted by the employees for the respective years, were calculated by Aon, as set out in Attachment 1. The projected employee contributions reflect employee contribution provisions set out in Ex. F4-3-1, Section 7.0.1.

Projected benefit payments for OPEB plans reflect the cash flows of the underlying accounting benefit obligations discussed in Section 4.0.

As in previous proceedings, total OPG projected RPP contributions and OPEB payments were attributed to OPG's regulated facilities in proportion to the respective benefit costs. The resulting cash amounts for OPG's regulated facilities are presented in Charts 4, 5, and 5A above.

5.2 Pension and OPEB Cash Amounts Trends

OPG's RPP contributions were stable throughout the 2020-2022 period, reflecting such minimum required contributions pursuant to the respective actuarial valuations filed with FSRA. OPEB benefit payments were stable throughout the 2020-2022 period.

OPG's RRP contribution decreased from 2022 to 2023, reflecting lower minimum required contributions pursuant to the actuarial valuation as of January 1, 2023 filed with FSRA. OPEB benefit payments increased from 2022 to 2023, mainly due to retiree health and dental claims returning to typical levels following the COVID-19 pandemic.

OPG's RPP contribution increased from 2023 to 2024, reflecting lower minimum required contributions pursuant to the actuarial valuation as of January 1, 2024 filed with FSRA. The RPP contribution is forecasted to decrease from 2024 to 2025, reflecting the reduction in OPG's contributions to match the level of employee contributions effective March 1, 2025.

There were no going concern or solvency special payments required under the respective actuarial valuations of the RPP filed with FSRA and none were made over the 2020-2024 period.

OPG's RPP contributions are forecasted to increase over the 2025-2031 period reflecting the expected increase in estimated employee contributions, which OPG's contributions have been set to match as a result of the availability of AAS, due to an increase in headcounts and employee pensionable earnings. OPEB benefit payments are forecasted to increase gradually over the same period reflecting the growing retiree population and expected increases in per capita health and dental costs.

LIST OF ATTACHMENTS

Attachment 1:	Aon Report on OPG's Estimated Pension and OPEB Costs for 2025-2031
Attachment 2:	Aon Report on OPG's Pension and OPEB Costs for 2023 and 2024
Attachment 3:	Aon Report on OPG's Pension and OPEB Costs for 2020-2022
Attachment 4:	Aon Report on the actuarial valuation as at January 1, 2025 for OPG's pension plan
Attachment 5:	Summary Appendices of the historical, bridge period and IR term, actual pension and OPEB accrual costs, compared to the OEB-approved expenses, and pension contributions and OPEB payments

Note: The Aon Report included in Attachment 4 is marked "Proprietary and Confidential" by Aon, but for purposes of this Application and having received permission from Aon, it is being treated as non-confidential in its entirety.

AON

Report on the Estimated Accounting Cost for Post Employment Benefit Plans for Fiscal Years 2025 to 2031

Ontario Power Generation Inc.

January 1, 2025 to December 31, 2031

December 2025



Table of Contents

Introduction 2
Actuarial Report 4
Schedule 1A – Summary of Estimated 2025 US GAAP Results 9
Schedule 1B – Summary of Estimated 2026 US GAAP Results 10
Schedule 1C – Summary of Estimated 2027 US GAAP Results 11
Schedule 1D – Summary of Estimated 2028 US GAAP Results 12
Schedule 1E – Summary of Estimated 2029 US GAAP Results 13
Schedule 1F – Summary of Estimated 2030 US GAAP Results 14
Schedule 1G – Summary of Estimated 2031 US GAAP Results 15

Introduction

This report summarizes the estimated accounting costs for fiscal years 2025 through 2031 for the post employment benefit plans sponsored by Ontario Power Generation Inc. (“OPG”).

This report covers the following plans sponsored by OPG:

- Ontario Power Generation Inc. Pension Plan (“RPP”);
- Ontario Power Generation Inc. Supplementary Pension Plan (“SPP”) ;
- Non-pension Post Retirement Plan which provides other post-retirement benefits (“OPRB”) including retiree medical, dental, life insurance, and retirement bonus benefits; and
- Post Employment Plan which provides long-term disability benefits (“LTD”) including sick leave benefits before LTD begins and the continuation of medical, dental and life insurance while on LTD.

Collectively SPP, OPRB and LTD are known as Other Post-Employment Benefits (“OPEB”).

The results cover the fiscal years from January 1, 2025 to December 31, 2031. The results have been developed in accordance with US Generally Accepted Accounting Principles (“US GAAP”) under ASC 710, 712 and 715.

The results in this report do not include amounts related to the benefit plans of the Nuclear Waste Management Organization or operating subsidiaries which are included in OPG’s consolidated financial statements.

Unless otherwise stated, all assumptions, data elements, methodologies, plan provisions, and information about assets reflected in this report are the same as those underlying and/or contained in the December 31, 2024 disclosure reports ("the Reports") prepared by Aon in accordance with US GAAP for the post employment benefit plans sponsored by OPG. These disclosure reports were dated March 2025 and are titled as follows:

- US GAAP Accounting Information – Non Pension Post-retirement and Post-employment Benefits Plans, and
- US GAAP Accounting Information – Pension Plans.

Sincerely,

Aon

[Original signed by]

Linda M. Byron
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

Aon

[Original signed by]

Isabelle Hasbani
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

December 2025

AON

Actuarial Report

Projected Results for Fiscal Years 2025 to 2031

OPG's total estimated pension and OPEB costs for fiscal years 2025 through 2031 as determined in accordance with US GAAP are as follows:

(in Canadian $000s)	2025	2026	2027	2028	2029	2030	2031
RPP	$ (15,119)	$ 14,390	$ 35,103	$ 22,286	$ 18,592	$ 13,837	$ 14,794
SPP	29,697	30,041	31,754	32,345	32,954	33,605	34,354
OPRB	153,898	171,893	190,173	199,779	209,709	217,760	228,793
LTD	51,814	53,243	55,082	56,591	59,755	63,096	66,624
Total	**$ 220,290**	**$ 269,567**	**$ 312,112**	**$ 311,001**	**$ 321,010**	**$ 328,298**	**$ 344,565**

Further details of the above OPG-wide estimated costs, by plan, as well as OPG's estimated contributions to the RPP fund and benefit payments for OPEB are provided in Schedules 1A through 1G to this report.

The estimated 2025 costs for the RPP, SPP and OPRB plans are not expected to change, unless a significant event, such as a curtailment or settlement or other unexpected changes to OPG's operations, were to take place prior to December 31, 2025. The final 2025 cost under US GAAP for the LTD plan will be determined at December 31, 2025 based on applicable information and assumptions at that date.

The final 2026 to 2031 costs for all plans under US GAAP will be determined based on applicable information, experience and assumptions in the future.

We continue to update membership for the LTD plan annually.

Actuarial Methods and Assumptions

The actuarial methodology and accounting policies used in the development of the estimated costs for fiscal years 2025 through 2031 under US GAAP are summarized below.

- Benefit obligations for RPP, SPP and OPRB are determined using the projected benefit method prorated on service;
- Benefit obligations for LTD are determined using the projected benefit method on a terminal basis such that the total estimated future benefit is attributed to the year of service in which a disability occurs;
- The discount rates have been determined in accordance with US GAAP, with reference to those representative of AA corporate bond yields in Canada having duration similar to the liabilities of the plans. For the estimated pension and OPEB costs for 2025 through 2031, the discount rates were set using the applicable bond yields used to determine the corresponding benefit obligations as of December 31, 2024.
- The following effective discount rates (per annum) were used to estimate OPG's 2025 to 2031 pension and OPEB costs under the full yield curve approach:[1]

	RPP and SPP	OPRB	LTD
Current Service Cost	4.80%	4.81%	4.37%
Interest Cost[2]	4.39%	4.47%	3.98%

The discount rates used to determine the projected benefit obligations as at December 31, 2024 and subsequent fiscal year-ends are 4.70% per annum for RPP and SPP, 4.73% per annum for OPRB and 4.37% per annum for LTD;

Under the full yield curve approach, individual spot discount rates along the yield curve are applied to the projected cash flows at the relevant maturity, resulting in a more precise measurement of interest cost. The service cost is also more precisely determined under the full yield curve approach, based on duration specific spot rates applied to discount the service cost projected cash flows.

[1] A series of individual spot rates applied to projected cash flows under the full yield curve approach is expressed as a single effective discount rate for disclosure purposes.

[2] The rates shown apply to interest cost on the projected benefit obligations at the beginning of the year. Under the full yield curve approach, a separate rate is used to calculate the interest cost on the current service cost recognized during the year. This rate is 4.71% for RPP and SPP costs, 4.79% for OPRB costs and 3.98% for LTD costs.

- A building block approach is used in determining the expected long-term rate of return on plan assets. Historical markets are studied and long-term historical relationships between equities and fixed-income are preserved consistent with the widely accepted capital market principle that assets with higher volatility generate a greater return over the long run. Current market factors such as inflation and interest rates are evaluated before long-term capital market assumptions are determined. The long-term portfolio return is established using the fund's asset allocations, via a building block approach with proper consideration of diversification and rebalancing. Aon calculated the expected return based on this methodology. An expected rate of return on assets of 6.25% per annum determined using the above approach was used for determining the estimated 2025 through 2031 RPP costs;
- The actual asset value for the RPP as at December 31, 2024 was used to determine the estimated 2025 RPP costs. The projected asset value for the RPP as at December 31, 2025 and subsequent fiscal year-ends used to estimate the 2026 through 2031 RPP costs are based on the actual asset value at December 31, 2024, projected using the expected rate of return on assets of 6.25% per annum;
- As recommended by Aon, in estimating the 2027 through 2031 costs for the pension and OPRB plans, the best estimate assumption for mortality improvement rates has been updated to reflect the MI-2024 Improvement Scale ("MI-2024") developed by the Canadian Institute of Actuaries ("CIA"), effective December 31, 2026. This updated improvement scale was published by the CIA in 2024 based on a study using experience data from 1980 to 2019 and was informed by statistical methods used to determine the best estimate of future mortality improvement rates in Canada. The CIA has communicated that the study will help inform the valuation and reporting of Canadian pension plans and determine commuted values, after the CIA completes the review and endorsement process in early 2026. Therefore Aon expects MI-2024 to be widely adopted by pension plan sponsors in Canada starting in 2026, as a best estimate of mortality improvement assumption for the Canadian pensioner population.
- Other actuarial assumptions are management's best estimate of future events, as determined in consultation with us and as set out in the Reports. These assumptions include the inflation rate, which was established at 2.00% per annum, and the salary scale increase rates, which, for determining 2025 through 2031 costs, were established at 2.75% per annum for all employee representations, with the exception of using the provisions of existing collective agreements to assume wage increases of 3.75% per year in 2025 and 2.50% per year in 2026 for employees represented by the Power Workers' Union ("PWU"), and 3.25% per year for 2025 for employees represented by the Society of United Professionals ("Society") (plus Promotion, Progression, Merit for all years);
- Changes coming into effect during 2025 for the pension plans have been reflected in the 2025 to 2031 RPP and SPP costs. These include changes to unreduced early retirement eligibility effective January 1, 2025 for management group employees, and March 31, 2025 for members represented by the PWU or Society, and changes to the earnings averaging period used to calculate pension benefits effective March 31, 2025 for members represented by the PWU or Society. The plan changes coming into effect in 2025 are described in the Plan Provisions section of the Actuarial Valuation as at January 1, 2025 for Ontario Power Generation Pension Plan.
- The active membership headcount is calculated based on the assumed decrements, and then compared to the estimated December 31, 2024 to December 31, 2031 active headcounts as provided by OPG. If the calculated headcount differs from the estimated headcount, appropriate

adjustments are made via retirements, terminations or new entrants assumed, to align the headcounts. The estimated December 31, 2024 to December 31, 2031 active headcounts used are as follows:

End of Year	2024	2025	2026	2027	2028	2029	2030	2031
Total	9,916	[redacted]						

- Actuarial gains or losses for RPP, SPP and OPRB have been amortized using the 10% corridor method, except where immediate recognition is required under US GAAP for non-routine events during the year (none expected during 2025 through 2031);
- Past service costs for RPP, SPP and OPRB have been amortized on a straight-line basis over the expected average remaining service lifetime at the amendment date, except where immediate recognition is required under US GAAP during the year (none expected during 2025 through 2031);
- Special termination benefits, if any, are immediately recognized under US GAAP (none expected during 2025 through 2031);
- For LTD, all actuarial gains and losses and past service costs are required to be recognized immediately in the cost. Therefore, under US GAAP, the cost is equal to the change in the benefit obligation plus benefit payments; and
- Expected return on assets and amortization of actuarial gains/losses are based on a market-related value of assets where investment gains and losses on equity assets in excess of an expected return of 6.00% per annum plus the increase in Consumer Price Index are smoothed over five years.

The 2025 to 2027 contributions to the RPP fund are based on the latest filed actuarial valuation for funding purposes as of January 1, 2025 of the RPP, taking into account the Available Actuarial Surplus ("AAS"). The next actuarial valuation for funding purposes must have an effective date no later than January 1, 2028. We have assumed that based on a triennial filing, the next actuarial valuation for funding purposes would have an effective date of January 1, 2028, with a subsequent actuarial valuation for funding purposes prepared with an effective date of January 1, 2031. The estimated contributions for 2028 to 2031 to the RPP fund are based on the projected going concern and solvency valuations as of the assumed funding valuation dates of January 1, 2028 and January 1, 2031.

During each year from 2025 to 2031, OPG's contributions to the RPP are set equal to the estimated required employee contributions to reflect OPG's decision to utilize AAS as permitted under the *Pension Benefits Act* (Ontario). The existence of a sufficient AAS over this period based on an estimate of the going concern and solvency positions of the RPP on January 1 of each year, including years in which full valuations are not required, has been tested and confirmed based on the assumptions outlined in this document. The estimated annual required employee contributions reflect the above actuarial assumptions and active headcounts.

The assumptions and methods used for the determination of the projected going concern funded status as of January 1 of each year between 2026 and 2031 are the same as those used for the funding valuation as of January 1, 2025, with the exception of the mortality improvement scale which has been

updated to MI-2024 for the estimated going concern position for January 1, 2028 and onwards. The assumptions and methods used for the determination of the projected solvency funded status as of January 1 of each year between 2026 and 2031 are the same as those used for the funding valuation as of January 1, 2025.

The projected benefit payments for the OPEB plans reflect the estimated cash flows of the underlying benefit obligations.

Schedule 1A – Summary of Estimated 2025 US GAAP Results

The following table provides a summary of the estimated US GAAP results for 2025 for the post employment benefit plans sponsored by OPG. The estimated net periodic pension/benefit cost for the period January 1, 2025 to December 31, 2025 is determined based on the actual balance sheet items at January 1, 2025.

(in Canadian $000's)	RPP	SPP	OPRB	LTD
Net Asset (Liability) Recognized as at January 1, 2025				
Projected Benefit Obligation	(17,338,912)	(388,714)	(2,561,110)	(254,803)
Fair Value of Plan Assets	17,641,433	-	-	-
Net Asset (Liability) Recognized	**302,521**	**(388,714)**	**(2,561,110)**	**(254,803)**
Amounts Recognized in Accumulated Other Comprehensive Income as at January 1, 2025				
Unrecognized Past Service Costs (Credits)	9,838	439	49,854	-
Unrecognized Net Actuarial Loss (Gain)	529,074	94,075	(670,971)	-
Total Accumulated Other Comprehensive Loss (Income)	**538,912**	**94,514**	**(621,117)**	**-**
Components of Estimated Net Periodic Pension/Benefit Cost, January 1, 2025 to December 31, 2025				
Employer Current Service Cost	289,906	8,865	61,755	39,749
Interest Cost	759,452	17,107	115,341	10,988
Expected Return on Plan Assets	(1,064,526)	-	-	-
Recognition of LTD Actuarial Loss (Gain)	-	-	-	1,077
Amortization of Past Service Cost	49	45	3,706	-
Amortization of Net Loss (Gain)	-	3,680	(26,904)	-
Total Cost	**(15,119)**	**29,697**	**153,898**	**51,814**
2025 Estimated Employer Pension Contributions / Benefit Payments	**124,829[1]**	**17,090**	**94,137**	**36,942**

[1] $202,939,000 was used in the calculation of the Expected Return on Plan Assets component of the estimated 2025 cost.

Schedule 1B – Summary of Estimated 2026 US GAAP Results

The following table provides a summary of the estimated US GAAP results for 2026 for the post employment benefit plans sponsored by OPG. The estimated net periodic pension/benefit cost for the period January 1, 2026 to December 31, 2026 is determined based on the projected balance sheet items at January 1, 2026.

(in Canadian $000's)	RPP	SPP	OPRB	LTD
Projected Net Asset (Liability) Recognized as at January 1, 2026				
Projected Benefit Obligation	(17,728,599)	(399,023)	(2,654,510)	(269,675)
Fair Value of Plan Assets	18,108,872	-	-	-
Net Asset (Liability) Recognized	**380,273**	**(399,023)**	**(2,654,510)**	**(269,675)**
Estimated Amounts Recognized in Accumulated Other Comprehensive Income as at January 1, 2026				
Unrecognized Past Service Costs (Credits)	9,789	394	46,148	-
Unrecognized Net Actuarial Loss (Gain)	591,319	91,822	(633,626)	-
Total Accumulated Other Comprehensive Loss (Income)	**601,108**	**92,216**	**(587,478)**	**-**
Components of Estimated Net Periodic Pension/Benefit Cost, January 1, 2026 to December 31, 2026				
Employer Current Service Cost	331,414	9,105	71,385	40,451
Interest Cost	776,637	17,563	119,813	11,651
Expected Return on Plan Assets	(1,093,710)	-	-	-
Recognition of LTD Actuarial Loss (Gain)	-	-	-	1,141
Amortization of Past Service Cost	49	45	3,706	-
Amortization of Net Loss (Gain)	-	3,328	(23,011)	-
Total Cost	**14,390**	**30,041**	**171,893**	**53,243**
2026 Estimated Employer Pension Contributions / Benefit Payments	**134,275**	**17,432**	**100,496**	**34,788**

Schedule 1C – Summary of Estimated 2027 US GAAP Results

The following table provides a summary of the estimated US GAAP results for 2027 for the post employment benefit plans sponsored by OPG. The estimated net periodic pension/benefit cost for the period January 1, 2027 to December 31, 2027 is determined based on the projected balance sheet items at January 1, 2027.

(in Canadian $000's)	RPP	SPP	OPRB	LTD
Projected Net Asset (Liability) Recognized as at January 1, 2027				
Projected Benefit Obligation	(18,560,619)	(419,048)	(2,823,927)	(288,130)
Fair Value of Plan Assets	18,558,239	-	-	-
Net Asset (Liability) Recognized	**(2,380)**	**(419,048)**	**(2,823,927)**	**(288,130)**
Estimated Amounts Recognized in Accumulated Other Comprehensive Income as at January 1, 2027				
Unrecognized Past Service Costs (Credits)	9,740	349	42,442	-
Unrecognized Net Actuarial Loss (Gain)	1,093,906	99,283	(531,900)	-
Total Accumulated Other Comprehensive Loss (Income)	**1,103,646**	**99,632**	**(489,458)**	**-**
Components of Estimated Net Periodic Pension/Benefit Cost, January 1, 2027 to December 31, 2027				
Employer Current Service Cost	342,944	9,551	74,575	41,490
Interest Cost	814,478	18,456	127,584	12,379
Expected Return on Plan Assets	(1,122,368)	-	-	-
Recognition of LTD Actuarial Loss (Gain)	-	-	-	1,213
Amortization of Past Service Cost	49	45	3,706	-
Amortization of Net Loss (Gain)	-	3,702	(15,692)	-
Total Cost	**35,103**	**31,754**	**190,173**	**55,082**
2027 Estimated Employer Pension Contributions / Benefit Payments	**135,883**	**17,781**	**104,430**	**37,169**

Schedule 1D – Summary of Estimated 2028 US GAAP Results

The following table provides a summary of the estimated US GAAP results for 2028 for the post employment benefit plans sponsored by OPG. The estimated net periodic pension/benefit cost for the period January 1, 2028 to December 31, 2028 is determined based on the projected balance sheet items at January 1, 2028.

(in Canadian $000's)	RPP	SPP	OPRB	LTD
Projected Net Asset (Liability) Recognized as at January 1, 2028				
Projected Benefit Obligation	(19,029,577)	(430,827)	(2,929,356)	(306,043)
Fair Value of Plan Assets	19,073,522	-	-	-
Net Asset (Liability) Recognized	**43,945**	**(430,827)**	**(2,929,356)**	**(306,043)**
Estimated Amounts Recognized in Accumulated Other Comprehensive Income as at January 1, 2028				
Unrecognized Past Service Costs (Credits)	9,691	304	38,736	-
Unrecognized Net Actuarial Loss (Gain)	1,148,410	97,134	(508,508)	-
Total Accumulated Other Comprehensive Loss (Income)	**1,158,101**	**97,438**	**(469,772)**	**-**
Components of Estimated Net Periodic Pension/Benefit Cost, January 1, 2028 to December 31, 2028				
Employer Current Service Cost	351,619	9,813	77,410	42,234
Interest Cost	834,554	18,977	132,307	13,076
Expected Return on Plan Assets	(1,163,936)	-	-	-
Recognition of LTD Actuarial Loss (Gain)	-	-	-	1,281
Amortization of Past Service Cost	49	45	3,706	-
Amortization of Net Loss (Gain)	-	3,510	(13,644)	-
Total Cost	**22,286**	**32,345**	**199,779**	**56,591**
2028 Estimated Employer Pension Contributions / Benefit Payments	**140,926**	**18,137**	**109,152**	**39,480**

Schedule 1E – Summary of Estimated 2029 US GAAP Results

The following table provides a summary of the estimated US GAAP results for 2029 for the post employment benefit plans sponsored by OPG. The estimated net periodic pension/benefit cost for the period January 1, 2029 to December 31, 2029 is determined based on the projected balance sheet items at January 1, 2024.

(in Canadian $000's)	RPP	SPP	OPRB	LTD
Projected Net Asset (Liability) Recognized as at January 1, 2029				
Projected Benefit Obligation	(19,488,402)	(443,079)	(3,038,725)	(323,155)
Fair Value of Plan Assets	19,582,617	-	-	-
Net Asset (Liability) Recognized	**94,215**	**(443,079)**	**(3,038,725)**	**(323,155)**
Estimated Amounts Recognized in Accumulated Other Comprehensive Income as at January 1, 2029				
Unrecognized Past Service Costs (Credits)	9,642	259	35,030	-
Unrecognized Net Actuarial Loss (Gain)	1,216,829	95,223	(486,060)	-
Total Accumulated Other Comprehensive Loss (Income)	**1,226,471**	**95,482**	**(451,030)**	**-**
Components of Estimated Net Periodic Pension/Benefit Cost, January 1, 2029 to December 31, 2029				
Employer Current Service Cost	366,211	10,083	80,476	44,595
Interest Cost	854,729	19,520	137,206	13,807
Expected Return on Plan Assets	(1,202,487)	-	-	-
Recognition of LTD Actuarial Loss (Gain)	-	-	-	1,353
Amortization of Past Service Cost	139	45	3,706	-
Amortization of Net Loss (Gain)	-	3,306	(11,679)	-
Total Cost	**18,592**	**32,954**	**209,709**	**59,755**
2029 Estimated Employer Pension Contributions / Benefit Payments	**147,909**	**18,500**	**115,744**	**41,687**

Schedule 1F – Summary of Estimated 2030 US GAAP Results

The following table provides a summary of the estimated US GAAP results for 2030 for the post employment benefit plans sponsored by OPG. The estimated net periodic pension/benefit cost for the period January 1, 2030 to December 31, 2030 is determined based on the projected balance sheet items at January 1, 2030.

(in Canadian $000's)	RPP	SPP	OPRB	LTD
Projected Net Asset (Liability) Recognized as at January 1, 2030				
Projected Benefit Obligation	(19,943,145)	(455,825)	(3,144,033)	(341,223)
Fair Value of Plan Assets	20,099,450	-	-	-
Net Asset (Liability) Recognized	**156,305**	**(455,825)**	**(3,144,033)**	**(341,223)**
Estimated Amounts Recognized in Accumulated Other Comprehensive Income as at January 1, 2030				
Unrecognized Past Service Costs (Credits)	9,503	214	31,324	-
Unrecognized Net Actuarial Loss (Gain)	1,284,195	93,560	(471,011)	-
Total Accumulated Other Comprehensive Loss (Income)	**1,293,698**	**93,774**	**(439,687)**	**-**
Components of Estimated Net Periodic Pension/Benefit Cost, January 1, 2030 to December 31, 2030				
Employer Current Service Cost	372,882	10,361	82,254	47,089
Interest Cost	875,400	20,085	141,839	14,579
Expected Return on Plan Assets	(1,235,446)	-	-	-
Recognition of LTD Actuarial Loss (Gain)	-	-	-	1,428
Amortization of Past Service Cost	1,001	23	3,771	-
Amortization of Net Loss (Gain)	-	3,136	(10,104)	-
Total Cost	**13,837**	**33,605**	**217,760**	**63,096**
2030 Estimated Employer Pension Contributions / Benefit Payments	**151,288**	**18,870**	**119,186**	**44,018**

Schedule 1G – Summary of Estimated 2031 US GAAP Results

The following table provides a summary of the estimated US GAAP results for 2031 for the post employment benefit plans sponsored by OPG. The estimated net periodic pension/benefit cost for the period January 1, 2031 to December 31, 2031 is determined based on the projected balance sheet items at January 1, 2031.

(in Canadian $000's)	RPP	SPP	OPRB	LTD
Projected Net Asset (Liability) Recognized as at January 1, 2031				
Projected Benefit Obligation	(20,452,268)	(469,091)	(3,258,365)	(360,446)
Fair Value of Plan Assets	20,670,280	-	-	-
Net Asset (Liability) Recognized	**218,012**	**(469,091)**	**(3,258,365)**	**(360,446)**
Estimated Amounts Recognized in Accumulated Other Comprehensive Income as at January 1, 2031				
Unrecognized Past Service Costs (Credits)	8,502	191	27,553	-
Unrecognized Net Actuarial Loss (Gain)	1,360,940	92,114	(451,482)	-
Total Accumulated Other Comprehensive Loss (Income)	**1,369,442**	**92,305**	**(423,929)**	**-**
Components of Estimated Net Periodic Pension/Benefit Cost, January 1, 2031 to December 31, 2031				
Employer Current Service Cost	386,420	10,646	85,512	49,722
Interest Cost	897,739	20,672	146,988	15,394
Expected Return on Plan Assets	(1,270,366)	-	-	-
Recognition of LTD Actuarial Loss (Gain)	-	-	-	1,508
Amortization of Past Service Cost	1,001	22	4,505	-
Amortization of Net Loss (Gain)	-	3,014	(8,212)	-
Total Cost	**14,794**	**34,354**	**228,793**	**66,624**
2031 Estimated Employer Pension Contributions / Benefit Payments	**157,044**	**19,247**	**124,279**	**46,479**

About Aon

Aon plc (NYSE: AON) exists to shape decisions for the better — to protect and enrich the lives of people around the world. Our colleagues provide our clients in over 120 countries with advice and solutions that give them the clarity and confidence to make better decisions to protect and grow their business.

© Aon Solutions Canada Inc 2025. All rights reserved.

www.aon.com

© 2025 Aon Solutions Canada Inc. All Rights Reserved.

AON

Report on the Accounting Cost for Post Employment Benefit Plans for Fiscal Years 2023 and 2024

Ontario Power Generation Inc.

January 1, 2023 to December 31, 2024

December 2025



AON

Table of Contents

Introduction 2

Actuarial Report 4

Actuarial Methods and Assumptions 6

Schedule 1 – Summary of 2023 US GAAP Results 9

Schedule 2 – Summary of 2024 US GAAP Results 10

Introduction

This report summarizes the accounting costs for fiscal years 2023 and 2024 for the post employment benefit plans sponsored by Ontario Power Generation Inc. ("OPG"). In addition, Aon prepared this report to provide an independent actuary's confirmation of information for the post employment benefit plans sponsored by OPG in relation to the December 31, 2024 balances in OPG's Pension & OPEB Cash Versus Accrual Differential Deferral Account, the Pension & OPEB Cash Payment Variance Account and the Pension and OPEB Cost Variance Account, established by the Ontario Energy Board ("OEB"). We understand that this report is expected to be filed with the OEB.

This report covers the following post-employment benefit plans sponsored by OPG:

- Ontario Power Generation Inc. Pension Plan ("OPG RPP");
- Ontario Power Generation Inc. Supplementary Pension Plan ("SPP");
- Non-pension Post-Retirement Plan which provides other postretirement Benefits ("OPRB") including retiree medical, retiree dental, retiree life insurance, and retirement bonus benefits; and
- Post-Employment Plan which provides Long-Term Disability ("LTD") benefits including sick leave benefits before LTD begins and the continuation of medical, dental and life insurance while on LTD.

Collectively SPP, OPRB and LTD are known as Other Post Employment Benefits ("OPEB").

The results cover the fiscal years from January 1, 2023 to December 31, 2023, and from January 1, 2024 to December 31, 2024. The results have been developed in accordance with US Generally Accepted Accounting Principles ("US GAAP") under ASC 710, 712 and 715.

The results in this report do not include amounts related to the benefit plans of the Nuclear Waste Management Organization or operating subsidiaries which are included in OPG's consolidated financial statements. Where applicable, the registered pension plan ("RPP") results in this report include amounts related to the New Horizon System Solutions Pension Plan, which was assumed by OPG effective November 1, 2022 following insourcing of information technology service operations and, following subsequent regulatory approval, was transferred into OPG's RPP in July 2024.

Unless otherwise stated, all assumptions, data elements, methodologies, plan provisions, and information about assets reflected in this report are the same as those underlying and/or contained in the December 31, 2023 or the December 31, 2024 disclosure reports ("the Reports") prepared by Aon in accordance with US GAAP for the post employment benefit plans sponsored by OPG. These disclosure reports were dated March 2024 and March 2025, respectively, and are titled as follows:

- US GAAP Accounting Information – Non Pension Post-Retirement and Post-Employment Benefits Plans, and
- US GAAP Accounting Information – Pension Plans.

Sincerely,

Aon

[Original signed by]

Nathan LaPierre
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

Aon

[Original signed by]

Isabelle Hasbani
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries
For OPRB and LTD Plans

Aon

[Original signed by]

Linda M. Byron
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

December 2025

AON

Actuarial Report

Results for 2023 and 2024

This report confirms OPG's total actual pension and OPEB costs for the period from January 1, 2023 to December 31, 2024, as determined in accordance with US GAAP, are as follows:

(in Canadian $ 000's)	January 1, 2023 to December 31, 2023	January 1, 2024 to December 31, 2024
RPP	$ (35,725)	$ 60,022
SPP	19,074	27,119
OPRB	101,905	145,448
LTD	75,312	28,553
Total	**$ 160,566**	**$ 261,142**

Further details of the OPG-wide costs provided above, by plan, as well as OPG's actual contributions to the RPP fund and benefit payments for OPEB for the periods from January 1, 2023 to December 31, 2024 are provided in Schedules 1 and 2 to this report.

In its November 2014 decision under case number EB-2013-0321, the OEB established the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB Cash Payment Variance Account for OPG's nuclear and regulated hydroelectric businesses, effective November 1, 2014. The OEB authorized the continuation of these accounts in subsequent OPG applications.

As shown in materials being filed by OPG under OEB case number EB-2025-0297, additions to the Pension & OPEB Cash Versus Accrual Differential Deferral Account for the period from January 1, 2023 to December 31, 2024 were calculated by OPG by comparing the portion of the January 1, 2023 to December 31, 2024 OPG-wide US GAAP pension and OPEB costs attributed to OPG's regulated hydroelectric business to the regulated hydroelectric business' portion of OPG's total actual RPP fund contributions and actual benefit payments under OPEB plans for the corresponding periods. As also shown in those materials, additions to the Pension & OPEB Cash Payment Variance Account for the period from January 1, 2023 to December 31, 2024 were calculated by OPG by comparing the regulated hydroelectric business' portion of the total actual RPP fund contributions and actual benefit payments under OPEB plans to such forecast amounts included in the regulated prices established by the OEB under case number EB-2013-0321.

The OEB established the Pension and OPEB Cost Variance in its June 2011 decision under case number EB-2011-0090 and subsequently authorized its continuation in subsequent OPG applications. In its November 2014 decision under case number EB-2013-0321, the OEB ordered that no new variances be recorded in the account effective November 1, 2014. In its decisions and orders under case number EB-2020-0290, the OEB authorized the account to resume recording variances for the nuclear business effective January 1, 2022. As shown in materials being filed by OPG under OEB case number EB-2025-0297, additions to the Pension and OPEB Cost Variance Account for the period from January 1, 2023 to

December 31, 2024 were calculated by OPG by comparing the portion of the January 1, 2023 to December 31, 2024 OPG-wide US GAAP pension and OPEB costs attributed to OPG's nuclear business and related tax impacts to such forecast amounts reflected in the regulated prices for the nuclear business established by the OEB under case number EB-2020-0290.

The resulting unamortized balances of the Pension & OPEB Cash Versus Accrual Differential Deferral Account, the Pension & OPEB Cash Payment Variance Account and the Pension and OPEB Cost Variance Account calculated and recorded by OPG as at December 31, 2024 were $376 million to be recovered from ratepayers, and $321 million and $411 million to be paid to ratepayers, respectively, as reported in the audited schedule of regulatory balances as at December 31, 2024, prepared by OPG for filing with the OEB and dated November 28, 2025, and a copy of which was provided to Aon.

Actuarial Methods and Assumptions

Aon confirms that the OPG-wide costs for the years ended December 31, 2023 and December 31, 2024 as disclosed in this report were determined using the actuarial methodology and accounting standards described below. We furthermore confirm that the methodology under US GAAP is consistent with the methodology outlined in OPG's application to the OEB under case number EB-2020-0290 used to determine the forecast of OPG-wide pension and OPEB costs for 2023 and 2024, which were presented by OPG in that proceeding through the filing of our report on these costs, "Report on the Estimated Accounting Cost for Post Employment Benefit Plans for Fiscal Years 2021 to 2026" dated December 2020.

- Benefit obligations for RPP, SPP and OPRB are determined using the projected benefit method prorated on service;
- Benefit obligations for LTD are determined using the projected benefit method on a terminal basis such that the total estimated future benefit is attributed to the year of service in which a disability occurs; and
- The discount rates have been determined in accordance with US GAAP, with reference to those representative of AA corporate bond yields in Canada having duration similar to the liabilities of the plans. For the RPP, SPP, and OPRB costs for 2023 and 2024, the discount rates were set using the applicable bond yields used to determine the corresponding benefit obligations as of December 31, 2022 and December 31, 2023, respectively.

  The following effective discount rates for determining the 2023 pension and OPEB costs under the full yield curve approach[1] were as follows:

	RPP and SPP	OPRB	LTD
Current Service Cost	5.25% per annum	5.25% per annum	5.21% per annum
Interest Cost[2]	5.23% per annum	5.24% per annum	5.19% per annum

  The discount rate used to determine the projected benefit obligation at December 31, 2023 was 4.61% per annum for LTD;

[1] A series of individual spot rates applied to projected cash flows under the full yield curve approach is expressed as a single effective discount rate for disclosure purposes.

[2] The rates shown apply to interest cost on the projected benefit obligations at the beginning of the year. Under the full yield curve approach, a separate rate is used to calculate the interest cost on the current service cost recognized during the year. For 2023, this rate was 5.25% for RPP and SPP costs, 5.27% for OPRB costs and 5.19% for LTD costs.

AON

The effective discount rates for determining the 2024 pension and OPEB costs under the full yield curve approach were as follows:

	RPP and SPP	OPRB	LTD
Current Service Cost	4.62% per annum	4.61% per annum	4.61% per annum
Interest Cost[1]	4.63% per annum	4.63% per annum	4.63% per annum

The discount rate used to determine the projected benefit obligation at December 31, 2024 was 4.37% per annum for LTD;

Under the full yield curve approach, individual spot discount rates along the yield curve are applied to the projected cash flows at the relevant maturity, resulting in a more precise measurement of interest cost. The service cost is also more precisely determined under the full yield curve approach, based on duration specific spot rates applied to discount the service cost projected cash flows.

- A building block approach is used in determining the expected long-term rate of return on plan assets. Historical markets are studied and long-term historical relationships between equities and fixed-income are preserved consistent with the widely accepted capital market principle that assets with higher volatility generate a greater return over the long run. Current market factors such as inflation and interest rates are evaluated before long-term capital market assumptions are determined. The long-term portfolio return is established using the fund's asset allocations, via a building block approach with proper consideration of diversification and rebalancing. Aon calculated the expected return based on this methodology. An expected rate of return on assets of 6.25% per annum determined using the above approach was used for determining the 2023 and 2024 OPG RPP costs.

- Other actuarial assumptions are management's best estimate of future events, as determined in consultation with us and as set out in the Reports. For 2023 and 2024 costs, the inflation rate was set at 2.00% per annum. The salary scale increase rate set for 2023 costs was established at 2.00% per annum to the end of 2026 for all employee representations, with the exception of 1.00% per annum for 2022 and 2023 for employees represented by the Power Workers' Union ("PWU"), and 1.80% for 2022 followed by 1.00% per annum to end of 2024 for members represented by the Society of United Professionals ("Society"), and 1.80% per annum for 2022 and 2023 for non-represented members, and 2.50% per annum for all employee representations thereafter (plus Promotion, Progression, Merit for all years). For the 2024 costs, the assumed salary scale increase rate was established at 2.75% per annum, with the exception of 3.50% for 2023 for employees represented by the PWU, and 3.25% for 2023 followed by 4.75% for 2024 and 3.25% for 2025 for members represented by the Society (plus Promotion, Progression, Merit for all years);
- Actuarial gains or losses for RPP, SPP and OPRB have been amortized using the 10% corridor method, except where immediate recognition is required under US GAAP for non-routine events during the year (none during 2023 and 2024);

[1] The rates shown apply to interest cost on the projected benefit obligations at the beginning of the year. Under the full yield curve approach, a separate rate is used to calculate the interest cost on the current service cost recognized during the year. For 2024, this rate was 4.63% for RPP, SPP, OPRB, and LTD costs.

- Past service costs for RPP, SPP and OPRB have been amortized on a straight-line basis over the expected average remaining service lifetime at the measurement date, except where immediate recognition is required under US GAAP for non-routine events during the year (none during 2023 and 2024);
- For LTD, all actuarial gains and losses and past service costs are required to be recognized immediately in the cost. Therefore, under US GAAP, the cost is equal to the change in the benefit obligation plus benefit payments; and
- Expected return on assets and amortization of actuarial gains/losses are based on a market-related value of assets for the RPP where investment gains and losses on equity assets in excess of an expected return of 6.00% per annum plus the increase in Consumer Price Index are smoothed over five years.

For the period January 1, 2023 to December 31, 2023, OPG's contributions to the RPP funds were made pursuant to the filed actuarial valuation reports for funding purposes as of January 1, 2023 of the plans. For the period January 1, 2024 to December 31, 2024, OPG's contributions to the RPP funds were made pursuant to the filed actuarial valuation report for funding purposes as of January 1, 2024 of the plan.

AON

Schedule 1 – Summary of 2023 US GAAP Results

The following table provides a summary of US GAAP results for 2023 for the post employment benefit plans sponsored by OPG. The net periodic pension/benefit cost for this period was determined based on the balance sheet items at January 1, 2023.

(in Canadian $ 000s)	RPP	SPP	OPRB	LTD
Net Asset (Liability) Recognized as at January 1, 2023				
Projected Benefit Obligation	$ (15,100,435)	$ (303,746)	$ (2,195,299)	$ (216,695)
Fair Value of Plan Assets	15,804,843	-	-	-
Net Asset (Liability) Recognized	**$ 704,408**	**$ (303,746)**	**$ (2,195,299)**	**$ (216,695)**
Amounts Recognized in Accumulated Other Comprehensive Income as at January 1, 2023				
Unrecognized Past Service Costs (Credits)	$ (6,102)	$ 162	$ 9,326	$ -
Unrecognized Net Actuarial Loss (Gain)	(201,787)	22,087	(920,844)	-
Total Accumulated Other Comprehensive Loss (Income)	**$ (207,889)**	**$ 22,249**	**$ (911,518)**	**$ -**
Components of Net Periodic Pension/Benefit Cost, January 1, 2023 to December 31, 2023				
Employer Current Service Cost	$ 177,808	$ 3,472	$ 37,951	$ 24,434
Interest Cost	779,260	15,579	114,781	11,650
Expected Return on Plan Assets	(991,909)	-	-	-
Recognition of LTD Past Service Cost (Credit)	-	-	-	347
Recognition of LTD Actuarial (Gain) Loss	-	-	-	38,881
Amortization of Past Service Cost (Credit)	(884)	23	364	-
Amortization of Net Actuarial Loss (Gain)			(51,191)	-
Total Cost	**$ (35,725)**	**$ 19,074**	**$ 101,905**	**$ 75,312**
2023 Estimated Employer Pension Contributions / Benefit Payments				
Amounts used for developing net periodic pension/benefit costs	$ 192,653	$ 18,711	$ 85,977	$ 33,331
2023 Actual Employer Pension Contributions / Benefit Payments	**$ 163,830**	**$ 16,681**	**$ 84,714**	**$ 35,132**

AON

Schedule 2 – Summary of 2024 US GAAP Results

The following table provides a summary of US GAAP results for 2024 for the post employment benefit plans sponsored by OPG. The net periodic pension/benefit cost for this period was determined based on the balance sheet items at January 1, 2024.

(in Canadian $ 000s)	RPP	SPP	OPRB	LTD
Net Asset (Liability) Recognized as at January 1, 2024				
Projected Benefit Obligation	$ (17,035,094)	$ (367,764)	$ (2,481,610)	$ (256,875)
Fair Value of Plan Assets	16,489,172	-	-	-
Net Asset (Liability) Recognized	**$ (545,922)**	**$ (367,764)**	**$ (2,481,610)**	**$ (256,875)**
Amounts Recognized in Accumulated Other Comprehensive Income as at January 1, 2024				
Unrecognized Past Service Costs (Credits)	$ (5,622)	$ 139	$ 28,159	$ -
Unrecognized Net Actuarial Loss (Gain)	1,247,214	83,735	(671,462)	-
Total Accumulated Other Comprehensive Loss (Income)	**$ 1,241,592**	**$ 83,874**	**$ (643,303)**	**$ -**
Components of Net Periodic Pension/Benefit Cost, January 1, 2024 to December 31, 2024				
Employer Current Service Cost	$ 298,296	$ 6,741	$ 56,887	$ 40,586
Interest Cost	785,440	16,952	115,473	12,914
Expected Return on Plan Assets	(1,022,762)	-	-	-
Recognition of LTD Past Service Cost (Credit)	-	-	-	797
Recognition of LTD Actuarial (Gain) Loss	-	-	-	(25,744)
Amortization of Past Service Cost (Credit)	(952)	23	1,884	-
Amortization of Net Actuarial Loss (Gain)		3,403	(28,796)	-
Total Cost	**$ 60,022**	**$ 27,119**	**$ 145,448**	**$ 28,553**
2024 Estimated Employer Pension Contributions / Benefit Payments				
Amounts used for developing net periodic pension/benefit cost	$ 186,778	$ 16,727	$ 90,900	$ 37,065
2024 Actual Employer Pension Contributions / Benefit Payments	**$ 205,785**	**$ 16,809**	**$ 88,134**	**$ 30,625**



About Aon

Aon plc (NYSE: AON) exists to shape decisions for the better—to protect and enrich the lives of people around the world. Our colleagues provide our clients in over 120 countries with advice and solutions that give them the clarity and confidence to make better decisions to protect and grow their business.

www.aon.com

© 2025 Aon Solutions Canada Inc. All Rights Reserved.

AON

Report on the Accounting Cost for Post Employment Benefit Plans for Fiscal Years 2020, 2021 and 2022

Ontario Power Generation Inc.

January 1, 2020 to December 31, 2022



AON

Table of Contents

Introduction	2
Actuarial Report	4
Actuarial Methods and Assumptions	6
Schedule 1–Summary of 2020 US GAAP Results	9
Schedule 2–Summary of 2021 US GAAP Results	10
Schedule 3–Summary of 2022 US GAAP Results	11

AON

Introduction

This report summarizes the accounting costs for fiscal years 2020, 2021 and 2022 for the post employment benefit plans sponsored by Ontario Power Generation Inc. ("OPG"). In addition, Aon prepared this report to provide an independent actuary's confirmation of information for the post employment benefit plans sponsored by OPG in relation to the December 31, 2022 balances in OPG's Pension & OPEB Cash Versus Accrual Differential Deferral Account, the Pension & OPEB Cash Payment Variance Account and the Pension and OPEB Cost Variance Account, established by the Ontario Energy Board ("OEB"). We understand that this report is expected to be filed with the OEB.

This report covers the following plans sponsored by OPG:

- Ontario Power Generation Inc. Pension Plan ("OPG RPP");
- Ontario Power Generation Inc. Supplementary Pension Plan ("SPP");
- Non-Pension Post Retirement Plan which provides other post retirement benefits ("OPRB") including retiree medical, retiree dental, retiree life insurance, and retirement bonus benefits; and
- Post Employment Plan which provides long-term disability benefits ("LTD") including sick leave benefits before LTD begins and the continuation of medical, dental and life insurance while on LTD.

Collectively SPP, OPRB and LTD are known as Other Post Employment Benefits ("OPEB").

The results cover the fiscal years from January 1, 2020 to December 31, 2020, January 1, 2021 to December 31, 2021, and from January 1, 2022 to December 31, 2022. The results have been developed in accordance with US generally accepted accounting principles ("US GAAP") under ASC 710, 712 and 715.

The results in this report do not include amounts related to the benefit plans of the Nuclear Waste Management Organization or operating subsidiaries which are included in OPG's consolidated financial statements. Where applicable, the registered pension plan ("RPP") results in this report include amounts related to the New Horizon System Solutions Pension Plan, which was assumed by OPG effective November 1, 2022 following insourcing of information technology service operations.

Unless otherwise stated, all assumptions, data elements, methodologies, plan provisions, and information about assets reflected in this report are the same as those underlying and/or contained in the December 31, 2020, December 31, 2021, or the December 31, 2022 disclosure reports ("the Reports") prepared by Aon in accordance with US GAAP for the post employment benefit plans sponsored by OPG. These disclosure reports were dated March 2021, March 2022, and March 2023 respectively, and are titled as follows:

- US GAAP Accounting Information Non-pension Post-retirement and Post-employment Benefits Plans; and
- US GAAP Accounting Information – Pension Plans.

Sincerely,

Aon

[Original signed by]

Linda M. Byron
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

Aon

[Original signed by]

Isabelle Hasbani
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

November 2023

AON

Actuarial Report

Results for 2020, 2021 and 2022

This report confirms OPG's total actual pension and OPEB costs for the period from January 1, 2020 to December 31, 2022, as determined in accordance with US GAAP, are as follows:

(in Canadian $ 000's)	January 1, 2020 to December 31, 2020	January 1, 2021 to December 31, 2021	January 1, 2022 to December 31, 2022
RPP	$ 158,857	$ 199,089	$ 85,612
SPP	26,408	26,902	24,859
OPRB	156,539	150,020	154,882
LTD	42,515	35,765	17,403
Total	**$ 384,319**	**$ 411,776**	**$ 282,756**

Further details of the OPG-wide costs provided above, by plan, as well as OPG's actual contributions to the RPP fund and benefit payments for OPEB for the periods from January 1, 2020 to December 31, 2022 are provided in Schedules 1, 2 and 3 to this report.

In its November 2014 decision under case number EB-2013-0321, the OEB established the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB Cash Payment Variance Account for OPG's nuclear and regulated hydroelectric businesses, effective November 1, 2014. The OEB authorized the continuation of these accounts in subsequent OPG applications.

As shown in materials being filed by OPG under OEB case number EB-2023-0336, additions to the Pension & OPEB Cash Versus Accrual Differential Deferral Account for the period from January 1, 2020 to December 31, 2022 were calculated by OPG by comparing the portion of the January 1, 2020 to December 31, 2022 OPG-wide US GAAP pension and OPEB costs attributed to OPG's regulated businesses[1] to the regulated businesses'[1] portion of OPG's total actual RPP fund contributions and actual benefit payments under OPEB plans for the corresponding periods. As also shown in those materials, additions to the Pension & OPEB Cash Payment Variance Account for the period from January 1, 2020 to December 31, 2022 were calculated by OPG by comparing the regulated businesses'[1] portion of the total actual RPP fund contributions and actual benefit payments under OPEB plans to such forecast amounts included in the regulated prices established by the OEB under case number EB-2016-0152 (for 2020 and 2021) and EB-2020-0290 (for 2022) for the nuclear business and EB-2013-0321 for the regulated hydroelectric business.

The OEB established the Pension and OPEB Cost Variance in its June 2011 decision under case number EB-2011-0090 and subsequently authorized its continuation in subsequent OPG applications. In its November 2014 decision under case number EB-2013-0321, the OEB ordered that no new variances be recorded in the account effective November 1, 2014. In its decisions and orders under case number EB-

[1] Nuclear and regulated hydroelectric for 2020 and 2021, regulated hydroelectric only for 2022.

2020-0290, the OEB authorized the account to resume recording variances for the nuclear business effective January 1, 2022. As shown in materials being filed by OPG under OEB case number EB-2023-0336, additions to the Pension and OPEB Cost Variance Account for the period from January 1, 2022 to December 31, 2022 were calculated by OPG by comparing the portion of the January 1, 2022 to December 31, 2022 OPG-wide US GAAP pension and OPEB costs attributed to OPG's nuclear business and related tax impacts to such forecast amounts reflected in the regulated prices for the nuclear business established by the OEB under case number EB-2020-0290.

The resulting unamortized balances of the Pension & OPEB Cash Versus Accrual Differential Deferral Account, the Pension & OPEB Cash Payment Variance Account and the Pension and OPEB Cost Variance Account calculated and recorded by OPG as at December 31, 2022 were $799 million to be recovered from ratepayers, and $460 million and $78 million to be paid to ratepayers, respectively, as reported in the audited schedule of regulatory balances as at December 31, 2022, prepared by OPG for filing with the OEB and dated November 28, 2023, and a copy of which was provided to Aon.

AON

Actuarial Methods and Assumptions

Aon confirms that the OPG-wide costs for the years ended December 31, 2020, December 31, 2021 and December 31, 2022 as disclosed in this report were determined using the actuarial methodology and accounting standards described below. We furthermore confirm that the methodology under US GAAP is consistent with the methodology outlined in OPG's application to the OEB under case number EB-2016-0152 and used to determine the forecast of OPG-wide pension and OPEB costs for 2020 and 2021, which were presented by OPG in that proceeding through the filing of our report on these costs, "Report on the Estimated Accounting Cost for Post Employment Benefit Plans for Fiscal Years 2017 to 2021" dated December 2016. Finally, we confirm that the methodology under US GAAP is consistent with the methodology outlined in OPG's application to the OEB under case number EB-2020-0290 and used to determine the forecast of OPG-wide pension and OPEB costs for 2022, which were presented by OPG in that proceeding through the filing of our report on these costs, "Report on the Estimated Accounting Cost for Post Employment Benefit Plans for Fiscal Years 2021 to 2026" dated December 2020.

- Benefit obligations for RPP, SPP and OPRB are determined using the projected benefit method prorated on service;
- Benefit obligations for LTD are determined using the projected benefit method on a terminal basis such that the total estimated future benefit is attributed to the year of service in which a disability occurs;
- The discount rates have been determined in accordance with US GAAP, with reference to those representative of AA corporate bond yields in Canada having duration similar to the liabilities of the plans. For the OPG RPP, SPP and OPRB costs for 2020 to 2022, the discount rates were set using the applicable bond yields used to determine the corresponding benefit obligations as of December 31, 2019, December 31, 2020 and December 31, 2021, respectively;

  The following effective discount rates for determining the 2020 pension and OPEB costs under the full yield curve approach[1] were as follows:

	OPG RPP and SPP	OPRB	LTD
Current Service Cost	3.19% per annum	3.21% per annum	2.83% per annum
Interest Cost[2]	2.91% per annum	3.00% per annum	2.55% per annum

  The discount rate used to determine the projected benefit obligation at December 31, 2020 was 1.89% per annum for LTD;

[1] A series of individual spot rates applied to projected cash flows under the full yield curve approach is expressed as a single effective discount rate for disclosure purposes.

[2] The rates shown apply to interest cost on the projected benefit obligations at the beginning of the year. Under the full yield curve approach, a separate rate is used to calculate the interest cost on the current service cost recognized during the year. For 2020, this rate was 3.11% for OPG RPP and SPP costs, 3.19% for OPRB costs and 2.55% for LTD costs.

AON

The effective discount rates for determining the 2021 pension and OPEB costs under the full yield curve approach were as follows:

	OPG RPP and SPP	OPRB	LTD
Current Service Cost	2.86% per annum	2.93% per annum	1.89% per annum
Interest Cost[1]	2.10% per annum	2.29% per annum	1.28% per annum

The discount rate used to determine the projected benefit obligation at December 31, 2021 was 2.69% per annum for LTD;

The effective discount rates for determining the 2022 pension and OPEB costs under the full yield curve approach were as follows:

	OPG RPP and SPP	OPRB	LTD
Current Service Cost	3.38% per annum	3.43% per annum	2.69% per annum
Interest Cost[2]	2.79% per annum	2.91% per annum	2.16% per annum

The discount rate used to determine the projected benefit obligation at December 31, 2022 was 5.21% per annum for LTD.

Under the full yield curve approach, individual spot discount rates along the yield curve are applied to the projected cash flows at the relevant maturity, resulting in a more precise measurement of interest cost. The service cost is also more precisely determined under the full yield curve approach, based on duration specific spot rates applied to discount the service cost projected cash flows.

- A building block approach is used in determining the expected long-term rate of return on plan assets. Historical markets are studied and long-term historical relationships between equities and fixed-income are preserved consistent with the widely accepted capital market principle that assets with higher volatility generate a greater return over the long run. Current market factors such as inflation and interest rates are evaluated before long-term capital market assumptions are determined. The long-term portfolio return is established using the fund's asset allocations, via a building block approach with proper consideration of diversification and rebalancing. Aon calculated the expected return based on this methodology. An expected rate of return on assets of 6.00% per annum determined using the above approach was used for determining the 2020 OPG

[1] The rates shown apply to interest cost on the projected benefit obligations at the beginning of the year. Under the full yield curve approach, a separate rate is used to calculate the interest cost on the current service cost recognized during the year. For 2021, this rate was 2.60% for OPG RPP and SPP costs, 2.84% for OPRB costs and 1.28% for LTD costs.

[2] The rates shown apply to interest cost on the projected benefit obligations at the beginning of the year. Under the full yield curve approach, a separate rate is used to calculate the interest cost on the current service cost recognized during the year. For 2022, this rate was 3.17% for OPG RPP and SPP costs, 3.37% for OPRB costs and 2.16% for LTD costs.

RPP costs. For 2021 and 2022 OPG RPP costs, an expected rate of return on assets of 5.75% per annum determined using the above approach was used.

- Other actuarial assumptions are management's best estimate of future events, as determined in consultation with us and as set out in the Reports. For 2020 and 2021 costs, the inflation rate was set at 1.75% per annum. For 2022 costs, the inflation rate was set at 2.00% per annum. The salary scale increase rate set for 2020 and 2021 costs was established at 2.00% per annum to the end of 2026 for all employee representations, with the exception of 1.80% per annum for 2021 followed by 1.00% per annum to end of 2023 for employees represented by the Power Workers Union ("PWU"), and 1.80% for 2022 followed by 1.00% per annum to end of 2024 for members represented by the Society of United Professionals ("Society"), and 1.00% per annum for 2022 to end of 2024 for non-represented members, and 2.25% per annum for all employee representations thereafter (plus Promotion, Progression, Merit for all years). For the 2022 costs, the same assumed salary scale increase rates were used for employees represented by PWU and Society, with the exception of 2.50% per annum used for all periods after December 31, 2026 (plus Promotion, Progression, Merit for all years). For 2022 costs, the salary increase rate for non-represented employees was set at 1.80% per annum to the end of 2023, followed by 2.00% per annum to the end of 2026 and 2.50% per annum for all periods after December 31, 2026 (plus Promotion, Progression, Merit for all years);
- Actuarial gains or losses for RPP, SPP and OPRB have been amortized using the 10% corridor method, except where immediate recognition is required under US GAAP for non-routine events during the year (none during 2020, 2021 and 2022);
- Past service costs for RPP, SPP and OPRB have been amortized on a straight-line basis over the expected average remaining service lifetime at the amendment date, except where immediate recognition is required under US GAAP for non-routine events during the year (none during 2020, 2021, and 2022);
- For LTD, all actuarial gains and losses and past service costs are required to be recognized immediately in the cost. Therefore, under US GAAP, the cost is equal to the change in the benefit obligation plus benefit payments; and
- Expected return on assets and amortization of actuarial gains/losses are based on a market-related value of assets for the OPG RPP where investment gains and losses on equity assets in excess of an expected return of 6.00% per annum plus the increase in Consumer Price Index are smoothed over five years.

For the period January 1, 2020 to March 31, 2021, OPG's contributions to the OPG RPP fund were made pursuant to the filed actuarial valuation report for funding purposes as of January 1, 2020 of the plan. For the period April 1, 2021 to December 31, 2021, OPG's contributions to the OPG RPP fund were made pursuant to the filed actuarial valuation report for funding purposes as of April 1, 2021 of the plan. For the period January 1, 2022 to December 31, 2022, OPG's contributions to the OPG RPP fund were made pursuant to the filed actuarial valuation report for funding purposes as of January 1, 2022 of the plan.

AON

Schedule 1–Summary of 2020 US GAAP Results

The following table provides a summary of US GAAP results for 2020 for the post employment benefit plans sponsored by OPG. The net periodic pension/benefit cost for this period was determined based on the balance sheet items at January 1, 2020.

(in Canadian $ 000s)	RPP	SPP	OPRB	LTD
Net Asset (Liability) Recognized as at January 1, 2020				
Projected Benefit Obligation	$ (18,005,986)	$ (379,251)	$ (2,978,758)	$ (196,612)
Fair Value of Plan Assets	14,800,027	-	-	-
Net Asset (Liability) Recognized	**$ (3,205,959)**	**$ (379,251)**	**$ (2,978,758)**	**$ (196,612)**
Amounts Recognized in Accumulated Other Comprehensive Income as at January 1, 2020				
Unrecognized Past Service Costs (Credits)	$ -	$ -	$ (19,909)	$ -
Unrecognized Net Actuarial Loss (Gain)	3,602,258	125,975	221,330	-
Total Accumulated Other Comprehensive Loss (Income)	**$ 3,602,258**	**$ 125,975**	**$ 201,421**	**$ -**
Components of Net Periodic Pension/Benefit Cost, January 1, 2020 to December 31, 2020				
Employer Current Service Cost	$ 334,182	$ 8,203	$ 67,887	$ 18,678
Interest Cost	525,977	11,046	90,371	5,149
Expected Return on Plan Assets	(863,255)	-	-	-
Recognition of LTD Past Service Cost (Credit)	-	-	-	-
Recognition of LTD Actuarial (Gain) Loss	-	-	-	18,688
Amortization of Past Service Cost (Credit)	-	-	(1,719)	-
Amortization of Net Actuarial Loss (Gain)	161,953	7,159	-	-
Total Cost	**$ 158,857**	**$ 26,408**	**$ 156,539**	**$ 42,515**
2020 Estimated Employer Pension Contributions / Benefit Payments				
Amounts used for developing net periodic pension/benefit costs	$ 180,776	$ 16,878	$ 77,164	$ 26,731
2020 Actual Employer Pension Contributions / Benefit Payments	**$ 186,097**	**$ 16,780**	**$ 62,586**	**$ 24,816**

AON

Schedule 2–Summary of 2021 US GAAP Results

The following table provides a summary of US GAAP results for 2021 for the post employment benefit plans sponsored by OPG. The net periodic pension/benefit cost for this period was determined based on the balance sheet items at January 1, 2021.

(in Canadian $ 000s)	RPP	SPP	OPRB	LTD
Net Asset (Liability) Recognized as at January 1, 2021				
Projected Benefit Obligation	$ (19,847,478)	$ (418,216)	$ (3,256,931)	$ (214,311)
Fair Value of Plan Assets	15,249,239	-	-	-
Net Asset (Liability) Recognized	**$ (4,598,239)**	**$ (418,216)**	**$ (3,256,931)**	**$ (214,311)**
Amounts Recognized in Accumulated Other Comprehensive Income as at January 1, 2021				
Unrecognized Past Service Costs (Credits)	$ -	$ -	$ (18,190)	$ -
Unrecognized Net Actuarial Loss (Gain)	5,021,778	155,312	403,831	-
Total Accumulated Other Comprehensive Loss (Income)	**$ 5,021,778**	**$ 155,312**	**$ 385,641**	**$ -**
Components of Net Periodic Pension/Benefit Cost, January 1, 2021 to December 31, 2021				
Employer Current Service Cost	$ 360,697	$ 8,467	$ 70,112	$ 21,645
Interest Cost	418,431	8,817	75,662	2,850
Expected Return on Plan Assets	(852,701)	-	-	-
Recognition of LTD Past Service Cost (Credit)	-	-	-	292
Recognition of LTD Actuarial (Gain) Loss	-	-	-	10,978
Amortization of Past Service Cost (Credit)	-	-	(1,719)	-
Amortization of Net Actuarial Loss (Gain)	272,662	9,618	5,965	-
Total Cost	**$ 199,089**	**$ 26,902**	**$ 150,020**	**$ 35,765**
2021 Estimated Employer Pension Contributions / Benefit Payments				
Amounts used for developing net periodic pension/benefit cost	$ 189,820	$ 17,697	$ 79,722	$ 26,677
2021 Actual Employer Pension Contributions / Benefit Payments	**$ 177,600**	**$ 18,572**	**$ 70,037**	**$ 26,371**

AON

Schedule 3–Summary of 2022 US GAAP Results

The following table provides a summary of US GAAP results for 2022 for the post employment benefit plans sponsored by OPG. The net periodic pension/benefit cost for this period was determined based on the balance sheet items at January 1, 2022.

(in Canadian $ 000s)	RPP	SPP	OPRB	LTD
Projected Benefit Obligation	$ (18,834,637)	$ (396,263)	$ (3,070,231)	$ (223,705)
Fair Value of Plan Assets	16,348,498	-	-	-
Net Asset (Liability) Recognized	**$ (2,486,139)**	**$ (396,263)**	**$ (3,070,231)**	**$ (223,705)**
Unrecognized Past Service Costs (Credits)	$ -	$ -	$ 9,148	$ -
Unrecognized Net Actuarial Loss (Gain)	2,888,189	125,029	109,810	-
Total Accumulated Other Comprehensive Loss (Income)	**$ 2,888,189**	**$ 125,029**	**$ 118,958**	**$ -**
Employer Current Service Cost	$ 339,419	$ 6,478	$ 63,436	$ 23,936
Interest Cost	530,542	11,019	91,148	5,035
Expected Return on Plan Assets	(906,163)	-	-	-
Recognition of LTD Past Service Cost (Credit)	-	-	-	-
Recognition of LTD Actuarial (Gain) Loss	-	-	-	(11,568)
Amortization of Past Service Cost (Credit)	(120)	-	298	-
Amortization of Net Actuarial Loss (Gain)	121,934	7,362	-	-
Total Cost	**$ 85,612**	**$ 24,859**	**$ 154,882**	**$ 17,403**
2022 Estimated Employer Pension Contributions / Benefit Payments				
Amounts used for developing net periodic pension/benefit cost	$ 177,911	$ 18,020	$ 84,003	$ 29,101
2022 Estimated Employer Pension Contributions / Benefit Payments	**$ 191,728**	**$ 15,968**	**$ 73,374**	**$ 24,982**

About Aon

Aon plc (NYSE: AON) exists to shape decisions for the better—to protect and enrich the lives of people around the world. Our colleagues provide our clients in over 120 countries with advice and solutions that give them the clarity and confidence to make better decisions to protect and grow their business.

www.aon.com

© 2023 Aon Solutions Canada Inc. All Rights Reserved.

Actuarial Valuation as at January 1, 2025 for Ontario Power Generation Inc. Pension Plan

Registration Number: 1059120

December 23, 2025



AON

Table of Contents

Executive Summary 3
Section 1: Introduction 7
Section 2: Going Concern Valuation Results 9
Section 3: Solvency Valuation Results 15
Section 4: Hypothetical Wind Up Valuation Results 20
Section 5: Contribution Requirements 22
Section 6: Actuarial Certificate 26
Appendix A: Assets 28
Appendix B: Membership Data 32
Appendix C: Going Concern Assumptions and Methods 38
Appendix D: Solvency and Hypothetical Wind Up Assumptions and Methods 51
Appendix E: Summary of Plan Provisions 58
Appendix F: Administrator Certification 69

AON

Executive Summary

An actuarial valuation has been prepared for the Ontario Power Generation Inc. Pension Plan (the "Plan") as at January 1, 2025 for the primary purpose of establishing a funding range in accordance with legislative requirements for the Plan until the next actuarial valuation is performed. This section provides an overview of the important results and the key valuation assumptions which have had a bearing on these results. The next actuarial valuation for the purposes of developing funding requirements should be performed no later than as at January 1, 2028.

Summary of Principal Results

Financial Position

$ (000s)	January 1, 2025	January 1, 2024
Going Concern		
Assets	$ 17,532,992	$ 16,934,569
Liabilities	14,429,568	13,964,329
Financial Position	**$ 3,103,424**	**$ 2,970,240**
Adjustments[1]	(837,898)	(809,586)
Surplus/(Unfunded Liability)	**$ 2,265,526**	**$ 2,160,654**
Solvency		
Assets[2]	$ 17,563,700	$ 16,490,526
Liabilities	13,755,965	13,402,115
Financial Position	**$ 3,807,735**	**$ 3,088,411**
Adjustments[1]	-	-
Surplus/(Unfunded Liability)	**$ 3,807,735**	**$ 3,088,411**
Hypothetical Wind Up		
Assets[3]	$ 17,563,700	$ 16,490,526
Liabilities	20,230,879	19,605,836
Surplus/(Unfunded Liability)	**$ (2,667,179)**	**$ (3,115,310)**

[1] Adjustments include Provision for Adverse Deviation, prior year credit balance, and all solvency liability and solvency asset adjustments, where applicable
[2] Net of estimated wind up expenses
[3] Net of estimated wind up expenses

AON

Normal Cost

$ (000s)	January 1, 2025	January 1, 2024
Company normal cost	$ 206,460	$ 205,706
As a % of pensionable earnings	14.38%	15.82%

Legislative Ratios

	January 1, 2025	January 1, 2024
Funded ratio	1.22	1.21
Solvency ratio	1.28	1.24
Transfer ratio	0.87	0.84

Minimum Contribution Requirements

Considering the funding and solvency status of the Plan, the minimum Company contributions for the period from January 1, 2025 to December 31, 2027 in accordance with legislative requirements, are as follows:

$ (000s)	Jan 1, 2025 to Dec 31, 2025	Jan 1, 2026 to Dec 31, 2026	Jan 1, 2027 to Dec 31, 2027
Company normal cost	$ 206,460	$ 208,539	$ 214,274
Special payments toward amortizing unfunded liability	-	-	-
Adjustments	-	-	-
Minimum Required Company Contribution	**$ 206,460**	**$ 208,539**	**$ 214,274**

Membership Data

	January 1, 2025	January 1, 2024
Active Members	9,867	8,748
Disabled Members	355	351
Deferred Members	801	746
Retired Members	10,890	10,890
Survivors (excluding children)	2,335	2,303
Children	10	9

AON

Key Assumptions

The principal assumptions to which the valuation results are most sensitive are outlined in the following table.

	January 1, 2025	January 1, 2024
Going Concern		
Discount rate	6.25% per year	Same
Provision for adverse deviation ("PfAD")	7.05% of non-indexed liabilities and normal cost	Same
Inflation rate	2.00% per year	Same
Increase in pensionable earnings		
Active members	2.75 per year[1] plus promotion progression and merit ("PPM") scale (Table A in Appendix C)	2.75% per year[2] plus PPM scale (Table A in Appendix C)
Disabled members	2.00% per year	Same
Increase in year's maximum pensionable earnings ("YMPE")	2.75% per year	Same
Increase in *Income Tax Act* ("ITA") maximum pension	2.75%per year	Same
Conversion rate for determining commuted values	4.50% per year	Same
Mortality table	OPG-specific mortality table (updated 2019) (Table B in Appendix C) with mortality improvements at scale MI-2017	Same

[1] Collectively bargained increases of 3.75% in 2025 and 2.50% in 2026 for PWU and 3.25% in 2025 for Society are reflected.

[2] Collectively bargained increases of 4.75% in 2024 and 3.25% in 2025 for Society are reflected.

	January 1, 2025	January 1, 2024
Solvency/ Hypothetical Wind Up		
Discount rate		
Solvency (excludes indexation)	Annuity purchases: 4.72% per year Transfers: 3.90% per year for 10 years, 4.60% per year thereafter	Annuity purchases: 4.55% per year Transfers: 4.10% per year for 10 years, 4.20% per year thereafter
Hypothetical Wind Up (includes indexation)	Annuity purchases: 1.51% per year Transfers: 2.00% per year for 10 years, 2.70% per year thereafter	Annuity purchases: 1.40% per year Transfers: 2.40% per year for 10 years, 2.50% per year thereafter
Mortality Table	2014 Canadian Pensioner Mortality Table with generational improvements using CPM Scale B	Same

AON

Section 1: Introduction

Purpose and Terms of Engagement

We have been engaged by Ontario Power Generation Inc., and hereafter referred to as the Company, to conduct an actuarial valuation of the Plan, registered in Ontario, as at January 1, 2025 for the general purpose of determining the minimum and maximum funding contributions required by pension standards, based on the actuarial assumptions and methods summarized herein. Specifically, the purposes of the valuation are to:

- Determine the financial position of the Plan as at January 1, 2025 on a going concern basis;
- Determine the financial position of the Plan as at January 1, 2025 on solvency and hypothetical wind up bases;
- Determine the funding requirements of the Plan as at January 1, 2025; and
- Provide the necessary actuarial certification required under the *Pension Benefits Act* (Ontario) (the "*Act*") and the *Income Tax Act.*

The results of this report may not be appropriate for accounting purposes or any other purposes not listed above.

The next required valuation will be as at January 1, 2028.

Summary of Changes Since the Last Valuation

The last such actuarial valuation in respect of the Plan was performed as at January 1, 2024. Since the time of the last valuation, we note that the following events have occurred:

- Certain economic and demographic assumptions have been changed.
- Plan amendments affecting the benefits for Management Group employees hired before July 1, 2014[1] came into effect January 1, 2025. Plan amendments affecting members represented by the Power Workers' Union ("PWU") came into effect November 22, 2024[2] and March 31, 2025[3]. Plan amendments affecting the benefits for members represented by the Society of United Professionals ("Society") came into effect March 31, 2025[3]. The impacts of these Plan amendments are included in this report. Further details can be found in the Plan Provisions section of this report.

---

[1] Eligibility for an unreduced early retirement benefit changed from attainment of 84 age-plus-continuous service points to attainment of 90 age-plus-continuous service points, for benefits earned for service on or after January 1, 2025; Special provisions apply to members with 84 age-plus-continuous points on the effective date

[2] 2024 pensionable earnings include a one-time lump sum payment in 2024

[3] For benefits earned for service on and after March 31, 2025, the earnings-averaging period changed from Highest Three-Year to Highest Five-Year and eligibility for an unreduced early retirement benefit changed from attainment of 82 age-plus-continuous service points to attainment of 85 age-plus-continuous service points. Special provisions apply to members with 20 or more years of service on the effective date.

AON

Company Information and Inputs

In order to prepare our valuation, we have relied upon the following information:

- A copy of the previous valuation report as at January 1, 2024;
- A copy of the actuarial Cost Certificate as at January 1, 2025 dated March 26, 2025 ("March 26 Cost Certificate");
- A copy of the Statement of Investment Policies and Procedures ("SIPP") for the Plan;
- Membership data compiled as at January 1, 2025 by the Company;
- Asset data provided by CIBC Mellon;
- A copy of the Plan's financial statements as at December 31, 2024 audited by Ernst & Young LLP; and,
- A copy of the latest Plan text and amendments up to and including January 1, 2025.

Furthermore, our actuarial assumptions and methods have been chosen to reflect our understanding of the Company's desired funding objectives with due respect to accepted actuarial practice and regulatory constraints.

Subsequent Events

As of the date of this report, we have not been made aware of any subsequent events which would have an effect on the results of this valuation. However, the following points should be noted in this regard:

- Actual experience deviating from expected after January 1, 2025 will result in gains or losses which will be reflected in the next actuarial valuation report.
- To the best of our knowledge, the results contained in this report are based on the regulatory and legal environment in effect at the date of this report and do not take into consideration any potential changes that may be currently under review. To the extent that actual changes in the regulatory and legal environment transpire, any financial impact on the Plan as a result of such changes will be reflected in future valuations.

AON

Section 2: Going Concern Valuation Results

Going Concern Financial Position of the Plan

The going concern valuation provides an assessment of the Plan's financial position at the valuation date on the premise that the Plan continues on into the future indefinitely.

The selection of the applicable actuarial assumptions and methods reflect the Plan's funding objectives, as communicated by the Company, actuarial standards of practice, and pension standards.

On the basis of the Plan provisions, membership data, going concern assumptions and methods, and asset information described in the Appendices, the going concern financial position of the Plan as at January 1, 2025 is shown in the following table. The results as at January 1, 2024 are also shown for comparison purposes.

Going Concern Financial Position

$(000s)	January 1, 2025	January 1, 2024
Market Value of Assets	$ 17,637,000	$ 16,563,826
Smoothing Adjustment	(104,008)	370,743
Actuarial Value of Assets	**$ 17,532,992**	**$ 16,934,569**
Going Concern Liabilities		
Active and Disabled members	$ 4,642,915	$ 4,325,171
Deferred Vested members	103,725	115,530
Retirees and Spouses	9,682,928	9,523,628
Total Liabilities	**$ 14,429,568**	**$ 13,964,329**
Going Concern Position	**$ 3,103,424**	**$ 2,970,240**
Additional liabilities due to PfAD	837,898	809,586
Surplus/(Unfunded Liability)	**$ 2,265,526**	**$ 2,160,654**
Funded Ratio (before PfAD)	**1.22**	**1.21**
Funded Ratio (after PfAD)	**1.15**	**1.15**

The PfAD is not required to be applied to the liabilities in respect of future indexation of $2,544,484,000 as at January 1, 2025 and $2,480,842,000 as at January 1, 2024.

AON

Going Concern Normal Cost

On the basis of the Plan provisions, membership data, going concern assumptions and methods, asset information and legislative requirement described in the Appendices, the going concern normal cost of the Plan as at January 1, 2025 is shown in the following table. The normal cost as at January 1, 2024 is also shown for comparison purposes.

$(000s)	January 1, 2025	January 1, 2024
Normal Cost		
Current Service cost	$ 315,500	$ 303,292
Provision for non-investment expenses	-	-
Additional normal cost due to PfAD	17,394	16,764
Total Normal Cost	**$ 332,894**	**$ 320,056**
Required member contributions	(126,434)	(114,350)
Company Normal Cost	**$ 206,460**	**$ 205,706**
Total pensionable earnings (in year following valuation date)	$ 1,436,000	$ 1,300,000
Company Normal Cost		
As a % of total pensionable earnings	14.38%	15.82%

The PfAD is not required to be applied to the normal cost in respect of future indexation of $68,780,000 as at January 1, 2025 and $65,507,000 as at January 1, 2024.

AON

Change in Financial Position

The major components of the change in the Surplus/(Unfunded Liability) for the period from January 1, 2024 to January 1, 2025 are summarized in the following table.

$(000s)		
Surplus/(Unfunded Liability) as at January 1, 2024	**$**	**2,160,654**
Expected interest on Surplus/(Unfunded Liability)		135,041
Company special payments in inter-valuation period with interest		-
Expected Surplus/(Unfunded Liability) as at January 1, 2025	**$**	**2,295,695**
Change in Financial Position due to Experience Gains/(Losses)		
Gain from investment earnings greater than expected	$	50,247
Loss due to salary increases greater than expected		(107,820)
Loss due to indexation experience		(98,520)
Gain due to retirement experience		35,141
Gain due to mortality experience		18,347
Loss due to termination experience		(4,455)
Gain on Provision for Adverse Deviation experience		39,567
Net gain due to other experience and miscellaneous items		5,523
Surplus/(Unfunded Liability) After Experience Gains/(Losses) as at January 1, 2025	**$**	**2,233,725**
Impact of change in Salary Rates		(10,756)
Impact of change in Retirement Rates		42,557
Surplus/(Unfunded Liability) as at January 1, 2025	**$**	**2,265,526**

AON

Discussion of Changes in Assumptions

Effective January 1, 2025, the following assumptions were changed:

- The assumed increase in pensionable earnings for active members has been updated to reflect the bargained increases of 3.75% in 2025 and 2.50% in 2026 for PWU.
- The retirement rates were adjusted effective January 1, 2025 to reflect plan amendments coming into effect in 2025.

In combination, these changes in economic assumptions decreased the going concern liabilities by $31,801,000 and total normal cost by $1,464,000.

Going Concern Valuation Sensitivity Results

In accordance with the CIA Standards of Practice specific to pension plans, the table below presents the sensitivity of the going concern liabilities and the total normal cost (prior to the application of the Provision for Adverse Deviation) of using a discount rate 1% lower and 1% higher than that used for the going concern valuation.

			Effect	
January 1, 2025 $(000s)			**$**	**%**
Going Concern Liabilities	**$**	**14,429,568**		
Going concern liabilities (discount rate – 1%)	$	16,496,383	$ 2,066,815	14.3%
Going concern liabilities (discount rate + 1%)	$	12,778,408	$ (1,651,160)	(11.4%)
Normal Cost	**$**	**315,500**		
Normal cost (discount rate – 1%)	$	410,970	$ 95,470	30.3%
Normal cost (discount rate + 1%)	$	247,779	$ (67,721)	(21.5%)

AON

Plausible Adverse Scenarios

In accordance with the Canadian Institute of Actuaries Standards of Practice specific to pension plans, below is summarized scenarios of adverse but plausible assumptions, relative to the best estimate assumptions otherwise selected for the valuation. In consultation with Ontario Power Generation Inc., we have chosen to present these scenarios under the Going Concern basis.

Interest Rate Sensitivity

The table below presents the sensitivity of the going concern position of using interest rates 1% lower than the current level. Equity risk premiums are assumed to remain unchanged, so the future return on all asset classes and the going concern discount rate both decrease by 1%. In order to calculate the impact on the Actuarial Value of Assets, the decrease in interest rates only impacts fixed income assets. All other assumptions were not changed. We have applied the asset smoothing methodology in this scenario.

$(000s)	Base Scenario	Adverse Scenario	Impact ($)
Actuarial value of assets	$ 17,532,992	$ 17,656,792	$ 123,800
Going concern liabilities	14,429,568	16,496,383	2,066,815
Going Concern Position	**$ 3,103,424**	**$ 1,160,409**	**$ (1,943,015)**
Additional liabilities due to PfAD	837,898	942,513	104,615
Surplus/(Unfunded Liability)	**$ 2,265,526**	**$ 217,896**	**$ (2,047,630)**
Total Normal Cost			
January 1, 2025 to December 31, 2025	$ 332,894	$ 410,873	$ 77,979
January 1, 2026 to December 31, 2026	$ 338,311	$ 421,722	$ 83,411
January 1, 2027 to December 31, 2027	$ 347,615	$ 433,318	$ 85,703

AON

Deterioration in Asset Value

In assessing the risk related to the deterioration in asset value we have chosen an adverse scenario equal to a 20% reduction in the non-fixed income asset values and assume no change in future return expectations.

The table below presents the sensitivity of the going concern position of using the assets with a 20% reduction in non-fixed income asset values. The Actuarial Value of Assets was then calculated using the smoothing method reflected in the going concern valuation.

$(000s)	Base Scenario	Adverse Scenario	Impact ($)
Actuarial value of assets	$ 17,532,992	$ 17,085,718	$ (447,274)
Going concern liabilities	14,429,568	14,429,568	-
Going Concern Position	**$ 3,103,424**	**$ 2,656,150**	**$ (447,274)**
Additional liabilities due to PfAD	837,898	837,898	-
Surplus/(Unfunded Liability)	**$ 2,265,526**	**$ 1,818,252**	**$ (447,274)**
Total Normal Cost			
January 1, 2025 to December 31, 2025	$ 332,894	$ 332,894	$ -
January 1, 2026 to December 31, 2026	$ 338,311	$ 338,311	$ -
January 1, 2027 to December 31, 2027	$ 347,615	$ 347,615	$ -

Mortality Sensitivity

The table below presents the sensitivity of the going concern position of the Plan to using a mortality assumption with a 10% improvement to the base mortality rates.

$(000s)	Base Scenario	Adverse Scenario	Impact ($)
Actuarial value of assets	$ 17,532,992	$ 17,532,992	$ -
Going concern liabilities	14,429,568	14,601,040	171,472
Going Concern Position	**$ 3,103,424**	**$ 2,931,952**	**$ (171,472)**
Additional liabilities due to PfAD	837,898	846,228	8,330
Surplus/(Unfunded Liability)	**$ 2,265,526**	**$ 2,085,725**	**$ (179,802)**
Total Normal Cost			
January 1, 2025 to December 31, 2025	$ 332,894	$ 334,864	$ 1,970
January 1, 2026 to December 31, 2026	$ 338,311	$ 340,313	$ 2,002
January 1, 2027 to December 31, 2027	$ 347,615	$ 349,672	$ 2,057

AON

Section 3: Solvency Valuation Results

Solvency Financial Position of the Plan

The solvency valuation is a financial assessment of the Plan that is required by the *Act* and is performed in accordance with requirements prescribed by that legislation. It is intended to provide an assessment of the Plan's financial position at the valuation date on the premise that certain obligations as prescribed by the *Act* are settled on the valuation date for all members. The liabilities must be calculated based on a postulated scenario that maximizes liabilities on wind up of the Plan. Contingent benefits are included in the liabilities that would be payable under the postulated scenario, unless permitted to be omitted under the definition of solvency liabilities under the Regulations to the *Act.* All assumptions for the solvency valuation are listed in Appendix D.

On the basis of the Plan provisions, membership data, solvency assumptions and methods and asset information described in the Appendices, as well as the requirements of the *Act*, the solvency financial position of the Plan as at January 1, 2025 is shown in the following table. The solvency financial position of the Plan as at January 1, 2024 is shown for comparison purposes.

Solvency Financial Position

$(000s)	January 1, 2025	January 1, 2024
Assets		
Solvency assets	$ 17,637,000	$ 16,563,826
Estimated wind up expenses	(73,300)	(73,300)
Total Assets	**$ 17,563,700**	**$ 16,490,526**
Solvency Liabilities		
Active and Disabled members	$ 4,451,828	$ 4,111,663
Deferred Vested members	114,599	110,238
Retirees and Spouses	9,189,538	9,180,214
Total Liabilities	**$ 13,755,965**	**$ 13,402,115**
Solvency Position	**$ 3,807,735**	**$ 3,088,411**
Prior year credit balance	-	-
Present value of special payments	-	-
Solvency Surplus/(Deficiency)	**$ 3,807,735**	**$ 3,088,411**
Solvency Ratio[1]	**1.28**	**1.24**

The solvency liabilities exclude the value of future indexation. The value of these excluded benefits is $6,474,914,000 at January 1, 2025 and $6,203,721,000 at January 1, 2024.

[1] Solvency Assets divided by Solvency Liabilities

AON

Statutory Solvency Financial Position

The minimum funding requirements under the Regulation are based on the reduced solvency deficiency as at the valuation date which is calculated as follows:

$(000s)	January 1, 2025	January 1, 2024
The amount by which the sum of:		
85% of solvency liabilities	$ 11,692,570	$ 11,391,798
85% of solvency liability adjustment	0	0
Prior year credit balance	0	0
	$ 11,692,570	**$ 11,391,798**
Exceeds the sum of:		
Solvency assets net of wind-up expenses	$ 17,563,700	$ 16,490,526
Solvency asset adjustment	-	-
	$ 17,563,700	**$ 16,490,526**
Reduced Solvency Deficiency	**$ -**	**$ -**

Solvency Concerns

A report indicates solvency concerns under the *Act* if the ratio of the solvency assets to solvency liabilities is less than 0.85.

Where a report indicates solvency concerns, the effective date of the next valuation that needs to be filed under the *Act* is one year from the valuation date of the valuation that gave rise to the solvency concerns.

Since the ratio of solvency assets to solvency liabilities is equal to 1.28, this report does not indicate solvency concerns.

Solvency Valuation Sensitivity Results

In accordance with the CIA Standards of Practice specific to pension plans, the table below presents the sensitivity of the solvency liabilities to using a discount rate of 1% lower and 1% higher than that used for the solvency valuation.

January 1, 2025		Effect	
$(000s)		$	%
Solvency liabilities	**$ 13,755,965**		
Solvency liabilities (discount rate – 1%)	$ 15,470,893	$ 1,714,928	12.5%
Solvency liabilities (discount rate + 1%)	$ 12,358,378	$ (1,397,587)	(10.2%)

AON

Pension Benefits Guarantee Fund ("PBGF")

The development of the PBGF Assessment Base is as follows:

PBGF Assessment Base	January 1, 2025
(1) Solvency assets	$ 17,637,000
(2) PBGF liabilities	$ 13,755,965
(3) Solvency liabilities	$ 13,755,965
(4) Ontario asset ratio: [(2) divided by (3)]	1.0000
(5) Ontario portion of fund: [(1) multiplied by the ratio in (4)]	$ 17,637,000
PBGF Assessment Base: [(2) subtract (5); if negative, enter zero]	**$ -**

AON

PBGF Exposure

The table below summarizes the information required in relation to PBGF claim exposure.

	Pensions, including Bridging Benefits, in Pay	Accrued Pensions, including Bridging Benefits, Not in Pay	Total Amount
Modified PBGF liabilities (as described in s14(8.0.4.1))	$ 2,613,416,000	$ 1,587,253,000	$ 4,200,669,000
Number of Ontario beneficiaries	13,230	11,019	24,249
Number of Ontario beneficiaries at or below the $1,500 per month benefit maximum	1,469	4,371	5,840

	Pensions, including Bridging Benefits, in Pay		Accrued Pensions, including Bridging Benefits, Not in Pay	
Percentile	Maximum Monthly Benefit	PBGF Liability[1] $(000s)	Maximum Monthly Benefit	PBGF Liability[1] $(000s)
10th	$ 261	$ 4,541	$ 262	$ 19,923
20th	$ 1,041	$ 62,693	$ 1,043	$ 85,220
30th	$ 2,136	$ 285,829	$ 2,134	$ 238,560
40th	$ 3,231	$ 765,419	$ 3,231	$ 457,418
50th	$ 4,061	$ 1,445,858	$ 4,060	$ 869,328
60th	$ 4,750	$ 2,167,682	$ 4,750	$ 1,553,324
70th	$ 5,552	$ 3,148,270	$ 5,552	$ 2,290,678
80th	$ 6,488	$ 4,445,107	$ 6,486	$ 3,104,779
90th	$ 7,900	$ 6,350,789	$ 7,899	$ 3,792,237
100th	$ 37,759	$ 9,189,538	$ 13,601	$ 4,566,615
The amount of the largest monthly pension, including bridging benefits, in pay or accrued not in pay, under the plan to an Ontario beneficiary				**$ 37,759**

[1] In accordance with s 14(8.0.4)(h)(vii)

Methodology

The benefit amounts used in the percentiles are as follows:

- for pensions in payment, they are the actual amounts in payment as of the valuation date, including bridge benefits (if any);
- for amounts not currently in payment, the pension amounts are the accrued lifetime pension plus the accrued bridge benefit (if any), with no reduction for early commencement.

The modified PBGF liabilities represent an estimate of the PBGF liability with benefits capped at $1,500 per month (for lifetime pension and bridge combined, with the bridge benefit reduced first). For pensions not in payment, the modified PBGF liability reflects any early retirement reductions that apply, and reflects any change in optimal commencement age with the application of the $1,500 cap. To avoid extensive modifications to the valuation programs, certain simplifications may have been employed.

AON

Section 4: Hypothetical Wind Up Valuation Results

Hypothetical Wind Up Financial Position of the Plan

A hypothetical wind up valuation is performed to determine the financial position of the Plan as at the valuation date on a wind up basis, reflecting market settlement rates as of the valuation date. Unlike the solvency valuation, all benefits are included that would be payable under the postulated scenario that would maximize benefits. The hypothetical wind up valuation is determined using benefit entitlements on the assumption that the Plan has neither a surplus nor a deficit. Contingent benefits are included in the liabilities that would be payable under the postulated scenario. Assets are set equal to market value net of estimated wind up expenses. All assumptions for the hypothetical wind up valuation are listed in Appendix D.

On the basis of Plan provisions, membership data, hypothetical wind up assumptions and methods, and asset information described in the Appendices, as well as the requirements of the Act, the hypothetical wind up financial position of the Plan as at January 1, 2025 is shown in the following table. The hypothetical wind up financial position of the Plan as at January 1, 2024 is shown for comparison purposes.

Hypothetical Wind Up Financial Position

$(000s)	January 1, 2025	January 1, 2024
Assets		
Hypothetical wind up assets	$ 17,637,000	$ 16,563,826
Estimated wind up expenses	(73,300)	(73,300)
Total Assets	**$ 17,563,700**	**$ 16,490,526**
Hypothetical Wind Up Liabilities		
Active and Disabled members	$ 7,356,039	$ 6,720,262
Deferred Vested members	196,065	186,209
Retirees and Spouses	12,678,775	12,699,365
Total Liabilities	**$ 20,230,879**	**$ 19,605,836**
Hypothetical Wind Up Surplus/(Deficiency)	**$ (2,667,179)**	**$ (3,115,310)**

AON

Transfer Ratio

The transfer ratio is determined as follows:

$(000s)			January 1, 2025	January 1, 2024
(1)	Hypothetical wind up assets		$ 17,637,000	$ 16,563,826
	Prior year credit balance	(A)	$ -	$ -
	Total company normal cost and required special payments until next mandated valuation	(B)	$ 629,724	$ 635,078
(2)	Asset adjustment	Lesser of (A) and (B)	$ -	$ -
(3)	Hypothetical wind up liabilities		$ 20,230,879	$ 19,605,836
Transfer Ratio [(1)-(2)] / (3)			**0.87**	**0.84**

Hypothetical Wind Up Valuation Sensitivity Results

In accordance with the CIA Standards of Practice specific to pension plans, the table below presents the sensitivity of the hypothetical wind up liabilities to using a discount rate of 1% lower and 1% higher than that used for the hypothetical wind up valuation.

January 1, 2025		Effect	
$(000s)		$	%
Hypothetical Wind Up liabilities	**$ 20,230,879**		
Hypothetical Wind up liabilities (discount rate – 1%)	$ 23,677,763	$ 3,446,884	17.0%
Hypothetical Wind up liabilities (discount rate + 1%)	$ 17,552,204	$ (2,678,675)	(13.2%)

Incremental Cost on a Hypothetical Wind up Basis

The incremental cost on a hypothetical wind up basis represents the present value at January 1, 2025 of the expected aggregate change in the hypothetical wind up liabilities between January 1, 2025 and the next calculation date, that is January 1, 2028. Appendix D gives more details on the calculation methodology and on assumptions.

Based on this methodology and on these assumptions, the incremental cost on a hypothetical wind up basis can be found in the following table.

$(000s)	Jan 1, 2025 to Dec 31, 2025	Jan 1, 2026 to Dec 31, 2026	Jan 1, 2027 to Dec 31, 2027
Incremental cost on a hypothetical wind up basis	$ 467,983	$ 509,174	$ 496,253

AON

Section 5: Contribution Requirements

Contribution Requirements in Respect of the Normal Cost

The annual going concern cost of benefits in respect of service accruing after the valuation date is known as the normal cost. The following table sets out:

- The development of the rule to determine the normal cost;
- An estimate of the normal cost for the 3 years following the valuation date; and
- The portion of the going concern normal cost that is to be paid by the members.

$(000s)	Jan 1, 2025 to Dec 31, 2025	Jan 1, 2026 to Dec 31, 2026	Jan 1, 2027 to Dec 31, 2027
Normal Cost			
Current service cost	$ 315,500	$ 320,643	$ 329,461
Provision for non-investment expenses	-	-	-
Additional normal cost due to PfAD	17,394	17,668	18,154
Total Normal Cost	**$ 332,894**	**$ 338,311**	**$ 347,615**
Required member contributions	(126,434)	(129,772)	(133,341)
Company Normal Cost	**$ 206,460**	**$ 208,539**	**$ 214,274**
Total pensionable earnings	$ 1,436,000	$ 1,473,918	$ 1,514,451
Company Normal Cost			
As a % of pensionable earnings	14.38%	14.15%	14.15%

In the event an updated funding range in accordance with legislative requirements is not certified before January 1, 2028, the rule for determining the company normal cost contributions outlined in the above table will continue to be appropriate for the plan year commencing on the next valuation date of January 1, 2028. Adjustment to the company contributions may be required once the next actuarial funding range in accordance with legislative requirements is certified.

AON

Development of Special Payments

There are no special payments required after adjustments for gains and losses due to the going concern and solvency valuation results.

Prior Year Credit Balance ("PYCB")

The PYCB is nil as at January 1, 2025.

Available Actuarial Surplus $(000s)

As at January 1, 2025 the Available Actuarial Surplus is calculated as follows:

Going Concern Basis			
(A)	Total assets	$	17,532,992
(B)	Total liabilities		14,429,568
(C)	Additional liabilities due to PfAD		837,898
(D)	Prior year credit balance		-
(E)	**Available Surplus: Maximum (A – B – C – D); 0)**	**$**	**2,265,526**
Solvency Basis[1]			
(F)	Assets in excess of a solvency ratio of 105%	$	3,193,237
(G)	Prior year credit balance		-
(H)	Total required Company contributions until next valuation		629,273
(I)	**Available Surplus: Maximum (F – Minimum (G, H); 0)**	**$**	**3,193,237**
(J)	**Available Actuarial Surplus: Minimum (E; I)**	**$**	**2,265,526**

Excess Surplus

The *Income Tax Act* requires that any excess surplus first be applied to reduce or eliminate the company contribution requirements. Excess surplus is defined in Section 147.2(2)(d) of the *Income Tax Act*, as the portion of surplus (if any) that exceeds 25% of the going concern liabilities.

Since the surplus is less than 25% of the going concern liabilities plus the Provision for Adverse Deviation, there is no excess surplus and therefore it does not impact the development of the company contribution requirements.

[1] Because the Plan is a Broader Public Sector pension plan, the solvency ratio rather than Transfer ratio applies.

AON

Development of Minimum Required Company Contribution

The table below presents the development of the minimum required company contribution for each of the plan years covered by this report.

While we have shown a fixed company normal cost in the table below, the Company may actually fund the normal cost as a percentage of pensionable earnings.

$(000s)	Jan 1, 2025 to Dec 31, 2025	Jan 1, 2026 to Dec 31, 2026	Jan 1, 2027 to Dec 31, 2027
Company normal cost	$ 206,460	$ 208,539	$ 214,274
Special payments toward amortizing unfunded liability	-	-	-
Special payments toward amortizing solvency deficiency	-	-	-
Required application of excess surplus	-	-	-
Minimum Required Company Contribution	**$ 206,460**	**$ 208,539**	**$ 214,274**

Under Regulations 7.0.3(1), 7.0.3(3) and 7.0.3(4) of the Pension Benefits Act (Ontario), it may be permissible to use Available Actuarial Surplus to reduce the required Company normal cost contribution shown above. The permitted application of Available Actuarial Surplus is determined on an annual basis and is subject to the filing of an actuarial cost certificate within the first 90 days of the fiscal year showing a solvency ratio greater than 105% as of the beginning of the fiscal year. In addition, members must be advised in the manner prescribed in Regulation 8.(1), 8.(2), 8.(3), and 8.(4), of the Company's intention to use Available Actuarial Surplus. The total reduction in Company normal cost taken by the Company over the period covered by this report may not exceed the Available Actuarial Surplus.

Development of Maximum Deductible Company Contribution

The table below presents the development of the maximum deductible company contribution for each of the plan years covered by this report.

The maximum deductible company contribution presented in the table below for a given plan year is calculated assuming that the Company makes the maximum deductible company contribution in the first plan year covered by this report.

While we have shown a fixed company normal cost in the table below, the Company may actually fund the normal cost as a percentage of pensionable earnings.

$(000s)	Jan 1, 2025 to Dec 31, 2025	Jan 1, 2026 to Dec 31, 2026	Jan 1, 2027 to Dec 31, 2027
Company normal cost	$ 206,460	$ 208,539	$ 214,274
Greater of the Unfunded liability and the Hypothetical Wind Up Deficiency	2,667,179	-	-
Required application of excess surplus	-	-	-
Maximum Deductible Company Contribution	**$ 2,873,639**	**$ 208,539**	**$ 214,274**

If the Company wishes to make the maximum deductible company contribution, it is advisable to contact the Plan's actuary before making such contribution to ensure that the contribution will be permissible and deductible and that any regulatory requirements are considered.

Section 6: Actuarial Certificate

Actuarial Opinion, Advice and Certification for the Ontario Power Generation Inc. Pension Plan

Registration Number: 1059120

Opinion

This actuarial certification forms an integral part of the actuarial valuation report for the Plan as at January 1, 2025. We confirm that we have prepared an actuarial valuation of the Plan as at January 1, 2025 for the purposes outlined in the Introduction section to this report and consequently:

Our advice on funding is the following:

- The Company should contribute the amounts within the range of minimum and maximum contribution amounts as outlined in Section 5 of this report, in accordance with legislative requirements.
- The next actuarial valuation for the purpose of developing funding requirements should be performed no later than as at January 1, 2028.

We hereby certify that, in our opinion:

- The contribution range as outlined in this report is expected to be sufficient to satisfy the Plan's funding requirements.
- The company contribution range outlined in this report qualifies as eligible contributions under Section 147.2(2) of the *Income Tax Act*.
- The pre-1990 maximum pension restrictions in Subsection 8504(6) of the Regulations to the *Income Tax Act* do not apply to any members of the Plan.
- For the purposes of the valuation:
  - The data on which this valuation is based are sufficient and reliable;
  - The assumptions used are appropriate; and,
  - The actuarial cost methods and the asset valuation methods used are appropriate.

- This report and its associated work have been prepared, and our opinion given, in accordance with accepted actuarial practice in Canada and in compliance with the requirements outlined in subparagraphs 147.2(2)(a)(iii) and (iv) of the *Income Tax Act.*
- Notwithstanding the above certifications, emerging experience differing from the assumptions will result in gains or losses that will be revealed in subsequent valuations.

Sincerely,

Aon

[Original signed by]

Aon

[Original signed by]

Linda Byron, FCIA, FSA
Senior Partner

Nathan LaPierre, FCIA, FSA
Partner

Aon
20 Bay Street, Suite 2300
Toronto, ON M5J 2N9

September 2025

Appendix A: Assets

Asset Data

The Plan's assets are held by CIBC Mellon Trust Company. The asset information presented in this report is based on the financial statements of the pension fund as at December 31, 2024 audited by Ernst & Young LLP.

Tests of the sufficiency and reliability of the asset data were performed and the results were satisfactory. The tests included:

- A reconciliation of actual cash flow with expected cash flow from the previous actuarial report; and
- A reconciliation of any anticipated benefit payments (for retirees, terminated, or deceased members) against the financial statements of the pension fund for confirmation of payments.

Market Value of Assets

The following is a summary of the composition of the Plan's assets by asset type as reported by CIBC Mellon as at January 1, 2025. For comparison purposes, the composition at the previous valuation date of January 1, 2024 is also shown.

	January 1, 2025	January 1, 2024
	%	%
Cash and short term	(4.9%)	(5.5%)
Nominal bonds	13.0%	13.4%
Public credit	7.4%	7.4%
Real return bonds	11.7%	12.6%
Canadian equities	8.7%	7.9%
Global equities	16.5%	15.4%
Real assets	32.9%	34.4%
Private equity	7.6%	7.3%
Other Alternatives	2.6%	2.5%
Private credit	4.5%	4.6%
Total Invested Assets	**100.0%**	**100.0%**

AON

Target Asset Mix

The target asset mix of the Plan is contained in the Plan's Statement of Investment Policies and Procedures dated March 5, 2024, and is as follows:

	Target
Cash and short term	0.5%
Nominal bonds	12.0%
Public credit	12.0%
Inflation-linked bonds	12.0%
Canadian equities	9.0%
Global equities	17.0%
Infrastructure	18.5%
Real estate	14.0%
Other alternatives	2.0%
Private Equity	7.0%
Private Credit	5.5%
Leverage	(9.5%)
	100.0%

AON

Reconciliation of Changes in Market Value of Assets

The table below reconciles changes in the market value of assets between January 1, 2024 and December 31, 2024.

$(000s)		January 1, 2024 to December 31, 2024
Market Value of Assets, Beginning of Plan Year	**$**	**16,564,000**
Contributions During Plan Year		
Member	$	121,000
Company normal cost		206,000
Company special payments		-
Company transfer deficiency payments		-
Company ongoing expenses		-
Interest on contributions		-
Total	**$**	**327,000**
Benefit Payments During Plan Year		
Non-retired members[1]	$	51,000
Retired members		771,000
Total	**$**	**822,000**
Transfers During Plan Year		
Into plan	$	-
Out of plan		-
Total	**$**	**-**
Fees/Expenses		
Investment fees/expenses	$	81,000
Non-investment fees/expenses		15,000
Total	**$**	**96,000**
Investment Income	**$**	**1,664,000**
Market Value of Assets, End of Plan Year	**$**	**17,637,000**

[1] Includes members who have terminated employment or died

AON

Development of Actuarial Value of Assets

The actuarial value of assets is determined by modifying the market value of assets to recognize asset gains (losses) (i.e., the difference between actual investment return and expected investment return based on the valuation discount rate assumption) over a 5-year period.

The development of the actuarial value of assets as of January 1, 2025 is shown below:

$(000s) Year Ending		Original Amount of (Gain) Loss	(Gain) Loss Admitted in Prior Years	(Gain) Loss Admitted in Dec 31, 2024	(Gain) Loss to be Admitted in Future Years
December 31, 2020	$	(208,308)	(166,646)	(41,662)	-
March 31, 2021	$	76,340	57,255	15,268	3,817
December 31, 2021	$	(1,016,670)	(610,002)	(203,334)	(203,334)
December 31, 2022	$	1,315,180	526,072	263,036	526,072
December 31, 2023	$	13,600	2,720	2,720	8,160
December 31, 2024	$	(548,404)	-	(109,681)	(438,723)
			$ (190,601)	**$ (73,653)**	**$ (104,008)**

Market Value of Assets, January 1, 2025	**$ 17,637,000**
Actuarial Value of Assets, January 1, 2025	**$ 17,532,992**

AON

Appendix B: Membership Data

Source of Data

This valuation was based on member data provided by the Company as of January 1, 2025. Tests of the sufficiency and reliability of the member data were performed and the results were satisfactory. The tests included:

- A reconciliation of membership status against the membership status at the last valuation. This test was performed to ensure that all members were accounted for. A summary of this reconciliation follows on the next page;
- A reconciliation of birth, hire, and participation dates against the corresponding dates provided for the last valuation to ensure consistency of data;
- A reconciliation of credited service against the corresponding amount provided for the last valuation to ensure that no member accrued more than 1 year of credited service from January 1, 2024. This test also revealed any members who accrued less than 1 year of credited service;
- A reconciliation of pensionable earnings against the corresponding amounts provided for the last valuation to identify any unusual increases or decreases;
- A reconciliation of accrued benefits against the corresponding amounts provided for the last valuation to identify any unusual benefit accruals;
- A reconciliation of any stated benefit payments since January 1, 2024 (for retired, terminated, or deceased members) against the financial statements of the pension fund for confirmation of the payments; and
- A reconciliation of inactive member benefit amounts against the corresponding amounts provided for the last valuation to ensure consistency of data.

There was no information missing from the data, so no assumptions were required with respect to such data.

A copy of the administrator certification certifying the accuracy and completeness of the member data (and the Plan provisions summarized in this report) is included in Appendix G of this report.

AON

Membership Summary

The table below reconciles the number of members as of January 1, 2025 with the number of members as of January 1, 2024 and the changes due to experience in the period.

	Active	LTD	Deferred Vested	Pensioner	Survivor and Children	Total
Members, January 1, 2024	**8,748**	**351**	**746**	**10,890**	**2,312**	**23,047**
Changes due to:						
New entrants	1,618	-	-	-	-	1,618
Re-enrollment	3	-	(3)	-	-	-
Return to Active from Disability	19	(19)	-	-	-	-
To Disability	(52)	52	-	-	-	-
Termination						
Lump sum payments	(73)	(1)	(38)	-	-	(112)
Deferred vested	(126)	(4)	130	-	-	-
Retirements						
Monthly pension payments	(222)	(24)	(22)	268	-	-
Lump sum Payments	(18)		(8)	(2)		(28)
Death						
Lump sum payments	(4)	-	(5)	-	-	(9)
With survivor	(25)			(136)		(161)
No further benefits	-	-	-	(128)	(130)	(258)
New survivors	-	-	-	-	161	161
Data correction	(1)	-	1	(2)	2	-
Net change	1,119	4	55	0	33	1,211
Members, January 1, 2025	**9,867**	**355**	**801**	**10,890**	**2,345**	**24,258**

AON

Active Members

	January 1, 2025	January 1, 2024
Number	9,867	8,748
Average age	45.0	45.9
Average credited service (years)	12.1	13.1
Average pensionable earnings for the following year	$ 138,336	$ 131,853
Accumulated contributions with interest	$ 1,061,884,328	$ 953,036,964
Proportion female	24.1%	24.0%

Disabled Members

	January 1, 2025	January 1, 2024
Number	355	351
Average age	54.4	54.9
Average credited service (years)	21.9	22.0
Average pensionable earnings for the following year	$ 124,840	$ 116,084
Accumulated contributions with interest	$ 32,076,606	$ 29,389,257
Proportion female	37.2%	37.6%

Deferred Members

	January 1, 2025	January 1, 2024
Number	801	746
Average age	52.6	53.0
Total Annual Lifetime Pension	$ 13,545	$ 13,394
Proportion female	30.3%	30.0%

Retired Members

	January 1, 2025	January 1, 2024
Number	10,890	10,890
Number with Bridge	2,082	1,898
Average age	72.7	72.1
Average Annual Pension	$ 63,337	$ 61,485
Total Annual Bridge Pension	$ 42,430,822	$ 45,480,068
Proportion female	20.4%	20.1%

AON

Survivors (excluding children)

	January 1, 2025	January 1, 2024
Number	2,335	2,303
Average age	79.8	79.7
Total Annual Temporary Pension	$ 35,783	$ 34,027
Proportion female	93.9%	93.9%

Children

	January 1, 2025	January 1, 2024
Number	10	9
Average age	30.1	30.5
Total Annual Temporary Pension	$ 303,867	$ 288,086
Proportion female	40.0%	44.4%

AON

Active/Disabled Membership Distribution

The following table provides a detailed summary of the active/disabled membership at the valuation date by years of credited service and by age group. For privacy reasons, average pensionable earnings is not shown for groups with two or less members.

Age	< 5	5–10	10–15	15–20	20–25	25–30	>=30	Total
< 30	905	63						968
	$ 102,740	$127,820						$ 104,372
30–35	846	344	69	1				1,260
	$116,335	$ 135,883	$ 147,239	$ *				$ 123,383
35–40	604	296	208	235				1,343
	$ 122,588	$ 140,485	$ 155,710	$ 157,518				$ 137,774
40–45	369	223	163	662	148	1		1,566
	$ 128,297	$145,291	$ 147,081	$ 154,449	$ 154,088	$ *		$ 146,170
45–50	247	145	102	437	479	44		1,454
	$ 126,036	$ 146,375	$ 150,933	$ 150,208	$ 154,886	$ 162,286		$147,677
50–55	178	110	86	352	380	95	29	1,230
	$ 125,150	$ 146,958	$ 144,473	$ 147,211	$ 151,694	$ 162,931	$ 158,785	$ 146,677
55–60	130	97	55	286	335	75	226	1,204
	$ 124,385	$ 139,667	$ 147,865	$ 146,478	$ 149,078	$ 151,389	$ 153,607	$ 145,975
60–65	101	53	42	227	204	69	193	889
	$ 123,316	$ 153,660	$ 140,516	$ 140,441	$ 139,839	$ 150,403	$ 140,170	$ 139,863
>=65	36	21	13	67	74	24	73	308
	$ 115,530	$ 140,143	$ 133,464	$ 146,827	$ 145,185	$ 159,530	$ 142,226	$ 141,654
Total Count	**3,416**	**1,352**	**738**	**2,267**	**1,620**	**308**	**521**	**10,222**
Average Earnings	**$ 116,796**	**$ 141,127**	**$ 149,201**	**$ 150,185**	**$ 150,526**	**$ 156,870**	**$ 147,323**	**$ 137,868**

AON

Deferred Vested/Retired Membership Distribution

The following table provides a detailed summary of the deferred vested/retired membership at the valuation date by age group. For privacy reasons, average pensions are not shown for groups with two or less members.

Age	Deferred Vested Members	Retired Members and Beneficiaries
< 50	315	11
Average Annual Pension	$ 11,441	$ 23,150
Average Annual Bridge Pension	$ 2,155	$ 1,500
50–55	105	56
Average Annual Pension	$ 16,662	$ 61,675
Average Annual Bridge Pension	$ 2,942	$ 10,428
55–60	129	590
Average Annual Pension	$ 17,432	$ 73,419
Average Annual Bridge Pension	$ 3,101	$ 12,452
60–65	158	1,602
Average Annual Pension	$ 11,081	$ 66,429
Average Annual Bridge Pension	$ 2,152	$ 11,216
65[1]–70	94	2,420
Average Annual Pension	$ 15,919	$ 64,133
70–75	N/A	2,669
Average Annual Pension	$ N/A	$ 61,613
	$	
75–80	N/A	2,633
Average Annual Pension	$ N/A	$ 56,148
>=80	N/A	3,244
Average Annual Pension	$ N/A	$ 46,968
Count	**801**	**13,225**
Average Lifetime Pension	**$ 13,545**	**$ 58,472**
Average Bridge Pension	**$ 2,658**	**$ 21,352**

[1] Includes all deferred vested members over age 65

Appendix C: Going Concern Assumptions and Methods

Assumptions and Methods

A member's entitlements under a pension plan are generally funded during the period over which service is accrued by the member. The cost of each member's benefits is allocated in some fashion over the member's service. An actuarial valuation provides an assessment of the extent to which allocations relating to periods prior to a valuation date (often referred to as the actuarial liabilities) are covered by the plan's assets.

The going concern valuation provides an assessment of a pension plan on the premise that the plan continues on into the future indefinitely based on assumptions in respect of future events upon which a plan's benefits are contingent and methods that effectively determine the way in which a plan's costs will be allocated over the members' service. The true cost of a plan, however, will emerge only as experience develops, investment earnings are received, and benefit payments are made.

This appendix summarizes the going concern assumptions and methods that have been used for the going concern valuation of the Plan at the valuation date. The going concern assumptions and methods have been chosen to reflect our understanding of the Plan's funding objectives with due respect to accepted actuarial practice and regulatory constraints. For purposes of this valuation, the going concern methods and assumptions were reviewed and changes as indicated were made.

AON

The actuarial assumptions and methods used in the current and previous valuations are summarized below and described on the following pages.

	January 1, 2025	January 1, 2024
Economic Assumptions		
Discount rate	6.25% per year	Same
Inflation rate	2.00% per year	Same
Real discount rate	4.25% per year	4.25% per year
Increases in pensionable earnings		
Active members	2.75% per year[1] plus PPM scale (Table A following)	2.75% per year[2] plus PPM scale (Table A following)
Disabled members	2.00% per year	Same
Increases in YMPE	2.75% per year	Same
Increases in *Income Tax Act* maximum pension	2.75% per year	Same
Interest on member contributions	3.40% per year	Same
Conversion rate for determining commuted values	4.50% per year	Same
Real conversion rate for determining commuted values	2.50% per year	Same
Investment and Non-investment expenses	Implicit in discount rate	Same
Provision for adverse deviation	7.05% of non-indexed liabilities and normal cost	Same

[1] Collectively bargained increases of 3.75% in 2025 and 2.50% in 2026 for PWU and 3.25% in 2025 for Society are reflected.

[2] Collectively bargained increases of 4.75% in 2024 and 3.25% in 2025 for Society are reflected.

AON

	January 1, 2025	January 1, 2024
Demographic Assumptions		
Mortality table	OPG-specific mortality table (updated 2019) (Table B following) with mortality improvements at Scale MI-2017	Same
Retirement rates		Same
Active members	Variable by age (Table C following)	Same
Disabled members	Age 65	Same
Deferred Vested members	Earliest Unreduced Age	Same
Termination rates	Variable by age (Table D following)	Same
Disability rates	None	Same
Proportion married		
Non-retired proportion with spouse	90%	Same
Non-retired spousal age differential	Males spouse three years older than female spouse	Same
Retired members	Actual marital status and spousal ages are used where known; otherwise male spouse is assumed to be three years older than female spouse	Same
Proportion of members assumed to elect commuted value		
Retirement eligible	10%	Same
Not retirement eligible	50%	Same
Methods		
Actuarial cost method	Projected unit credit	Same
Asset valuation method	Smoothed value of assets with gains/losses deferred and amortized over 5 years	Same

AON

Table A—Promotion, Progression and Merit ("PPM") Scale

Sample service based rates used in this valuation are shown in the following table:

Service (years)	PPM increase
Under 4	7.00%
4-9	2.75%
10-19	1.00%
20+	0.50%

Table B—OPG-Specific Mortality Table (2019)

The OPG-Specific Mortality Table (2019) has been set at 103% of the CPM 2014 (Public) table with the 103% adjustment at each age, based on an experience study conducted during 2019 using data from 2012 to 2018. Mortality rates per 1,000 lives at selected ages under this table are summarized below. The mortality improvement scale has been applied to the OPG-Specific Mortality Table (2019) starting from year 2014.

OPG-Specific Mortality Table (2019) before Mortality Improvement (Base Year 2014)		
Age	Male	Female
20	0.783	0.185
25	1.030	0.247
30	1.143	0.309
35	1.143	0.433
40	1.298	0.618
45	1.813	0.886
50	2.534	1.318
55	3.739	2.122
60	5.469	3.584
65	7.849	5.747
70	12.041	9.064
75	20.590	15.028
80	38.471	27.923
85	74.335	54.755
90	139.462	105.400

AON

Table C — Retirement Rates

Age based retirement rates are in accordance with the following table:

	Eligible for Reduced Pension		Eligible for Unreduced Pension[1]
Age	Male	Female	Male and Female
20	0.00%	0.00%	n/a
25	0.00%	0.00%	n/a
30	0.00%	0.00%	n/a
35	0.00%	0.00%	n/a
40	0.00%	0.00%	n/a
45	0.00%	0.00%	n/a
50	0.00%	0.00%	20.00%
55	2.00%	5.00%	20.00%
56	2.00%	5.00%	20.00%
57	2.00%	5.00%	20.00%
58	2.00%	5.00%	20.00%
59	2.00%	5.00%	20.00%
60	2.00%	5.00%	20.00%
61	7.00%	10.00%	25.00%
62	7.00%	10.00%	25.00%
63	7.00%	10.00%	25.00%
64	7.00%	10.00%	25.00%
65	100.00%	100.00%	100.00%

[1] Note that for members with 20 years of continuous service at January 1, 2025 (for non-represented employees) and April 1, 2025 (for represented employees), eligibility for an unreduced pension for the purpose of assumed retirement rates means entitlement to an unreduced pension for service earned up to January 1, 2025 for non-represented employees and April 1, 2025 for represented employees. For all other members, eligibility for an unreduced pension for the purpose of assumed retirement rates means entitlement to an unreduced pension considering all service

Table D — Termination Rates

Sample rates used in this valuation are shown in the following table:

Age	Male	Female
20	2.90%	3.30%
25	2.20%	2.50%
30	1.60%	2.40%
35	1.30%	2.00%
40	1.00%	1.60%
45	0.90%	1.40%
50	0.90%	1.40%
55 +	0.00%	0.00%

AON

Justification of Actuarial Assumptions and Methods

Economic Assumptions

Discount Rate

The overall expected return was developed using best-estimate returns for each major asset class in which the pension fund is invested. A Monte Carlo simulation is performed over 30 years where the portfolio returns are projected assuming annual rebalancing. The results are used to develop an overall best-estimate rate of return for the entire pension fund. Gains from rebalancing and diversification are implicit to this return.

The following table lays out the adjustments that have been made to the overall expected rate of return in order to arrive at our going concern discount rate assumption:

Development of Discount Rate				
Overall expected return				6.43%
Non-investment expenses				(0.10)%
Investment expenses				
Passive	(1)	(0.08)%		
Actively managed	(2)	(0.00)%		
			(1)+(2)	(0.08)%
Discount Rate				**6.25%**

Inflation Rate

The assumption reflects the 1.00% to 3.00% band that Bank of Canada has set for inflation, with monetary policy aimed at a 2.00% target midpoint. The assumed inflation rate is used to determine the other economic assumptions that are inflation-based. Since benefits under the Plan are directly related to inflation (before retirement, through salary increases and after termination/retirement, through the indexation formula), it is the difference between the inflation rate and the other economic assumptions that is the most important variable.

Increases in Pensionable Earnings

We have assumed future salary increases will be 2.75% per year, which is the long-term assumed increase in earnings. Note that for 2025 and 2026, we have reflected known increases included in collective bargaining agreements for the Society and PWU.

In addition to the base rate, we assume rates of increase as a result of individual employee promotion, progression and merit based on a scale which varies by service as shown in Table A.

AON

Increases in YMPE

As the benefits paid to a member from the Plan are dependent on the future YMPE, it is necessary to make an assumption regarding the future increases in the YMPE.

The YMPE is assumed to increase up until the time the member retires, dies or terminates from active employment at the rate of 2.75% per year. This is comprised of an annual increase of 2.00% on account of inflation, plus 0.75% in the long-term on account of productivity growth, which is consistent with historical real economic growth.

Increases in the Maximum Pension Limit

Pensions are limited to the maximum limits under the *Income Tax Act*. The maximum lifetime annual pension per year of pensionable service payable under the *Income Tax Act* is $3,756.67 in 2025. It is assumed that the maximum limit will increase at the rate of 2.75% per year. This is comprised of an annual increase of 2.00% on account of inflation, plus 0.75% in the long-term on account of productivity growth, which is consistent with historical real economic growth.

Interest on Member Contributions

Interest is credited on member contributions at 3.40% per year. The assumption reflects the best-estimate expectations of future yield of five-year personal fixed term chartered bank deposits.

Expenses

Since the discount rate has been established net of all expenses, no explicit assumption is required for all/investment expenses.

Conversion Rate

The conversion rate for commuted values is assumed to be 4.50% nominal (2.50% real) per year. This rate was derived based on the weighted-average time to expected payout of commuted value payments, using best-estimate expectations of future conversion rates determined in a manner consistent with the expected returns of the fixed income asset classes used for the derivation of the discount rate in accordance with the CIA guidance. This is a blended rate of the discount rate for the select period of 10 years and ultimate rate.

AON

Provision for Adverse Deviation

For the purpose of this valuation, the PfAD is established based on the target asset allocation for each category of investments set out in the Plan's Statement of Investment Policies and Procedures (SIPP) in effect at the date of this report.

Asset Mix Component	Investment Categorization under Regulation 76 (12)	Categorization under Regulation 11.2 (8)[1]	Target Asset Allocation (%)
Cash and short term	4	Fixed Income ("L")	(9.0)%
Investment-grade Fixed-income	15	Fixed Income ("L")	34.0%
Canadian stocks	13	Non-Fixed Income	9.0%
Non-Canadian stocks	14	Non-Fixed Income	17.0%
Other investments[2]	17	Alternative Investment ("M")	35.0%
Real estate	7	Alternative Investment ("M")	14.0%
			100.0%

Fixed income ("L")	25.0%
Alternative Investment ("M")	49.0%
(a) Percentage of fixed income for PfAD ["L" + 50%* "M"]	49.50%
(b) Percentage of non-fixed income for PfAD [100%-(a)]	50.50%
(c) Asset mix component (see table below)[3]	3.05%

Percent of Non-Fixed Income Assets	PfAD for Closed Plans	PfAD for Open Plans
0%	0%	0%
20%	2%	1%
40%	4%	2%
50%	5%	3%
60%	7%	4%
70%	11%	6%
80%	15%	8%
100%	23%	12%

[1] The fixed income investments satisfy the minimum credit rating requirements prescribed by the Regulation.
[2] Included non-investment-grade fixed income
[3] Based on linear interpolation

Benchmark Discount Rate (BDR)	
(d) V39056 rate at the valuation date	3.33%
(e) BDR [(d)+1.5%*(a)+5.0%*(b)+0.5%]	7.10%
(f) Best estimate discount rate[1]	6.43%
(g) Plan duration	12.49
PfAD is Determined as Follows:	
Fixed component (open 4% or closed 5%)	4.00%
Asset mix component	3.05%
BDR component [Max [0, (g)*((f)-(e))]]	0.00%
Total	**7.05%**

[1] Gross of non-investment expenses and passive investment management fees.

AON

Demographic Assumptions

Mortality

During 2019, Aon undertook a study of the mortality experience of OPG's pensioners. (The previous study was undertaken in 2013). Aon updated the OPG-specific base mortality table to reflect the experience of OPG's pensioners over the period from 2012 to 2018. This updated mortality table was used in this valuation and the prior valuation.

Future mortality improvements on a generational basis are assumed in accordance with improvement scale MI-2017 and are applied to the base mortality rates from 2014 onward (the base year for the table). This improvement scale was developed by the CIA in 2017 and reflects updated expectations of improvement in mortality and was also used in the prior valuation.

In April 2024, the Canadian Institute of Actuaries (CIA) released a new research paper on mortality improvements in Canada. In May 2024, the CIA issued guidance indicating that both the new mortality improvement scale and the mortality improvement scale currently used are appropriate to value pension plans. With this guidance, we continue to use the existing mortality improvement scale at this time.

Retirement

The rates of retirement have been developed as our expectation of the best-estimate rates of retirement based on the plan provisions and the historical retirement experience of the Plan. We have made assumptions as to how the plan changes in 2025 affecting early retirement eligibility will impact members' retirement patterns. We believe the assumed retirement rates reflect the long term anticipated retirement pattern in the Plan.

Disabled members are assumed to retire at age 65, since their Company-provided disability benefits are assumed to continue to that age, and earlier retirement election could jeopardize those disability benefits.

Termination of Employment

A member's benefit entitlement under the Plan is affected by whether the member terminates employment prior to retirement for reasons other than death. In order to account for this in the calculation of the actuarial liability, an assumption regarding the probability that a member will terminate employment for reasons other than death has been made.

The termination rates were developed based on a 2016 review of Plan experience since 2010. Consequently, the termination rates are considered to be best estimate.

Disability

If an active Plan member becomes disabled, service continues to accrue until pension commencement age, but employee contributions are waived. Disabled members are assumed to stay disabled until the age of 65.

Based on our 2016 review of OPG's disability experience since 2010, and materiality, an assumption of no incidence of disability has been made.

AON

Proportion of Members with Spouses and Spousal Age Differential

These assumptions are relevant to the valuation of benefits since there is a subsidized joint and survivor benefit available for members with a spouse. The spousal age differential is based on an analysis of pensioner data. The proportion of members who are assumed to have a spouse at retirement is consistent with observed Plan experience.

Proportion of Members Electing a Commuted Value at Termination or Retirement

10% of retirement eligible members and 50% of members not eligible to retire are assumed to elect a commuted value in lieu of immediate or deferred monthly pension payments upon retirement/termination. This assumption is consistent with observed Plan experience.

Margins for Adverse Deviations

The actuary has discussed the Plan's experience with the Company and compared it to the expected experience. Based on this review a decision was made not to include any margins for adverse deviation in addition to the PfAD. The PfAD that is required by Ontario Regulation is discussed in the preceding section.

Other

Actuarial Cost Method

An actuarial cost method is a technique used to allocate in a systematic and consistent manner the expected cost of a pension plan over the years of service during which Plan members earn benefits under the Plan. By funding the cost of a pension plan in an orderly and rational manner, the security of benefits provided under the terms of the Plan in respect of service that has already been rendered is significantly enhanced.

The projected unit credit actuarial cost method has been used for this valuation. Under this method, the actuarial present value of benefits in respect of service prior to the valuation date, but based on pensionable earnings projected to retirement, is compared with the actuarial asset value, revealing either a surplus or an unfunded actuarial liability.

With respect to service after the valuation date, the expected value of benefits for service in the year following the valuation date (i.e., the normal cost) net of any required employee contributions is expressed as a percentage of the expected value of participating payroll for that year. The employer normal cost contributions are determined each year by applying this percentage to the actual participating payroll for the year.

When calculating the actuarial present value of benefits at the valuation date, the present value of all retirement, withdrawal and preretirement death benefits are included. For each member, the retirement, withdrawal and preretirement death benefits for a particular period of service are first projected each year into the future taking into account future vesting, early retirement entitlements and minimum pension/value entitlements. These projected benefits for each future year are then capitalized, multiplied by the probability of the member leaving the Plan in that year and discounted with interest and survivorship to the valuation date. The actuarial present value of benefits for the particular period of service is then determined by summing the present values of these projected benefits.

The pattern of future contributions necessary to pre fund future benefit accruals for any one particular individual will increase gradually as a percentage of their pensionable earnings as the individual approaches retirement. For a stable population (i.e., one where the demographics of the group remain constant from year to year), the normal cost will remain relatively level as a percentage of payroll. The projected unit credit actuarial cost method therefore allocates contributions among different periods in an orderly and rational manner for a stable population group.

In the event of future adverse experience, contributions in addition to the normal cost calculated under the projected unit credit actuarial cost method may be required to ensure that the Plan's assets are adequate to provide the benefits. Conversely, favourable experience may generate surplus which may serve to reduce future contribution requirements.

Asset Valuation Method

The Company uses asset-smoothing which can reduce the volatility in the Company's contribution requirements.

Appendix D: Solvency and Hypothetical Wind Up Assumptions and Methods

Valuation Assumptions

	January 1, 2025	January 1, 2024
Economic Assumptions		
Discount rate		
Solvency (excludes indexation)		
—Benefits assumed to be settled by commuted value	3.90% per year for 10 years 4.60% per year thereafter	4.10% per year for 10 years 4.20% per year thereafter
—Benefits assumed to be settled by annuity purchase	4.72% per year	4.55% per year
Hypothetical Wind Up (includes indexation)		
—Benefits assumed to be settled by commuted value	2.00% per year for 10 years 2.70% per year thereafter	2.40% per year for 10 years 2.50% per year thereafter
—Benefits assumed to be settled by annuity purchase	1.51% per year	1.40% per year
Duration used for Annuity Purchase	10.28	10.42

	January 1, 2025	January 1, 2024
Demographic Assumptions		
Mortality table	2014 Canadian Pension Mortality Table with generational improvements using CPM Scale B[1] (sex-distinct rates)	Same
Termination rates	Not applicable	Same
Retirement age		
Active, disabled and deferred vested members	50% at the member's earliest unreduced retirement age and 50% at the age that produces the highest value	Same
Retired members and beneficiaries	Not applicable	Same
Termination of employment	Terminate with full vesting	Same
Marital status		
Non-retired spousal proportion	90% assumed to have a spouse at retirement	Same
Non-retired spousal age differential	Male spouses are assumed to be three years older than female spouses	Same
Retired members	Actual marital status and spousal ages are used where known; If not known, a male spouse is assumed to be three years older than a female spouse	Same
Other		
Wind up expenses	$73.3 million	Same
Actuarial cost method	Unit credit	Same
Asset valuation method	Market value of assets adjusted to reflect contributions, benefit payments, transfers and fees/expenses in transit as of the valuation date	Same

[1] No preretirement mortality was applied

Based on the CIA's Guidance and information such as pension legislation, Plan provisions and Plan experience, we have made the following assumptions regarding how the Plan's benefits would be settled on Plan wind up:

	Percent of Liability Assumed to be Settled By Purchase of Annuities	Percent of Liability Assumed to be Settled By Lump-Sum Transfer
Active Members		
Not retirement eligible	50%	50%
Retirement eligible	90%	10%
Deferred Vested Members		
Not retirement eligible	50%	50%
Retirement eligible	90%	10%
Retired Members and Beneficiaries	100%	0%

Postulated Scenario

The postulated scenario is the assumption of immediate termination of employment for the active group at the valuation date. Therefore, no allowance for future salary increases or demographic experience are reflected.

Benefits Valued

	Solvency Valuation	Hypothetical Wind Up Valuation
Vesting	We have treated all accrued benefits as vested on Plan wind up.	We have treated all accrued benefits as vested on Plan wind up.
Grow-in Benefits	Active members employed in Ontario with at least 55 age-plus-service points are eligible to receive grow-in benefits.	Active members employed in Ontario with at least 55 age-plus-service points are eligible to receive grow-in benefits.
Indexing	Not included in the valuation	Included in the valuation

AON

Justification for Valuation Assumptions

We have set the aforementioned assumptions based on guidance prepared by the CIA Pension Plan Financial Reporting Committee ("PPFRC") in Explanatory Report – Guidance for Assumptions for Hypothetical Wind-Up and Solvency Valuations Update – Effective December 31, 2024, and Applicable to Valuations with Effective Dates on or after December 31, 2024, and no later than June 29, 2025 ("CIA Guidance") issued February 27, 2025.

For benefit entitlements that are expected to be settled by lump-sum transfer, we based the assumptions on Section 3500 (Pension Commuted Values) of the CIA Standards of Practice, using rates corresponding to a valuation date of January 1, 2025.

For benefit entitlements that are expected to be settled by purchase of annuities, we based the assumptions on information compiled by the PPFRC from insurance companies active in the group annuity market as described in the educational note.

Solvency lump-sum discount rate for 10 years adjustment	= V122542[1] + Mid-term bond yield spread = 3.175% +0.691% **= 3.866% (rounded to 3.90%) per year**
Solvency lump-sum discount rate thereafter	= V122544[1]+ 0.5 x (V122544[1] – V122542[1]) + Long-term bond yield spread adjustment = 3.398% + 0.5 x (3.398% – 3.175%) + 1.103% **= 4.613% (rounded to 4.60%) per year**
Solvency annuity purchase discount rate	= V39062 + Duration Adjustment = 3.32% +1.40% **= 4.72% per year**

Indexed Rates

Theoretical yield on 7-year RRGCB (r7)	= V122553 x (V122542 / V122544) = 1.55% x (3.17% / 3.40%) = 1.33%
Indexation rate for 10 years (c1-10)	= (1 + V122542) / (1 + r7) - 1 = (1 + 3.17%) / (1 + 1.33%) - 1 = 1.82%
Indexation rate thereafter (c10+)	= [1+V122544+0.5x(V122544-V122542)] / [1+V122553+0.5x(V122553-r7)] - 1 = [1+3.40%+0.5x(3.40%-3.17%)] /[1+1.55%+0.5x(1.55%-1.33%)]-1 = 1.82%

[1] CANSIM Series (annualized)

Fully indexed lump-sum discount rate for 10 years (r1-10)

= [(1 + i1-10) / (1 + c1-10)] - 1
= [(1 + 3.87%) / (1 + 1.82%)] - 1
= 2.01% (rounded to 2.00%) per year

Fully indexed lump-sum discount rate thereafter (r10+)

= [(1 + i10+)/ (1 + c10+)] - 1
= [(1 + 4.61%) / (1 + 1.82%)] - 1
= 2.74% (rounded to 2.70%) per year

Full indexed annuity purchase discount rate = V39057 – 0 bps
= 1.51% - 0.00%
= 1.51% per year

Mortality Table

In accordance with the CIA Guidance, the derivation of the discount rate above is in conjunction with the 2014 Canadian Pensioners' Mortality Table combined with mortality improvement scale CPM-B.

Preretirement Mortality

We have made no allowance for preretirement mortality. The impact of including such an assumption would not have a material impact on the valuation, since the value of the death benefit is approximately equal to the value of the accrued pension.

Pensionable Earnings

To estimate active and disabled members' best average earnings, we have used actual historical member earnings.

Assumptions Not Needed

The following are not relevant to the solvency or hypothetical wind up valuation:

- Increases in pensionable earnings;
- Termination of employment rates;
- Increases in CPP (2025 amount was used) and OAS benefits (Q1 2025 amount was used);
- Increases in YMPE (2025 amount was used) ; and
- Disability rates.

Estimated Wind Up Expenses

Plan wind up expenses would normally include such items as fees related to preparation of the actuarial wind up report, fees imposed by a pension supervisory authority, legal fees, administration, custodial and investment management expenses. We have assumed these fees would total $73.3 million.

Calculation of Special Solvency Payments

Since there is a Solvency Surplus, there are no solvency special payments.

Unisex Assumption

The liabilities are valued on a sex-distinct basis.

Actuarial Cost Methods

Unit credit (accrued benefit) cost method as prescribed.

Asset Valuation Method Considerations

Assets for solvency purposes have been determined using market value.

AON

Incremental Cost

The incremental cost represents the present value, at the calculation date (time 0), of the expected aggregate change in the liabilities between time 0 and the next calculation date (time t), adjusted upwards for expected benefit payments between time 0 and time t.

An educational note was published in December 2010 by the CIA Committee on PPFRC to provide guidance for actuaries on the calculation of this information.

The calculation methodology can be summarized as follows:

- The present value at time 0 of expected benefit payments between time 0 and time t, discounted to time 0,

plus

- Projected liabilities at time t, discounted to time 0, allowing for, if applicable to the pension plan being valued:
    - expected decrements and related changes in membership status between time 0 and time t,
    - accrual of service to time t,
    - expected changes in benefits to time t,
    - a projection of pensionable earnings to time t,

minus

- The liabilities at time 0.

The projection calculations take into account the following assumptions and additional considerations:

- The assumptions for the expected benefit payments and decrement probabilities, service accruals, and projected changes in benefits and/or pensionable earnings would be consistent with the assumptions used in the pension plan's going concern valuation.
- The assumptions used to calculate the projected liability at time t are consistent with the assumptions for the liabilities at time 0, assuming that interest rates remain at the levels applicable at time 0, that the select period is reset at time t for interest rate assumptions that are select and ultimate and that the Standards of Practice for the calculation of commuted values and the guidance for estimated annuity purchase costs in effect at time 0 remain in effect at time t.
    - Active and inactive Plan members as of time 0 are considered in calculating the incremental cost.

AON

Appendix E: Summary of Plan Provisions

This funding valuation was based on Plan design information provided by the Company as of January 1, 2025. The following is a summary of the main provisions of the Plan.

Effective Date	
	January 1, 2000
Jurisdiction of Registration	
	Ontario
Eligibility for Membership	
Regular Employees	(a) All regular and probationary employees join the Plan on the date of hire; (b) Employees for whom the Office and Professional employees International Union was the bargaining agent prior to July 30, 1982 joined the Plan in accordance with the Plan rules at the time of hire; and, (c) Employees who became continuing construction clerical employees after July 29, 1982 and before August 8, 1984 joined the Plan in accordance with the Plan rules at the time of hire.
Other Employees	Other employees (with the exception of, and not limited to, PWU Term employees, and temporary Management Group employees who were not eligible to join effective July 1, 2014) may join the Plan after completion of 24 months of continuous service, and either (a) earning 35% of the YMPE; or (b) having 700 hours of employment in each of the two preceding calendar years.

Normal Retirement	
Eligibility	The attainment of age 65 (age 60 for female employees hired before January 1, 1976 or any subsequent day when she in fact retires which is not later than her 65th birthday).
Benefit	Annual benefit equal to (a) minus (b) below: (a) For members represented by the PWU or Society – 2.0% of Highest Three-Year Average Earnings times Credited Service prior to March 31, 2025 plus 2.0% of Highest Five-Year Average Earnings times Credited Service on and after March 31, 2025; or For Management Group employees – 2.0% of Highest Three-Year Average Earnings times Credited Service. For all members, Credited Service is limited to 35 years unless member elects to contribute beyond 35 years and earn Credited Service. (b) 0.5% of Highest Five-Year Average Earnings up to the Average YMPE times Credited Service after December 31, 1965.
Early Retirement	
Eligibility	(a) For members represented by the PWU or Society – Attainment of 82 age-plus-continuous service points prior to March 31, 2025, or attainment of 85 age-plus-continuous service points on or after March 31, 2025; or For Management Group employees – Attainment of 84 age-plus-continuous service points prior to January 1, 2025 for employees hired before July 1, 2014, or attainment of 90 age-plus-continuous service points for Management Group employees hired on or after July 1, 2014, or attainment of 90 age-plus-continuous service points on or after January 1, 2025 for Management Group employees hired before July 1, 2014. (b) For members represented by the PWU or Society – Attainment of 82 age-plus-continuous service points but less than 85 age-plus-continuous service points, and with 25 or more years of continuous service on or after March 31, 2025.

(c) For members represented by the PWU or Society – Attainment of 82 age-plus-continuous service points but less than 85 age-plus-continuous service points, and with less than 25 years of continuous service on or after March 31, 2025.

(d) For Management Group employees hired before July 1, 2014 – Attainment of 84 age-plus-continuous service points but less than 90 age-plus-continuous service points and with more than 25 years of continuous service on or after January 1, 2025.

(e) For Management Group employees hired before July 1, 2014 – Attainment of 84 age-plus-continuous service points but less than 90 age-plus-continuous service points and with less than 25 years of continuous service on or after January 1, 2025.

(f) Age 55 with 25 years of continuous service.

(g) A female employee whose continuous employment commenced prior to 1976 with age 50 and at least 15 years of continuous service or any other employee with age 55 and at least 15 years of continuous service, but less than 25 years of continuous service.

(h) Age 55.

Benefit

(a) Normal retirement benefit earned to early retirement date, unreduced for early commencement.

(b) Normal retirement benefit earned for service prior to March 31, 2025 unreduced for early commencement plus normal retirement benefit earned for service on or after March 31, 2025 reduced by 3% for each year that early retirement date precedes age 60. Notwithstanding the aforementioned, for members represented by the PWU or Society who have 20 or more years of service on March 31, 2025, the normal retirement benefit earned for service on or after March 31, 2025 will be reduced by 3% per year prior to the date the member's age-plus-continuous service would equal 85 (growing service and age).

(c) Normal retirement benefit earned for service prior to March 31, 2025 unreduced for early commencement plus normal retirement benefit earned for service on or after March 31, 2025 reduced by 2% for each year up to 5 years and by 3% for each additional year that early retirement date precedes age 65 (age 60 for females hired prior to 1976). Notwithstanding the aforementioned, for members represented by the PWU or Society who have 20 or more years of service on March 31, 2025, the normal retirement benefit earned for service on or after March 31, 2025 will be reduced by 3% per year prior to the date the member's age-plus-continuous service would equal 85 (growing service and age).

(d) Normal retirement benefit earned for service prior to January 1, 2025 unreduced for early commencement plus normal retirement benefit earned for service on or after January 1, 2025 reduced by 3% for each year that early retirement date precedes age 60.

(e) Normal retirement benefit earned for service prior to January 1, 2025 unreduced for early commencement plus normal retirement benefit earned for service on or after January 1, 2025 reduced by 2% for each year up to 5 years and by 3% for each additional year that early retirement date precedes age 65 (age 60 for females hired prior to 1976).

(f) Normal retirement benefit earned to early retirement date, reduced by 3% for each year that early retirement date precedes age 60.

(g) Normal retirement benefit earned to early retirement date, reduced by 2% for each year up to five years and by 3% for each additional year that early retirement date precedes age 65 (age 60 for females hired prior to 1976).

(h) Normal retirement benefit earned to early retirement date, actuarially reduced for early commencement.

Supplement (Bridge Pension)	
Eligibility	(a), (b), (c), (d), (e), (f), (g), and (h) as described under Early Retirement.
Benefit	0.625% of Highest Five-Year Average Earnings up to the Average YMPE times Credited Service (maximum 30 years), multiplied by the ratio 35/30, plus the number of years that the member contributed beyond 35 years, payable from early retirement date to age 6. The supplement is subject to the same early retirement reductions as the lifetime pension. Under (h), the lifetime pension plus the supplement are the actuarial equivalent of the defined benefit lifetime pension payable at age 65.
Disability Benefit	
Eligibility	Qualification for benefits from an income replacement plan.
Benefit	Credited Service continues to accrue. Member required contributions cease. Base Annual Earnings prior to disability is indexed on an annual basis by 100% of the increase in CPI (Ontario) for the 12 month period ending on the preceding June 30th, subject to a maximum increase of 8% with carry forward provisions. Actual YMPE at retirement date is used (subject to maximum indexation provisions).

AON

Termination of Employment	
Eligibility	(a) Less than 25 years of continuous service and not a Management Group employee hired on or after July 1, 2014. (b) Management Group employee hired on or after July 1, 2014 with less than 25 years of continuous service. (c) Twenty-five or more years of continuous service.
Benefit	(a) Accrued Normal Retirement Benefit payable and reduced in accordance with the provisions described under Early Retirement (a), (b), (c), (d), and (e) for members meeting those requirements using service at termination and age at retirement, or as early as age 55 on an actuarially reduced basis. (b) Accrued Normal Retirement Benefit payable at age 65, or as early as age 55 on an actuarially reduced basis. (c) Accrued Normal Retirement Benefit payable at age 65, or as early as age 55. The pension is reduced by 0.25% for each month that Early Retirement Date precedes age 60. In lieu of the deferred pension described in (a), (b) and (c) above, the member may be eligible to transfer the commuted value of the deferred pension to a locked-in RRSP or other retirement vehicle or be entitled to a refund of contributions. Portions of the pre-1987 benefit may be taken as a cash payment by members.

AON

Preretirement Survivor Benefit	
Eligibility	(a) Less than 10 years of continuous service. (b) Ten or more years of continuous service.
Benefit	(a) Commuted value of accrued Normal Retirement Pension. (b) (i) Member with a Spouse. Greater of an immediate pension of 66-2/3% of accrued Normal Retirement Benefit (with no early retirement reductions), or an immediate pension equivalent in value to the commuted value of the member's accrued Normal Retirement Pension. In lieu of (i) the surviving spouse may elect a deferred pension equivalent in value to the commuted value of the member's accrued pension at the date of death or may elect to receive the commuted value of the accrued Normal Retirement Pension. (ii) Member with Eligible Children but no Spouse. Immediate pension of 66-2/3% of accrued Normal Retirement Benefit paid to the children until age 18 (longer if in school or disabled). (iii) Member without a Spouse or Eligible Children. Commuted value of accrued Normal Retirement Benefit.

Required Member Contributions	
	(a) For members represented by the PWU – 7.50% of Base Annual Earnings up to the YMPE, plus 10.00% of Base Annual Earnings in excess of the YMPE. (b) For members represented by the Society – 9.00% of Base Annual Earnings. (c) For Management Group employees– 7.60% of Base Annual Earnings up to YMPE, plus 9.50% of Base Annual Earnings in excess of the YMPE.

Maximum Pension	
	The benefits in respect of continuous employment after 1991 are limited to the maximum allowable under the *Income Tax Act.*
Excess Contributions	
	On retirement, death, or termination, the required member contributions made on or after January 1, 1987 with interest cannot provide more than 50% of the commuted value of the benefit earned for Credited Service after January 1, 1987 In the event the required member contributions with interest provide more than 50% of the benefit, the excess will be refunded to the member (to the spouse, beneficiary or estate in the case of death). On retirement, death, or termination of a member who was not represented by the PWU, the required member contributions made prior to January 1, 1987 with interest cannot exceed the commuted value of the benefits earned for Credited Service prior to January 1, 1987. The excess is refunded to the member (to the spouse, beneficiary or estate in the case of death).
Normal Form of Payment	
Member without a Spouse or Dependent Children at Retirement	Life annuity with a guarantee of at least 60 monthly payments.
Member With a Spouse or Dependent Children at Retirement	Joint and 66-2/3% survivor annuity (no reduction for survivor benefit).

AON

Prior Plan Benefits

For active members represented by a union, the portion of their benefits under the OPG Plan in respect of service recognized for pension accrual purposes ("pensionable service") under the New Horizon System Solutions Pension Plan (the "NHSS Plan") will be determined based on the terms of the OPG Plan, as amended from time to time, and the member's combined pensionable earnings from NHSS and OPG. In no event will the value of any such member's benefits under the OPG Plan in respect of pensionable service under the NHSS Plan be less than the value of the member's benefit accrued under the NHSS Plan in respect of such service.

For active members not represented by a union, the portion of their benefits under the OPG Plan in respect of pensionable service under the NHSS Plan will be determined in same manner as for active members represented by a union (as described above), except that such portion of their benefit shall be subject to an unreduced early retirement benefit upon attaining age and continuous employment equal to 82; whereas the remainder of their benefit under the OPG Plan shall be subject to the early retirement benefit provisions of the OPG Plan, as amended from time to time.

For all other members, their benefit under the OPG Plan in respect of pensionable service under the NHSS Plan will be same as they had been entitled to under the NHSS Plan.

AON

Indexation	
	Pensions to retired and deferred vested members (and their survivors) are increased each January 1st (while in payment or during the deferral period) by 100% of the increase in CPI (Ontario) for the 12 month period ending on the preceding June 30th, subject to a maximum increase of 8% with carry forward provisions.
Definitions	
Base Annual Earnings	Member's Base Annual Earnings include Performance Incentive Plan Payments up to: • a maximum of 5% of a member's base annual earnings for Management Group employees in Bands A to M; • a maximum of 28% of a member's base annual earnings for Authorized Nuclear Operators; • a maximum of 25.2% of a member's base annual earnings for Certified Unit 0 Control Room Operators; • a monthly maximum of 28% of a member's base annual earnings divided by 12 for Society-represented control Room Shift Supervisors and Control Room Shift Operating Supervisors; • a maximum of 21% of a member's base annual earnings for Society-represented Authorization Training Supervisors; and • a maximum of 18.9% of a member's base annual earnings for Unit 0 Training Specialists who were formerly certified Unit 0 control Room Operators. • a supervisory premium of 5% of member's base annual earnings to PWU board certified thermal operators employed at the Lennox Thermal Plant or at the Atikokan Thermal Plant, For members represented by the PWU, 2024 Base Annual Earnings also include a one-time lumpsum payment pursuant to the Memorandum of Settlement for a Renewal Collective Agreement dated October 30, 2024.
Highest Three-Year Average Earnings	The average of a member's Base Annual Earnings during the 36 consecutive months which gives the highest amount, up to the date of retirement, termination, or death.

Highest Five-Year Average Earnings	The average of a member's Base Annual Earnings during the 60 consecutive months which gives the highest amount, up to the date of retirement, termination, or death.
Credited Interest	Average yield of five-year personal fixed term chartered bank deposits as determined under CANSIM B 14045 for the 12-month period ending June 30th.
Credited/Established Service	Credited service under the Prior Plan plus credited service while a member of the Plan on and after January 1, 2000, to a maximum of 35 years of credited service. Members may elect to contribute beyond 35 years and receive additional credited service.
Average YMPE	The average YMPE (i.e., Year's Maximum Pensionable Earnings under the Canada/Quebec Pension Plan) during the 60 consecutive months when Base Annual Earnings were highest.
Prior Plan	The New Horizon System Solutions Pension Plan. Defined benefit assets and liabilities of the Prior Plan were transferred into the Plan effective January 1, 2023 with the transfer completed in 2024.

A copy of a letter from the Company certifying the accuracy and completeness of the Plan provisions summarized in this report is included in Appendix F of this report.

Appendix F: Administrator Certification

With respect to the Ontario Power Generation Inc. Pension Plan, forming part of the actuarial report as at January 1, 2025, I hereby certify that, to the best of my knowledge and belief:

- The asset data provided or made available to the actuary is complete and accurate;
- The membership data and subsequent query answers provided or made available to the actuary are complete and accurate for all persons who are entitled to benefits under the terms of the Plan in respect of service up to the date of the valuation;
- The Plan provisions provided or made available to the actuary are complete and accurate up to and including January 1, 2025;
- The actuary has been notified of all relevant events subsequent to the valuation measurement date; and
- The terms of engagement contained in Section 1 of this report are accurate and reflect the plan administrator's direction.

Name (print) of Authorized Signatory	Title
Signature	Date

AON

About

Aon plc (NYSE: AON) exists to shape decisions for the better —to protect and enrich the lives of people around the world. Through actionable analytic insight, globally integrated Risk Capital and Human Capital expertise, and locally relevant solutions, our colleagues in over 120 countries and sovereignties provide our clients with the clarity and confidence to make better risk and people decisions that help protect and grow their businesses.

www.aon.com

© 2025 Aon Solutions Canada Inc. All Rights Reserved.

This document contains confidential information and trade secrets protected by copyrights owned by Aon. The document is intended to remain strictly confidential and to be used only for your internal needs and only for the purpose for which it was initially created by Aon. No part of this document may be disclosed to any third party or reproduced by any means without the prior written consent of Aon.

Appendix 1: EB-2020-0290 versus EB-2025-0297 Pension and OPEB Accrual Costs - OPG Nuclear

Line No.		Reference	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Pension	EB-2025-0297 Ex. F4-3-2, Chart 1	124.0	154.9	65.7	(27.9)	47.2	(12.0)	10.0	22.6	13.8	11.2	7.8	9.3
2	OPEB	EB-2025-0297 Ex. F4-3-2, Chart 1	179.0	165.0	151.1	153.5	158.0	186.8	190.5	204.0	211.0	222.0	231.2	241.7
	Total		303.0	319.9	216.8	125.6	205.2	174.8	200.5	226.6	224.8	233.2	239.0	251.0
			2020 Budget	2021 Budget	2022 Plan	2023 Plan	2024 Actual	2025 Plan	2026 Plan					
3	Pension	EB-2020-0290 Ex. F4-3-2, Chart 1	124.4	171.1	154.0	134.2	111.7	71.3	36.7					
4	OPEB	EB-2020-0290 Ex. F4-3-2, Chart 1	170.5	154.8	157.7	159.9	161.1	156.9	146.8					
	Total		294.9	325.9	311.7	294.1	272.8	228.2	183.5					
5	Pension Difference	Line 1 - Line 3	(0.4)	(16.2)	(88.3)	(162.1)	(64.5)	(83.3)	(26.7)					
6	OPEB Difference	Line 2 - Line 4	8.5	10.2	(6.6)	(6.4)	(3.1)	29.9	43.7					
7	Total Difference	Line 5+ Line 6	8.1	(43.2)	(24.5)	41.9	18.5	(43.2)	17.0					

Appendix 2: EB-2025-0297 - Pension and OPEB Accrual-Cash Differential Amounts - OPG Nuclear

Line No.	EB-2025-0297	Reference	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Pension													
1	Accrual Costs	Ex. F4-3-2, Chart 1	124.0	154.9	65.7	(27.9)	47.2	(12.0)	10.0	22.6	13.8	11.2	7.8	9.3
2	Contributions	Ex. F4-3-2, Chart 4	148.3	137.7	147.0	128.2	161.7	99.1	100.4	100.6	103.4	109.0	111.6	115.3
3	Difference	Line 1 - Line 2	(24.3)	17.2	(81.3)	(156.1)	(114.5)	(111.1)	(90.4)	(78.0)	(89.6)	(97.8)	(103.8)	(106.0)
	OPEB													
4	Accrual Costs	Ex. F4-3-2, Chart 1	179.0	165.0	151.1	153.5	158.0	186.8	190.5	204.0	211.0	222.0	231.2	241.7
5	Cash Payments	Ex. F4-3-2, Chart 4	83.1	89.2	87.5	106.8	106.6	117.6	114.1	118.0	122.4	129.6	134.3	139.4
6	Difference	Line 4 - Line 5	95.9	75.8	63.6	46.7	51.4	69.2	76.4	86.0	88.6	92.4	96.9	102.3
7	Pension Difference	Line 3	(24.3)	17.2	(81.3)	(156.1)	(114.5)	(111.1)	(90.4)	(78.0)	(89.6)	(97.8)	(103.8)	(106.0)
8	OPEB Difference	Line 6	95.9	75.8	63.6	46.7	51.4	69.2	76.4	86.0	88.6	92.4	96.9	102.3
9	Total Difference	Line 3 + Line 6	71.6	93.0	(17.7)	(109.4)	(63.1)	(41.9)	(14.0)	8.0	(1.0)	(5.4)	(6.9)	(3.7)

Appendix 3: EB-2025-0297 Pension and OPEB Accrual-Cash Differential Amounts - Regulated Hydroeletric

Line No.	EB-2025-0297	Reference	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
	Pension																	
1	Accrual Costs	Ex. F4-3-2, Chart 2 and 2A	46.6	28.8	34.6	33.2	23.0	28.4	12.4	(5.0)	8.1	(2.0)	1.7	4.6	2.7	2.2	1.5	1.6
2	Contributions	Ex. F4-3-2, Chart 5	32.5	26.3	25.3	24.1	24.6	25.7	27.9	23.1	27.6	16.9	19.5	19.5	20.2	21.4	22.1	22.9
3	Difference	Line 1 - Line 2	14.1	2.5	9.3	9.1	(1.6)	2.7	(15.5)	(28.1)	(19.5)	(18.9)	(17.8)	(14.9)	(17.5)	(19.2)	(20.6)	(21.3)
	OPEB																	
4	Accrual Costs	Ex. F4-3-2, Chart 2 and 2A	24.1	25.5	27.8	27.7	30.3	30.7	28.6	27.7	26.9	31.9	36.8	39.6	41.2	43.5	45.7	48.0
5	Cash Payments	Ex. F4-3-2, Chart 5	13.7	13.5	14.4	15.4	13.8	16.6	16.6	19.3	18.2	20.1	22.1	22.9	23.8	25.4	26.6	27.7
6	Difference	Line 4 - Line 5	10.4	12.0	13.4	12.3	16.5	14.1	12.0	8.4	8.7	11.8	14.7	16.7	17.4	18.1	19.1	20.3
7	Pension Difference	Line 3	14.1	2.5	9.3	9.1	(1.6)	2.7	(15.5)	(28.1)	(19.5)	(18.9)	(17.8)	(14.9)	(17.5)	(19.2)	(20.6)	(21.3)
8	OPEB Difference	Line 6	10.4	12.0	13.4	12.3	16.5	14.1	12.0	8.4	8.7	11.8	14.7	16.7	17.4	18.1	19.1	20.3
9	Total Difference	Line 3 + Line 6	24.5	14.5	22.7	21.4	14.9	16.8	(3.5)	(19.7)	(10.8)	(7.1)	(3.1)	1.8	(0.1)	(1.1)	(1.5)	(1.0)

CENTRALLY-HELD COSTS

1.0 PURPOSE

This evidence presents OPG's centrally-held costs and the period-over-period comparisons of centrally-held costs that are directly assigned and allocated to OPG's regulated hydroelectric facilities and nuclear facilities, and the Darlington New Nuclear Program ("DNNP") facilities.

2.0 OVERVIEW

This evidence supports the approval sought for the centrally-held costs included in the revenue requirements for OPG's nuclear facilities and the DNNP facilities for the IR term. Consistent with the Application's proposal to set hydroelectric payment amounts using a price-cap index Custom IR framework, it also supports the request for approval of the centrally-held costs included in the 2027 revenue requirement for OPG's regulated hydroelectric facilities.

The forecast centrally-held cost amounts included in the revenue requirements for OPG's nuclear facilities are -$35.4M for 2027, -$30.8M for 2028, -$60.1M for 2029, -$33.3M for 2030, and -$21.6M for 2031.[1] The forecast centrally-held costs included in the revenue requirements for the DNNP facilities are -$3.7M for 2027, -$4.1M for 2028, -$3.6M for 2029, $5.2M for 2030, and $14.2M for 2031.[2] The forecast centrally-held cost amounts included in the revenue requirement for OPG's regulated hydroelectric facilities for the 2027 test year is $5.6M.[3]

Centrally-held costs are an integral part of the costs of operating the regulated generation facilities. They are OPG's company-wide costs that are recorded centrally for a variety of reasons, such as achieving record-keeping efficiency and maintaining proper oversight. They are not Support Services costs.

Categories of centrally-held costs are separately identified for those exceeding $10M per year on average over the IR term. The category of "Other" reflects the remaining centrally-held

[1] Ex. F4-4-1, Table 3, line 7.
[2] Ex. F4-4-1, Table 4, line 7.
[3] Ex. F4-4-1, Table 2, line 6.

costs, with a description of some of the more significant items provided in Section 7.0. The centrally-held cost items described below were identified in previous OPG applications, and the nature of these costs is unchanged.

Centrally-held costs continue to be directly assigned or allocated to the regulated operations using the same methodology as in EB-2020-0290 and as reviewed by Elenchus (see Ex. F3-1-4). The methodology is applied to OPG-wide centrally-held costs presented in Ex. F4-4-1, Table 1, which results in costs attributed to OPG's regulated hydroelectric facilities, OPG's nuclear facilities and the DNNP facilities as presented in Ex. F4-4-1, Tables 2, 3, and 4 respectively. As discussed in Ex. F3-1-4, the same methodology is used to directly assign and allocate centrally-held costs to the DNNP facilities as for OPG's regulated facilities.

Exhibit F4-4-1, Tables 5a, 5b and 5c provide the period-over-period comparisons for the historical, bridge and forecast years for the regulated hydroelectric facilities, OPG's nuclear facilities and the DNNP facilities, as applicable, and a comparison to the OEB-approved amounts for OPG's nuclear facilities. Consistent with the OEB's letter dated September 17, 2024 issued in EB-2024-0136, this evidence provides nine years of historical data for OPG's regulated hydroelectric facilities, for the period 2016-2024.

This evidence provides a description of the categories of centrally-held costs and discusses the trends and variances for each category. The key drivers of these costs are identified within the discussions of trends and variances. Where these drivers do not adequately explain a year-over-year variance, a specific explanation is provided to the extent the variance is equal to or greater than 10%.

Total centrally-held costs vary and generally decrease over 2020 to 2024, primarily as a result of lower pension and other post employment benefit ("OPEB")-related accrual costs. Over the 2025-2031 period, centrally-held costs for OPG's nuclear and regulated hydroelectric facilities are forecast to be lower than the 2024 levels due to lower pension and OPEB-related amounts.

3.0 PENSION AND OPEB-RELATED ACCRUAL COSTS

3.1 Description

Certain components of pension and OPEB accrual costs for all of OPG's employees and retirees continue to be included in centrally-held costs. These cost components include interest costs on the obligations, the expected return on pension plan assets, amounts in respect of past service costs, amounts in respect of actuarial gains and losses, and variances from the estimated current service cost amounts charged to each of the businesses and functions through standard labour rates. As in prior applications, the pension and OPEB-related accrual costs are directly assigned and allocated to the businesses in proportion to the pension and OPEB costs charged to the businesses, including amounts assigned and allocated as part of corporate Support Services costs.

3.2 Trends and Variances

Centrally-held pension and OPEB accrual costs are negative over the IR term, reducing the proposed revenue requirements. Specific trends and variances in these costs are discussed in Section 4.3 of Ex. F4-3-2. In summary, variability in the centrally-held pension and OPEB accrual costs in the historical and bridge period is primarily related to: fluctuations in discount rates, updated inflation and salary escalation rate actuarial assumptions, differences in pension fund asset values. The costs are generally stable over the IR term.

4.0 OPG-WIDE AND NUCLEAR INSURANCE

4.1 Description

These are the costs of OPG's company-wide (corporate) insurance program and the additional nuclear-specific insurance program. The company-wide program covers commercial general liability, directors and officers and fiduciary liability, cyber risks, all risk property, boiler and machinery breakdown, including statutory boiler and pressure vessel inspections, and business interruption ("BI"). BI coverage provides protection against potential loss of earnings caused by physical damage to the station from a non-nuclear peril.

As in prior OPG applications, the costs of the company-wide insurance program are primarily directly assigned to the businesses based on the applicability of each type of insurance

coverage and the asset replacement cost of the generation facilities. The nuclear-specific insurance program relates to liability insurance associated with nuclear operations and property insurance for damage to the nuclear portions of the nuclear generating stations, which complements the conventional property insurance program. This portion of insurance costs is directly assigned to the respective nuclear facilities. Subject to regulatory requirements and market availability, it is assumed that DNNP LP will have its own nuclear-specific insurance policies.

4.2 Trends and Variances

Over the bridge and IR term, OPG-wide insurance costs are expected to continue to increase relative to historical levels due to the restrictive limit availability in the insurance market, continued challenges and losses with natural catastrophic events and inflationary concerns. The impact of OPG's July 2025 insurance renewal is reflected in the IR term forecast.

OPG Corporate Insurance Program: As discussed in EB-2020-0290, following a period of higher catastrophes and financial losses experienced by insurers in the 2017-2018 period, the insurance market tightened in 2020 with increased premiums and constricted capacity, compounded by impacts of the COVID-19 pandemic.[4] As anticipated in EB-2020-0290, OPG's premiums continued to increase beyond 2020, reflecting the effects of the limited capacity supply and other emergent factors such as higher inflationary impacts and increases in reinsurance costs.[5] OPG continued to take steps to mitigate these pressures, where possible, through extensive communication with insurers, differentiating itself by demonstrating the company's quality of risk, proficiency in operations and asset management, excellence in dam safety, and use of equipment monitoring and diagnostics. The resulting actual costs through 2024 for OPG's nuclear facilities were largely in line with the EB-2020-0290 forecast. In 2025, the insurance market is showing some signs of beginning to stabilize, with new capacity entering the market.

[4] EB-2020-0290, Ex. L-F4-04-VECC-035.
[5] Reinsurance is insurance purchased by insurance companies from other insurers to reduce their own risk of large losses.

For OPG's nuclear facilities, a step decrease in the corporate insurance program costs is forecasted beginning in 2025, mainly due to the end of commercial operation of Pickering Units 1 and 4 in 2024 and the opportunity identified by OPG to restructure the property program to include coverage for Pickering Units 5-8 assets outside of the 'nuclear island' under the nuclear property policy beginning in 2025 and through the four-unit refurbishment outage. These savings are primarily related to a conclusion that BI coverage provided by the conventional property program is not required until the first Pickering unit returns to service, given that no electricity will be produced at the station during the four-unit refurbishment outage and taking into account the BI coverage waiting period. This is also the main driver for the 2025 forecast costs for OPG's nuclear facilities being lower than the OEB-approved amount. The forecast costs increase in 2031 to reflect the reinstatement of this coverage. The budgeted costs for the nuclear facilities for 2026 are the same as the OEB-approved amount, reflecting the net effect of the latter assuming an end of Pickering commercial operation in 2025, the restructuring of Pickering's conventional property coverage and other factors.

For the regulated hydroelectric facilities, the higher capital investment levels for the aging assets are expected to continue to increase the value the assets, and resulting insurance premiums, in the forecast period.

In addition to the above factors, the forecast costs for both OPG's nuclear facilities and the regulated hydroelectric facilities reflect expectations of continued upward pressure on the premiums during the IR term from such factors as inflation, the global trade environment and supply chain risks.

Nuclear Insurance Program: OPG's nuclear insurance premiums have increased since 2020 for the same market condition reasons as discussed above. OPG was able to work with its insurers to mitigate some of the increases, relative to those forecast in EB-2020-0290. The resulting actual costs through 2024 and budgeted cost for 2025 are lower than the OEB-approved amounts, in part due to Pickering's positive operational performance exceeding insurer's expectations. The forecast costs for 2026 are higher than the OEB-approved amount due to the latter assuming an end of Pickering commercial operation in 2025.

OPG forecasts a step increase in its nuclear insurance costs in 2027 for two main reasons. First, the forecast reflects an anticipated increase in the current statutory nuclear insurance liability limit under the *Nuclear Liability and Compensation Act* ("NLCA"). Effective 2027, subject to final confirmation by the Department of Natural Resources Canada ("NRCan"), the nuclear liability limit is expected to increase from $1B to $1.2B, for each of Pickering and Darlington, following a five-year review of such limits completed by NRCan under this legislation.

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

Based on advice from Marsh, power generators in Canada typically purchase BI coverage. Historically, OPG has secured this coverage for conventional, non-nuclear risks across its nuclear operations. Moving forward, OPG plans to extend BI coverage to include nuclear-related risks for the operations at Darlington and Pickering, upon return to service from refurbishment. This coverage is also expected for the DNNP facilities, once operational.

DNNP facilities' nuclear insurance costs for the operating period will begin with Unit 1 entering service, scheduled in October 2030. Subject to NLCA regulatory requirements and market availability, it is assumed that DNNP LP will have its own insurance policies for nuclear liability, nuclear property and nuclear BI that are separate from OPG's existing stations. The 2031 forecast costs for the DNNP facilities reflect the first full year of operation and are based on information provided by insurance broker Marsh.

OPG will need to maintain nuclear liability and nuclear property insurance for Pickering Units 5-8 during their refurbishment. Nuclear liability insurance remains a requirement under the NLCA for a licensed facility, whether it is in operation or undergoing a refurbishment. Additionally, radioactive materials remain on site (e.g., spent fuel, activated components, contaminated structures), and property coverage is required for any perils that may occur during the refurbishment.

5.0 PERFORMANCE INCENTIVES

5.1 Description

These costs are for the annual pay for performance program that compensates OPG's management (i.e., non-unionized) employees based on the achievement of corporate and individual performance objectives. The costs are attributed to OPG's regulated hydroelectric facilities, OPG's nuclear facilities, and the DNNP facilities based on the labour costs of management employees (see Ex. F3-1-4). As discussed further in Ex. F4-3-1, Section 6.2.3 and previously in EB-2020-0290, since 2021, the budget for the program is set using a financial results model based on a percentage applied to forecast corporate earnings before tax.[6]

5.2 Trends and Variances

Actual performance incentives may vary over time based on the forecast corporate earnings before tax ("EBT"), the percentage applied to forecast EBT reflecting underlying business objectives for that year, and the actual corporate scorecard results. The percentage applied to forecast EBT, the actual corporate scorecard results and the incentive payouts are subject to OPG's Board of Directors' approval.

Over the 2021-2024 period, OPG experienced variability in its forecast EBT, driven in large part by nuclear production. The percentage applied to EBT to set the incentive budget was adjusted to help stabilize the impact of these fluctuations on performance incentive costs. Between 2021-2024, 2% was applied on average to forecast EBT[7] and OPG's corporate score ranged from 0.97 to 1.28.

[6] EB-2020-0290, Ex. L-F4-03-Staff-279.
[7] Willis Towers Watson indicates that annual incentive pools range from 2-7% of EBT/EBITDA.

Between 2022-2024, actual performance incentive costs reflect the forecast financial results model and strong corporate scorecard results, underscoring the alignment of incentive costs with measurable organizational achievements.[8] In the bridge period and through the IR term, the budgeted and planned incentive costs primarily reflect increasing forecast financial earnings over the period.

OPG's management compensation benchmarking continues to be positioned below market median on a Total Direct Compensation and Total Remuneration basis. OPG's management compensation, including the pay for performance program, and compensation benchmarking results are discussed in Ex. F4-3-1.

6.0 IESO NON-ENERGY CHARGES

6.1 Description

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

6.2 Trends and Variances

IESO non-energy costs for OPG's regulated hydroelectric facilities over the 2020 to 2027 period are relatively stable. Variances are primarily due to the variability in Global Adjustment rates.

Year-over-year variances in IESO non-energy costs for OPG's nuclear facilities over the 2020 to 2031 period are primarily due to changes in withdrawals of energy related to the Darlington and Pickering refurbishment schedules and variability in Global Adjustment rates.

[8] Over the reporting period, accruals for incentives are trued up in each subsequent year to align with actual payment amounts. Notably, an under accrual of approximately $6.0M in 2022 was trued up in 2023, resulting in greater variability in amounts shown in Table F4-4-1, Tables 2 and 3 and in F4-4-1, Tables 5a, 5b and 5c in these years.

Variances between actual and OEB-approved costs for the nuclear facilities for 2020-2024 and such budget and OEB-approved costs for 2025 are primarily due to differences in Global Adjustment rates and early return to service of Darlington units from refurbishment. In 2026, in addition to these factors, the variance is due to the continued operation of Pickering Units 5-8, whereas the OEB-approved amount assumed an end of commercial operation at the end of 2025.

IESO non-energy costs associated with DNNP facilities' reflect planned Unit 1 in-service in October 2030.

7.0 OTHER

7.1 Description

As in EB-2020-0290, Other costs consist of a number of relatively smaller items. In the IR term, these are comprised primarily of labour-related costs such as the fiscal calendar and labour balancing adjustments, and the vacation accrual.

The fiscal calendar adjustment is a wage adjustment covering all business units that reflect the difference in the number of days between the 52 or 53 week fiscal calendar used for payroll accounting and OPG's financial year ending on December 31. The adjustment is temporary and fluctuates from year to year, as the starting and ending days of the fiscal calendar vary from year to year. A negative adjustment (i.e., a reduction to costs) can occur in years when the fiscal calendar has 53 weeks. The costs (or a reduction to costs) are allocated to the business segments on the basis of payroll costs.

The labour balancing adjustments relate to non-pension and OPEB components of the standard labour rates. These adjustments capture variances (positive or negative) between the amount of such costs charged or planned to be charged to the OPG businesses and functions through standard labour rates and the final actual or planned amount of these costs.

The vacation accrual represents the cost to OPG of the estimated outstanding vacation entitlement for all of its employees and is allocated to the business segments on the basis of payroll costs.

7.2 Trends and Variances

Variances in Other costs over the 2020-2026 period, including relative to the OEB-approved nuclear amounts are mainly caused by the variability in labour balancing, fiscal calendar adjustments and assumed Corporate Headquarters ("CHQ") related employee relocation costs in 2025 in line with collective agreements and the management relocation expense standard. Actual amounts of the labour balancing adjustments are a function of each year's payroll related transactions processed by OPG on account of thousands of individual employees.

Over the IR term, Other costs are relatively stable, with the exception of a negative fiscal calendar adjustment in 2029. This negative fiscal calendar adjustment anticipated due to OPG's 2029 fiscal year being four days longer than the 2029 calendar year (the other fiscal years in the IR term are shorter than the respective calendar years except 2028 in which the fiscal and calendar years are equal).

Numbers may not add due to rounding.

Table 1
Centrally Held Costs ($M)
OPG

Line No.	Corporate Costs	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	**Pension/OPEB Related Accrual Costs**	12.8	39.5	(93.2)	(246.5)	(75.1)	(227.5)	(210.7)	(194.0)	(212.6)	(225.3)	(223.8)	(226.6)
2	**OPG-Wide Insurance**	25.3	30.5	34.1	35.0	35.4	34.2	32.9	37.0	39.6	41.9	45.2	50.5
3	**Nuclear Insurance**	19.5	20.7	21.1	21.5	22.2	18.2	18.1	28.6	28.8	29.4	34.4	40.7
4	**Performance Incentives**	32.7	32.2	30.1	45.7	45.2	48.3	45.1	47.0	50.6	52.5	53.1	54.6
5	**IESO Non-Energy Charges**	133.5	61.4	61.8	84.1	88.5	65.1	48.2	31.9	53.8	45.4	53.6	62.0
6	**Other**	35.3	77.3	49.3	41.3	26.2	27.5	24.0	28.3	19.7	1.1	25.0	27.4
7	**Total**	259.1	261.6	103.2	(18.9)	142.5	(34.3)	(42.4)	(21.2)	(20.1)	(55.0)	(12.4)	8.6

Numbers may not add due to rounding.

Table 2
Allocation of Centrally Held Costs - Regulated Hydroelectric ($M)

Line No.	Costs	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	**Pension/OPEB Related Costs**	26.4	11.8	20.0	16.0	1.7	5.8	(13.9)	(34.9)	(10.0)	(30.8)	(30.5)	(27.8)
2	**OPG-Wide Insurance**	6.7	7.4	7.3	7.5	9.1	11.1	12.4	13.1	14.3	17.6	17.2	19.5
3	**Performance Incentives**	3.1	4.1	4.0	3.8	3.7	3.3	3.1	5.7	5.4	5.9	5.8	6.0
4	**IESO Non-Energy Charges**	11.5	9.7	5.8	2.1	2.5	1.1	2.8	4.5	3.3	3.2	3.0	3.0
5	**Other**	(3.1)	(6.8)	(8.0)	(5.3)	(1.0)	7.5	3.6	(0.4)	(0.3)	5.7	3.9	4.9
6	**Total**	44.6	26.2	29.2	24.1	15.9	28.8	8.0	(12.0)	12.6	1.6	(0.7)	5.6

Notes:

1 As discussed in Ex. F4-4-1 and Ex. F4-3-2, the 2027 amounts reflect OPG's proposal to include accrued amounts for the pension and OPEB in the hydroelectric revenue requirement.

Numbers may not add due to rounding.

Table 3
Allocation of Centrally Held Costs - OPG Nuclear Facilities ($M)

Line No.	Costs	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	**Pension/OPEB Related Accrual Costs**	10.2	30.4	(71.0)	(194.6)	(59.2)	(180.6)	(157.5)	(143.6)	(156.0)	(166.0)	(165.1)	(166.4)
2	**OPG-Wide Insurance**	8.3	10.2	11.3	12.0	12.0	6.6	6.4	7.1	7.6	8.2	8.6	11.8
3	**Nuclear Insurance** [1]	19.5	20.7	21.1	21.5	22.2	18.2	18.1	28.6	28.8	29.4	30.0	31.6
4	**Performance Incentives**	27.2	26.7	24.8	35.5	35.2	39.0	32.7	33.4	35.6	37.0	37.2	38.6
5	**IESO Non-Energy Charges** [2]	113.2	49.4	48.5	67.4	72.7	49.6	34.7	18.6	38.2	31.6	38.4	43.1
6	**Other**	36.6	71.8	41.6	39.8	21.7	19.1	18.5	20.5	14.9	(0.3)	17.5	19.8
7	**Total**	215.0	209.3	76.3	(18.5)	104.7	(48.1)	(47.2)	(35.4)	(30.8)	(60.1)	(33.3)	(21.6)

Notes:

1 Breakdown of Nuclear Insurance by station:

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Darlington NGS	7.4	7.9	8.1	8.2	9.4	8.6	8.9	18.3	18.7	19.1	19.5	19.8
Pickering NGS	12.0	12.7	13.1	13.3	12.8	9.5	9.2	10.3	10.1	10.3	10.5	11.7

2 Breakdown of IESO Non-Energy Charges by station:

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Darlington NGS	39.3	0.5	12.2	17.6	23.7	16.9	12.4	11.0	15.0	12.1	14.7	16.0
Pickering NGS	73.9	48.9	36.3	49.8	49.0	32.7	22.3	7.6	23.2	19.5	23.8	27.2

Numbers may not add due to rounding.

Updated: 2026-03-10
EB-2025-0297
Exhibit F4
Tab 4
Schedule 1
Table 4

Table 4
Allocation of Centrally Held Costs - DNNP Facilities ($M)

Line No.	Costs	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Pension/OPEB Related Accrual Costs**	(7.7)	(8.9)	(9.8)	(8.6)	(7.1)	(6.4)
2	**OPG-Wide Insurance**	0.0	0.0	0.0	0.0	0.8	1.7
3	**Nuclear Insurance**	0.0	0.0	0.0	0.0	4.5	9.1
4	**Performance Incentives**	3.4	4.2	4.9	5.2	5.5	5.4
5	**IESO Non-Energy Charges**	0.0	0.0	0.0	0.0	0.4	3.3
6	**Other**	0.7	1.0	0.8	(0.2)	1.1	1.2
7	**Total**	(3.7)	(3.7)	(4.1)	(3.6)	5.2	14.2

Numbers may not add due to rounding.

Table 5a
Comparison of Allocation of Centrally Held Costs ($M)
Regulated Hydroelectric

Line No.	Business Unit	2016 Actual	(c)-(a) Change	2017 Actual	(e)-(c) Change	2018 Actual	(g)-(e) Change	2019 Actual	(i)-(g) Change	2020 Actual	(k)-(i) Change	2021 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**Pension/OPEB Related Costs**	26.4	(14.7)	11.8	8.3	20.0	(4.0)	16.0	(14.3)	1.7	4.1	5.8
2	**OPG-Wide Insurance**	6.7	0.7	7.4	(0.1)	7.3	0.2	7.5	1.6	9.1	2.0	11.1
3	**Performance Incentives**	3.1	1.1	4.1	(0.2)	4.0	(0.2)	3.8	(0.1)	3.7	(0.4)	3.3
4	**IESO Non-Energy Charges**	11.5	(1.8)	9.7	(3.9)	5.8	(3.7)	2.1	0.4	2.5	(1.3)	1.1
5	**Other**	(3.1)	(3.7)	(6.8)	(1.2)	(8.0)	2.7	(5.3)	4.2	(1.0)	8.5	7.5
6	**Total**	44.6	(18.4)	26.2	3.0	29.2	(5.0)	24.1	(8.2)	15.9	12.9	28.8

Line No.	Business Unit	2021 Actual	(c)-(a) Change	2022 Actual	(e)-(c) Change	2023 Actual	(g)-(e) Change	2024 Actual	(i)-(g) Change	2025 Budget	(k)-(i) Change	2026 Budget
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
7	**Pension/OPEB Related Costs**	5.8	(19.7)	(13.9)	(21.0)	(34.9)	24.9	(10.0)	(20.8)	(30.8)	0.3	(30.5)
8	**OPG-Wide Insurance**	11.1	1.2	12.4	0.8	13.1	1.1	14.3	3.3	17.6	(0.4)	17.2
9	**Performance Incentives**	3.3	(0.2)	3.1	2.6	5.7	(0.3)	5.4	0.5	5.9	(0.1)	5.8
10	**IESO Non-Energy Charges**	1.1	1.7	2.8	1.7	4.5	(1.2)	3.3	(0.1)	3.2	(0.2)	3.0
11	**Other**	7.5	(3.9)	3.6	(4.0)	(0.4)	0.1	(0.3)	6.0	5.7	(1.9)	3.9
12	**Total**	28.8	(20.8)	8.0	(20.0)	(12.0)	24.6	12.6	(11.0)	1.6	(2.3)	(0.7)

Line No.	Business Unit	2026 Budget	(c)-(a) Change	2027 Plan
		(a)	(b)	(c)
13	**Pension/OPEB Related Costs**[1]	(30.5)	2.7	(27.8)
14	**OPG-Wide Insurance**	17.2	2.4	19.5
15	**Performance Incentives**	5.8	0.3	6.0
16	**IESO Non-Energy Charges**	3.0	0.0	3.0
17	**Other**[1]	3.9	1.0	4.9
18	**Total**	(0.7)	6.3	5.6

Notes:
1 As discussed in Ex. F4-4-1 and Ex. F4-3-2, the 2027 amounts reflect OPG's proposal to include accrued amounts for the pension and OPEB in the hydroelectric revenue requirement.

Numbers may not add due to rounding.

Table 5b
Comparison of Allocation of Centrally Held Costs ($M)
OPG Nuclear Facilities

Line No.	Business Unit	2020 OEB Approved	(c)-(a) Change	2020 Actual	(g)-(c) Change	2021 OEB Approved	(g)-(e) Change	2021 Actual	(k)-(g) Change	2022 OEB Approved	(k)-(i) Change	2022 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**Pension/OPEB Related Accrual Costs**	30.1	(20.0)	10.2	20.2	30.0	0.5	30.4	(101.4)	12.0	(83.0)	(71.0)
2	**Pension/OPEB Adjustment for Test Period Cash to Accrual Differences**[1]	11.6	(11.6)	0.0	0.0	16.3	(16.3)	0.0	0.0	0.0	0.0	0.0
3	**OPG-Wide Insurance**	7.0	1.3	8.3	1.9	6.8	3.4	10.2	1.1	11.3	(0.0)	11.3
4	**Nuclear Insurance**	26.5	(7.0)	19.5	1.2	27.1	(6.4)	20.7	0.4	24.6	(3.5)	21.1
5	**Performance Incentives**	18.5	8.7	27.2	(0.5)	18.5	8.2	26.7	(1.9)	27.3	(2.5)	24.8
6	**IESO Non-Energy Charges**	54.5	58.7	113.2	(63.8)	42.0	7.5	49.4	(1.0)	97.7	(49.3)	48.5
7	**Other**	16.0	20.6	36.6	35.2	13.0	58.7	71.8	(30.2)	11.6	30.1	41.6
8	**Total**	164.3	50.7	215.0	(5.7)	153.7	55.6	209.3	(133.0)	184.5	(108.2)	76.3

Line No.	Business Unit	2022 Actual	(e)-(a) Change	2023 OEB Approved	(e)-(c) Change	2023 Actual	(i)-(e) Change	2024 OEB Approved	(i)-(g) Change	2024 Actual	(k)-(i) Change	2025 OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
9	**Pension/OPEB Related Accrual Costs**	(71.0)	(123.6)	(5.9)	(188.7)	(194.6)	135.4	(29.2)	(30.0)	(59.2)	18.8	(40.4)
10	**OPG-Wide Insurance**	11.3	0.7	11.9	0.1	12.0	0.0	12.1	(0.2)	12.0	(0.7)	11.3
11	**Nuclear Insurance**	21.1	0.3	27.1	(5.7)	21.5	0.8	30.0	(7.7)	22.2	4.0	26.2
12	**Performance Incentives**	24.8	10.6	27.6	7.9	35.5	(0.2)	27.8	7.4	35.2	(10.6)	24.6
13	**IESO Non-Energy Charges**	48.5	19.0	89.4	(22.0)	67.4	5.3	99.9	(27.1)	72.7	(8.1)	64.6
14	**Other**	41.6	(1.8)	12.2	27.6	39.8	(18.1)	7.9	13.8	21.7	(5.4)	16.4
15	**Total**	76.3	(94.8)	162.2	(180.7)	(18.5)	123.2	148.5	(43.7)	104.7	(2.0)	102.7

Notes:

1 The adjustment for 2020 and 2021 OEB approved reflects the EB-2016-0152 Decision and Order that, at the time, limited the amount of pension and OPEB costs reflected in the approved revenue requirement to cash amounts, with differences between accrual costs and cash amounts recorded in the Pension & OPEB Cash versus Accrual Differential Deferral Account for future consideration.

Numbers may not add due to rounding.

Table 5c
Comparison of Allocation of Centrally Held Costs ($M)
OPG Nuclear Facilities

Line No.	Business Unit	2025 OEB Approved	(c)-(a) Change	2025 Budget	(g)-(c) Change	2026 OEB Approved	(g)-(e) Change	2026 Budget	(i)-(g) Change	2027 Plan	(k)-(i) Change	2028 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
16	**Pension/OPEB Related Accrual Costs**	(40.4)	(140.2)	(180.6)	23.1	(56.2)	(101.3)	(157.5)	13.9	(143.6)	(12.4)	(156.0)
17	**OPG-Wide Insurance**	11.3	(4.7)	6.6	(0.3)	6.4	(0.0)	6.4	0.7	7.1	0.5	7.6
18	**Nuclear Insurance**	26.2	(8.1)	18.2	(0.1)	14.9	3.2	18.1	10.5	28.6	0.2	28.8
19	**Performance Incentives**	24.6	14.4	39.0	(6.3)	21.5	11.3	32.7	0.7	33.4	2.2	35.6
20	**IESO Non-Energy Charges**	64.6	(14.9)	49.6	(15.0)	19.9	14.8	34.7	(16.1)	18.6	19.6	38.2
21	**Other**	16.4	2.8	19.1	(0.6)	8.3	10.2	18.5	2.0	20.5	(5.6)	14.9
22	**Total**	102.7	(150.8)	(48.1)	0.9	14.7	(61.9)	(47.2)	11.8	(35.4)	4.6	(30.8)

Line No.	Business Unit	2028 Plan	(c)-(a) Change	2029 Plan	(e)-(c) Change	2030 Plan	(g)-(e) Change	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
23	**Pension/OPEB Related Accrual Costs**	(156.0)	(10.0)	(166.0)	0.9	(165.1)	(1.3)	(166.4)
24	**OPG-Wide Insurance**	7.6	0.6	8.2	0.4	8.6	3.2	11.8
25	**Nuclear Insurance**	28.8	0.6	29.4	0.6	30.0	1.6	31.6
26	**Performance Incentives**	35.6	1.4	37.0	0.3	37.2	1.3	38.6
27	**IESO Non-Energy Charges**	38.2	(6.6)	31.6	6.8	38.4	4.7	43.1
28	**Other**	14.9	(15.2)	(0.3)	17.8	17.5	2.3	19.8
29	**Total**	(30.8)	(29.3)	(60.1)	26.8	(33.3)	11.8	(21.6)

Numbers may not add due to rounding.

Updated: 2026-03-10
EB-2025-0297
Exhibit F4
Tab 4
Schedule 1
Table 5d

Table 5d
Comparison of Allocation of Centrally Held Costs ($M)
DNNP Facilities

Line No.	Business Unit	2026 Budget	(c)-(a) Change	2027 Plan	(e)-(c) Change	2028 Plan	(g)-(e) Change	2029 Plan	(i)-(g) Change	2030 Plan	(k)-(i) Change	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**Pension/OPEB Related Accrual Costs**	(7.7)	(1.2)	(8.9)	(0.8)	(9.8)	1.2	(8.6)	1.5	(7.1)	0.7	(6.4)
2	**OPG-Wide Insurance**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.8	0.8	1.7
3	**Nuclear Insurance**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5	4.5	4.7	9.1
4	**Performance Incentives**	3.4	0.8	4.2	0.7	4.9	0.3	5.2	0.3	5.5	(0.1)	5.4
5	**IESO Non-Energy Charges**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.4	2.8	3.3
6	**Other**	0.7	0.4	1.0	(0.3)	0.8	(1.0)	(0.2)	1.3	1.1	0.1	1.2
7	**Total**	(3.7)	0.0	(3.7)	(0.4)	(4.1)	0.5	(3.6)	8.8	5.2	9.0	14.2

OTHER REVENUES – REGULATED HYDROELECTRIC

1.0 PURPOSE

The purpose of this evidence is to present the forecast of revenues for the 2027 test year from sources other than energy production ("Other Revenues") from OPG's regulated hydroelectric generating facilities and to explain the proposed treatment of these revenues.

The forecast of Other Revenues is included as an offset in the calculation of OPG's 2027 revenue requirement for the regulated hydroelectric facilities presented in this Application.

2.0 OVERVIEW

Other Revenues earned by OPG's regulated hydroelectric facilities are revenues associated with ancillary services,[1] segregated mode of operation ("SMO"), water transactions, the Installed Capacity ("ICAP") market, and Clean Energy Credits ("CEC"). Other Revenues also include the Hydroelectric Incentive Mechanism ("HIM") Revenue Requirement Adjustment.

Consistent with the methodology approved in EB-2013-0321, differences between forecast and actual revenues associated with ancillary services, including impacts of future contract negotiations with the IESO, are recorded in the Ancillary Service Net Revenue Variance Account – Hydroelectric Sub Account (Ex. H1-1-1, Section 5.2).

The treatment of potential impacts of the IESO's Market Renewal Program ("Renewed Market") is discussed below as part of the detailed description of each Other Revenues forecast.

Exhibit G1-1-1, Table 1 presents the Other Revenues associated with the regulated hydroelectric assets for the period 2016-2027. Where possible, Other Revenues are tracked and recorded on a facility-specific basis. For the purposes of this exhibit, only those revenues that are directly associated with the regulated generation facilities have been included.

[1] Ancillary Services include black start capability, operating reserve ("OR"), reactive support/voltage control, and Regulation Service (formerly referred to as Automatic Generation Control).

3.0 ANCILLARY SERVICES

Under the IESO Market Rules, ancillary service suppliers receive compensation for costs associated with supplying ancillary services. These include out-of-pocket costs, lost production costs and opportunity costs when providing the service, and any other compensation deemed by the IESO to be fair and reasonable.

Ancillary service revenues are tracked at the station level and only those revenues related to the regulated facilities are included in this exhibit.

Ancillary service revenue forecasts are expected to remain largely unaffected in the Renewed Market. Aside from OR, ancillary service revenues are generally determined by system needs and operating conditions rather than by market price signals or other changes that were introduced in the Renewed Market. Any variances from the forecast of revenues will be recorded and captured in the Ancillary Services Net Revenues Variance Account.

3.1 Black Start Capability

Black start capability, as defined in the Market Rules, refers to the capability of a generation facility to start without an outside electrical supply so as to be used to energize a defined portion of the IESO-controlled grid.

Black start revenues are paid to OPG on a fixed basis annually and are not impacted by the implementation of the Renewed Market.

OPG forecasts revenues for black start capability for the 2027 test year on the same basis as the terms of the IESO-OPG Procurement of Certified Black Start Facilities Agreement effective June 1, 2021-May 31, 2026.

3.2 Reactive Support/Voltage Control Service

Under the IESO Market Rules, Reactive Support and Voltage Control services (“RSVC”) refer to services provided by a market participant to allow the IESO to maintain the reactive power and voltage levels required by the IESO-controlled grid.

RSVC is not scheduled or settled based on market price and as a result is not impacted by the implementation of the Renewed Market.

OPG forecasts revenues for RSVC for the 2027 test year per the terms of the IESO-OPG agreement for RSVC service effective August 1, 2025-July 31, 2028.

3.3 Regulation Service

As defined in the IESO Market Rules, Regulation Service refers to the process that automatically adjusts the output from a generation facility based on automated, electronic signals in order to provide frequency control and to maintain the balance between the demand from load and the supply from generation facilities.

In the Legacy Market (referring to the market prior to the Renewed Market), the Regulation Service contract provided payments related to OR-related opportunity losses. In the Renewed Market these losses are compensated as Real-Time OR Make-Whole Payments and captured within OR revenues as described in Section 3.4. OPG forecasts revenues for Regulation Service for the 2027 test year as per the terms of the IESO-OPG Procurement of Regulation Services Agreement effective February 1, 2023-January 31, 2034.

3.3.1 Niagara Hydrogen Centre

Currently, the provision of Regulation Service at Sir Adam Beck 2 GS requires turbine modulation that can result in a portion of water flows not being utilized by OPG for electricity production ("Unutilized Water").

The Niagara Hydrogen Centre ("NHC"), to be constructed and operated by Atura H2 L.P and expected to enter service in 2026, will make use of this otherwise Unutilized Water. Specifically, the NHC's electrolyzer will produce low-carbon hydrogen using electricity generated behind the meter at the Sir Adam Beck 2 GS facility from water that generally would not be used for electricity production. The Regulation Service agreement incorporates

provisions related to the NHC and is consistent with the expectations set out in the Ministry of Energy's letter to the IESO dated December 9, 2022.[2]

3.4 Operating Reserve

OPG's regulated hydroelectric fleet offers OR as an ancillary service to the IESO. Operating Reserve refers to the capacity that can be called upon in short notice by the IESO to replace scheduled energy supply that is unavailable because of an unexpected outage or to augment scheduled energy due to unexpected demand or other contingencies. In the Renewed Market, the IESO procures OR in both day-ahead and real-time for all three categories of OR.[3]

Other changes to OR introduced in the Renewed Market include a single OR schedule in both the Day-Ahead Market and the Real-Time Balancing Market, both of which are settled on Locational Marginal Prices ("LMP"), and the use of an OR Demand Curve during periods of scarcity. As OR CMSCs are eliminated, the Renewed Market uses Day-Ahead and Real-Time OR Make Whole Payments to ensure revenue sufficiency in cases of uneconomic OR scheduling. Chart 1 provides a summary of OR revenues received by OPG's regulated hydroelectric facilities during the first five months in the Renewed Market.

Chart 1 – OR Market Revenues Since Market Renewal Implementation

	DA OR Revenues	RT OR Revenues	DA OR MWP	RT OR MWP	Total OR Revenues
Month	$M	$M	$M	$M	$M
May	8.1	(0.8)	0.1	1.8	9.1
June	6.2	(6.1)	0.0	3.2	3.4
July	7.7	(3.5)	0.0	2.3	6.5
August	3.3	(0.3)	0.0	0.5	3.5
September	1.1	(0.3)	0.0	0.5	1.3

[2] Smith, T, *Letter to Ms. Lesley Gallinger regarding the Niagara Hydrogen Centre and Regulation Service Contract*, December 9, 2022 <https://www.ieso.ca/-/media/Files/IESO/Document-Library/corporate/ministerial-directives/Letter-from-the-Minister-of-Energy-20221209.pdf>.

[3] 10-minute synchronized (spinning) reserve, 10-minute non-synchronized (non-spinning) reserve, and 30-minute reserve (non-synchronized).

As described in Ex. E1-2-1, the ability to draw conclusions from data in the Renewed Market is limited due to (i) short duration the renewed market has been in operation; (ii) participants learning how the Renewed Market works and adjusting their strategies; and (iii) experience in only two seasons.[4] As such, OPG does not expect the observed increase in average total OR revenues in the Renewed Market as compared to the Legacy Market to sustain into the future. The higher OR revenues in the first few months of the Renewed Market and subsequent declining trend could be explained by a combination of system conditions as well as a maturation of participant behavior. OPG notes that its total OR revenues in the month of September of $1.3M are in line with its historical monthly average of $1.2M for the 2020-2024 period. As discussed in Ex. E1-2-1, Section 6.1, the IESO will be making targeted changes to Market Rules to address specific circumstances under which unwarranted MWPs are calculated. This change is expected to result in lower MWPs, including OR MWPs. Additionally, in OPG's view the expected addition of approximately 3,000 MW of battery energy storage facilities between 2025-2028 will put downward pressure on OR prices beyond those experienced in the Legacy Market.

Considering the insufficient data from a steady-state, Renewed Market, OPG's OR revenue forecast for the 2027 test year is based primarily on historical volumes and forecasted OR market prices inclusive of the expected price dampening impact of battery energy storage facilities expected in the coming years.

4.0 SEGREGATED MODE OF OPERATION

Segregated Mode of Operation is defined in the Market Rules as an electrical configuration where a portion of the IESO-controlled grid is used to connect one or more registered generating facilities to a neighbouring control area using a radial intertie for the purposes of delivering electricity. R.H. Saunders GS and Chats Falls GS, both in the Eastern Region, are the only prescribed hydroelectric facilities that are capable of entering into SMO. As a result, all SMO revenues are included within this exhibit.

[4] IESO, "Update on Renewed Market Performance and Operations", August 21, 2025 <https://ieso.ca/-/media/Files/IESO/Document-Library/engage/renewed-market/rmo-20250821-presentation-renewed-market-update.pdf>.

Segregated Mode of Operation is conducted by OPG when it identifies economic opportunities in neighbouring markets. These transactions are arranged in advance with counterparties. Forecast market prices in Ontario and surrounding markets are the economic drivers considered when deciding whether to engage in a SMO transaction.

Segregated Mode of Operation net revenues are calculated by subtracting the incremental costs associated with these transactions from the SMO revenues received. The incremental costs incurred in transacting SMO consist of export fees, transmission losses between generator source and point of delivery, production losses during the switching process between control areas, and the costs associated with the non-regulated trading business to carry out these transactions.

The Renewed Market introduces two main changes that affect SMO: IESO transaction approval timelines and market prices. Under the new Day-Ahead Market framework, the IESO's approval process for SMO transactions is more restrictive than it was in the Legacy Market. While this change is expected to reduce the number of SMO transactions OPG can conduct, uncertainty related to prevailing market prices in the Renewed Market will also impact SMO revenue.

Based on the limited experience OPG has had in the Renewed Market, OPG has forecast 2027 SMO revenues on the historical five-year average of SMO revenues and has not made adjustments for market prices. This approach smooths out annual variability in performance and addresses the inherent challenges of producing forward forecasts with limited experience in the Renewed Market.

5.0 WATER TRANSACTIONS

The New York Power Authority ("NYPA") and OPG are responsible for operating hydroelectric facilities on the Niagara and St. Lawrence Rivers. Pursuant to an agreement between the parties, NYPA and OPG coordinate certain operations to maximize energy production from the total volume of water available for generation under the relevant international treaties.

The Water Transfer agreements between OPG and NYPA allow one entity the opportunity to extract the potential energy from the other entity's share of water (i.e., referred to as a "Water Transfer") in order to optimize the use of available water. Water Transfers could be done at the request of the sender, receiver, or the Niagara River Control Centre.

The transferred water is used to generate electricity that is then sold into the respective entity's electricity market (the IESO-administered market if OPG is the receiving entity, or the New York Independent System Operator ("NYISO") administered market if NYPA is the receiving entity). The water transfer agreements specify how the benefits and costs associated with the types of water transfer are shared between entities. Water Transfers only pertain to regulated hydroelectric facilities. As a result, all Water Transaction revenues are included within this Exhibit.

The volume of Water Transactions completed in a year is not impacted by the implementation of the Renewed Market. Water Transaction revenues, however, are impacted by market prices. To the extent the Renewed Market leads to higher or lower average market prices than the Legacy Market, there will be a corresponding impact on Water Transaction revenues.

To calculate net water transfer revenues, accommodation charges and gross revenue charges attributable to these transactions are subtracted from the gross water transfer revenues. Based on the limited experience OPG has had in the Renewed Market, OPG has forecast the 2027 water transfer revenues based on the historical five-year average of net water transfer revenues and has not made adjustments for market prices. This approach smooths out annual variability in the volume of water transactions and addresses the inherent challenges of producing forward forecasts with limited experience in the Renewed Market.

6.0 CAPACITY EXPORT TRANSACTIONS

Installed Capacity market transactions are permitted under the IESO Market Rules when a market participant has Ontario-based generating capacity that the IESO has determined to be surplus to Ontario's reliability and planned resource adequacy requirements. The IESO currently has a capacity export agreement in place with the NYISO along with a process in place to enable market participants to participate in the NYISO capacity market. OPG currently

has three aggregates at the Sir Adam Beck 2 GS[5] registered to participate in the NYISO capacity market and has been participating in this market since 2016.

The amount of capacity that can be sold by OPG to NYISO (and therefore revenues earned) depends on a number of factors that are not within OPG's control and are difficult to forecast. These factors include, but are not limited to, the amount of capacity the IESO approves to be released from the Ontario market, the external capacity rights NYISO allocates to Ontario, and capacity market clearing prices in the NYISO market.

The ICAP net revenues are calculated by subtracting the incremental costs associated with these transactions from the gross ICAP revenues received. The incremental costs incurred in ICAP transactions include auction participation costs and the cost of meeting NYISO ICAP compliance obligations. The ICAP revenues only pertain to regulated hydroelectric facilities. As a result, all ICAP revenues are included within this Exhibit.

The ICAP revenues are not influenced by Ontario market prices and as a result are not impacted by the Renewed Market. These revenues are determined by two external factors: the capacity market clearing prices established in New York's capacity auctions, and the amount of Ontario capacity that the IESO releases to participate in that market. The IESO's decision on how much capacity to release is based on Ontario's resource adequacy requirements, ensuring that domestic reliability needs are met before any export is permitted. As a result, ICAP revenues reflect New York capacity market outcomes and IESO capacity release decisions, rather than Ontario market price dynamics.

OPG forecasts ICAP net revenues for the 2027 test year based on the historical five-year average of ICAP net revenues. This approach smooths out annual variability in performance and addresses the inherent challenges of producing accurate forward forecasts.

[5] There are three aggregated generation units at the facility registered with the IESO for export capacity to NYISO, each comprising a pair of generators: Generators 11 and 12, Generators 13 and 14, and Generators 17 and 18.

7.0 HIM REVENUE REQUIREMENT ADJUSTMENT

OPG forecasts HIM net revenues by applying market and operational information to the OEB-approved HIM formulas. Key inputs include Ontario supply and demand forecasts, LMP projections, water flow forecasts, and operational information for OPG's regulated hydroelectric fleet. OPG's proprietary model also incorporates external sources and market forecasts, to form the basis of OPG's HIM projections.

Within its model, hydroelectric resources are scheduled according to expected water flows and operating limits, following Ontario's demand profile net of baseload nuclear, wind, and solar generation. When electricity prices are anticipated to fall below the Gross Revenue Charge, certain hydro units are considered uneconomic, leading to forecast Surplus Baseload Generation spill. These conditions inform both the expected incentives for time-shifting water and the calculation of unintended benefits under the HIM.

OPG's HIM forecasting has been updated to incorporate features of the redesigned HIM in the Renewed Market as described in Ex. E1-2-1. These include the shift from monthly to daily averaging, the replacement of the Hourly Ontario Energy Price with LMP, and the introduction of a Day-Ahead HIM. While OPG's models reflect the design of the Renewed Market, forecasting HIM net revenues is subject to uncertainties.[6] The expected integration of battery energy storage facilities between 2025 and 2028 is expected to put downward pressure on LMP price spreads, reducing OPG's opportunities to earn HIM net revenues. The outcomes of the first few months of the Renewed Market are not sufficient to serve as a dependable model input on account of high month-to-month variability. Overall, OPG expects its forecast 2027 HIM net revenue, which is an increase from OPG's HIM net revenues in the Legacy Market, to adequately capture OPG's revenues in a mature Renewed Market.

OPG proposes to continue to include a revenue offset equal to 50% of forecast annual HIM net revenues. This treatment is consistent with the HIM Revenue Requirement Adjustment established in EB-2010-0008 and EB-2013-0321.

[6] The model is based on average price spreads and does not fully reflect the ability of the PGS to respond to significant short-run differences in hourly prices.

OPG is also proposing to eliminate the sharing of HIM net revenues that exceed the HIM revenue forecast as described in Ex. E1-2-1, Section 5.0.

8.0 CLEAN ENERGY CREDITS

Within the Ontario CEC market, OPG sells environmental attributes associated with its regulated hydroelectric and nuclear generation facilities.

On March 29, 2023, the Province of Ontario announced the launch of the Clean Energy Credit Registry, to be administered by the IESO with the stated objective being to boost Ontario's competitiveness in attracting investment and jobs.[7] As part of the announcement, the Province noted that proceeds from the sale of CECs held by the IESO and OPG would be directed to the government's Future Clean Electricity Fund, which will "help keep costs down for electricity ratepayers by supporting the development of new clean energy projects as the province builds out our grid to meet the demands of a growing population and economy, as well as the electrification of transportation and industry".[8]

As part of the accompanying O. Reg 39/23 *Clean Energy Credits*, under section 4.2, the Province specifies that the proceeds OPG is to remit is equivalent to 80% of its revenues net of costs from the sale of CECs to the Province's Future Clean Electricity Fund. As such, the Province has already legislated the amount to be returned to the benefit of ratepayers through investments of the Future Clean Electricity Fund. OPG proposes to retain the remaining 20% of net revenues from the sale of CECs to provide an appropriate incentive for the organization to continue pursuing CEC sales.

[7] Province of Ontario, News Release: Ontario launches Clean Energy Credit Registry to Boost Competitiveness and Attract Jobs, March 29, 2023 <https://news.ontario.ca/en/release/1002876/ontario-launches-clean-energy-credit-registry-to-boost-competitiveness-and-attract-jobs>.
[8] *Ibid*.

Numbers may not add due to rounding.

Updated: 2026-03-10
EB-2025-0297
Exhibit G1
Tab 1
Schedule 1
Table 1

Table 1
Other Revenues - Regulated Hydroelectric ($M)

Line No.	Revenue Source	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	**Ancillary Services[1]**	70.1	78.7	70.5	71.8	55.5	50.1	71.6	62.3	58.5	56.1	51.5	49.1
2	**Segregated Mode of Operation[2]**	0.4	3.1	2.7	0.0	0.0	0.0	8.0	0.4	1.2	1.9	1.9	1.9
3	**Water Transactions[3]**	1.1	0.9	1.6	0.9	0.2	0.6	0.6	1.6	3.5	1.3	1.3	1.3
4	**Capacity Exports[4]**	0.1	0.6	2.3	0.2	0.0	0.4	0.0	1.5	3.0	1.0	1.0	1.0
5	**Total Ancillary Services**	71.8	83.2	77.1	72.8	55.7	51.1	80.2	65.8	66.4	60.3	55.8	53.3
6	**HIM Revenue**	14.0	12.3	10.9	6.2	5.1	16.8	14.3	14.8	28.4	10.5	20.2	17.8
7	**Total of Other Revenues**	85.8	95.5	88.0	79.0	60.7	67.8	94.5	80.6	94.7	70.9	76.0	62.2

Notes:

1 Ancillary Services related to regulated hydroelectric facilities are discussed in Ex. G1-1-1, Section 3.

2 Segregated Mode of Operation (SMO) net revenues are gross revenues less HOEP, less export fees, transmission charges in other control areas, transmission losses, production losses during the switching process between control areas and costs associated with the non-regulated Trading business.

3 Water Transactions revenues are gross revenues net of accommodation charges and Gross Revenue Charges (GRC).

4 2027 Total of Other Revenues includes 50% of the HIM Revenue forecast as described in Ex. G1-1-1, Section 7.

COMPARISON OF OTHER REVENUES
REGULATED HYDROELECTRIC

1.0 PURPOSE

This evidence presents period-over-period comparisons of Other Revenues for OPG's regulated hydroelectric facilities based on actuals for 2016-2024 and forecast for 2025-2027. Corresponding Other Revenues are provided on Ex. G1-1-2, Table 1.

The treatment of potential impacts of the IESO's Market Renewal Program ("Renewed Market") are described within Ex. G1-1-1. The expected impacts of the Market Renewal Program have generally not resulted in any material annual variances in the forecast of Other Revenues.

Consistent with the OEB's letter dated September 17, 2024, issued in EB-2024-0136, OPG has included nine years of historical data for its regulated hydroelectric business below, for the period 2016-2024. As there is no OEB-approved other revenues information for 2015 onwards, OPG has only provided year-over-year variance analysis for the historical (2016-2024), bridge (2025-2026), and test year (2027).

2.0 PERIOD-OVER-PERIOD CHANGES – TEST YEAR

2027 Plan versus 2026 Budget

The 2027 Plan Hydroelectric Incentive Mechanism ("HIM") revenues are expected to be $2.4M lower than 2026 Budget due to lower average price spreads forecasted for most of 2027 when compared to 2026.

3.0 PERIOD-OVER-PERIOD CHANGES – BRIDGE YEARS

2026 Budget versus 2025 Budget

2026 Budget HIM revenues are expected to be $9.7M higher than 2025 Budget due to higher average forecast Locational Marginal Prices in 2026 compared to 2025.

2025 Budget versus 2024 Actual

The 2025 Budget HIM revenues are expected to be $17.8M lower than 2024 Actual due to lower average budgeted price spreads in 2025 compared to actual 2024 price spreads.

The 2025 Budget WT revenue is expected to be $2.2M lower than 2024 Actual. The 2025 Budget is established based on the average of the 2020-2024 actuals.

The 2025 Budget ICAP revenue is expected to be $2.0M lower than 2024 Actual. The 2025 Budget is established based on the average of the 2020-2024 actuals.

4.0 PERIOD-OVER-PERIOD CHANGES – HISTORICAL YEARS

2024 Actual versus 2023 Actual

The 2024 Actual HIM revenue is $13.6M higher than 2023 Actual due to higher average price spreads and lower inflows during freshet which lead to a lower unintended benefit adjustment in 2024 compared to 2023.

The 2024 Actual WT revenue is $1.9M higher than 2023 Actual due to lower unit availability at R.H. Saunders GS, resulting in more water available to transfer to New York Power Authority ("NYPA").

The 2024 ICAP revenue is $1.5M higher than 2023 Actual mostly due to OPG clearing New York Independent System Operator's ("NYISO") capacity auction for more commitment months in 2024 compared to 2023.

2023 Actual versus 2022 Actual

The 2023 Actual Ancillary Services revenue is $9.3M lower than 2022 Actual mostly due to lower Operating Reserve ("OR") and Regulation Service revenues.

The 2023 Actual SMO revenue is $7.7M lower than 2022 Actual due to lower energy prices in 2023 coupled with decreased volume of SMO transactions.

The 2023 Actual ICAP revenue is $1.5M higher than 2022 Actual mostly due to OPG clearing NYISO's capacity auction for more commitment months in 2023 compared to 2022.

The 2023 Actual WT revenue is $1.0M higher than 2022 Actual due to decreased unit availability at R.H. Saunders GS in 2023, resulting in higher water availability to NYPA.

There are no reportable variances for HIM revenues in 2023 Actual vs. 2022 Actual.

2022 Actual versus 2021 Actual

2022 Actual Ancillary Services revenue is $21.5M higher than 2021 Actual. While Reactive Support and Voltage Control ("RSVC") revenues in 2022 were lower due to lower system utilization of the service, there was a net increase in 2022 ancillary revenues due to OR and Regulation Service revenues. The OR revenues increased as a result of significantly higher OR prices. The Regulation Service revenues increased mainly due to higher production costs associated with providing the service.

The SMO transactions resumed in 2022 following the COVID-19 pandemic. The SMO revenues in 2022 reached $8.0M which is higher than achieved in trailing historical years. In 2022 demand was higher than typical due to colder than normal winter weather, coupled with higher energy prices in Québec and Ontario. These higher energy prices are due to strong natural gas demand in 2022 driven from the conflict in Ukraine.

The 2022 Actual HIM revenue is $2.5M lower than 2021 Actual due to higher average off-peak HOEP in 2022 compared to 2021.

2021 Actual versus 2020 Actual

The 2021 Actual HIM revenue is $11.7M higher than 2020 Actual due to higher average price spreads in 2021 compared to 2020.

The 2021 Actual Ancillary Services revenue is $5.4M lower than 2020 Actual predominantly due to lower OR and Regulation Service revenues partially offset by higher RSVC revenues.

There are no reportable variances for SMO, WT, and ICAP revenues in 2021 Actual vs. 2020 Actual. SMO revenues for both years were $0M primarily due to lack of commercial opportunity resulting from the COVID-19 pandemic.

5.0 PERIOD-OVER-PERIOD CHANGES – EXTENDED HISTORICAL YEARS

Pursuant to the OEB's letter dated September 17, 2024, issued in EB-2024-0136, OPG has included four additional years of historical data.

2020 Actual versus 2019 Actual

The 2020 Actual Ancillary Services revenue is $16.3M lower than 2019 Actual primarily due to lower Regulation Service revenues, as a result of new contract terms with the IESO.

2020 Actual HIM revenue is $1.1M lower than 2019 Actual due to lower average price spreads in 2020 compared to 2019.

2019 Actual versus 2018 Actual

The 2019 Actual HIM revenue is $4.7M lower than the 2018 Actual due to lower average price spreads in 2019 compared to 2018.

The 2019 Actual SMO revenue is $2.7M lower than 2018 Actual. There were no net revenues for 2019 due to lack of commercial opportunity resulting from the COVID-19 pandemic.

The 2019 Actual Capacity Exports revenue is $2.2M lower than 2018 Actual due to a decrease in the amount of capacity clearing the NYISO capacity auction in 2019.

2018 Actual versus 2017 Actual

The 2018 Actual Ancillary Services revenue is $8.1M lower than 2017 Actual mostly due to lower OR and RSVC revenues.

The 2018 Actual ICAP revenue is $1.7M higher than 2017 Actual due to more capacity commitments being made to NYISO.

The 2018 Actual HIM revenue is $1.4M lower than 2017 Actual due to lower average price spreads in 2018 compared to 2017.

2017 Actual versus 2016 Actual

The 2017 Actual Ancillary Services revenue is $8.5M higher than 2016 Actual due to higher Regulation Service, OR, and RSVC revenues.

The 2017 Actual SMO revenue is $2.7M higher than 2016 Actual due to higher energy prices in 2017 compared to 2016.

The 2017 Actual HIM Revenue is $1.7M lower than 2016 Actual due to higher inflows throughout the freshet and summer months of 2017, which lead to a higher unintended benefit adjustment when compared to 2016.

Numbers may not add due to rounding.

Updated: 2026-03-10
EB-2025-0297
Exhibit G1
Tab 1
Schedule 2
Table 1

Table 1
Comparison of Other Revenues - Regulated Hydroelectric ($M)

Line No.	Business Unit	2016 Actual	(c)-(a) Change	2017 Actual	(e)-(c) Change	2018 Actual	(g)-(e) Change	2019 Actual	(i)-(g) Change	2020 Actual	(k)-(i) Change	2021 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**Ancillary Services[1]**	70.1	8.5	78.7	(8.1)	70.5	1.3	71.8	(16.3)	55.5	(5.4)	50.1
2	**Segregated Mode of Operation[2]**	0.4	2.7	3.1	(0.4)	2.7	(2.7)	0.0	(0.0)	0.0	0.0	0.0
3	**Water Transactions[3]**	1.1	(0.3)	0.9	0.7	1.6	(0.7)	0.9	(0.7)	0.2	0.4	0.6
4	**Capacity Exports[4]**	0.1	0.4	0.6	1.7	2.3	(2.2)	0.2	(0.2)	0.0	0.4	0.4
5	**Total Ancillary Services**	71.8	11.4	83.2	(6.1)	77.1	(4.3)	72.8	(17.2)	55.7	(4.6)	51.1
6	**HIM Revenue**	14.0	(1.7)	12.3	(1.4)	10.9	(4.7)	6.2	(1.1)	5.1	11.7	16.8
7	**Total of Other Revenues**	85.8	9.7	95.5	(7.5)	88.0	(9.0)	79.0	(18.3)	60.7	7.1	67.8

Line No.	Business Unit	2021 Actual	(c)-(a) Change	2022 Actual	(e)-(c) Change	2023 Actual	(g)-(e) Change	2024 Actual	(i)-(g) Change	2025 Budget	(k)-(i) Change	2026 Budget
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
8	**Ancillary Services[1]**	50.1	21.5	71.6	(9.3)	62.3	(3.7)	58.5	(2.4)	56.1	(4.6)	51.5
9	**Segregated Mode of Operation[2]**	0.0	8.0	8.0	(7.7)	0.4	0.9	1.2	0.7	1.9	0.0	1.9
10	**Water Transactions[3]**	0.6	0.0	0.6	1.0	1.6	1.9	3.5	(2.2)	1.3	0.0	1.3
11	**Capacity Exports[4]**	0.4	(0.4)	0.0	1.5	1.5	1.5	3.0	(2.0)	1.0	0.0	1.0
12	**Total Ancillary Services**	51.1	29.1	80.2	(14.4)	65.8	0.5	66.4	(6.0)	60.3	(4.6)	55.8
13	**HIM Revenue**	16.8	(2.5)	14.3	0.5	14.8	13.6	28.4	(17.8)	10.5	9.7	20.2
14	**Total of Other Revenues**	67.8	26.6	94.5	(13.9)	80.6	14.2	94.7	(23.9)	70.9	5.1	76.0

Line No.	Business Unit	2026 Budget	(c)-(a) Change	2027 Plan	(e)-(c) Change	2028 Plan	(g)-(e) Change	2029 Plan	(i)-(g) Change	2030 Plan	(k)-(i) Change	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
15	**Ancillary Services[1]**	51.5	(2.4)	49.1	0.9	50.0	0.9	50.9	0.7	51.6	(0.0)	51.6
16	**Segregated Mode of Operation[2]**	1.9	0.0	1.9	0.0	1.9	0.0	1.9	0.0	1.9	0.0	1.9
17	**Water Transactions[3]**	1.3	0.0	1.3	0.0	1.3	0.0	1.3	0.0	1.3	0.0	1.3
18	**Capacity Exports**	1.0	0.0	1.0	0.0	1.0	0.0	1.0	0.0	1.0	0.0	1.0
19	**Total Ancillary Services**	55.8	(2.4)	53.3	0.9	54.3	0.9	55.1	0.7	55.8	(0.0)	55.8
20	**HIM Revenue**	20.2	(2.4)	17.8	(9.6)	8.2	1.0	9.2	4.5	13.7	(1.3)	12.4
21	**Total of Other Revenues[4]**	76.0	(4.8)	62.2	(8.7)	62.5	1.9	64.3	5.2	69.5	(1.3)	68.2

Notes:

1 Ancillary Services related to regulated hydroelectric facilities are discussed in Ex. G1-1-1, Section 3.

2 Segregated Mode of Operation (SMO) net revenues are gross revenues less HOEP, less export fees, transmission charges in other control areas, transmission losses, production losses during the switching process between control areas and costs associated with the non-regulated Trading business.

3 Water Transactions revenues are gross revenues net of accommodation charges and Gross Revenue Charges (GRC).

4 2027 Total of Other Revenues includes 50% of the HIM Revenue forecast as described in Ex. G1-1-1, Section 7.

BRUCE GENERATING STATIONS – REVENUES AND COSTS

1.0 PURPOSE

This evidence presents the revenues earned by OPG under the Bruce lease agreement and associated agreements (collectively, "Bruce Lease") and the related costs incurred by OPG with respect to the Bruce Nuclear Generating Stations ("Bruce stations").

2.0 OVERVIEW

OPG leases the Bruce A (Units 1-4) and Bruce B (Units 5-8) Nuclear Generating Stations and associated lands and facilities to Bruce Power L.P. ("Bruce Power"). The Second Amended and Restated Bruce Lease Agreement ("Bruce Lease Agreement") as further amended, restated or replaced from time to time, sets out the main terms and conditions of the lease arrangement between OPG and Bruce Power, including lease payments.

In addition, OPG and Bruce Power have signed a number of associated agreements for the provision of services by OPG to Bruce Power or by Bruce Power to OPG. These agreements include the Amended and Restated Used Fuel Waste and Cobalt-60 Agreement ("Used Fuel Agreement"), the Amended and Restated Low and Intermediate Level Waste Agreement ("L&ILW Agreement"), and the Amended and Restated Bruce Site Services Agreement ("BSSA"), each as further amended, restated or replaced from time to time.

Bruce Power has options to renew the lease to December 31, 2064. OPG's IR term forecasts assume that Bruce Power will exercise its options to renew the lease.

The treatment of revenues and costs associated with the Bruce Lease Agreement and associated agreements, including the methodology for assigning and allocating such revenues and costs, is unchanged from previous OPG proceedings since EB-2007-0905.

For the IR term , the net amounts of Bruce Lease revenues and costs are forecast to be -$5.2M for 2027, $11.5M for 2028, -$18.1M for 2029, $7.3M for 2030, and -$17.1M for 2031 as shown

in Ex. G2-2-1, Table 1. In accordance with O. Reg. 53/05 and the OEB's previous findings,[1] as applicable, these net amounts reduce or are applied towards the nuclear revenue requirements. Specifically, sections 6(2)9 and 6(2)10 of the O. Reg. 53/05 provide that the OEB shall ensure that OPG recovers all the costs it incurs with respect to the Bruce stations, and that any revenues earned from the Bruce Lease in excess of costs be used to offset the nuclear payment amounts. Forecast revenues and costs applied towards the nuclear revenue requirements are trued-up to the actual revenues and costs through the Bruce Lease Net Revenues Variance Account.

Section 3.0 considers revenues from the Bruce Lease Agreement and associated agreements. Section 4.0 considers the costs incurred by OPG associated with the Bruce Lease. Discussion of Bruce Lease revenues and costs for the years 2020-2031 is provided in Sections 3.5 and 4.10, respectively.

3.0 BRUCE LEASE REVENUES

The forecast Bruce Lease revenues for the IR term are $235.3M for 2027, $257.0M for 2028, $230.2M for 2029, $264.5M for 2030, and $233.7M for 2031. Actual Bruce Lease revenues earned by OPG during the 2020-2024 period and the Bruce Lease revenues forecast to be earned during the 2025-2031 period are summarized in Ex. G2-2-1, Table 2. As in prior payment amounts proceedings, OPG derives revenues from the Bruce Lease Agreement and associated agreements as further described in Sections 3.1-3.4 below.

3.1 Bruce Lease Agreement Revenues

Revenues from the Bruce Lease consist of base rent and supplemental rent. Base rent is discussed in Section 3.1.1 and supplemental rent is discussed in Section 3.1.2.

[1] Decision and Order, EB-2016-0152, December 28, 2017, p. 91; Decision with Reason, EB-2013-0321, November 20, 2014, p.107; Decision with Reasons, EB-2010-0008, March 10, 2011, pp.100-101; Decision with Reasons, EB-2007-0905, November 3, 2008, pp. 105-112.

3.1.1 Base Rent Revenue

Pursuant to the Bruce Lease Agreement, Bruce Power paid OPG specified base rent payments for each year of the initial lease term up to the end of 2018. After the initial one-year renewal term in 2019, Bruce Power pays OPG base rent of $32M (2018$) for each subsequent two-year renewal period, upfront. These renewal payments are subject to Consumer Price Index ("CPI") escalation and are generally intended to cover the executory costs incurred by OPG in connection with the lease.[2]

As per the OEB's direction, OPG continues to determine lease revenue in accordance with GAAP for non-regulated businesses. As in prior OPG proceedings, this requires the application of a straight-line basis to determine lease revenue by dividing the total expected base rent revenues, excluding any payments intended to cover the lessor's executory costs, by the number of years in the expected lease term as determined for accounting purposes. Given that the full amount of base rent receivable since 2019 is considered to be for executory costs, the annual straight-line revenue amount remains fixed at $9.1M based on the base rent payments received prior to 2019 and the expected lease term for accounting purposes to the end of 2064.[3] The renewal base rent payments received beginning in 2019 are generally recognized on the same basis as the related executory costs. Accordingly, the forecast annual base rent revenue in this Application is a combination of the above fixed straight-line amount and one-half of the respective two-year renewal base rent payment. For the IR term, the resulting forecast base rent revenue increases gradually from $28.8M in 2027 to $30.4M in 2031.

Base rent revenue amounts are set out in Ex. G2-2-1, Table 2.

[2] An additional base rent (positive or negative) was introduced pursuant to an amendment to the Bruce Lease Agreement entered in 2024, as a mechanism to true-up recovery of certain OPG's costs related to the management of non-routine waste generated as part of Bruce Power's Major Component Replacement ("MCR") program. Any revenue related to this provision is included in low and intermediate level waste services revenues. Refer to Section 3.3 for further details.

[3] See EB-2020-0290, Ex. G2-02-Staff-318, Chart 1, columns [A] and [B].

3.1.2 Supplemental Rent Revenue

The monthly supplemental rent payable to OPG in addition to base rent represents the volumetric cost-based fee for managing Bruce Power's used fuel. OPG holds the liability for the interim storage and future disposal of the used fuel waste from the Bruce A and Bruce B reactors under the Used Fuel Agreement.

The costs used to determine the per fuel bundle fee (for all Bruce units) are based on the prevailing Ontario Nuclear Funds Agreement ("ONFA") Reference Plan estimates and are subject to annual CPI escalation. Accordingly, supplemental rent varies each period with the number of fuel bundles discharged by Bruce Power into the irradiated fuel bays. Supplemental rent payments are also subject to a retrospective true-up adjustment to address any over or under-recovery of cost estimates, based on the most recent approved ONFA Reference Plan, for the used fuel discharged from January 1, 2016 onwards. The adjustment is payable or refundable over the remaining expected life of the longest running Bruce unit, less five years, and is reset following each approved ONFA Reference Plan.

Aside from the retrospective true-up adjustment, supplemental rent revenue is recognized on a cash basis for financial accounting purposes, as it is not a fixed amount. Each retrospective true-up adjustment is recognized as an increase or decrease to revenue, in full, in the period it is determined based on an approved ONFA Reference Plan. The forecast annual supplemental rent revenue is set out in Ex. G2-2-1 Table 2, ranging from $169.9M to $218.1M over the IR term. The year-over-year variability in the revenue is discussed further in Section 3.5.

3.2 Spent Cobalt-60 Revenues under the Used Fuel Agreement

Under the Used Fuel Agreement, OPG holds the liability for the interim storage and future disposal of Bruce Power's spent Cobalt-60 and, in return, receives payments from Bruce Power. As set out in Ex. G2-2-1, Table 2, the revenue from Bruce Power's Cobalt-60 storage and disposal services ranges from $0.7M to $0.8M per year during the IR term. Revenues for Cobalt-60 storage and disposal services are recorded as the services are provided.

3.3 Low and Intermediate Level Waste Agreements Revenues

Under the L&ILW Agreement, OPG manages the routine L&ILW received from Bruce Power.[4] In return for these services, Bruce Power pays OPG a volumetric, cost-based fee. The current agreement requires OPG to maintain the capacity to accept all of the L&ILW generated on the leased premises by or on behalf of Bruce Power. Similar to the used fuel fees (i.e., supplemental rent), the costs used to determine the volumetric fee rates are based on the prevailing ONFA Reference Plan estimates and are subject to annual CPI escalation. L&ILW fees are also subject to a retrospective true-up adjustment to address any over or under-recovery of cost estimates, based on the most recent approved ONFA Reference Plan, for the wastes received from January 1, 2016 onwards. The adjustment is payable or refundable over the remaining expected life of the longest running Bruce unit, less five years, and is reset following each approved ONFA Reference Plan.

Since 2020, OPG and Bruce Power have entered into three supplemental agreements to the L&ILW Agreement related to non-routine waste generated as part of Bruce Power's Major Component Replacement program ("MCR Supplemental Waste Agreements"). These agreements require Bruce Power to pay upfront fees determined on the basis of OPG's estimated costs of managing such L&ILW (e.g., steam generators and reactor pressure tubes) received from Bruce Power as a result of the MCRs for Bruce Units 6, 3 and 4, respectively. OPG expects to enter into a similar agreement for the MCR for Bruce Unit 5 by 2026. The corresponding revenues are reflected as L&ILW services revenues in 2020 and 2021 for Unit 6, 2024 and 2025 for Unit 3, 2025 and 2026 for Unit 4, and 2027 and 2028 for Unit 5.

In 2024, the parties amended the Bruce Lease Agreement and L&ILW Agreement to implement a true-up mechanism for certain cost estimates underpinning the fees payable by Bruce Power under the MCR Supplemental Waste Agreements. Under this mechanism, eligible costs are updated as additional base rent (positive or negative), based on the most recent approved ONFA Reference Plan, with any differences amortized over the remaining expected life of the longest running Bruce unit, less five years. The mechanism is intended to address the

[4] The L&ILW Agreement does not include non-routine waste generated as part of Bruce Power's Major Component Replacement program.

uncertainty and risk inherent in estimating future costs of managing the waste.

Revenues under the L&ILW Agreement and the MCR Supplemental Waste Agreements are recorded as the services are provided. Each retrospective true-up adjustment for routine or MCR waste fees, as applicable, is recognized as an increase or decrease to revenue, in full, in the period it is determined based on an approved ONFA Reference Plan. The forecast L&ILW services revenues are forecast to range from $14.6M to $35.3M over the IR term, as shown in Ex. G2-2-1, Table 2. The year-over-year variability in the revenue is discussed further in Section 3.5.

3.4 Bruce Site Services Agreement Revenues

The BSSA provides for various support and maintenance services that are provided by OPG to Bruce Power, and Bruce Power to OPG, on a cost recovery basis. The services contemplated by this agreement are necessary to accommodate the joint occupancy and use of the Bruce site by OPG and Bruce Power. OPG's site services revenues are set out in Ex. G2-2-1, Table 2 and are forecasted to range from $0.5M to $0.6M per year during the IR term.

Together, revenues under the L&ILW Agreement, the MCR Supplemental Waste Agreements and the BSSA, as well as spent Cobalt-60 revenues, comprise the services component of OPG's revenues from Bruce Power.

3.5 Comparison of Revenues

A comparison of revenues from the Bruce Lease for the 2020-2031 period is provided in Ex. G2-2-1, Tables 3a and 3b. Total annual revenues over the period range from $169.6M to $269.3M.

The fluctuations in services revenue over 2020-2031, from a low of $3.6M in 2022 to a high of $51.6M in 2024, primarily reflects variability in routine L&ILW volumes being received from Bruce Power, a decrease in revenue recognized in 2022 for the retrospective true-up adjustment of the routine waste fees under the L&ILW Agreement based on the 2022 ONFA Reference Plan cost estimates, and revenues under the MCR Supplemental Waste

Agreements in certain years. As in previous proceedings, OPG projects revenues under the L&ILW Agreement based on information received from Bruce Power regarding forecasted routine L&ILW volumes, while the actual waste volumes received are affected by the operations and refurbishment of the Bruce units. As noted in Section 3.3, the services revenue over the period includes revenue under the MCR Supplemental Waste Agreements in 2021 and each of 2024-2028.

Actual services revenue was above the OEB-approved amount in 2021 mainly due to revenues received under the MCR Supplemental Waste Agreement for Bruce Unit 6. The 2022 actual amounts were below the OEB-approved amount mainly due to a decrease in revenue recognized for the retrospective true-up adjustment of the routine waste fees under the L&ILW Agreement based on the 2022 ONFA Reference Plan cost estimates. In 2023, actual amounts were below the OEB-approved amount mainly due to lower than forecasted volumes of routine L&ILW waste received. In 2024, actual amounts were above the OEB-approved amount mainly due to revenues received under the MCR Supplemental Waste Agreement for Bruce Unit 3. Forecasted services revenue is above the OEB-approved amounts in 2025 and 2026 mainly due to revenues forecasted under the MCR Supplemental Waste Agreements for Bruce Unit 3 (in 2025) and Unit 4 (in 2025 and 2026).

Actual base rent revenue increased from $25.4M in 2020 to $28.0M in 2024 and is expected to continue to modestly increase to $30.4M in 2031, as forecast executory costs escalate at a CPI rate annually. There were no significant variances to OEB-approved amounts.

The fluctuations in supplemental rent revenue over 2020-2031, from a low of $139.7M in 2022 to a high of $218.1M in 2030, primarily reflect variability in the number of fuel bundles being discharged from the Bruce reactors. Such variability, together with differences in per fuel bundle fees, is also the primary reason for the supplemental rent revenue variance against the OEB-approved amounts in 2024-2026. As in previous proceedings, OPG projects supplemental rent revenues based on information received from Bruce Power regarding the forecasted number of used fuel bundles, while the actual number of fuel bundles discharged is affected by the operations and refurbishment of the Bruce units.

The discharged fuel bundles include those arising during the defueling of the Bruce units as they are taken offline for refurbishment as part of Bruce Power's MCR program. During the historical years, defuelling took place in 2020 (Unit 6) and 2023 (Unit 3). Defuelling estimates for the four remaining Bruce units to undergo refurbishment (Unit 4, Unit 5, Unit 7, and Unit 8) are reflected in the forecast period, based on information received from Bruce Power. These one-time increases in used fuel bundles are the main reason for the higher supplemental rent revenue amounts in the respective years. Otherwise, supplemental rent revenue is lower as Bruce units are offline for refurbishment.

4.0 BRUCE LEASE COSTS

For the IR term, the Bruce Lease costs forecast to be incurred by OPG are $240.5M for 2027, $245.5M for 2028, $248.3M for 2029, $257.1M for 2030, and $250.7M for 2031. Actual Bruce Lease costs incurred by OPG in the 2020-2024 period and forecast costs for the 2025-2031 period are summarized in Ex. G2-2-1, Table 1 and are further detailed in Ex. G2-2-1, Table 5. The categories of costs incurred by OPG with respect to the Bruce stations are consistent with those presented in the previous proceedings. Certain relatively minor costs incurred by OPG with respect to the Bruce stations, including services provided under the BSSA and for contract management oversight and administration, continue to be reflected in other aspects of OPG's nuclear revenue requirement and do not form part of the Bruce Lease net revenues.

4.1 Depreciation

Depreciation is calculated on the historical fixed assets owned by OPG at the Bruce site and leased to Bruce Power. These fixed assets primarily comprise the associated asset retirement costs ("ARC") shown in Ex. C2-1-1, Table 3. OPG applied the same methodology and depreciation policy as in previous proceedings, summarized in Ex. F4-1-1, to derive the depreciation expense for the 2020-2031 period. The average depreciation expense is forecast at $44.3M per year over the IR term, based on the closing December 31, 2024 Bruce station fixed asset balances. The continuity of Bruce fixed asset balances for the 2020-2031 period is presented in Ex. G2-2-1, Table 4.[5]

[5] There are no additions to the Bruce fixed assets, except for accounting changes to ARC, as any additions to the leased property made by Bruce Power are not recorded in OPG's accounting records.

4.2 Property Tax

Pursuant to the provisions of the Bruce Lease Agreement, OPG continues to pay property taxes for the Bruce site as a whole. OPG manages the annual tax assessment process and payments of municipal property taxes to the Municipality of Kincardine and payments-in-lieu of property tax to the Ontario Electricity Financial Corporation, as described in Ex. F4-2-1, Section 6.0. The average property tax cost is forecast at $15.7M per year during the IR term.

4.3 Accretion

Accretion expense represents the growth in the present value-based asset retirement obligation ("ARO") due to the passage of time. The forecast accretion expense for 2025-2031 is derived by reference to the December 31, 2024 ARO balances attributed to the Bruce stations in OPG's 2024 year-end consolidated financial statements, using the same methodology as in previous proceedings. The recovery methodology for OPG's nuclear liabilities costs, including accretion expense, is discussed in further detail in Ex. C2-1-1. The continuity schedule for the Bruce stations' portion of the ARO is presented in Ex. C2-1-1, Table 3. The average accretion expense is forecast at $628.0M per year during the IR term.

4.4 Earnings on Nuclear Segregated Funds

OPG includes the portion of earnings from investments in the nuclear segregated funds attributed to the Bruce stations as a negative cost associated with these stations. These funds are maintained by OPG in accordance with the ONFA to provide funding for the long-term programs of the nuclear liabilities for the existing facilities. Discussed further in Ex. C2-1-1, the segregated fund earnings form part of the OEB-approved methodology for recovery of costs associated with OPG's nuclear liabilities for the Bruce facilities. The forecast segregated fund earnings for the 2025-2031 period are determined using the same methodology as in previous proceedings, by reference to the actual closing balance of the funds attributable to the Bruce stations as reflected in OPG's 2024 year-end consolidated financial statements. The continuity schedule for the portion of the segregated funds attributable to the Bruce stations is presented in Ex. C2-1-1, Table 3. The average earnings on the segregated funds are forecast at $537.6M per year during the IR term.

4.5 Used Fuel Storage and Disposal Costs

As discussed in Ex. C2-1-1, OPG incurs variable costs associated with the storage and disposal of incremental used nuclear fuel produced at the OPG-owned nuclear stations, including the stations on lease to Bruce Power. These costs are included as expenses related to the applicable nuclear facilities in the period incurred and are presented as part of the nuclear fuel expense in OPG's consolidated financial statements. The average used fuel storage and disposal variable expenses are forecast at $69.9M per year during the IR term.

4.6 Waste Management Variable Expenses, Facilities Removal and Other Costs

As discussed in Ex. C2-1-1, OPG incurs variable costs associated with managing incremental L&ILW produced at the OPG-owned nuclear facilities, including the stations on lease to Bruce Power. In addition to routine waste received from Bruce Power, this includes incremental nuclear liabilities' costs incurred for any non-routine waste received under an MCR Supplemental Waste Agreement. Waste management variable costs are included as expenses related to the applicable nuclear facilities in the period incurred and are presented as part of OM&A expenses in OPG's consolidated financial statements. Any facilities removal costs or costs not otherwise categorized in this evidence that may be incurred by OPG to meet its obligations under the Bruce Lease are also included in this category of expenses. The average waste management variable expenses, facilities removal and other costs are forecast at $12.1M per year during the IR term per Ex. C2-1-1 Table 3, of which all costs relate to waste management variable expenses.

4.7 Interest

Interest related to the Bruce assets represents an allocation of the actual/forecast corporate-wide accounting interest expense after attributing interest related to specific projects and other investments to appropriate OPG businesses. As in EB-2020-0290, the allocation is based on a forecast of the proportion of the average net book value of the fixed assets leased to Bruce Power relative to the total average net book value of OPG's in-service fixed assets (including intangible assets and excluding in-service assets with specific attributed debt). The average interest expense over the IR term is forecast at $17.5M per year as shown on Ex. G2-2-1, Table 5.

4.8 Current Income Taxes

Current income taxes for the Bruce assets are calculated in accordance with the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by the *Electricity Act, 1998* and related regulations. These are the applicable pieces of legislation that together form the basis for OPG's overall payments in lieu of corporate income taxes. The amount of taxes is determined by applying the enacted statutory tax rate to taxable income. Taxable income is computed by making adjustments, in accordance with applicable legislation, to the Bruce assets' stand-alone accounting earnings before tax determined in accordance with US GAAP, for items with different accounting and tax treatment. The adjustments for 2020-2031 are consistent with those presented in prior OPG applications, subject to the incorporation of the excessive interest and financing expenses limitation ("EIFEL") rules, which took effect under the *Income Tax Act* (Canada) for taxation years beginning on or after October 1, 2023. As further discussed in Ex. F4-2-1, Section 3.2.9, the EIFEL rules can restrict the tax-deductible amounts of net interest and financing expenses for affected enterprises. The overall average current income tax expense is a forecast credit of $20.2M per year during the IR term. In addition to the above calculation of corporate income taxes.

4.9 Deferred Income Taxes

Deferred income taxes generally represent the amount of tax that will be payable/recoverable in the future upon reversal of temporary differences between the tax basis and the accounting carrying value of items recorded in the current year.[6] The deferred income tax expense is determined in accordance with GAAP for unregulated entities. The actual (2020-2024) and forecast (2025-2031) deferred income taxes are calculated on a stand-alone basis using the actual/forecast Bruce Lease revenue and Bruce Lease costs, as shown in Ex. G2-2-1, Tables 7 and 8. These calculations are consistent with those presented in prior OPG applications. The average deferred income tax expense is forecast at $21.6M per year during the IR term.

[6] EB-2013-0321, Ex. G2-2-1, Section 5.9.

4.10 Comparison of Bruce Costs

A comparison of Bruce Lease costs for 2020-2031 is set out in Ex. G2-2-1, Tables 6a and 6b.

4.10.1 Depreciation

After decreasing from $69.6M in 2020 to $52.4M in 2022 and then to $44.3M in 2024, depreciation expense is expected to be stable over the remaining period to 2031. The decrease in 2022 was due to the year-end 2021 decrease in the Bruce stations' ARC of $599.9M, reflecting the 2022 ONFA Reference Plan update. In 2024, the year-end 2023 decrease in the Bruce stations' ARC of $314.3M, related to the extension of the accounting end-of-life dates for Pickering Units 5-8. Actual/forecasted depreciation expense is lower than the OEB-approved amounts from 2022-2026 for the same reasons. The ARC adjustments are discussed in Ex. C2-1-1.

4.10.2 Property Tax

Property tax expense increases gradually over the 2020-2031 from $12.3M in 2020 to $16.3M in 2031. Actual and budget property tax expenses are largely in line with OEB-approved from 2021-2026. Increase in the forecast property tax over the IR term reflects inflationary increases.

4.10.3 Accretion

Accretion expense decreased by $8.7M in 2022 over 2021, primarily due to the year-end 2021 decrease in the Bruce stations' ARO of $599.9M reflecting the 2022 ONFA Reference Plan update. Accretion expense in 2024 was substantially unchanged from 2023, as the impact of the year-end 2023 decrease in the Bruce stations' ARO of $438.7M related to the extension of the accounting end-of-life dates for Pickering Units 5-8 was largely offset by normal present value growth of the liability due to the passage of time. For the remainder of the period to 2031, the gradual increase in accretion expense is primarily a result of normal present value growth of the liability due to the passage of time. By 2031, forecast accretion expense is $668.1M. Adjustments to ARO are discussed in Ex. C2-1-1.

Actual 2020 and 2021 accretion expenses were higher than the OEB-approved amounts, primarily due to the impact of the year-end 2017 ARO adjustment related to changes in the

accounting end-of-life dates for Pickering and lower expenditures against the ARO. Actual 2022 and 2023 accretion expenses were lower than the OEB-approved amount, mainly due to the year-end 2021 decrease in the Bruce stations' ARO. Actual and forecast accretion expense for 2024 to 2026 is lower than the OEB-approved amounts, mainly due to the combination of the year-end 2021 and year-end 2023 decreases to the Bruce stations' ARO.

4.10.4 Earnings on Nuclear Segregated Funds

The variability in the nuclear segregated funds earnings over the historical years primarily reflects a combination of the growth rate per the prevailing approved ONFA Reference Plan of 5.15% per annum, the impact of the contribution amounts pursuant to the prevailing ONFA contribution schedule, disbursements, and an adjustment to the accounting value of the funds recorded in 2022 to reflect the change in the funding liabilities as a result of the 2022 ONFA Reference Plan. As discussed further in Ex. C2-1-1, when both the Decommissioning Segregated Fund and the Used Fuel Fund are in a surplus position, as was the case during the historical period, fund asset values recognized for accounting purposes are limited by the funding liabilities and fund earnings are recorded at the rate of growth of the funding liabilities per the prevailing ONFA Reference Plan.

For 2025-2031, nuclear segregated fund earnings are forecast at a rate of 5.15% per annum consistent with the 2022 ONFA Reference Plan, which, together with the contribution amounts pursuant to the 2022 ONFA Contribution Schedule and projected disbursements, results in gradual increases in the earnings averaging approximately $17.0M per year over the period. By 2031, nuclear segregated fund earnings are forecast to reach $578.7M.

Actual 2020 nuclear segregated fund earnings were higher than the OEB-approved amount, primarily due to lower fund disbursements and a higher portion of the earnings attributable to the Bruce facilities. Actual 2022 nuclear segregated fund earnings were higher than the OEB-approved amount, primarily due to an adjustment to the accounting value of the funds to reflect the change in the funding liabilities as a result of the 2022 ONFA Reference Plan. Forecasted 2025 and 2026 nuclear segregated fund earnings are lower than the OEB-approved amount, primarily due to higher cumulative contribution amounts pursuant to the prevailing ONFA

contribution schedule and higher cumulative actual and forecast disbursements. There are no significant variances relative to the OEB-approved amounts for the remaining historical and bridge years.

4.10.5 Used Fuel Storage and Disposal Costs

The variability in the used fuel storage and disposal variable expenses over the historical and bridge years and the IR term, from a low of $57.2M in 2026 to a high of $96.7M in 2023, primarily reflects a combination of the variability in the number of fuel bundles loaded into the Bruce reactors and changes in the per fuel bundle cost rates following each ARO adjustment recorded during the period. The number of actual and forecasted fuel bundles is based on information received from Bruce Power and, beginning in 2020, includes the effects of Bruce Power's ongoing MCR program, both from lower utilization of bundles due to the MCR outages and from higher utilization reflecting initial fuel loads into the refurbished reactors.[7]

The higher expenses in 2021 also reflected the impact of the year-end 2020 ARO adjustment related to changes in the accounting end-of-life dates for Pickering Units 1 and 4, which resulted in an increase in per fuel bundle cost rates due to a lower discount rate of 2.01% compared to the discount rate of 2.94% in effect prior to 2021.[8] The lower expenses in 2024 reflected the impact of the year-end 2023 ARO adjustment related to the extension of the accounting end-of-life dates for Pickering Units 5-8, which resulted in a decrease in per fuel bundle costs rates due to a higher discount rate of 3.93%.

Differences in used fuel variable expenses relative to OEB-approved amounts in the historical period are primarily a result of higher per bundle costs rates in 2021, 2022, and 2023, as discussed above. In 2025 and 2026, forecast used fuel variable expenses are lower than the OEB-approved amounts, primarily as a result of differences in the number of fuel bundles projected to be loaded into the Bruce reactors.

[7] Used fuel variable expenses are recognized at the time fuel is loaded into a reactor and becomes irradiated.
[8] EB-2020-0290, Ex. C2-1-1, Sections 4.1.2.

4.10.6 Waste Management Variable Expenses, Facilities Removal and Other Costs

The higher waste management variable expenses, facilities removal costs and other costs of $19.6M in 2021 reflected incremental costs related to the receipt of waste under the MCR Supplemental Waste Agreement for Bruce Unit 6, as well as a one-time cost incurred as part of a settlement reached with British Energy Limited and British Energy International Holdings Limited (together, "British Energy"), as an initial owner of Bruce Power, regarding their claim of contribution and indemnity from OPG for amounts British Energy was found liable for in an arbitration commenced against it by purchasers of British Energy's interest in Bruce Power. The action and arbitration pertained to corrosion of a steam generator unit, discovered after OPG leased the Bruce stations to Bruce Power. The higher actual/forecast expenses averaging $18.2M over 2024-2028 reflect incremental costs related to the actual or anticipated receipt of waste under the MCR Supplemental Waste Agreements for Bruce Unit 3, Unit 4, and Unit 5.

In addition to the above factors, differences in waste management variable expenses, facilities removal and other costs relative to OEB-approved amounts in the historical and bridge periods reflect higher volumetric L&ILW cost rates based on the 2022 ONFA Reference Plan update beginning in 2022. Over the 2020-2031 period, expenses also reflect variability in routine waste volumes received from, or projected to be received based on information provided by, Bruce Power.

4.10.7 Interest

The interest expense associated with the Bruce assets decreased over the historical period, from $23.1M in 2020 to $5.6M in 2024, primarily due to a lower allocation factor for the Bruce assets, reflecting increases in-service assets for OPG's prescribed facilities and decreases in the Bruce fixed assets owing to the year-end 2021 and 2023 ARO and ARC adjustments. Beginning in 2027, the interest expense associated with the Bruce assets is forecasted to increase, peaking at $25.3M in 2030 before declining to $18.6M in 2031. This reflects an increase in OPG's corporate debt levels, partly offset by a declining allocation factor for the Bruce assets due to increases in in-service assets for OPG's prescribed facilities, including upon return to service of Pickering Unit 5 from refurbishment in 2031.

The actual/forecasted interest expense associated with the Bruce assets is lower than the OEB-approved amounts for 2020-2026, mainly due to a lower allocation factor for the Bruce assets. For 2020 and 2021, this was mainly due to the use of a historical allocation factor to determine the EB-2016-0152 forecast amounts, which did not reflect the decrease in the Bruce fixed assets resulting from the subsequent year-end 2016 ARO and ARC adjustment reflecting the 2017 ONFA Reference Plan. For 2022-2024, the historical allocation factor used to determine the EB-2020-0290 forecast amounts similarly did not reflect the subsequent decreases in the Bruce fixed assets resulting from the year-end 2021 and year-end 2023 ARO and ARC adjustments.

4.10.8 Current Income Taxes

Actual current income tax expense in 2020, 2021, 2022, 2023 and 2024 was $33.1M, $45.0M, $69.8M, $78.0M, and $69.9M, respectively. Forecast amounts peak in 2025 at $82.5M before gradually declining to $37.3M, $25.5M, $24.3M, $10.2M, $21.2M, and $19.8M in 2026, 2027, 2028, 2029, 2030, and 2031, respectively. The higher current income taxes in years 2022-2024 were mainly due to lower nuclear segregated fund contribution amounts per the 2022 ONFA Contribution Schedule, compared to the previous approved contribution schedule in effect through 2021. The forecast peak income tax expense in 2025 is due primarily to higher segregated fund disbursements in that year. The declining trend through the IR term reflects lower forecast earnings before tax.

Actual income taxes for 2020 were lower than OEB-approved amounts mainly due to lower receipts from the nuclear segregated funds and lower Other deductible items. Actual income taxes in 2023 and 2024 and forecast income taxes in 2026 are higher than OEB-approved amounts mainly due to lower nuclear segregated fund contribution amounts per the 2022 ONFA Contribution Schedule. Forecast income taxes in 2025 are higher than OEB-approved amount due to lower nuclear segregated fund contribution amounts per the 2022 ONFA Contribution Schedule and higher earnings before tax.

4.10.9 Deferred Income Taxes

Actual deferred income taxes were -$37.0M, -$67.9M, -$81.5M, -$86.6M and -$55.8M in 2020,

2021, 2022, 2023 and 2024, respectively. Forecast deferred income taxes gradually increase and then level off through the IR term, at -$70.6M, -$28.4M, -$27.2M, -$20.5M, -$16.3M, -$18.7M and -$25.5M in 2025, 2026, 2027, 2028, 2029, 2030, and 2031, respectively. The lower deferred income tax expense in 2021 was due to temporary differences arising from higher receipts from the nuclear segregated funds and higher used fuel and waste management variable expenses. The further decline in deferred income tax expense in 2022 was primarily due to lower contributions to the nuclear segregated funds per the 2022 ONFA Contribution Schedule. The increase in deferred income tax expense in 2024 was due to higher expenditures on decommissioning, used fuel and nuclear waste management activities. This is followed by a decrease in forecast deferred income tax expense in 2025 due to higher receipts from the nuclear segregated funds, and an increase in 2026 due to higher contributions to the nuclear segregated funds. The forecast deferred income tax expense varies over the IR term, reflecting smaller year-over-year variances across a number of sources of temporary differences.

The lower receipts from the nuclear segregated funds were the primary driver of the higher deferred income tax expense in 2020 compared to the OEB-approved amount. The lower deferred income tax expense in 2021 compared to the OEB-approved amount was due to lower expenditures on decommissioning, and higher used fuel and waste management variable expenses, partially offset by lower receipts from the nuclear segregated funds. The lower deferred income tax expense than the OEB-approved amount in 2023 (actual) and 2025 (forecast) is due to higher contributions to the nuclear segregated funds per the 2022 ONFA Contribution Schedule. The higher deferred income tax expense in 2024 compared to the OEB-approved amount was due to lower depreciation and accretion expenses and higher expenditures on decommissioning, used fuel and nuclear waste management, partially offset by higher contributions to the nuclear segregated funds per the 2022 ONFA Contribution Schedule. The higher deferred income tax expense forecast in 2026 compared to the OEB-approved amount is due to higher receipts from the nuclear segregated funds, partially offset by lower depreciation and accretion expenses.

Numbers may not add due to rounding.

Table 1
Bruce Lease Net Revenues ($M)

Line No.	Item	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Bruce Lease Net Revenues:												
1	**Bruce Lease Revenues**	218.2	202.7	169.6	219.6	261.1	269.3	255.2	235.3	257.0	230.2	264.5	233.7
2	**Bruce Costs**	230.1	271.4	204.7	245.4	218.6	233.6	228.8	240.5	245.5	248.3	257.1	250.7
3	**Bruce Lease Net Revenues** (line 1 - line 2)	(11.9)	(68.7)	(35.1)	(25.8)	42.5	35.8	26.5	(5.2)	11.5	(18.1)	7.3	(17.1)

Numbers may not add due to rounding.

Table 2
Bruce Lease Revenues ($M)

Line No.	Revenue Source	Note	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	**Site Services (OPG to Bruce Power)**		0.7	0.7	0.6	0.5	1.1	0.5	0.5	0.5	0.6	0.6	0.6	0.6
2	**Low & Intermediate Level Waste Services**		21.2	29.9	2.4	14.6	50.0	46.0	29.9	35.3	25.0	24.7	14.6	23.8
3	**Cobalt-60**		0.8	0.4	0.6	0.5	0.5	0.7	0.7	0.7	0.7	0.8	0.8	0.8
4	**Total Services Revenue**		22.7	30.9	3.6	15.6	51.6	47.2	31.1	36.6	26.4	26.0	16.0	25.2
5	**Fixed (Base) Rent**		25.4	25.4	26.3	26.3	28.0	28.0	28.8	28.8	29.6	29.6	30.4	30.4
6	**Supplemental Rent**		170.2	146.5	139.7	177.7	181.5	194.1	195.3	169.9	201.0	174.5	218.1	178.0
7	**Total Rent Revenue**		195.6	171.8	166.0	204.0	209.5	222.1	224.1	198.7	230.6	204.1	248.5	208.4
8	**Total Revenue** (line 4 + line 7)		218.2	202.7	169.6	219.6	261.1	269.3	255.2	235.3	257.0	230.2	264.5	233.7

Numbers may not add due to rounding.

Table 3a
Comparison of Bruce Lease Revenues ($M)

Line No.	Business Unit	2020 OEB Approved	(c)-(a) Change	2020 Actual	(g)-(c) Change	2021 OEB Approved	(g)-(e) Change	2021 Actual	(k)-(g) Change	2022 OEB Approved	(k)-(i) Change	2022 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Note 1		Note 3		Note 1		Note 3		Note 2		Note 3
1	**Site Services (OPG to Bruce Power)**	0.7	0.0	0.7	(0.0)	0.7	0.0	0.7	(0.0)	0.5	0.1	0.6
2	**Low & Intermediate Level Waste Services**	18.6	2.6	21.2	8.7	21.6	8.3	29.9	(27.5)	18.1	(15.7)	2.4
3	**Cobalt-60**	0.5	0.2	0.8	(0.4)	0.5	(0.2)	0.4	0.2	0.6	(0.1)	0.6
4	**Total Services Revenue**	19.8	2.9	22.7	8.2	22.8	8.1	30.9	(27.3)	19.2	(15.6)	3.6
5	**Fixed (Base) Rent**	25.4	(0.0)	25.4	(0.0)	25.7	(0.4)	25.4	0.9	26.1	0.2	26.3
6	**Supplemental Rent**	174.5	(4.3)	170.2	(23.7)	140.1	6.3	146.5	(6.8)	140.4	(0.7)	139.7
7	**Total Rent Revenue**	200.0	(4.4)	195.6	(23.7)	165.9	5.9	171.8	(5.8)	166.5	(0.5)	166.0
8	**Total Revenue** (line 4 + line 7)	219.8	(1.5)	218.2	(15.5)	188.7	14.0	202.7	(33.2)	185.7	(16.1)	169.6

Line No.	Business Unit	2022 Actual	(e)-(a) Change	2023 OEB Approved	(e)-(c) Change	2023 Actual	(i)-(e) Change	2024 OEB Approved	(i)-(g) Change	2024 Actual	(k)-(i) Change	2025 Budget
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Note 3		Note 2				Note 2				
9	**Site Services (OPG to Bruce Power)**	0.6	(0.1)	0.5	(0.0)	0.5	0.6	0.5	0.6	1.1	(0.6)	0.5
10	**Low & Intermediate Level Waste Services**	2.4	12.2	23.2	(8.6)	14.6	35.5	25.1	25.0	50.0	(4.1)	46.0
11	**Cobalt-60**	0.6	(0.0)	0.7	(0.1)	0.5	(0.1)	0.7	(0.2)	0.5	0.2	0.7
12	**Total Services Revenue**	3.6	12.0	24.4	(8.8)	15.6	36.0	26.3	25.3	51.6	(4.4)	47.2
13	**Fixed (Base) Rent**	26.3	0.0	26.4	(0.1)	26.3	1.7	26.8	1.2	28.0	(0.0)	28.0
14	**Supplemental Rent**	139.7	38.1	166.8	10.9	177.7	3.7	150.7	30.8	181.5	12.7	194.1
15	**Total Rent Revenue**	166.0	38.1	193.3	10.8	204.0	5.4	177.5	32.0	209.5	12.6	222.1
16	**Total Revenue** (line 12 + line 15)	169.6	50.1	217.6	2.0	219.6	41.5	203.7	57.3	261.1	8.2	269.3

Note:

1 2020 and 2021 OEB-approved amounts per EB-2016-0152, Ex. J21.2, Attachment 1, Table 1.

2 2022 to 2026 OEB-approved amounts per EB-2020-0290, Ex. G2-2-1, Table 2.

3 2020 to 2022 actuals as shown in EB-2023-0336, Ex. H1-1-1, Table 11a.

Numbers may not add due to rounding.

Table 3b
Comparison of Bruce Lease Revenues ($M)

Line No.	Business Unit	2025 OEB Approved	(c)-(a) Change	2025 Budget	(g)-(c) Change	2026 OEB Approved	(g)-(e) Change	2026 Budget	(i)-(g) Change	2027 Plan	(k)-(i) Change	2028 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Note 1				Note 1						
17	**Site Services (OPG to Bruce Power)**	0.5	0.0	0.5	0.0	0.5	0.0	0.5	(0.0)	0.5	0.1	0.6
18	**Low & Intermediate Level Waste Services**	20.3	25.7	46.0	(16.1)	24.3	5.6	29.9	5.5	35.3	(10.3)	25.0
19	**Cobalt-60**	0.7	0.0	0.7	0.0	0.7	0.0	0.7	0.0	0.7	0.0	0.7
20	**Total Services Revenue**	21.5	25.7	47.2	(16.1)	25.5	5.6	31.1	5.5	36.6	(10.2)	26.4
21	**Fixed (Base) Rent**	27.1	0.9	28.0	0.8	27.5	1.3	28.8	0.0	28.8	0.8	29.6
22	**Supplemental Rent**	169.7	24.4	194.1	1.2	168.0	27.3	195.3	(25.4)	169.9	31.1	201.0
23	**Total Rent Revenue**	196.9	25.3	222.1	2.0	195.5	28.6	224.1	(25.4)	198.7	31.9	230.6
24	**Total Revenue** (line 20 + line 23)	218.4	50.9	269.3	(14.1)	221.0	34.2	255.2	(20.0)	235.3	21.7	257.0

Line No.	Business Unit	2028 Plan	(c)-(a) Change	2029 Plan	(e)-(c) Change	2030 Plan	(g)-(e) Change	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
25	**Site Services (OPG to Bruce Power)**	0.6	0.0	0.6	0.0	0.6	0.0	0.6
26	**Low & Intermediate Level Waste Services**	25.0	(0.4)	24.7	(10.1)	14.6	9.2	23.8
27	**Cobalt-60**	0.7	0.0	0.8	0.0	0.8	0.0	0.8
28	**Total Services Revenue**	26.4	(0.3)	26.0	(10.1)	16.0	9.2	25.2
29	**Fixed (Base) Rent**	29.6	(0.0)	29.6	0.8	30.4	0.0	30.4
30	**Supplemental Rent**	201.0	(26.5)	174.5	43.6	218.1	(40.0)	178.0
31	**Total Rent Revenue**	230.6	(26.5)	204.1	44.4	248.5	(40.0)	208.4
32	**Total Revenue** (line 28 + line 31)	257.0	(26.9)	230.2	34.3	264.5	(30.8)	233.7

Note:
1 2022 to 2026 OEB-approved amounts per EB-2020-0290, Ex. G2-2-1, Table 2.

Numbers may not add due to rounding.

Table 4

Bruce Net Fixed Assets[1] ($M)

Line No.	Item	2020 Actual [2]	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	**Opening Net Book Value**	2,822.3	2,765.7	2,096.0	2,043.6	1,676.8	1,632.5	1,588.2	1,543.9	1,499.6	1,455.4	1,411.1	1,366.8
2	**Add: Nuclear Liabilities Adjustment** [3]	13.0	(599.9)	0.0	(314.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	**Add: Additions**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	**Less: Depreciation**	69.6	69.8	52.4	52.4	44.3	44.3	44.3	44.3	44.3	44.3	44.3	44.3
5	**Closing Net Book Value**	2,765.7	2,096.0	2,043.6	1,676.8	1,632.5	1,588.2	1,543.9	1,499.6	1,455.4	1,411.1	1,366.8	1,322.6

Notes:

1 Includes asset retirement costs presented in Ex. C2-1-1, Table 3.

2 2020 Actual Opening Net Book Value from EB-2020-0290, Ex. G2-2-1,Table 4, line 5, col (d).

3 Represents change in asset retirement costs effective December 31, 2020, December 31, 2021, and December 31, 2023 as shown at Ex. C2-1-1, Table 3: line 10, col (a); line 9, col. (b); and line 10, col. (d) respectively.

Numbers may not add due to rounding.

Table 5
Bruce Costs ($M)

Line No.	Cost Item	Note	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	**Depreciation**		69.6	69.8	52.4	52.4	44.3	44.3	44.3	44.3	44.3	44.3	44.3	44.3
2	**Property Tax**		12.3	12.6	13.0	13.5	14.1	14.2	14.6	15.1	15.4	15.7	16.0	16.3
3	**Accretion**		504.1	522.3	513.6	534.1	535.7	550.5	567.3	587.8	607.6	626.9	649.5	668.1
4	**(Earnings) Losses on Segregated Funds**		(439.0)	(431.6)	(471.3)	(460.0)	(473.8)	(476.7)	(486.1)	(500.7)	(516.6)	(535.3)	(556.5)	(578.7)
5	**Used Fuel Storage and Disposal**		60.1	84.1	86.9	96.7	59.0	64.9	57.2	68.4	61.1	73.1	69.4	77.7
6	**Waste Management Expenses, Facilities Removal and Other Costs**		4.0	19.6	10.5	11.3	19.5	18.8	18.5	18.7	15.7	9.2	6.8	10.2
7	**Interest**		23.1	17.6	11.2	6.0	5.6	5.6	4.1	8.7	14.3	20.5	25.3	18.6
8	**Total Costs Before Income Tax**		234.1	294.3	216.4	254.0	204.5	221.6	219.9	242.3	241.7	254.3	254.7	256.4
9	**Income Tax - Current**		33.1	45.0	69.8	78.0	69.9	82.5	37.3	25.5	24.3	10.2	21.2	19.8
10	**Income Tax - Deferred**		(37.0)	(67.9)	(81.5)	(86.6)	(55.8)	(70.6)	(28.4)	(27.2)	(20.5)	(16.3)	(18.7)	(25.5)
11	**Total Income Tax**		(4.0)	(22.9)	(11.7)	(8.6)	14.2	11.9	8.8	(1.7)	3.8	(6.0)	2.4	(5.7)
12	**Total Costs** (line 8 + line 11)		230.1	271.4	204.7	245.4	218.6	233.6	228.8	240.5	245.5	248.3	257.1	250.7

Numbers may not add due to rounding.

Table 6a
Comparison of Bruce Costs ($M)

Line No.	Business Unit	Note	2020 OEB Approved	(c)-(a) Change	2020 Actual	(g)-(c) Change	2021 OEB Approved	(g)-(e) Change	2021 Actual	(k)-(g) Change	2022 OEB Approved	(k)-(i) Change	2022 Actual
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
			Note 7		Note 9		Note 7		Note 9		Note 8		Note 9
1	**Depreciation**		68.4	1.2	69.6	0.2	68.4	1.4	69.8	(17.4)	69.6	(17.2)	52.4
2	**Property Tax**		14.0	(1.7)	12.3	0.2	15.1	(2.5)	12.6	0.4	12.6	0.4	13.0
3	**Accretion**	1	495.8	8.2	504.1	18.3	512.4	9.9	522.3	(8.7)	537.5	(23.9)	513.6
4	**(Earnings) Losses on Segregated Funds**	2	(426.2)	(12.8)	(439.0)	7.4	(436.0)	4.5	(431.6)	(39.7)	(452.6)	(18.7)	(471.3)
5	**Used Fuel Storage and Disposal**	3	64.2	(4.2)	60.1	24.0	52.2	31.9	84.1	2.9	57.9	29.0	86.9
6	**Waste Management Expenses, Facilities Removal Costs, and Other Costs**	4	3.4	0.6	4.0	15.6	4.6	14.9	19.6	(9.0)	3.2	7.4	10.5
7	**Interest**		26.8	(3.7)	23.1	(5.5)	25.8	(8.2)	17.6	(6.4)	18.3	(7.1)	11.2
8	**Total Costs Before Income Tax**		246.4	(12.3)	234.1	60.2	242.5	51.8	294.3	(78.0)	246.5	(30.1)	216.4
9	**Income Tax - Current**	5	47.0	(13.9)	33.1	12.0	41.7	3.4	45.0	24.8	75.9	(6.1)	69.8
10	**Income Tax - Deferred**	6	(53.6)	16.6	(37.0)	(30.9)	(55.1)	(12.8)	(67.9)	(13.6)	(91.1)	9.6	(81.5)
11	**Total Income Tax**		(6.7)	2.7	(4.0)	(18.9)	(13.4)	(9.5)	(22.9)	11.2	(15.2)	3.5	(11.7)
12	**Total Costs** (line 8 + line 11)		239.8	(9.6)	230.1	41.3	229.1	42.4	271.4	(66.8)	231.3	(26.6)	204.7

Line No.	Business Unit	Note	2022 Actual	(e)-(a) Change	2023 OEB Approved	(e)-(c) Change	2023 Actual	(i)-(e) Change	2024 OEB Approved	(i)-(g) Change	2024 Actual	(k)-(i) Change	2025 Budget
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
			Note 9		Note 8				Note 8				
13	**Depreciation**		52.4	(0.0)	69.6	(17.2)	52.4	(8.1)	69.6	(25.3)	44.3	(0.0)	44.3
14	**Property Tax**		13.0	0.5	12.6	0.9	13.5	0.6	12.6	1.5	14.1	0.1	14.2
15	**Accretion**	1	513.6	20.5	556.8	(22.7)	534.1	1.6	576.7	(41.0)	535.7	14.8	550.5
16	**(Earnings) Losses on Segregated Funds**	2	(471.3)	11.3	(462.0)	2.0	(460.0)	(13.8)	(475.1)	1.3	(473.8)	(3.0)	(476.7)
17	**Used Fuel Storage and Disposal**	3	86.9	9.7	69.5	27.2	96.7	(37.7)	63.3	(4.3)	59.0	5.9	64.9
18	**Waste Management Expenses, Facilities Removal, and Other Costs**	4	10.5	0.8	4.2	7.1	11.3	8.2	4.5	15.1	19.5	(0.7)	18.8
19	**Interest**		11.2	(5.2)	18.6	(12.6)	6.0	(0.4)	16.3	(10.7)	5.6	0.0	5.6
20	**Total Costs Before Income Tax**		216.4	37.7	269.3	(15.2)	254.0	(49.6)	267.9	(63.5)	204.5	17.2	221.637
21	**Income Tax - Current**	5	69.8	8.2	48.9	29.1	78.0	(8.1)	49.8	20.1	69.9	12.6	82.5
22	**Income Tax - Deferred**	6	(81.5)	(5.1)	(61.8)	(24.8)	(86.6)	30.8	(65.9)	10.1	(55.8)	(14.8)	(70.6)
23	**Total Income Tax**		(11.7)	3.1	(12.9)	4.3	(8.6)	22.8	(16.0)	30.2	14.2	(2.2)	11.9
24	**Total Costs** (line 20 + line 23)		204.7	40.8	256.3	(10.9)	245.4	(26.8)	251.9	(33.3)	218.6	14.9	233.6

Notes:

1 2020 to 2024 Actual, 2025 to 2026 Budget, and 2027 to 2031 Plan from Ex. C2-1-1, Table 3, line 4.
2 2020 to 2024 Actual, 2025 to 2026 Budget, and 2027 to 2031 Plan from Ex. C2-1-1, Table 3, line 13.
3 2020 to 2024 Actual, 2025 to 2026 Budget, and 2027 to 2031 Plan from Ex. C2-1-1, Table 3, line 2.
4 2020 to 2024 Actual, 2025 to 2026 Budget, and 2027 to 2031 Plan from Ex. C2-1-1, Table 3, line 3.
5 2020 to 2024 Actual and 2025 Budget from Ex. G2-2-1, Table 7, line 20. 2026 Budget and 2027 to 2031 Plan from Ex. G2-2-1, Table 8, line 20 and line 21.
6 2020 to 2024 Actual and 2025 Budget from Ex. G2-2-1, Table 7, line 28. 2026 Budget and 2027 to 2031 Plan from Ex. G2-2-1, Table 8, line 28.
7 2020 and 2021 OEB-approved amounts per EB-2016-0152, Ex. J21.2, Attachment 1, Table 1.
8 2022 to 2026 OEB-approved amounts per EB-2020-0290, Ex. G2-2-1, Table 5.
9 2020 to 2022 actuals as shown in EB-2023-0336, Ex. H1-1-1, Table 11a; amount in line 18, col. (a) reflects updated calculations of the dollar per cubic metre cost rates for low and intermediate level waste based on the 2022 ONFA Reference Plan.

Numbers may not add due to rounding.

Table 6b
Comparison of Bruce Costs ($M)

Line No.	Business Unit	Note	2025 OEB Approved	(c)-(a) Change	2025 Budget	(g)-(c) Change	2026 OEB Approved	(g)-(e) Change	2026 Budget	(i)-(g) Change	2027 Plan	(k)-(i) Change	2028 Plan
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
			Note 7				Note 7						
25	**Depreciation**		69.6	(25.2)	44.3	(0.0)	69.5	(25.2)	44.3	(0.0)	44.3	0.0	44.3
26	**Property Tax**		12.6	1.6	14.2	0.4	12.6	2.0	14.6	0.4	15.1	0.3	15.4
27	**Accretion**	1	599.6	(49.1)	550.5	16.8	623.7	(56.4)	567.3	20.5	587.8	19.8	607.6
28	**(Earnings) Losses on Segregated Funds**	2	(491.0)	14.2	(476.7)	(9.4)	(510.3)	24.2	(486.1)	(14.6)	(500.7)	(15.9)	(516.6)
29	**Used Fuel Storage and Disposal**	3	72.0	(7.1)	64.9	(7.7)	59.7	(2.5)	57.2	11.2	68.4	(7.3)	61.1
30	**Waste Management Expenses, Facilities Removal, and Other Costs**	4	3.8	15.0	18.8	(0.3)	4.7	13.8	18.5	0.2	18.7	(3.0)	15.7
31	**Interest**		13.8	(8.2)	5.6	(1.5)	12.2	(8.1)	4.1	4.6	8.7	5.5	14.3
32	**Total Costs Before Income Tax**		280.3	(58.7)	221.6	(1.7)	272.1	(52.2)	219.9	22.3	242.3	(0.6)	241.7
33	**Income Tax - Current**	5	31.3	51.2	82.5	(45.3)	28.8	8.4	37.3	(11.8)	25.5	(1.2)	24.3
34	**Income Tax - Deferred**	6	(46.8)	(23.8)	(70.6)	42.2	(41.6)	13.2	(28.4)	1.2	(27.2)	6.7	(20.5)
35	**Total Income Tax**		(15.5)	27.4	11.9	(3.1)	(12.8)	21.6	8.8	(10.6)	(1.7)	5.6	3.8
36	**Total Costs** (line 32 + line 35)		264.9	(31.3)	233.6	(4.8)	259.3	(30.6)	228.8	11.8	240.5	5.0	245.5

Line No.	Business Unit	Note	2028 Plan	(c)-(a) Change	2029 Plan	(e)-(c) Change	2030 Plan	(g)-(e) Change	2031 Plan
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
37	**Depreciation**		44.3	(0.0)	44.3	0.0	44.3	(0.0)	44.3
38	**Property Tax**		15.4	0.3	15.7	0.3	16.0	0.3	16.3
39	**Accretion**	1	607.6	19.3	626.9	22.6	649.5	18.6	668.1
40	**(Earnings) Losses on Segregated Funds**	2	(516.6)	(18.7)	(535.3)	(21.2)	(556.5)	(22.2)	(578.7)
41	**Used Fuel Storage and Disposal**	3	61.1	12.0	73.1	(3.7)	69.4	8.3	77.7
42	**Waste Management Expenses, Facilities Removal, and Other Costs**	4	15.7	(6.5)	9.2	(2.4)	6.8	3.4	10.2
43	**Interest**		14.3	6.3	20.5	4.7	25.3	(6.7)	18.6
44	**Total Costs Before Income Tax**		241.7	12.6	254.3	0.4	254.7	1.8	256.4
45	**Income Tax - Current**	5	24.3	(14.1)	10.2	11.0	21.2	(1.4)	19.8
46	**Income Tax - Deferred**	6	(20.5)	4.2	(16.3)	(2.5)	(18.7)	(6.7)	(25.5)
47	**Total Income Tax**		3.8	(9.9)	(6.0)	8.5	2.4	(8.1)	(5.7)
48	**Total Costs** (line 44 + line 47)		245.5	2.8	248.3	8.8	257.1	(6.4)	250.7

Notes:

1 2020 to 2024 Actual, 2025 to 2026 Budget, and 2027 to 2031 Plan from Ex. C2-1-1, Table 3, line 4.
2 2020 to 2024 Actual, 2025 to 2026 Budget, and 2027 to 2031 Plan from Ex. C2-1-1, Table 3, line 13.
3 2020 to 2024 Actual, 2025 to 2026 Budget, and 2027 to 2031 Plan from Ex. C2-1-1, Table 3, line 2.
4 2020 to 2024 Actual, 2025 to 2026 Budget, and 2027 to 2031 Plan from Ex. C2-1-1, Table 3, line 3.
5 2020 to 2024 Actual and 2025 Budget from Ex. G2-2-1, Table 7, line 20. 2026 Budget and 2027 to 2031 Plan from Ex. G2-2-1, Table 8, line 20 and line 21.
6 2020 to 2024 Actual and 2025 Budget from Ex. G2-2-1, Table 7, line 28. 2026 Budget and 2027 to 2031 Plan from Ex. G2-2-1, Table 8, line 28.
7 2022 to 2026 OEB-approved amounts per EB-2020-0290, Ex. G2-2-1, Table 5.

Table 7
Calculation of Bruce Income Taxes ($M)
Years Ending December 31, 2020, 2021, 2022, 2023, 2024 and 2025

Line No.	Particulars	Note	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget
			(a)	(b)	(c)	(d)	(e)	(f)
	Determination of Taxable Income							
1	**Earnings (Loss) Before Tax**	1	(15.9)	(91.6)	(46.8)	(34.4)	56.6	47.7
	Additions for Tax Purposes - Temporary Differences:							
2	**Base Rent Accrual**		(9.1)	(9.1)	(9.1)	(9.1)	(9.1)	(9.1)
3	**Depreciation**		69.6	69.8	52.4	52.4	44.3	44.3
4	**Accretion**		504.1	522.3	513.6	534.1	535.7	550.5
5	**Restricted Net Interest and Financing Expenses**		0.0	0.0	0.0	0.0	0.0	0.0
6	**Used Fuel and Waste Management Expenses and Facilities Removal Costs**		64.0	92.6	97.5	108.0	78.5	83.7
7	**Receipts from Nuclear Segregated Funds**		72.7	93.7	102.0	84.0	95.0	219.6
8	**Other**		(29.4)	10.9	2.4	6.4	9.7	5.6
9	**Total Additions - Temporary Differences** (lines 2 through 8)		671.9	780.2	758.8	775.9	754.1	894.6
	Deductions for Tax Purposes - Temporary Differences:							
10	**CCA**		12.9	10.9	10.9	10.1	8.2	8.2
11	**Cash Expenditures for Used Fuel, Waste Management & Decommissioning and Facilities Removal**		174.4	168.6	150.5	159.5	249.1	243.6
12	**Contributions to Nuclear Segregated Funds**		(102.5)	(102.5)	(200.1)	(200.1)	(200.1)	(116.4)
13	**Earnings (Losses) on Nuclear Segregated Funds**		439.0	431.6	471.3	460.0	473.8	476.7
14	**Total Deductions - Temporary Differences** (lines 10 through 13)		523.8	508.5	432.6	429.5	531.1	612.1
15	**Taxable Income/(Loss) Before Loss Carry-Over** (line 1 + line 9 - line 14)		132.2	180.1	279.4	312.0	279.7	330.1
16	**Tax Loss Carry-Over to Future Years / (from Prior Years)**		0.0	0.0	0.0	0.0	0.0	0.0
17	**Taxable Income After Loss Carry-Over** (line 15 + line 16)		132.2	180.1	279.4	312.0	279.7	330.1
	Determination of Total Current Income Taxes							
18	**Taxable Income After Loss Carry-Over** (from line 17)		132.2	180.1	279.4	312.0	279.7	330.1
19	**Income Tax Rate - Current**		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
20	**Income Taxes - Current** (line 18 x line 19)		33.1	45.0	69.8	78.0	69.9	82.5
	Determination of Total Deferred Income Taxes							
22	**Total Net Temporary Differences** (line 9 - line 14)		148.1	271.7	326.1	346.4	223.1	282.5
23	**Income Tax Rate - Deferred**		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
24	**Deferred Income Taxes** (line 22 x -1 x line 23)		(37.0)	(67.9)	(81.5)	(86.6)	(55.8)	(70.6)
25	**Tax Loss / Tax Loss Carry-Over** (line 15 or line 16)		0.0	0.0	0.0	0.0	0.0	0.0
26	**Income Tax Rate**		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
27	**Deferred Income Taxes - Tax Loss / Tax Loss Carry-Over** (line 25 x line 26)		0.0	0.0	0.0	0.0	0.0	0.0
28	**Deferred Income Taxes - Total** (line 24 + line 27)		(37.0)	(67.9)	(81.5)	(86.6)	(55.8)	(70.6)
	Income Tax Rate - Current							
29	**Federal Tax**		15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
30	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
31	**Total Income Tax Rate - Current**		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
	Income Tax Rate - Long-Term							
32	**Federal Tax**		15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
33	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
34	**Total Income Tax Rate - Long-Term**		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%

Notes:
1 Earnings (Loss) Before Tax is derived as the difference between Total Revenues in Ex. G2-2-1 Table 2, Line 8 and Total Costs Before Income Tax in Ex. G2-2-1 Table 5, Line 8 for each corresponding year.

Table 8
Calculation of Bruce Income Taxes ($M)
Years Ending December 31, 2026, 2027, 2028, 2029, 2030 and 2031

Line No.	Particulars	Note	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
			(a)	(b)	(c)	(d)	(e)	(f)
	Determination of Taxable Income							
1	**Earnings (Loss) Before Tax**	1	35.3	(7.0)	15.3	(24.2)	9.8	(22.8)
	Additions for Tax Purposes - Temporary Differences:							
2	**Base Rent Accrual**		(9.1)	(9.1)	(9.1)	(9.1)	(9.1)	(9.1)
3	**Depreciation**		44.3	44.3	44.3	44.3	44.3	44.3
4	**Accretion**		567.3	587.8	607.6	626.9	649.5	668.1
5	**Restricted Net Interest and Financing Expenses**		0.0	0.0	0.0	0.0	0.0	0.0
6	**Used Fuel and Waste Management Expenses and Facilities Removal Costs**		75.7	87.1	76.8	82.3	76.2	87.9
7	**Receipts from Nuclear Segregated Funds**		170.5	196.0	187.0	118.4	129.9	122.0
8	**Other**		1.6	3.8	0.0	0.0	0.0	0.0
9	**Total Additions - Temporary Differences** (lines 2 through 8)		850.3	909.8	906.6	862.7	890.8	913.2
	Deductions for Tax Purposes - Temporary Differences:							
10	**CCA**		7.4	6.5	5.9	5.4	4.7	4.1
11	**Cash Expenditures for Used Fuel, Waste Management & Decommissioning and Facilities Removal**		282.3	293.8	302.2	256.9	254.6	228.6
12	**Contributions to Nuclear Segregated Funds**		(39.2)	0.0	0.0	0.0	0.0	0.0
13	**Earnings (Losses) on Nuclear Segregated Funds**		486.1	500.7	516.6	535.3	556.5	578.7
14	**Total Deductions - Temporary Differences** (lines 10 through 13)		736.5	800.9	824.7	797.7	815.8	811.4
15	**Taxable Income/(Loss) Before Loss Carry-Over** (line 1 + line 9 - line 14)		149.0	101.9	97.3	40.9	84.7	79.0
16	**Tax Loss Carry-Over to Future Years / (from Prior Years)**		0.0	0.0	0.0	0.0	0.0	0.0
17	**Taxable Income After Loss Carry-Over** (line 15 + line 16)		149.0	101.9	97.3	40.9	84.7	79.0
	Determination of Current Income Taxes							
18	**Taxable Income After Loss Carry-Over** (from line 17)		149.0	101.9	97.3	40.9	84.7	79.0
19	**Income Tax Rate - Current**		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
20	**Income Taxes - Current** (line 18 x line 19)		37.3	25.5	24.3	10.2	21.2	19.8
	Determination of Total Deferred Income Taxes							
22	**Total Net Temporary Differences** (line 9 - line 14**)**		113.7	108.9	81.9	65.1	75.0	101.8
23	**Income Tax Rate - Deferred**		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
24	**Deferred Income Taxes** (line 22 x -1 x line 23)		(28.4)	(27.2)	(20.5)	(16.3)	(18.7)	(25.5)
25	**Tax Loss / Tax Loss Carry-Over** (line 15 or line 16)		0.0	0.0	0.0	0.0	0.0	0.0
26	**Income Tax Rate**		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
27	**Deferred Income Taxes - Tax Loss / Tax Loss Carry-Over** (line 25 x line 26)		0.0	0.0	0.0	0.0	0.0	0.0
28	**Deferred Income Taxes - Total** (line 24 + line 27)		(28.4)	(27.2)	(20.5)	(16.3)	(18.7)	(25.5)
	Income Tax Rate - Current							
29	**Federal Tax**		15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
30	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
31	**Total Income Tax Rate - Current**		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
	Income Tax Rate - Long-Term							
32	**Federal Tax**		15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
33	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
34	**Total Income Tax Rate - Long-Term**		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%

Notes:

1 Earnings (Loss) Before Tax is derived as the difference between Total Revenues in Ex. G2-2-1 Table 2, Line 8 and Total Costs Before Income Tax in Ex. G2-2-1, Table 5, Line 8 for each corresponding year.

DEFERRAL AND VARIANCE ACCOUNTS

1.0 PURPOSE

This evidence describes OPG and DNNP LP's existing deferral and variance accounts and presents the amounts recorded in OPG's accounts as of December 31, 2024 that are proposed for clearance in this Application. The accounts were established pursuant to Ontario Regulation 53/05 ("O. Reg. 53/05") and past OEB decisions and orders. This evidence also describes new deferral and variance accounts that the Application proposes to establish for OPG and DNNP LP.

To distinguish between existing or new accounts by the same name for OPG and DNNP LP, a corresponding notation of "(OPG)" or "(DNNP)" has been added to the account nomenclature throughout this Application, where applicable.

2.0 OVERVIEW

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 in EB-2023-0336 and EB-2020-0290 for the 2025-2026 period, with the exceptions noted below. The Application is not seeking clearance of the following balances in OPG's accounts: the hydroelectric components of the Capacity Refurbishment Variance Account ("CRVA"), the components of the Nuclear Development Variance Account ("NDVA") not related to the Darlington New Nuclear Program ("DNNP"), and the Pickering B Variance Account.[1] OPG proposes to defer the clearance of these balances to a future application for the reasons discussed later in this exhibit. The proposal to clear the remaining account balances is consistent with the OEB's expectation that "all accounts should be reviewed and disposed of in a cost of service proceeding unless there is a compelling reason to not do so."[2]

[1] The following deferral and variance accounts have a zero balance as at December 31, 2024: Gross Revenue Charge Variance Account, Hydroelectric Incentive Mechanism Variance Account, Earnings Sharing Deferral Account, Incremental Cloud Computing Arrangement Implementation Costs Deferral Account, and Impact for IFRS Deferral Account.

[2] Decision with Reasons, EB-2013-0321, November 20, 2014, p.125.

Adjusted for 2025-2026 amortization amounts approved in EB-2020-0290 and EB-2023-0336, the proposed year-end 2024 account balances for disposition in this Application are a net credit balance of $102.4M[3] for OPG's regulated hydroelectric facilities and a net debit balance of $878.8M[4] for OPG's nuclear facilities.[5] There are no account balances for DNNP LP as at December 31, 2024, as DNNP LP was not then in existence.[6]

Details regarding proposed account clearance and riders are presented in Ex. H1-2-1. The audited balances in each of the deferral and variance accounts are shown in Ex. H1-1-1, Table 1. The unqualified Independent Auditors' Report prepared by Ernst & Young LLP on the Schedule of Regulatory Balances as at December 31, 2024 is presented as Attachment 1. The Schedule of Regulatory Balances as at December 31, 2024 itself is presented as Attachment 2.

The Application proposes to continue all existing deferral and variance accounts, using the methodologies that have been used to record entries into the accounts to date as approved by the OEB, with certain exceptions as discussed in this exhibit. The Application proposes to terminate the Hydroelectric Incentive Mechanism Variance Account, the Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account and the Incremental Cloud Computing Arrangement Implementation Costs Deferral Account. The Application also proposes to: (i) align the methodology of the CRVA as it applies to the regulated hydroelectric facilities with the proposed rate-setting framework for the 2027-2031 ("IR") term; (ii) expand the scope of the Gross Revenue Charge Variance Account to apply to all of OPG's regulated hydroelectric facilities, along with capturing the revenue requirement impact of any legislated or regulatory changes to the gross revenue charge ("GRC") construct; and (iii) extend the SR&ED ITC Variance Account (OPG) to include OPG's regulated hydroelectric facilities. These proposals, as well as proposals for a number of new deferral and variance accounts for OPG and DNNP LP, are discussed later in this exhibit.

[3] Ex. H1-2-1, Table 1, col. (f) line 16.
[4] Ex. H1-2-1, Table 2, col. (f) line 30.
[5] A debit entry or balance is an amount to be collected from ratepayers. A credit entry or balance is an amount to be returned to ratepayers.
[6] Refer to Ex. A1-4-4 for an overview of DNNP LP and its representation in this Application.

The following information is provided in this exhibit:

- Section 3.0 lists the existing and proposed new deferral and variance accounts for each of OPG and DNNP LP.
- Section 4.0 describes the proposed approach to determining the applicable reference amounts for additions to OPG and DNNP LP's deferral and variance accounts as of the effective date of the payment amounts order for this application.
- Section 5.0 describes OPG's existing deferral and variance accounts and details how additions to each of the accounts have been determined, and are proposed to be determined as of the effective date of the payment amounts order in this proceeding, or as otherwise applicable.
- Section 6.0 describes DNNP LP's existing deferral and variance accounts, which are established pursuant to O. Reg. 53/05, and outlines how additions are proposed to be determined as of the effective date of the payment amounts order in this proceeding, or as otherwise applicable.
- Section 7.0 sets out the details of new deferral and variance accounts proposed to be established for OPG as of the effective date of the payment amounts order in this proceeding.
- Section 8.0 sets out the details of new deferral and variance accounts proposed to be established for DNNP LP as of the effective date of the payment amounts order in this proceeding.
- Section 9.0 discusses the application of interest to the balances in the accounts.

3.0 LISTING OF EXISTING AND PROPOSED NEW ACCOUNTS

3.1 Existing Accounts for OPG

The authorized deferral and variance accounts for OPG are listed below. The Application proposes to continue all of the existing deferral and variance accounts, unless otherwise noted.

The following existing accounts are proposed to continue to record additions:

- Hydroelectric Water Conditions Variance Account
- Ancillary Services Net Revenue Variance Account – Hydroelectric Sub-Account
- Hydroelectric Surplus Baseload Generation Variance Account

- Income and Other Taxes Variance Account (OPG)
- Capacity Refurbishment Variance Account
- Pension and OPEB Cost Variance Account (OPG)
- Hydroelectric Deferral and Variance Over/Under Recovery Variance Account
- Gross Revenue Charge Variance Account
- Nuclear Liability Deferral Account
- Nuclear Development Variance Account
- Bruce Lease Net Revenues Variance Account
- Nuclear Deferral and Variance Over/Under Recovery Variance Account (OPG)
- Rate Smoothing Deferral Account
- SR&ED ITC Variance Account (OPG)
- Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Variance Account – Primary and Contra Sub-Accounts, and Carrying Charges Sub-Account
- Pickering Closure Costs Deferral Account
- Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account
- Earnings Sharing Deferral Account
- Impact for IFRS Deferral Account (OPG)
- Pickering B Variance Account[7]
- Pickering B Refurbishment Project Variance Account, effective January 1, 2026[8]
- Darlington New Nuclear Project Variance Account, effective January 1, 2026[9].

The following existing accounts are proposed to continue to record only amortization and interest, as applicable:

- Ancillary Services Net Revenue Variance Account – Nuclear Sub-Account
- Pension & OPEB Cash Payment Variance Account
- Pension & OPEB Cash Versus Accrual Differential Deferral Account
- Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account
- Fitness for Duty Deferral Account

[7] Established pursuant to amendments to O. Reg. 53/05 made in December 2022 and July 2025.
[8] Established pursuant to amendment to O. Reg. 53/05 made in December 2025.
[9] Established pursuant to amendment to O. Reg. 53/05 made in December 2025.

- Clarington Corporate Campus Deferral Account
- Sale of Unprescribed Kipling Site Deferral Account.

The following existing accounts are proposed to be terminated:

- Hydroelectric Incentive Mechanism Variance Account
- Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account
- Incremental Cloud Computing Arrangement Implementation Costs Deferral Account.

3.2 Existing Accounts for DNNP LP

The authorized deferral and variance accounts for DNNP LP are listed below. The Application proposes to continue recording additions in all of the existing deferral and variance accounts.

- Darlington New Nuclear Project Variance Account re Development, expected to be effective January 1, 2026[10]
- Darlington New Nuclear Project Variance Account re Capital Cost Amounts, expected to be effective January 1, 2026[11]
- DNNP Generator Capital Structure Variance Account, expected to be effective January 1, 2026.[12]

3.3 Proposed New Accounts for OPG

New deferral and variance accounts proposed for OPG as of the effective date of the payment amounts order in this proceeding are listed below.

- Change of Laws Deferral Account (OPG)
- Global Hydroelectric Capital Variance Account
- Clean Electricity ITC Variance Account (OPG)
- Payment Amount Shaping Deferral Account

[10] Established pursuant to amendment to O. Reg. 53/05 made in December 2025, subject to conditions set out in in O. Reg. 53/05 s. 8.
[11] Established pursuant to amendment to O. Reg. 53/05 made in December 2025, subject to conditions set out in in O. Reg. 53/05 s. 8.
[12] Established pursuant to amendment to O. Reg. 53/05 made in December 2025, subject to conditions set out in in O. Reg. 53/05 s. 8.

- DNNP Nuclear Liability Deferral Account.

3.4 Proposed New Accounts for DNNP LP

New deferral and variance accounts proposed for DNNP LP as of the effective date of the payment amounts order in this proceeding are listed below.

- 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 Variance Account (DNNP)
- Impact of Change in Tax Status Variance Account (DNNP)
- Change of Laws Deferral Account (DNNP)

4.0 ACCOUNT ADDITIONS AS OF THE EFFECTIVE DATE OF THE PAYMENT AMOUNTS ORDER IN THIS PROCEEDING

4.1 OPG's Hydroelectric Deferral and Variance Account Additions

The Application proposes that the reference amounts used to determine additions to the following OPG hydroelectric deferral and variance accounts as of the effective date of the payment amounts order in this proceeding be the forecasts underpinning the approved regulated hydroelectric revenue requirement and payment amounts for 2027, where applicable:

- Hydroelectric Water Conditions Variance Account
- Ancillary Services Net Revenue Variance Account – Hydroelectric Sub-Account
- Pension & OPEB Cost Variance Account (OPG)
- Capacity Refurbishment Variance Account (non-capital portion)
- Gross Revenue Charge Variance Account
- SR&ED ITC Variance Account (OPG)
- Change of Laws Deferral Account (OPG) (non-capital portion)

As discussed in Ex. A1-3-2, Section 2.0, the Application proposes that the hydroelectric payment amounts be set in this proceeding to reflect, through the combination of the capital funding provided through the I-X formula and the C-factor, the respective annual revenue requirement impact of the forecast capital costs (including income tax expense) for OPG's regulated hydroelectric facilities (net of stretch factor adjustment). Consistent with this methodology, it is proposed that the reference amounts for the CRVA (capital portion), the Income and Other Taxes Variance Account, the proposed Change of Laws Deferral Account (capital portion), and the proposed Clean Electricity ITC Variance Account accounts reflect the corresponding annual amounts forecast for each respective year.

Based on the nature of the other hydroelectric deferral and variance accounts, their reference amounts are not based on the OEB-approved forecast amounts underpinning the payment amounts.

4.2 OPG and DNNP LP's Nuclear Deferral and Variance Account Additions

OPG proposes that the reference amounts used to determine additions to OPG and DNNP LP's applicable nuclear deferral and variance accounts as of the effective date of the payment amounts order in this proceeding be the annual forecasts underpinning the respective approved nuclear revenue requirements for each year, unless otherwise specified in the account descriptions.

5.0 OPG's ACCOUNT DESCRIPTIONS AND ENTRIES

This section provides a description and sets out the purpose of OPG's existing deferral and variance accounts, describes how additions to the accounts are determined, and outlines the reasons for the credits and debits recorded to the accounts that the Application seeks to clear. Unless otherwise specified, no changes have been made to the process by which entries are recorded to the accounts since they were last approved by the OEB, including in EB-2023-0336.

5.1 Hydroelectric Water Conditions Variance Account

The Hydroelectric Water Conditions Variance Account was originally established by O. Reg. 53/05. It was subsequently approved by the OEB in EB-2007-0905 and all subsequent OPG applications in recognition of the fact that water conditions are subject to a high degree of forecast risk due to factors that are beyond OPG's ability to manage or control, such as weather.

This account records the financial impact of differences, including changes in GRC costs, between the actual production amount for the regulated hydroelectric facilities and the reference production amount, arising from changes in actual water conditions. The account applies to the 27 prescribed hydroelectric stations that are listed in Ex. E1-1-1, Appendix 1.

For the Sir Adam Beck 1 and 2 and the R.H. Saunders generating stations, which became regulated by the OEB effective on April 1, 2008, OPG determines the 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 payment amounts approved by the OEB, holding all other variables constant. Deviations from the forecast are determined as the difference between the calculated production resulting from entering actual flow for the month into the forecast model and the energy production forecast approved by the OEB. Until the effective date of the payment amounts order in this proceeding, deviations from the forecast for these facilities are calculated using the average of the corresponding monthly forecasts for 2014 and 2015 underpinning the EB-2013-0321 payment amounts.

Until the effective date of the payment amounts order in this proceeding, for the 21 remaining regulated hydroelectric stations listed in Ex. E1-1-1, Attachment 1, deviations from the forecast for January 1-June 30 of each year are calculated using the corresponding monthly production forecasts for 2015 underpinning the EB-2013-0321 payment amounts. For July 1-December 31 of each year, the reference amounts are the average of the corresponding monthly production forecasts for 2014 and 2015 underpinning the EB-2013-0321 payment amounts. These stations became regulated by the OEB effective on July 1, 2014.

The revenue impact of the production deviations resulting from the above process is recorded in the account by multiplying the deviation by the approved hydroelectric payment amount in effect.[13]

As of the effective date of the payment amounts order in this proceeding, the Application proposes that the above methods used to calculate deviations in energy production due to actual water flows and associated financial impact continue to be used, for the same stations as identified above, substituting the 2014 and 2015 forecasts with the 2027 annual production forecasts described in Ex. E1-1-1.

Models are not used to derive energy production forecasts for the remaining 27 regulated hydroelectric facilities, listed in Ex. E1-1-1, Attachment 2. These stations account for less than 2% of total production from all regulated hydroelectric stations. Given the small size of these facilities, and consistent with prior OEB decisions, these facilities are excluded from the scope of the Hydroelectric Water Conditions Variance Account.

The account also records changes in GRC costs from those that underpin the payment amounts that were approved by the OEB, as a result of differences in energy production calculated as above. Amounts recorded in the account in respect of these costs are determined by multiplying the production deviation by the applicable GRC rate. The account also records any production related variances in the amounts payable to the St. Lawrence Seaway Management Corporation for the conveyance of water in the Welland Ship Canal, as well as any production related variances in the amounts payable to the Government of Quebec for water rentals, from those reflected in the payment amounts that were approved by the OEB. Additional details on the GRC, water rental and similar costs can be found in Ex. F1-4-1.

Due to favourable water supply conditions, the calculated actual hydroelectric production was higher than the reference forecast production by 1,756 GWh (in 2023) and 1,424 GWh (in 2024) for the Niagara and R.H. Saunders facilities. This was partially offset by lower calculated

[13] For the DeCew Falls generating stations, which became regulated by the OEB effective on April 1, 2008, account entries are limited to instances when actual Lake Erie levels reduce water diversion to the stations.

actual production for the remaining regulated hydroelectric facilities of 290 GWh (in 2023) and 206 GWh (in 2024). These variances resulted in a net credit addition of $41.3M to the account in 2023 and $35.1M in 2024. The derivation of the variances is shown in Ex. H1-1-1, Table 2.

5.2 Ancillary Services Net Revenue Variance Account – Hydroelectric and Nuclear Sub Accounts

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

The account is divided into the Ancillary Services Net Revenue Variance Account – Hydroelectric and Ancillary Services Net Revenue Variance Account – Nuclear sub-accounts. Ancillary services for regulated hydroelectric operations include black start capability, operating reserve, regulation service, and reactive support/voltage control service, as discussed in Ex. G1-1-1. Ancillary services for the nuclear operations include reactive support/voltage control service, as discussed in Ex. G2-1-1.

For the Hydroelectric Sub-Account, until the effective date of the payment amounts order in this proceeding, the variance recorded is calculated as between actual regulated hydroelectric ancillary services net revenue and the average of the monthly forecast amounts for 2014 and 2015 underpinning the regulated hydroelectric revenue requirement approved by the OEB in EB-2013-0321. As of the effective date of the payment amounts order in this proceeding, the Application proposes to continue this method of determining additions to the Hydroelectric Sub-Account, substituting the 2014 and 2015 forecasts with the annual forecast reflected in the 2027 regulated hydroelectric revenue requirement approved by the OEB. Forecast regulated hydroelectric ancillary services revenue for 2027 is provided at Ex. G1-1-1, Table 1, line 7.

As discussed in Ex. G2-1-1, OPG does not expect to receive any nuclear ancillary services revenue, beginning in 2027, under the new reactive support and voltage control agreement with the IESO. As a result, and given the relatively modest variance amounts historically settled through this sub-account, OPG proposes to discontinue entries in the Nuclear Sub-Account as of the effective date of the payments amounts order in this proceeding.

The derivation of entries in the Hydroelectric Sub-Account is shown in Ex. H1-1-1, Table 3, with a $6.7M credit entry for 2023 and a $3.0M credit entry for 2024. Hydroelectric ancillary services revenue in 2023 and 2024 was higher than the reference amount because of higher regulation service and operating reserve revenues, partially offset by lower reactive support revenue. The derivation of entries in the Nuclear Sub-Account is shown in Ex. H1-1-1, Table 3, with a $2.0M credit entry for 2023 and a $1.1M credit entry for 2024. The reasons for these variances are discussed in Ex. G2-1-2.

5.3 Hydroelectric Incentive Mechanism Variance Account

The Hydroelectric Incentive Mechanism Variance Account was originally approved in EB-2010-0008 along with OPG's hydroelectric incentive mechanism ("HIM") and has been approved in all subsequent OPG applications. Until the effective date of the payments amounts order in this proceeding, the account records a credit to ratepayers of 50% of OPG's HIM revenues above an OEB-specified threshold, set at $54.5M based on the forecast of HIM revenues reflected in the hydroelectric payment amounts approved in EB-2013-0321.

There were no additions to the account in 2023 and 2024 as actual HIM revenues of $14.8M in 2023 and $28.4M in 2024 were below the threshold, as shown in Ex. H1-1-1, Table 4.

For the reasons discussed in Ex. E1-2-1, Section 5.5, as of the effective date of the payment amounts order in this proceeding, OPG proposes to eliminate the sharing of HIM revenues exceeding the forecast HIM revenues and therefore proposes to terminate this account.

5.4 Hydroelectric Surplus Baseload Generation Variance Account

The Hydroelectric Surplus Baseload Generation Variance Account ("SBGVA") was originally approved in EB-2010-0008 and has been approved in all subsequent OPG applications. This account records the financial impact of foregone production at the regulated hydroelectric facilities listed in Ex. E1-1-1 Appendix 1,[14] due to surplus baseload generation ("SBG") conditions. The amounts recorded in the account are net of avoided GRC costs calculated by multiplying the foregone production volume by the applicable GRC rates. In EB-2010-0008, the OEB concluded that the approach used to address the impact of SBG conditions on OPG's hydroelectric production forecast would be to "capture the impacts of all SBG through a variance account, with no allowance built into the [hydroelectric production] forecast."[15]

For the same reasons as noted in Section 5.1 with respect to the Hydroelectric Water Conditions Variance Account, the 27 small regulated hydroelectric facilities that comprise less than 2% of total regulated hydroelectric production are excluded from the scope of this account.

Entries in the account have been and, as of the effective date of the payment amounts order in this proceeding, are proposed to continue to be calculated by multiplying the foregone production volume due to SBG conditions (in MWh), determined as per below, by the approved regulated hydroelectric payment amount in effect, net of the avoided GRC costs. The account is also proposed to continue recording any production related variances in amounts payable to the St. Lawrence Seaway Management Corporation for the conveyance of water in the Welland Ship Canal and in the amounts payable to the Government of Quebec for water rentals, as a result of foregone production due to SBG conditions. Additional details on the GRC, water rental and similar costs can be found in Ex. F1-4-1.

[14] Following the May 1, 2025 implementation of the Renewed Market, under the revised SBGVA methodology approved in EB-2023-0336, no entries to this account are made for the Calabogie GS as it is an embedded generator that does not have a nodal price.
[15] Decision with Reasons, EB-2010-0008, March 10, 2011, p. 22.

Up to and including April 30, 2025, foregone production due to SBG conditions has been calculated as set out in the EB-2020-0290 Payment Amounts Order,[16] by starting with the total volume of spill and subtracting the volume of spill due to:

- water conveyance constraints (e.g., the Sir Adam Beck Generating Station tunnel capacity constraints);
- production capability constrains (e.g., unit outages; operating regulatory requirements etc.);
- market constraints (i.e., IESO dispatch constraints; market or transmission system); and
- contractual obligations (e.g., regulation service).

The remaining spill volume was identified as potential SBG spill. SBG conditions were considered to be present when the uniform market price fell below the GRC price threshold. The SBGVA entries were calculated using the volume of spill remaining after excluding the spill amounts incurred by OPG that was not attributable to the impact of SBG conditions.

On May 1, 2025, the IESO implemented its market renewal program ("MRP"). Pursuant to the OEB's Decision and Order in EB-2023-0336, OPG received approval to record entries to the SBGVA upon the implementation of MRP until the effective date of the payment amounts order in this proceeding, based on a revised methodology that addresses the impacts of the Renewed Market on OPG's compensation for foregone production due to global and local SBG.[17] OPG proposes to continue to use this methodology, as further discussed in Ex. E1-2-1, Section 4.3, to record entries to this account as of the effective date of the payment amounts order in this proceeding.

The derivation of account entries for 2023 and 2024 is shown in Ex. H1-1-1, Table 5. Actual foregone production due to SBG conditions was approximately 977 GWh in 2023 and 350

[16] EB-2020-0290 Payment Amounts Order, App. E, pp. 5-6.

[17] Additionally, in accordance with the OEB-approved EB-2023-0336 settlement proposal, OPG is recording, following the May 1, 2025 implementation of the Renewed Market and until the effective date of the payment amounts order in this proceeding, a credit entry of $0.6M per month to offset debit additions to the SBGVA. OPG also credits the SBGVA when Real-Time Make Whole Payments are received concurrently with an SBGVA entry at the resource level, with the credited amount limited to the lesser of the two, as discussed in Ex. E1-2-1.

GWh in 2024. Net of avoided GRC and related costs, the resulting debit entries in the account were $29.7M in 2023 and $10.6M in 2024.

Pursuant to the OEB-approved EB-2023-0336 settlement proposal, this Application is providing the stipulated information in support of the requested clearance of the SBGVA amounts in Attachments 3 and 4.[18]

5.5 Income and Other Taxes Variance Account (OPG)

The Income and Other Taxes Variance Account (OPG) was originally approved in EB-2007-0905 and has been approved in all subsequent OPG applications. This account records and, as of the effective date of the payment amounts order in this proceeding is proposed to continue to record, the financial impact on OPG's revenue requirements of the following:

- 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 ("OEFC") 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 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).

[18] Information as set out in EB-2023-0336, Ex. L-H-SEC-04, Attachment 1 and Ex. L-H-SEC-05, Attachment 1 with additional information described at p. 15 of the EB-2023-0336 settlement proposal (EB-2023-0336, Ex. O1-1-1).

The account does not record the impact of the above in relation to the Scientific Research and Experimental Development investment tax credits ("SR&ED ITCs") and the income taxes payable thereon for OPG's nuclear facilities for taxation periods effective June 1, 2017. Such impacts are recorded in the SR&ED ITC Variance Account established in EB-2016-0152 effective June 1, 2017 and subsequently continued in EB-2020-0290.

The account is not proposed to include the revenue requirement impact of the Clean Electricity Investment Tax Credits ("CEITCs") that may be available to OPG's regulated facilities. Instead, the Application proposes to record any such impacts in applicable accounts as follows: the CRVA for CRVA-eligible projects, the NDVA for NDVA-eligible projects, and the proposed new Clean Electricity ITC Variance Account (OPG) for the remaining eligible expenditures (Section 7.3). Clean Electricity Investment Tax Credits are discussed in Ex. F4-2-1 Section 3.6.

Entries into the account are recorded relative to the income tax provision and the underlying inputs reflected in OPG's approved revenue requirement for the corresponding year. For the regulated hydroelectric facilities, until the effective date of the payment amounts order in this proceeding, the reference amounts used in determining variances are those reflected in the average 2014 and 2015 income tax provision approved by the OEB in EB-2013-0321, as adjusted for the removal of the application of OPG's regulated nuclear facilities' tax loss to the regulated hydroelectric facilities in 2015. As of the effective date of the payment amounts order in this proceeding, the Application proposes that the reference amounts used in determining any such variances be the corresponding 2027-2031 annual income tax provisions detailed in Ex. F4-2-1, Table 3b. This approach reflects the proposed hydroelectric rate-setting framework for the 2027-2031 term, whereby such annual income tax provision is included in the determination of the forecast capital-related revenue requirements ("CRRR") underpinning the proposed custom capital factor ("C-factor"). The hydroelectric rate-setting proposal is discussed in Ex. A1-3-2, Section 2.0, with the potential resulting interaction between the Income and Other Taxes Variance Account (OPG) and the Global Hydroelectric Capital Variance Account addressed in Ex. A1-3-2, Section 2.3.5.[19]

[19] Any additions to the Income and Other Taxes Variance Account will be calculated without duplication with other accounts that may be impacted such as the CRVA.

For OPG's nuclear facilities, the reference amount used in determining variances is the corresponding annual income tax provision reflected in OPG's nuclear revenue requirement approved by the OEB. The Application proposes to continue this approach as of the effective date of the payment amounts order in this proceeding. The forecast annual income tax provision for OPG's nuclear facilities for the IR term is detailed in Ex. F4-2-1, Table 3d.

OPG recorded five entries to the variance account in 2023 and 2024, totaling a net credit of $5.2M in 2023 and a net credit of $2.3M in 2024, as follows:

1) Credit entries in 2023 and 2024 related to a capital cost allowance ("CCA") rule change pursuant to the passing of Bill C-97, the *Budget Implementation Act, 2019, No. 1* in 2019, which provides for a first-year increase in CCA deductions on eligible capital assets acquired after November 20, 2018, referred to as accelerated investment incentive property ("AIIP").[20] In 2023 and 2024, the entries were applicable to the regulated hydroelectric facilities only, since the impact of this change for OPG's nuclear facilities was reflected in the EB-2020-0290 nuclear revenue requirements. Impacts of this CCA rule change is reflected in the forecast revenue requirement for the regulated hydroelectric facilities beginning in 2027;
2) A credit entry related to an increase in the recognition of SR&ED ITCs for the 2017 taxation year from 75% to 100%, which, for the regulated nuclear facilities, was pro-rated for the period prior to the June 1, 2017 effective date for the SR&ED ITC Variance Account, based on the resolution of the 2017 income tax audit in 2023;
3) A credit entry related to an increase in the recognition of SR&ED ITCs for the 2018 taxation year from 75% to 100% for the regulated hydroelectric facilities, based on the resolution of the 2018 income tax audit in 2023;
4) A credit entry related to an increase in the recognition of SR&ED ITCs for the 2019 taxation year from 75% to 100% for the regulated hydroelectric facilities, based on the resolution of the 2019 income tax audit in 2024; and
5) A debit entry related to a reduction to the rate for the Ontario Research and Development Tax Credit from 4.5% to 3.5% of qualifying expenditures, effective June 1, 2016. This

[20] The entries do not include the impacts on projects subject to the CRVA or the NDVA, which are recorded in the respective accounts as part of the total CCA variances for those projects.

entry applies to the regulated hydroelectric facilities only, as the impact of this change for the nuclear facilities was reflected in the EB-2020-0290 nuclear revenue requirements.

The above entries are the same in nature and calculation as the equivalent entries previously recorded in the account. Entry 1) continues to be calculated by applying the accelerated CCA rules to the forecast capital additions reflected in the EB-2013-0321 regulated hydroelectric revenue requirements, using the percentage of eligible actual regulated hydroelectric projects (for the corresponding year) as a proxy. Entries 2), 3), and 4) recognize a credit to ratepayers of an additional 25% of the benefit of SR&ED ITCs that were previously credited to ratepayers at 75% in relation to 2014 and 2015 through the EB-2013-0321 payment amounts. SR&ED ITCs are discussed further in Ex. F4-2-1, Section 3.5. The derivation of the entries is shown at Ex. H1-1-1, Table 6.

5.6 Capacity Refurbishment Variance Account

The CRVA was originally approved in EB-2007-0905 and has been approved in all subsequent OPG applications. This account was established pursuant to section 6(2)4 of O. Reg. 53/05 to record the financial impacts of variances between the actual capital and non-capital costs and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to a prescribed generation facility referred to in section 2 of O. Reg. 53/05 and those forecast costs and firm financial commitments underpinning the revenue requirement that was approved by the OEB, including for the Darlington Refurbishment Program ("DRP"). As required by O. Reg. 53/05, section 6(2)4, the account includes assessment costs and pre-engineering costs and commitments.

There are some differences in the approved and proposed methodologies for recording additions to the account between OPG's regulated hydroelectric facilities and OPG's nuclear facilities, reflecting the differences in the respective rate-setting frameworks, as discussed below.

5.6.1 Regulated Hydroelectric

As set out in the EB-2020-0290 Payment Amounts Order, until the effective date of the payment amounts order in this proceeding, the CRVA records entries for the regulated hydroelectric facilities relative to the annual reference amount of $1.0M, being the $0.9M reflected in the OEB-approved revenue requirement for 2014 and 2015 in EB-2013-0321 as escalated by the price-cap index applied to adjust OPG's hydroelectric payment amounts approved by the OEB for 2018 through 2021. The EB-2020-0290 Payment Amounts Order also stipulates that effective January 1, 2022 and until the effective date of the payment amounts order in this proceeding, OPG is entitled to recover amounts recorded in the CRVA in relation to the regulated hydroelectric facilities to the extent that total capital in-service additions for these facilities (including any CRVA-eligible projects) from January 1, 2022-December 31, 2026 exceed the total funding available for capital expenditures through the regulated hydroelectric payment amounts established in the proceeding. The EB-2020-0290 Payment Amounts Order prescribed that such annual capital funding implicit in the regulated hydroelectric payment amounts be $153.0M, as determined by escalating the average 2014 and 2015 OEB-approved depreciation for the regulated hydroelectric facilities of $143.3M in EB-2013-0321 by the price-cap index applied to adjust OPG's hydroelectric payment amounts approved by the OEB for 2018 through 2021.[21] OPG is not seeking clearance of the hydroelectric balances in the CRVA in this Application. Consistent with the approach taken in EB-2020-0290, OPG proposes to defer such clearance to a future application, which would provide the necessary details to support an assessment of the recoverability of any such amounts recorded over the full 2022-2026 period in accordance with the above methodology.[22]

As discussed in Ex. A1-3-2, Section 2.0, the Application proposes to set payment amounts for the prescribed hydroelectric facilities using a price-cap index Custom IR framework, consistent with the approach applied for the 2017-2021 period in EB-2016-0152, but with the addition of the C-factor, among others. CRRR forecasts underpinning the 2027 test year and those that form the basis of the C-factors proposed from the 2028-2031 period – as shown in Ex. A1-3-

[21] EB-2020-0290 Payment Amounts Order, App. E, pp. 8-9.
[22] For the same reason, OPG did not seek clearance of the 2022 hydroelectric account additions in the CRVA in EB-2023-0336.

2, Chart 6, line 4 – include the capital-related revenue requirement impacts of forecast CRVA-eligible projects. Therefore, as discussed in Ex. A1-3-2, Section 2.3.5, the Application proposes to record entries in the CRVA for capital costs for the regulated hydroelectric facilities relative to the forecast revenue requirement impact of the CRVA-eligible projects as reflected in the forecast CRRR underpinning the C-factor. Chart 1 below summarizes these proposed capital-related reference amounts, which are further detailed in Attachment 5. The projects underpinning the reference amounts in Chart 1 are identified in Ex. D1-1-2, Tables 1, 2a, 2b, 5 and 5b, in the respective "CRVA Eligible" columns.[23]

Chart 1 – Hydroelectric CRVA Proposed Capital Related Reference Amounts ($M)

Line No.	Description	2027	2028	2029	2030	2031	Total
		(a)	(b)	(c)	(d)	(e)	(f)
1	Annual Reference Amount[1]	(6.8)	63.3	171.6	231.1	277.9	737.1

[1]Refer to Attachment 5 for the derivation of the 2027-2031 annual reference amounts.

As discussed in Section 7.2 below and detailed in Ex. A1-3-2, Section 2.3.5, the Application proposes establishing a Global Hydroelectric Capital Variance Account ("GHCVA") that is asymmetric in favour of ratepayers, wherein an amount could be credited to ratepayers if the CRRR determined based on actual capital in-service additions over the 2028-2031 period is less than the forecast CRRR underpinning the C-factor during these years. As set out in in Ex. A1-3-2, Section 2.3.5, to address the interaction between the CRVA and the GHCVA, the following limitations would apply to the CRVA, as of the effective date of the payment amounts order in this proceeding: [24]

- The recoverability of the net debit entries in the CRVA for the regulated hydroelectric facilities over the 2028-2031 period would be limited to an amount, if any, by which the actual CRRR exceeds the forecast CRRR; and

[23] All of these projects have a total cost of at least $10M; OPG does not propose to track any regulated hydroelectric or nuclear capital costs in the CRVA for projects with a total cost of less than $10M.
[24] Any additions to the CRVA will be calculated without duplication with other accounts that may be impacted such as the Income and Other Taxes Variance Account.

- The refundability of the net credit entries in the CRVA for the regulated hydroelectric facilities over the 2028-2031 period would be limited to an amount, if any, by which the actual CRRR is below the forecast CRRR.

These thresholds would be evaluated in aggregate on a cumulative basis over the 2028-2031 period. They would not apply to the 2027 CRVA entries as there would be no GHCVA entries in 2027.

The revenue requirement impact of actual capital costs for the regulated hydroelectric projects subject to the CRVA will include the impact of any CEITCs associated with such projects, as discussed further in Ex. A1-3-2, Section 2.3.5 and Ex. F4-2-1, Section 3.5.

The Application proposes to record entries in the CRVA for eligible non-capital costs for the regulated hydroelectric facilities during the IR term relative to such forecast costs reflected in the 2027 regulated hydroelectric revenue requirement approved by the OEB. Such forecast eligible non-capital costs for 2027 are $25.3M.[25]

Nuclear

For OPG's regulated nuclear facilities, the variances recorded in the CRVA are determined as between the revenue requirement impact of actual capital and non-capital costs for eligible projects and the corresponding forecast amounts included in OPG's annual nuclear revenue requirements approved by the OEB. The Application proposes to continue this method as of the effective date of the payment amounts order in this proceeding.

Chart 2 below summarizes the proposed capital-related reference amounts, which are further detailed in Attachment 6 (for the Pickering Refurbishment Program), Attachment 7 (for the Darlington Refurbishment Program) and Attachment 8 (for all other eligible projects identified in this Application). Other than the Pickering Refurbishment Program ("PRP") and the Darlington Refurbishment Program ("DRP"), the projects underpinning the reference amounts

[25] Ex. F1-3-1, Table 1, Note 4.

in Chart 2 are identified in Ex. D2-1-3, Tables 1a-1c, 2a-2g and 5a-5d, in the respective "CRVA Eligible" columns.

Chart 2 – Nuclear CRVA Proposed Capital Related Reference Amounts

Line No.	Description	2027	2028	2029	2030	2031	Total
		(a)	(b)	(c)	(d)	(e)	(f)
1	Annual Reference Amount - Pickering Refurbishment Program[1]	(72.7)	(170.4)	(297.9)	(370.1)	329.5	(581.5)
2	Annual Reference Amount - Darlington Refurbishment Program, excluding D2O Storage[2]	1,214.1	1,201.5	1,184.0	1,162.2	1,138.4	5,900.2
3	Annual Reference Amount - Other Eligible Nuclear Projects[3]	10.1	65.5	67.7	153.2	273.3	569.8

[1]Refer to Attachment 6 for the derivation of the 2027-2031 annual reference amounts.
[2]Refer to Attachment 7 for the derivation of the 2027-2031 annual reference amounts.
[3]Refer to Attachment 8 for the derivation of the 2027-2031 annual reference amounts.

Chart 3 below summarizes the proposed non-capital reference amounts, being the corresponding forecasts reflected in the proposed nuclear revenue requirements in this Application.

Chart 3 – Nuclear CRVA Proposed Non-Capital Related Reference Amounts

Line No.	Description	2027	2028	2029	2030	2031	Total
		(a)	(b)	(c)	(d)	(e)	(f)
1	Annual Reference Amount - Pickering Refurbishment Program[1]	100.3	94.1	84.9	52.7	46.5	378.5
2	Annual Reference Amount - Darlington Refurbishment Program[2]	0.0	0.0	0.0	0.0	0.0	0.0
3	Annual Reference Amount - Other Eligible Nuclear Projects[3]	8.7	0.0	4.7	4.3	4.4	22.1

[1]Refer to Ex. F2-8-1, Table 1, line 2, cols. (h) to (l).
[2]Refer to Ex. F2-7-1, Table 1. line 4, cols. (h) to (l).
[3]Col. (a) is the sum of Ex. F2-3-1, Table 1, col. (h), lines 13, 15, and amounts shown for 2027 in Note 3 therein. Cols. (b) to (e) from Ex. F2-3-1, Table 1, Note 3 for the respective years.

The revenue requirement impact of actual capital costs for OPG's nuclear projects subject to the CRVA will include the impact of any CEITCs associated with such projects, as discussed further in Ex. A1-3-2, Section 2.3.5 and Ex. F4-2-1, Section 3.5.

This Application seeks to clear the entirety of the nuclear CRVA balance as at December 31, 2024, including the DRP-related amounts previously deferred from disposition in EB-2018-0243, EB-2020-0290 and EB-2023-0336.

5.6.2.1 Darlington Refurbishment Program

As discussed in Ex. D2-2-1, OPG is nearing the end of the DRP, having successfully returned to service Units 2, 3 and 1 and forecasting to return Unit 4 to service in April 2026, ahead of the high confidence schedule. There have been no material changes to the scope of the DRP, and OPG expects the final cost of the DRP to be within the $12.8B budget previously approved by the OEB. Additionally, in order to facilitate an efficient regulatory review of the project in this proceeding, OPG commits not to seek recovery of any unlikely actual costs over $12.8B in any future proceeding. The total expenditures over the life of the DRP, including amounts forecast for 2025 and 2026, are summarized in Ex. D2-2-3, Table 1a.

The OEB-approved Settlement Proposal in EB-2020-0290 provides the following:

> The OEB will review the prudence of any amounts sought by OPG in excess of the $12.8B total, the appropriateness of any future material changes to the scope of the DRP and any corresponding changes in contracts, when OPG seeks disposition of the actual DRP costs through the Capacity Refurbishment Variance Account.[26]

The above settlement terms are consistent with the principles of the OEB's findings in the EB-2016-0152 Decision and Order with respect to the Unit 2 refurbishment, which stated the following:

> The OEB will not micromanage the DRP, but rather will hold OPG accountable to deliver the DRP on time and on budget. If OPG were to face CRVA scrutiny for each component part of the Unit 2 project, it may lead to unintended consequences and lessen the ability of OPG to deal with issues as they arise. As OPG argues convincingly in its reply submission, the refurbishment of Unit 2 is a single integrated project, not a web of independent projects. It must be managed on a holistic, dynamic basis, where "higher cost may be incurred in one area to address a risk or resolve an issue in another area, which when taken as a whole, is to the benefit of ratepayers." At the end of the day, it is OPG's responsibility to deliver the Unit 2 project (and the campus plan projects) within the budget envelope

[26] Decision and Order, EB-2020-0290, November 15, 2021, p. 86.

> approved in this proceeding … OPG should have some flexibility doing so.[27]

As OPG is committing to the recovery of any final cost of the DRP to be within the approved budget of $12.8B, the Application is seeking disposition of the DRP-related debit balance of $170.2M (inclusive of interest) recorded in the CRVA as at December 31, 2024.[28,29] This balance includes entries made (i) prior to June 1, 2017 relative to the reference amounts reflected in the EB-2013-0321 nuclear revenue requirements; (ii) for the period June 1, 2017-December 31, 2021, relative to the reference amounts reflected in the EB-2016-0152 nuclear revenue requirements; and (iii) beginning January 1, 2022, relative to the reference amounts reflected in the EB-2020-0290 nuclear revenue requirements. These entries arise from over- and under-variances in the amounts and/or timing of capital in-service additions (and their tax effects) and non-capital costs that collectively form the DRP, relative to the forecasts reflected in the respective OEB-approved revenue requirements.

The year-end 2024 DRP-related balance in the CRVA comprises net debit additions totaling $175.6M for the capital portion[30] and net credit additions of $11.5M for the non-capital portion,[31,32] all recorded over the 2016-2024 period.[33] The derivations of the entries are shown in Ex. H1-1-1, Table 16 (capital portion) and Ex. H1-1-1, Table 15 (non-capital portion). These tables also show projected account entries for 2025 and 2026, being net debit additions totaling $106.6M, provided in support of an efficient regulatory review of the project in this proceeding.

The year-end 2024 net debit additions for the DRP-related capital portion include net debit additions of $61.6M over the 2016-2019 period, net credit additions of $126.2M over the 2020-2021 period and net debit additions of $240.2M over the 2022-2024 period. For the 2016-2019

[27] Decision and Order, EB-2016-0152, December 18, 2017, p. 41.
[28] Ex. H1-1-1, Table 1, line 21, col. (c).
[29] Additionally, the Application seeks disposition of the remaining accumulated balances in the CRVA, wholly related to interest, for the Heavy Water Storage and Drum Handling Facility ("D2O Storage Project") and the impact of AIIP rules on DRP-related CCA amounts (Ex. H1-2-1, Table 2, lines 7 and 8, col. (f)).
[30] Ex. H1-1-1, Table 16, line 20, col. (l).
[31] Ex. H1-1-1, Table 15, line 7, col. (l).
[32] Non-capital additions exclude variances in DRP-related low and intermediate level waste variable expenses arising from the 2022 ONFA Reference Plan, which are captured in the Nuclear Liability Deferral Account.
[33] With the exception of the D2O Storage Project and the impact of AIIP rules on DRP-related CCA amounts, the DRP portion of the CRVA was most recently cleared in EB-2016-0152, based on the year-end 2015 balances.

period, the entries are driven primarily by higher amounts placed into service for several Early In-Service and Safety Improvement Opportunities projects and a shorter useful life applied to the retube & feeder replacement tooling used for removal activities[34], relative to the depreciation assumptions underpinning the forecasts reflected in the OEB-approved revenue requirements in EB-2016-0152; these impacts are partially offset by the tax impact of higher actual amounts for CCA and other deductions. For the 2020-2021 period, the entries are driven primarily by a later return to service of Unit 2 in June 2020, compared to the EB-2016-0152 forecast assumption of February 2020. For the 2022-2024 period, the entries are driven primarily by an earlier return to service of Unit 3 in July 2023, compared to the EB-2020-0290 forecast assumption of January 2024, and an earlier return to service of Unit 1 in November 2024, compared to the EB-2020-0290 forecast assumption of April 2025.

The year-end 2024 net credit additions for the DRP-related non-capital portion include net credit additions of $19.4M over the 2016-2021 period and net debit additions of $7.9M over the 2022-2024 period. For the 2016-2021 period, the entries are driven primarily by changes in timing and amounts of removal costs due to shifting refurbishment schedules and modified project scopes, among others. For the 2022-2024 period, the variances driving the entries are discussed in Ex. F2-7-1.

Over the IR term, it is proposed that the CRVA record the revenue requirement impact of any variances in the amount and/or timing of the final capital in-service additions for the DRP, subject to OPG's commitment not to seek recovery of any costs that exceed the $12.8B budget. The entries would then cease upon the effective date of a subsequent payment amounts order that reflects the balance of such actual in-service additions in the payment amounts.

5.6.2.2 Other Nuclear Initiatives

For non-DRP nuclear initiatives, the Application seeks disposition of net debit entries totaling $62.1M in 2023 and $6.5M in 2024 for the non-capital portion and net debit entries totaling

[34] As re-affirmed by the depreciation study in EB-2020-0290, Ex. F4-1-1, Attachment 1, p. 19 and the depreciation study filed in this proceeding Ex. F4-1-1, Attachment 1, p. 4-4.

$2.5M in 2023 and $2.7M in 2024 for the capital portion. The derivation of the entries is shown in Ex. H1-1-1, Table 13 (non-capital portion) and Ex. H1-1-1, Table 14 (capital portion).

The non-capital entries are driven primarily by variances from the following initiatives, which are further discussed below:

- Fuel Channel Life Extension Project
- Fuel Channel Life Extension Related Ongoing Costs
- Pickering B Refurbishment Feasibility Assessment
- Darlington Steam Generator Primary Moisture Separators Replacement projects
- Optimization of Pickering Shutdown
- Fuel Channel Life Management Phase V Project

The capital entries are driven primarily by the Darlington Steam Generator Primary Moisture Separators Replacement projects.

There are also minor variances recorded in respect of the final costs associated with the Pickering Extended Operations initiative, the Darlington Unit 3 Fuel Channel Component Retrieval Project and the Darlington Annulus Spacer Life Management Project, all of which have been completed within their respective budgets.

Fuel Channel Life Extension Project

Under this initiative, OPG performed work to update assessments of degradation mechanisms on fuel channels to demonstrate their fitness for service and capability to operate until a planned nuclear station end of life. It most recently focused on supporting the operation of the Pickering units to 295,000 equivalent full power hours ("EFPH"). The initiative was substantially completed in 2024 within budget. Additional research and testing, along with project close out activities performed in 2023 and 2024 relative to the forecast amounts reflected in the EB-2020-0290 nuclear revenue requirements gave rise to the non-capital debit entry of $3.0M in 2023 and credit entry of $0.1M in 2024.

Fuel Channel Life Extension Ongoing Costs

The fuel channel life extension ongoing (consequential) costs represent expenditures incurred for incremental work required to enable the operation of fuel channels and other major components, such as steam generators, until a nuclear station's planned end of life that is beyond original design targets. The non-capital debit entries of $28.0M in 2023 and $0.8M in 2024 were primarily driven by costs incurred for chemical cleaning performed in Pickering Unit 8 to address boiler (steam generator) level oscillations that can limit station operations. This work mitigated risk of a unit derate in support of Pickering's extended operations until September 2026, as discussed further in Ex. F2-3-3, Section 3.0.

Pickering B Refurbishment Feasibility Assessment

In September 2022, the Province of Ontario ("Province") requested OPG to update its previous feasibility assessment for refurbishing Pickering Units 5-8. In response, OPG assessed whether the refurbishment would be technically, economically, and operationally viable. In August 2023, OPG's Board of Directors approved the feasibility assessment. Subsequently, the Province announced their support in January 2024 for OPG to proceed with the next steps toward refurbishing Units 5-8, with OPG's Board of Directors ultimately approving OPG to proceed with the refurbishment in November 2025. The feasibility assessment work was not anticipated in the EB-2020-0290 nuclear revenue requirements. Non-capital costs of $0.2M in 2022 and $17.8M in 2023 incurred to carry out this assessment were recorded in the account as debit entries.[35] The feasibility assessment is further discussed in Ex. D2-3-4, Section 2.1.1 and Ex. F2-1-1, Section 5.2.

Darlington Steam Generator Primary Moisture Separators Replacement

OPG is replacing the primary moisture separators in the steam generators of all four Darlington units after inspections revealed irreversible damage in the form of increased degradation from flow-assisted corrosion. There were no forecast amounts included in the EB-2020-0290 nuclear revenue requirements associated with this work. The resulting non-capital debit entries to the account were $4.5M in 2023 and $3.8M in 2024, for costs incurred in connection with

[35] Disposition of the $0.2M debit entry recorded in 2022 in respect of the Pickering B Refurbishment Feasibility Assessment was deferred in EB-2023-0336.

the removal of existing primary moisture separators and associated support structures in the Darlington Units 1 and 4 steam generators, respectively. The resulting capital debit entries to the account were $3.4M in 2023 and $12.9M in 2024, representing the revenue requirement impacts of the in-service additions for the new primary moisture separators installed in two steam generators at Darlington Unit 3 and all steam generators at Darlington Unit 4, respectively. For further details on the project, refer to Ex. D2-1-3.

Optimization of Pickering Shutdown

The objective of the Optimization of Pickering Shutdown initiative, presented in EB-2020-0290, was to safely optimize the shutdown of the Pickering station by operating all six then-operating units until September 2024, five of the six units through 2024, and the remaining four units until December 2025, subject to the approval by the Canadian Nuclear Safety Commission ("CNSC"). The clearance of the account entries related to this initiative was deferred in EB-2023-0336, with large portions of the associated work ongoing at the time. With most of this work completed by the end of 2024 and the initiative tracking to completion below the budget of $50M presented in EB-2020-0290, the Application is seeking to recover the related non-capital net debit additions totaling $0.9M over the 2020-2024 period.[36] Further details of this initiative can be found in Ex. F2-1-1, Section 4.0.

Fuel Channel Life Management Phase V Project

This project was identified after EB-2020-0290 and gave rise to non-capital debit entries of $1.1M and $5.3M in 2023 and 2024. This project is required to demonstrate fitness-for-service and capability of the units to support current and extended EFPH targets at Darlington and Pickering. As discussed in Ex. F2-3-1, for Darlington, work performed is driven by additional pressure tube burst tests, updates to pressure tube fracture toughness models and uncertainty analysis. As discussed in Ex. F2-1-1, for Pickering, work performed will support extending the current aging limits on fuel channel components and support post-refurbishment operations for Units 5-8.

[36] The net debit additions of $0.9M represent the sum of: Ex. H1-1-1, Table 13, line 28, cols. (a)-(b) and EB-2023-0336, Ex. H1-1-1, Table 15, line 26, cols (a)-(c).

5.7 Pension and OPEB Cost Variance Account (OPG)

The Pension and OPEB Cost Variance Account was originally approved in EB-2011-0090 and has been continued in subsequent proceedings. As applicable, this account records the difference between (i) the pension and other post-employment benefit ("OPEB") costs, plus related income tax payments in lieu, reflected in the revenue requirement approved by the OEB; and (ii) OPG's actual pension and OPEB costs, and associated tax impacts, for the prescribed generation facilities. Actual pension and OPEB costs used in the calculation of the difference are calculated on an accrual basis using the same accounting standards as those used to derive the reference amount. The Application proposes to continue this methodology for recording entries in the account as of the effective date of the payment amounts order in this proceeding, for OPG's nuclear and regulated hydroelectric facilities.

For its nuclear facilities, OPG resumed recording additions to the account effective January 1, 2022.[37] These additions are identified in the Post-2021 Additions component of the account balance. There are no account additions being recorded for the regulated hydroelectric facilities over the 2022-2026 period as the EB-2013-0321 revenue requirement underpinning the regulated hydroelectric payment amounts in effect did not include pension and OPEB accrual costs.[38] As discussed in Ex. F4-3-2, the proposed revenue requirement for the regulated hydroelectric facilities for 2027 reflects pension and OPEB accrual costs.

The derivation of the $218.7M credit entry in 2023 and the $94.4M credit entry in 2024 for the nuclear facilities is shown in Ex. H1-1-1, Table 7b. These additions reflect actual pension and OPEB costs that were lower than the forecast amounts reflected in the corresponding EB-2020-0290 revenue requirements. Pension and OPEB costs are discussed in Ex. F4-3-2.

All other historical balances in the account will be amortized by the end of 2026 as approved in prior proceedings. No interest is being recorded on the balance of the account pursuant to the EB-2020-0290 Payment Amounts Order.

[37] Payment Amounts Order, EB-2020-0290, App. E, pp.10-11.
[38] Payment Amounts Order, EB-2020-0290, App. E, pp.10-11.

5.8 Hydroelectric Deferral and Variance Over/Under Recovery Variance Account

The Hydroelectric Deferral and Variance Over/Under Recovery Variance Account was originally approved in EB-2009-0174 and has been approved in all subsequent OPG applications. This account records the differences between the amounts approved for recovery or repayment in the hydroelectric deferral and variance accounts and the actual amounts recovered or repaid based on the actual regulated hydroelectric production and approved riders. Pursuant to the OEB's orders, the account also captures the transfer of the hydroelectric portions of the balances remaining in other accounts as they expire from time to time. The Application proposes to continue the above methodology for recording entries in the account as of the effective date of the payment amounts order in this proceeding.

The derivation of the $1.6M and $2.6M debit additions to the account for 2023 and 2024, respectively, is shown in Ex. H1-1-1, Table 8. There were no transfers from expiring accounts in 2023 or 2024.

5.9 Gross Revenue Charge Variance Account

The Gross Revenue Charge Variance Account was originally approved in EB-2013-0321 and has been approved in all subsequent OPG applications. As Ontario Regulation 124/02, s. 7, allows deductions to GRC for eligible capacity of new, redeveloped, or upgraded stations, this account records the cost impact of a GRC deduction, once approved by the Ontario Ministry of Natural Resources, pertaining to production increases at OPG's Sir Adam Beck stations due to the operation of the Niagara tunnel that was completed in 2013.

As no decision on the GRC deduction has been issued by the Ministry of Natural Resources to date, there have been no amounts recorded in the account since its inception.

The Application is seeking to expand the scope of this account in two ways, as of the effective date of the payment amounts order in this proceeding, with resulting variances over the IR term measured against the forecast GRC costs reflected in the 2027 regulated hydroelectric revenue requirement.

First, the Application proposes this account be expanded to apply to all of OPG's regulated hydroelectric facilities with respect to potential GRC deductions that may be approved by the Ontario Ministry of Natural Resources under Ontario Regulation 124/02 for eligible stations, so as to allow these amounts to be returned to ratepayers. While no GRC deductions are included in the GRC forecast, OPG expects to apply for GRC deductions for certain projects taking place during the 2027-2031 period, following project in-service and the required period of operations to determine the eligibility and magnitude of possible GRC deductions.

Second, the Application proposes that the scope of the account also capture 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 OPG's prescribed hydroelectric assets under Section 92.1 of the *Electricity Act, 1998*. Any potential legislative or regulatory changes in this regard are not known and are beyond OPG's control. With actual and forecasted GRC expenses in the order of $300M to $360M annually (Ex. F1-4-1, Table 1), these costs constitute a material component of the regulated hydroelectric payment amounts.[39] The proposed treatment would also be consistent with the scope of the Income and Other Taxes Variance Account (OPG) related to payments in lieu of taxes to the OEFC, as GRC payments constitute a levy primarily payable to the OEFC and the Ontario Ministry of Finance. Further details on the GRC regime can be found in Ex. F1-4-1, with the 2027 forecast costs presented in Ex. F1-4-1, Table 1.

5.10 Pension & OPEB Cash Payment Variance Account

The Pension & OPEB Cash Payment Variance Account was approved in EB-2013-0321 and has been continued in subsequent proceedings. As applicable, it records the difference between OPG's actual registered pension plan ("RPP") contributions and OPEB plan payments (including the long-term disability benefit plan) attributed to the prescribed generating facilities, and such forecast amounts underpinning the revenue requirement approved by the OEB.

[39] As discussed in Ex. A1-3-2, OPG has proposed that the GRC component of the 2027 regulated hydroelectric revenue requirement not be subject to the annual price-cap escalation for the duration of the IR term.

For its nuclear facilities, OPG ceased recording additions to the account effective January 1, 2022, as the EB-2020-0290 nuclear revenue requirements reflect pension and OPEB costs calculated on an accrual basis.[40] Account additions are being recorded for the regulated hydroelectric facilities over the 2022-2026 period, as the EB-2013-0321 revenue requirement underpinning the regulated hydroelectric payment amounts in effect included pension and OPEB amounts on a cash basis.[41] No additions will be required to the account as of the effective date of the payment amounts order in this proceeding, once the regulated hydroelectric payment amounts reflect pension and OPEB accrual costs, as discussed further in Ex. F4-3-2.

For the regulated hydroelectric facilities, the variances recorded over the 2022-2026 period are calculated as between actual RPP contributions and OPEB payments (including the long-term disability benefit plan) attributed to the regulated hydroelectric facilities and such forecast amounts underpinning the revenue requirement for 2014 and 2015 approved by the OEB in EB-2013-0321.

The derivation of the credit additions of $15.6M in 2023 and $12.1M in 2024 for the regulated hydroelectric facilities is shown in Ex. H1-1-1, Table 7. These additions reflect actual RPP contributions and OPEB payments (including the long-term disability benefit plan) that were overall lower than the forecast amounts reflected in the EB-2013-0321 revenue requirement. The cash amounts for pension and OPEB are discussed in Ex. F4-3-2.

5.11 Pension & OPEB Cash Versus Accrual Differential Deferral Account

The Pension & OPEB Cash Versus Accrual Differential Deferral Account was approved in EB-2013-0321 and has been continued in subsequent OPG applications. As applicable, the account records differences between: (i) OPG's actual pension and OPEB costs for its prescribed generating facilities determined using the accrual accounting method applied in OPG's audited consolidated financial statements; and, (ii) OPG's actual registered pension

[40] Payment Amounts Order, EB-2020-0290, App. E, p. 12.
[41] Payment Amounts Order, EB-2020-0290, App. E, p. 12.

plan contributions and other post-employment benefit plan payments (including the long-term disability benefit plan) attributed to OPG's prescribed generating facilities.[42]

For the regulated nuclear facilities, OPG ceased recording additions to the account effective January 1, 2022, as the EB-2020-0290 nuclear revenue requirements reflect pension and OPEB costs calculated on an accrual basis.[43] Account additions are being recorded for the regulated hydroelectric facilities over the 2022-2026 period, as the EB-2013-0321 revenue requirement underpinning the regulated hydroelectric payment amounts in effect did not include pension and OPEB accrual costs and reflected pension and OPEB amounts on a cash basis.[44] No additions will be required to the account as of the effective date of the payment amounts order in this proceeding, once the regulated hydroelectric payment amounts reflect pension and OPEB accrual costs, as discussed further in Ex. F4-3-2.

The derivation of the credit additions of $19.7M in 2023 and $10.8M in 2024 for the regulated hydroelectric facilities is shown in Ex. H1-1-1, Table 7. Pension and OPEB costs and cash amounts are discussed in Ex. F4-3-2. Included as Attachment 2 to that exhibit is Aon's independent actuary report on OPG's total accrual pension and OPEB costs determined in accordance with US GAAP for 2023 and 2024. As discussed in Ex. F4-3-2, OPG's total accrual pension and OPEB costs were attributed to the prescribed facilities using the same methodology as in the previous proceedings.

No interest is being recorded on the balance of the account pursuant to the EB-2020-0290 Payment Amounts Order.

[42] As noted in prior proceedings, the continued recognition of amounts recorded in the Pension & OPEB Cash Versus Accrual Differential Deferral Account as a regulatory asset in OPG's financial statements in accordance with US GAAP requires that the period of deferring amounts recorded in the account related to OPEB not exceed five years from the time that they were incurred. For example, this means any such amounts recorded at the beginning of 2023 must commence recovery as of the beginning of 2028 to satisfy US GAAP criteria.
[43] Payment Amounts Order, EB-2020-0290, App. E, p. 13.
[44] Payment Amounts Order, EB-2020-0290, App. E, p. 13.

5.12 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 continued in EB-2020-0290. The account has three sub-accounts, as described below.

The Primary Sub-Account tracks amortization amounts for the Pension & OPEB Cash Versus Accrual Differential Deferral Account, for both OPG's regulated hydroelectric and regulated nuclear facilities. Beginning January 1, 2022, for the nuclear facilities only, the Primary Sub-Account also tracks the difference between actual pension and OPEB accrual costs[45] and OPG's actual RPP contributions and OPEB plan payments (including the long-term disability benefit plan) (i.e., cash payments). When the cumulative accrual amount (including amortization amounts from the Pension & OPEB Cash Versus Accrual Differential Deferral Account) exceeds the cumulative cash payments, the sub-account holds a credit balance and accrues carrying charges asymmetrically in favour of ratepayers in the Carrying Charges Sub-Account. The Contra Sub-Account records offsetting entries with the Primary Sub-Account to enable book-keeping with offsetting entries. Carrying charges do not apply to this sub-account. The Carrying Charges Sub-Account records interest at the OEB's prescribed Construction Work In Progress ("CWIP") 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.

The Application proposes to continue the above methodology for recording entries into the account as of the effective date of the payment amounts order in this proceeding, for OPG's nuclear and regulated hydroelectric facilities. This will include the difference, and the associated interest per above, between actual pension and OPEB accrual costs and such actual cash amounts for the regulated hydroelectric facilities, once the regulated hydroelectric payment amounts reflect pension and OPEB accrual costs, as discussed further in Ex. F4-3-2.

[45] The actual amount of pension and OPEB accrual costs is used as the basis for entries in the Primary Sub-Account to account for the interaction of this account with the Pension and OPEB Cost Variance Account.

The entries to the Primary Sub-Account were a credit of $24.1M in 2023 and a credit of $29.7M in 2024 for the regulated hydroelectric facilities, representing the OEB-approved amortization amounts for the Pension & OPEB Cash Versus Accrual Differential Deferral Account. For the regulated nuclear facilities, the entries to the Primary Sub-Account were a credit of $43.6M in 2023 and a credit of $122.8M in 2024, representing the sum of the OEB-approved amortization amounts for the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the difference between actual pension and OPEB accrual costs and such actual cash payments for the respective year. The derivation of the entries and the associated cumulative balances are set out in Ex. H1-1-1, Table 7a.

The resulting credit additions to the Carrying Charges Sub-Account were $2.9M in 2023 and $4.0M in 2024 for the regulated hydroelectric facilities, and $14.8M in 2023 and $17.8M in 2024 for OPG's nuclear facilities.

No interest is being recorded on the balance of the Carrying Charges Sub-Account pursuant to the EB-2020-0290 Payment Amounts Order.

5.13 Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account

The Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account was approved in EB-2014-0369 and continued in all subsequent OPG applications. The account records the difference between the annual revenue requirement impact of the original Niagara Tunnel Project rate base addition disallowance of $28.0M per EB-2013-0321 and the varied disallowance of $6.4M per EB-2014-0369. As the payment amounts for the regulated hydroelectric facilities set in EB-2020-0290 reflected the EB-2013-0321 disallowance and not the impact of the varied disallowance, the account continues to record the above difference during the 2022-2026 period. No additions will be required to the account as of the effective date of the payment amounts order in this proceeding, once the regulated hydroelectric payment amounts reflect the impact of the varied disallowance.

The derivation of the $1.7M debit additions to the account in each of 2023 and 2024 is shown in Ex. H1-1-1, Table 9.

5.14 Nuclear Liability Deferral Account

The Nuclear Liability Deferral Account was originally approved in EB-2007-0905 pursuant to O. Reg. 53/05 and has been approved in all subsequent OPG applications. In accordance with section 5.2(1) of O. Reg. 53/05, this account records the revenue requirement impact on OPG's prescribed facilities of any change in OPG's nuclear decommissioning and used fuel and waste management liabilities ("nuclear liabilities") arising from an approved reference plan under the Ontario Nuclear Funds Agreement ("ONFA"), measured against the forecast impact reflected in the revenue requirement approved by the OEB.[46]

The nuclear revenue requirements approved in EB-2020-0290 reflected the approved 2017-2021 ONFA Reference Plan effective January 1, 2017 ("2017 ONFA Reference Plan"), which was the most recent approved ONFA reference plan at the time of the proceeding. Subsequent to the EB-2020-0290 proceeding, the Province approved the 2022-2026 ONFA Reference Plan effective January 1, 2022 ("2022 ONFA Reference Plan") and its attendant contribution schedule ("2022 ONFA Contribution Schedule"). The proposed IR term revenue requirements for OPG's nuclear facilities reflect the 2022 ONFA Reference Plan. The 2027-2031 ONFA Reference Plan ("2027 ONFA Reference Plan") is being developed and will be subject to approval by the Province after OPG submits it, expected in late 2026. OPG will continue to record entries in the account as of the effective date of the payment amounts order in this proceeding, once the 2027 ONFA Reference Plan is effective.[47]

Entries in the account are determined using the OEB-approved methodology for recovery of nuclear liabilities for OPG's prescribed facilities. As described in Ex. C2-1-1, the Application proposes to continue with such previously approved methodology in this proceeding. Consistent with the application of this methodology, for any year where there is a positive provision for the "lesser of Unfunded Nuclear Liabilities and Asset Retirement Cost" determined in OPG's approved capital structure approved by the OEB for such provision in

[46] 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 (subsection 6(2)).

[47] Any additions to the Nuclear Liability Deferral Account arising from the 2027 ONFA Reference Plan and such additions to any other accounts that may be impacted, such as the CRVA, will be calculated such that there is no duplication across the accounts.

setting the corresponding revenue requirement, the weighted average accretion rate used in setting the corresponding revenue requirement is used to determine the return on rate base component of any entries in the account. For any year where the provision for the "lesser of Unfunded Nuclear Liabilities and Asset Retirement Cost" in OPG's approved capital structure is set to zero (due to the Unfunded Nuclear Liability being negative), the weighted average cost of capital approved by the OEB in setting the corresponding revenue requirement is used to determine to the return on rate base component of any entries in the account.[48] The Application proposes to continue the above methodology for recording entries in the account as of the effective date of the payment amounts order in this proceeding.

OPG will be responsible for the nuclear waste management and decommissioning obligations arising for the DNNP facilities. Section 6(2)10.1 of O. Reg. 53/05 requires the OEB to ensure that OPG recovers all the costs it incurs in relation to its nuclear liabilities with respect to the DNNP facilities as they are reflected in OPG's audited financial statements.[49] Pursuant to the regulation, the Application proposes to establish a new deferral account to record these impacts, as discussed in Section 7.5 below, using the same methodology that the OEB has approved for the Bruce facilities. Accordingly, no amounts would be recorded for the DNNP facilities in the Nuclear Liability Deferral Account.

The debit entries to the account of $193.3M in 2023 and $187.5M in 2024 represent the revenue requirement impact on OPG's nuclear facilities related to changes in the nuclear liabilities arising from the approved 2022 ONFA Reference Plan. These entries were determined using the OEB-approved methodology for recovery of nuclear liabilities for OPG's prescribed facilities as reflected in the EB-2020-0290 revenue requirements. They were also calculated in the same manner as the equivalent entry for 2022, which formed part of the account balance approved in EB-2023-0336. The derivation of these additions is shown at Ex. H1-1-1, Table 17. This table also show projected account entries for 2025 and 2026, being net debit additions totaling $24.8M, provided in support of an efficient regulatory review of the balances.

[48] Payment Amounts Order, EB-2020-0290, App. E, p. 15; Ex. C2-1-1, Section 4.1.4.
[49] Subject to conditions set out in in O. Reg. 53/05 section 8, which the Application expects to satisfy at the end of 2025.

The revenue requirement impact of the 2022 ONFA Reference Plan recorded in the account reflects: i) the impacts of the associated change in the asset retirement obligation ("ARO") and asset retirement costs ("ARC") for OPG's regulated facilities recognized in OPG's financial statements at the end of 2021, ii) the impact of changes in the station-level segregated fund contribution schedule attendant to the 2022 ONFA Reference Plan ("2022 ONFA Contribution Schedule"), and iii) the nuclear liabilities' impacts of the extension of the accounting end-of-life ("EOL") date for Pickering Units 1 and 4 from December 31, 2022 to December 31, 2024, effective December 31, 2020, which was subsequently reflected in the 2022 ONFA Reference Plan and became eligible to be recorded in the Nuclear Liability Deferral Account in accordance with O. Reg. 53/05.[50]

The impacts of the year-end 2021 ARO/ARC adjustment and the 2022 ONFA Contribution Schedule comprise a debit amount of $123.9M in 2023 and $119.5M in 2024 (Ex. H1-1-1, Table 17, line 15) and are further discussed in Ex. C2-1-1, Section 5.1.

The nuclear liabilities' impacts of the extension of the Pickering Units 1 and 4 EOL date reflected the associated year-end 2020 ARO/ARC adjustment recognized in OPG's financial statements and the change in the ARC depreciation expense due to the extended useful life. These impacts comprise a debit amount of $69.4M in 2023 and $67.9M in 2024 (Ex. H1-1-1, Table 17, line 16) and were anticipated in EB-2020-0290.[51,52] The derivation of these amounts is further discussed in Section 5.23 below. The change in the EOL date for Pickering Units 1 and 4 is discussed further in Ex. F4-1-1, Section 3.5.

No interest is being recorded on the balance of the account pursuant to the EB-2020-0290 Payment Amounts Order.

[50] As discussed in Section 5.23 below, impacts of the Pickering Units 1 and 4 EOL date extension from changes to the non-ARC depreciation and amortization expense are recorded in the Impact Resulting from Optimization of Pickering Station End of Life Deferral Account.

[51] The Pickering Units 1 and 4 EOL date extension and its impacts were detailed during the course of the EB-2020-0290 proceeding, but due to the timing of preparing OPG's underlying business plan, were not included in the forecasts underpinning the approved payment amounts.

[52] OPG's responses to interrogatories in EB-2020-0290, which were completed after OPG had finalized the year-end 2020 financial information required to calculate these ARO/ARC impacts, projected a debit entry of $69.4M for 2023 and $67.9M for 2024 (EB-2020-0290, Ex. L-F4-01-Staff-271, Attachment 1, Table 2, line 17, cols. (b) and (c)).

5.15 Nuclear Development Variance Account

The Nuclear Development Variance Account was originally approved in EB-2007-0905 in accordance with section 5.4 of O. Reg. 53/05 and has been approved in all subsequent OPG applications. This account records differences between the revenue requirement impacts arising from the actual non-capital costs and capital costs incurred and firm financial commitments made for 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.[53]

The variance recorded in the account is 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 OPG's corresponding annual nuclear revenue requirement approved by the OEB. The Application proposes to continue this method of determining additions to the account as of the effective date of the payment amounts order in this proceeding.

The revenue requirement impact of actual capital costs for eligible projects will include the impact of any associated CEITCs, as discussed further in Ex. A1-3-2, Section 2.3.5 and Ex. F4-2-1, Section 3.5.

The account has been capturing entries related to the DNNP. With the exception of any true-up adjustments in connection with the periods prior to the asset transfer, no account additions related to the DNNP are expected to be recorded in the account following the transfer of the DNNP assets from OPG to DNNP LP, when the Darlington New Nuclear Project Variance Account re Development ("DNNPVARD") would begin to apply. DNNPVARD is discussed in Section 6.1 below.

[53] 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 (subsection 6(2)), to the extent the OEB is satisfied that the costs were prudently incurred and the firm financial commitment were prudently made.

With the DNNP Unit 1 forecast to enter rate base during the IR term, the Application proposes to clear DNNP-related account additions in this proceeding. Such credit entries of $8.1M in 2023 and $26.5M in 2024 primarily relate to the tax impacts of CCA and SR&ED qualifying expenditure deductions related to the project. The EB-2020-0290 revenue requirements did not reflect the DNNP or the associated tax deductions. The derivation of these additions is shown at Ex. H1-1-1, Table 20. Further details on the DNNP can be found at Ex. D2-4-1 to Ex. D2-4-10.

As noted in Ex. F2-1-1, Section 5.1, the proposed nuclear revenue requirements in the Application do not include non-capital or capital costs related to potential new nuclear generation facilities other than the DNNP, which will result in any such impacts incurred by OPG during the IR term being recorded in this variance account. The Application also proposes to defer the clearance of the year-end 2024 account balance related to the costs incurred to date in connection with these activities, which would allow such costs to be considered after these initiatives have been further advanced. The costs relate to advancing planning and preparation activities for potential new nuclear generation on OPG's sites, including the Wesleyville site, in line with the Province's plans for meeting Ontario's electricity demand.

5.16 Bruce Lease Net Revenues Variance Account

The Bruce Lease Net Revenues Variance Account was originally approved in EB-2007-0905 to ensure that the actual difference between OPG's revenues and costs for the Bruce facilities is ultimately reflected in the payment amounts and riders and that OPG recovers its actual costs associated with the Bruce facilities, giving effect to the requirements of sections 6(2)9 and 6(2)10 of O. Reg. 53/05. The account has been approved in all subsequent OPG applications.

The account records differences between (i) the forecast revenues and costs related to the Bruce lease that are factored into the nuclear revenue requirement approved by the OEB, and (ii) OPG's actual revenues and costs in respect of the Bruce facilities. The costs include nuclear liabilities' costs for the Bruce facilities.

The variance recorded in the account is determined by comparing (i) the quotient of the annual forecast amount of Bruce Lease net revenues reflected in the OEB-approved revenue requirement and the OEB approved nuclear production forecast ("rate of recovery") for the corresponding year multiplied by OPG's actual nuclear production for the year, and (ii) OPG's actual revenues and costs in respect of the Bruce facilities. The Application proposes to continue this methodology for determining additions to the account as of the effective date of the payment amounts order in this proceeding.

The derivation of the credit entries of $19.0M in 2023 and $89.2M in 2024 recorded in the account is shown in Ex. H1-1-1, Table 10. Bruce Lease net revenues are discussed in Ex. G2-2-1.

5.17 Nuclear Deferral and Variance Over/Under Recovery Variance Account (OPG)

The Nuclear Deferral and Variance Over/Under Recovery Variance Account was originally approved in EB-2009-0174 and has been approved in all subsequent OPG applications. This account records the differences between the amounts approved for recovery or repayment in nuclear deferral and variance accounts and the actual amounts recovered or repaid based on the actual nuclear production and approved riders. Pursuant to OEB's orders, the account also captures the transfer of the nuclear portions of the balances remaining in other OPG accounts as they expire from time to time. The Application proposes to continue the above methodology for recording entries into the account as of the effective date of the payment amounts order in this proceeding.

The derivation of the $6.1M and $1.2M credit additions to the account for 2023 and 2024, respectively, is shown in Ex. H1-1-1, Table 11. There were no transfers from expiring accounts in 2023 or 2024.

5.18 Rate Smoothing Deferral Account

The Rate Smoothing Deferral Account was established in accordance with section 5.5 of O. Reg. 53/05 and approved in EB-2016-0152. The account records the difference between: (i) the total annual nuclear revenue requirement approved by the OEB; and, (ii) the portion of

that revenue requirement in (i) that is used in connection with setting the nuclear payment amounts in each year ("the annual deferral amount"). According to O. Reg. 53/05, an annual deferral amount as determined by the OEB is recorded in the account from January 1, 2017 until the DRP ends (the "deferral period"). Section 6(2)12(iv) of O. Reg. 53/05 stipulates that the OEB shall ensure that OPG recovers the balance recorded in the account and shall authorize recovery of the account balance on a straight-line basis over a period not to exceed ten years commencing at the end of the deferral period.

The account has recorded the annual deferral amounts approved by the OEB since 2017. Pursuant to the EB-2016-0152 Payment Amounts Order, the approved annual deferral amounts recorded in the account are $0 in 2017, $0 in 2018, $102.2M in 2019, $390.6M in 2020, and $0 in 2021.[54] Pursuant to the EB-2020-0290 Payment Amounts Order, the approved annual deferral amounts recorded in the account are $19.0M in 2022, $64.0 in 2023, $0 in 2024, $0 in 2025, and $0 in 2026.[55]

With the DRP expected to return the last unit to service in 2026, no additions are anticipated to be required to the account as of the effective date of the payment amounts order in this proceeding. Section 5.5(2) of O. Reg. 53/05 stipulates that the deferral account shall record interest on the balance of the account at a long-term debt rate reflecting OPG's cost of long-term borrowing, as approved by the OEB, compounded annually.

The Application seeks to recover the year-end 2024 account balance of $677.4M over the maximum prescribed period of ten years[56], from January 1, 2027 to December 31, 2036.

5.19 Fitness for Duty Deferral Account

The Fitness for Duty Deferral Account was approved by the OEB in EB-2016-0152 and continued in EB-2020-0290. The account records OPG's costs to implement the CNSC Fitness for Duty program, which is a drug, alcohol, psychological and physical testing program for

[54] Payment Amounts Order, EB-2016-0152, App. H, p. 1.
[55] Payment Amounts Order, EB-2020-0290, App. E, p.19.
[56] In accordance with section 6(2)12(iv) of O. Reg. 53/05.

employees in nuclear facilities. Given uncertainties with respect to the cost of the program, no such forecasted amounts were included in either the EB-2016-0152 or EB-2020-0290 revenue requirements.

Given the conclusion of prior legal challenges regarding the Fitness for Duty requirements and the provisions tracking to be implemented by January 1, 2026, the Application seeks recovery of the debit balance of $2.5M, inclusive of interest, recorded in the account over the period of June 1, 2017 to December 31, 2024. The underlying account additions represent non-capital costs averaging $0.3M per year, related to program set-up and administration and testing based on reasonable grounds, for post-incident, and as follow up to return-to-duty for nuclear workers occupying safety critical or safety sensitive positions. No additions will be required to the account as of the effective date of the payment amounts order in this proceeding, once the nuclear payment amounts reflect the ongoing costs of the program.

5.20 SR&ED ITC Variance Account (OPG)

The SR&ED ITC Variance Account was approved in EB-2016-0152 and continued in EB-2020-0290. The account records the difference between actual SR&ED ITCs for OPG's nuclear facilities as determined after any tax audits and the forecast SR&ED ITCs reflected in the revenue requirement approved by the OEB, including the tax on the difference. For the reasons discussed in Ex. F4-2-1, Section 3.4, the Application proposes to continue this methodology for recording entries in the account for OPG's nuclear facilities, and to apply the same treatment to the regulated hydroelectric facilities, as of the effective date of the payment amounts order in this proceeding.

OPG recorded five entries to the account in 2023 and 2024, totaling a net credit of $18.0M in 2023 and a net credit of $5.5M in 2024, as follows:

1) A credit entry in 2023 and a debit entry in 2024 to record the difference between the estimated actual SR&ED ITCs (net of tax) attributed to OPG's nuclear facilities and the forecast SR&ED ITCs (net of tax) included in the corresponding OEB-approved nuclear revenue requirement for those years;

2) Credit entries in 2023 and 2024 for the true-up adjustments between the estimated actual and the final actual SR&ED ITCs (net of tax), as attributed to OPG's nuclear facilities, for the immediately preceding year based on the finalization of that year's income tax return;
3) A credit entry related to an increase in the recognition of actual SR&ED ITCs for the 2017 taxation year from 75% to 100% for OPG's nuclear facilities, as prorated for the period after the effective date of the SR&ED ITC Variance Account of June 1, 2017, based on the resolution of the 2017 income tax audit in 2023;
4) A credit entry related to an increase in the recognition of actual SR&ED ITCs for the 2018 taxation year from 75% to 100% for OPG's nuclear facilities, based on the resolution of the 2018 income tax audit in 2023; and
5) A credit entry related to an increase in the recognition of actual SR&ED ITCs for the 2019 taxation year from 75% to 100% for OPG's nuclear facilities, based on the resolution of the 2019 income tax audit in 2024.

Entries 1) and 2) are the same in nature and calculation as the equivalent annual SR&ED ITC impact entries previously recorded in the account. Entries 3), 4) and 5) are the same in nature and calculation as the equivalent SR&ED ITC entries recorded in the Income and Other Taxes Variance Account in relation to resolution of prior year income tax audits, prior to the effective date of this account. They recognize a credit to ratepayers of 25% of the benefit of SR&ED ITCs that were previously credited to ratepayers at 75% in relation to 2017, 2018 and 2019 through the EB-2016-0152 payment amounts and subsequent additions to this account. SR&ED ITCs are discussed further in Ex. F4-2-1, Section 3.5. The derivation of the entries is shown in Ex. H1-1-1, Table 12.

5.21 Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account

The Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account was approved in EB-2018-0002 and continued in EB-2020-0290. Effective January 1, 2018, this account recorded the revenue requirement impact for the prescribed facilities arising from changes to nuclear liabilities and depreciation and amortization expense resulting from the Pickering station EOL date changes that came into

effect on December 31, 2017. Pursuant to the EB-2020-0290 Payment Amounts Order, additions to this account ceased to be recorded effective January 1, 2022, as the impact arising from these EOL date changes was reflected in the revenue requirements approved in that proceeding.[57]

No interest is recorded in the account pursuant to the EB-2020-0290 Payment Amounts Order.

The December 31, 2024 balance in the account is expected to be fully amortized by December 31, 2026 pursuant to the OEB-approved settlement proposal in EB-2023-0336.[58] As such, the Application proposes to terminate this account as of the effective date of the payment amounts order in this proceeding and to transfer any remaining balance (expected to be nil) to the Nuclear Deferral and Variance Over/Under Recovery Variance Account (OPG).

5.22 Pickering Closure Costs Deferral Account

The Pickering Closure Costs Deferral Account was established in accordance with section 5.6 of O. Reg. 53/05. Effective January 1, 2021, this account records any employment-related costs and non-capital costs related to third party service providers incurred by OPG that arise from any Pickering closure activities. The regulation specifies that Pickering closure costs can be incurred before or after the closure of a Pickering unit but do not include costs that are eligible for reimbursement to OPG under the ONFA or have already been included in a payment amounts order, and are to 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 are calculated as the difference between actual Pickering closure costs and any such forecast amounts reflected in the corresponding annual nuclear revenue requirement approved by the OEB. This account will continue to record additions as of the effective date of the payment amounts order in this proceeding, as

[57] Payment Amounts Order, EB-2020-0290, App. E, p. 18.
[58] Decision and Order, EB-2023-0336, App. A, Table 2, line 23.

necessary, in accordance with the regulation provisions.[59] The EB-2020-0290 revenue requirements did not reflect any Pickering closure costs.

The Application seeks recovery of the debit balance of $7.6M, inclusive of interest, recorded in the account over the period from January 1, 2021 to December 31, 2024. The underlying account additions of $1.0M in 2021, $1.8M in 2022, $3.4M in 2023, and $0.9M in 2024 represent costs incurred for planning and preparing for the workforce effects of ending commercial operation of the Pickering units. These efforts were initially aimed at managing the effects from shutting down all Pickering units. As the organizational focus shifted to the possibility of refurbishing Pickering Units 5-8, these activities became increasingly concentrated on the shutdown of Pickering Units 1 and 4. Refer to Ex. F4-3-1, Section 4.0 for further discussion.

5.23 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 approved in EB-2020-0290. Effective January 1, 2021, this account records the revenue requirement impact for the prescribed facilities arising from changes to nuclear liabilities and depreciation and amortization expense resulting from changes to the Pickering station EOL dates. The impacts recorded in the account are determined by applying the revised Pickering station EOL dates to recalculate the corresponding OEB-approved values comprising the nuclear liabilities' revenue requirement impact (such as ARC depreciation expense, return on rate base, and used fuel and waste management variable expenses) and the non-ARC revenue requirement impact (such as depreciation expense and return on rate base), and associated tax impacts, holding other variables constant (such as capital in-service amounts). The Application proposes to continue this methodology for recording entries in the account as of the effective date of the payment amounts order in this proceeding should a change to the Pickering Units 5-8 EOL date arise in the future.

[59] No further additions are expected in this account as of the effective date of the payment amounts order in this proceeding.

End-of-Life Change Implemented December 31, 2020

These account additions in 2023 and 2024 represent the revenue requirement impacts of extending the accounting station EOL date for Pickering Units 1 and 4 from December 31, 2022 to December 31, 2024, effective December 31, 2020. This change and its impacts were anticipated during the course of the EB-2020-0290 proceeding but due to the timing of preparing OPG's underlying business plan, were not reflected in the forecasts underpinning the EB-2020-0290 approved payment amounts.

The derivation of the $54.6M debit entry in 2023 and $47.4M debit entry in 2024 is shown in Ex. H1-1-1, Table 18. These entries reflect the impact of changes to non-ARC depreciation and amortization expense.[60] They were calculated in the manner set out by OPG in EB-2020-0290 and reflected in the year-end 2022 balance of the account that was approved for recovery in EB-2023-0336, and are very close to the projection of these entries identified in EB-2020-0290.[61] Pickering Units 1 and 4 ended commercial operation and became fully depreciated by the end of 2024, as planned. The change in the EOL date for Pickering Units 1 and 4 is discussed in Ex. F4-1-1, Section 3.5.

As discussed in Section 5.14 above, beginning 2022, additions related to the nuclear liabilities' impact from the above EOL change are recorded in the Nuclear Liability Deferral Account in accordance with O. Reg. 53/05. The derivation of the nuclear liabilities' impact of $69.4M in 2023 and $67.9M in 2024 is included in Ex. H1-1-1, Table 18. The nuclear liabilities' impact reflects the increase in the ARO and associated ARC balances of $51.1M for the prescribed

[60] Ex. H1-1-1, Table 18, line 5, cols. (a) and (b), and EB-2023-0336, Ex. H1-1-1, Table 19, line 5 show a total change in non-ARC depreciation and amortization expense of $16.3M, rather than zero, over the 2021-2024 period in relation to these EOL date changes for Pickering Units 1 and 4. As discussed above, this amount, which is being recorded in the Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account, is determined by applying the revised Pickering Units 1 and 4 EOL dates to recalculate the corresponding OEB-approved values reflected in the EB-2016-0152 revenue requirement (for 2021) and EB-2020-0290 revenue requirement (for 2022-2024), holding other variables consistent with the respective revenue requirement. This approach allows for isolation of the EOL date change impact had it been known at the time of setting the original revenue requirement. Because, as a result, the impacts are calculated on a different set of underpinning forecasts (e.g., capital in-service additions) for 2021 versus 2022-2024, the net effect of the differences in non-ARC depreciation across these account entries over these four years may not be zero.

[61] OPG's responses to interrogatories in EB-2020-0290, which were completed after OPG had finalized the year-end 2020 financial information required to calculate the ARO/ARC impacts, projected comparable debit entries of $54.7M for 2023 and $47.5M for 2024 (EB-2020-0290, Ex. L-F4-01-Staff-271, Attachment 1, Table 2, line 18, cols. (b) and (c)).

facilities recorded in OPG's financial statements at year-end 2020 to reflect the changes in the Pickering Unit 1 and 4 EOL date, depreciation of existing ARC balances applied over a longer useful life, and higher used fuel variable expenses due to an increase in the per bundle cost rates reflecting a lower discount rate of 2.01% (compared to 2.94% used to forecast these costs in EB-2020-0290). The details of the year-end 2020 ARO/ARC adjustment are provided in Ex. C2-1-1, Table 4.

No additions will be required to the account related to the EOL change of Pickering Units 1 and 4 from December 31, 2022 to December 31, 2024 as of the effective date of the payment amounts order in this proceeding, once the nuclear payment amounts reflect these impacts.

End-of-Life Change Implemented December 31, 2023

As discussed in Ex. F4-1-1, Section 3.5, OPG revised the accounting station EOL date for Pickering Units 5-8 from December 31, 2024 to December 31, 2070, effective December 31, 2023. This change reflected OPG's expectation of the refurbishment of these units, taking into account the Province's support for OPG's plan to proceed with the initiation phase of the PRP. Additional amounts recorded to the account in 2024 represent the revenue requirement impacts of this change, which was not anticipated in the EB-2020-0290 revenue requirements that assumed the shutdown of all Pickering units. The nuclear liabilities' impact arising from these changes is recorded in this account, rather than the Nuclear Liability Deferral Account, as the 2022 ONFA Reference Plan did not contemplate the refurbishment of Pickering Units 5-8.

The derivation of the credit entry of $2.3M in 2024 is shown in Ex. H1-1-1, Table 19. It comprises debit additions of $82.6M for revenue requirement impacts arising from changes to nuclear liabilities and credit additions of $84.9M from changes to non-ARC depreciation and amortization expense. This table also show projected account entries for 2025 and 2026, being net debit additions totaling $29.3M, provided in support of an efficient regulatory review of the balances.

The nuclear liabilities' impact primarily reflects the $474.1M increase in ARC balances for the prescribed facilities recorded in OPG's financial statements at year-end 2023 to reflect the change in the Pickering station EOL date, depreciation of existing ARC balances applied over a longer useful life, and lower used fuel and low and intermediate level variable expenses due to a decrease in the volumetric cost rates reflecting a higher discount rate. These impacts are discussed further discussed in Ex. C2-1-1, Section 5.2, and the details of the year-end 2023 ARO/ARC adjustment are provided in Ex. C2-1-1, Table 4.

The impacts recorded in the account are determined by applying the revised Pickering station EOL dates that came into effect on December 31, 2023 to recalculate the corresponding OEB-approved values reflected in the EB-2020-0290 revenue requirement, holding other variables constant, and then adjusting for the impacts from the revised station EOL date for Pickering Units 1 and 4 (discussed above) and the implementation of the 2022 ONFA Reference Plan (discussed in Section 5.14) that are captured separately in deferral accounts to avoid duplication.

In calculating the above impacts, OPG applied the same methodologies used to make entries in respect of the accounting station EOL date extension for Pickering Units 1 and 4 discussed above, as well as those previously used to make entries into the Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account. The entries reflect the OEB-approved methodology for recovery of nuclear liabilities for OPG's prescribed facilities as reflected in the EB-2020-0290 revenue requirements. The Application proposes to continue to determine additions to this account on this basis as of the effective date of the payment amounts order in this proceeding for any future changes in Pickering EOL dates.

No additions will be required to the account related to the EOL change of Pickering Units 5-8 from December 31, 2024 to December 31, 2070 as of the effective date of the payment amounts order in this proceeding, once the nuclear payment amounts reflect these impacts.

No interest is recorded on the balance of the account pursuant to the EB-2020-0290 Payment Amounts Order.

5.24 Clarington Corporate Campus Deferral Account

The Clarington Corporate Campus Deferral Account was approved in EB-2020-0290, effective January 1, 2022, to record, for OPG's nuclear facilities, the revenue requirement impacts of OPG's capital expenditures and operating costs for the then planned Clarington Corporate Campus. Since it was established, the account recorded a single non-capital debit entry of $7.0M in 2023, resulting in a debit balance of $7.7M as of December 31, 2024, inclusive of interest. For the reasons discussed below, no additions will be required to the account as of the effective date of the payment amounts order in this proceeding.

At the time of the EB-2020-0290 proceeding, OPG was planning for the Clarington Corporate Campus project with the goal of supporting the consolidation of OPG's workspaces through the construction of a new headquarters building in the municipality of Clarington. The project subsequently progressed through the planning phase in accordance with OPG's project governance. Prior to entering the project execution phase, OPG identified the opportunity to purchase an existing office building located at 1908 Colonel Sam Drive, Oshawa, which was economically preferred compared to building a new office building, reflecting unanticipated inflationary and supply chain pressures following the COVID-19 pandemic. As a result, OPG proceeded with the purchase of the property at 1908 Colonel Sam Drive in 2023, ultimately renovating and opening the new headquarters in August 2025, and the Clarington Corporate Campus project was closed. The debit entry of $7.0M in the account represents the project costs, attributable to OPG's regulated nuclear facilities, that were incurred until the project was terminated and were subsequently written off. Additional details can be found in Ex. D3-1-2, Sections 3.3 and 3.4.

5.25 Sale of Unprescribed Kipling Site Deferral Account

The Sale of Unprescribed Kipling Site Deferral Account was established in EB-2020-0290, effective January 1, 2022, to track 23% of the net proceeds arising from any sale of OPG's unprescribed site located at 800 Kipling Avenue (the "Kipling Site") in Toronto during the 2022-

2026 period. The account was established as part of the OEB-approved settlement proposal in EB-2020-2090, which provided in connection with any amounts tracked in the account that a party may take any position as to whether any portion of this amount should be returned to ratepayers at the time of the account's disposition. Pursuant to the OEB-approved settlement proposal in EB-2023-0336, the parties agreed that the deferral account would be disposed of, to the benefit of ratepayers, with an agreed upon balance of $12.7M as of December 31, 2022, which represented 50% of 23% of the after-tax gain recognized by OPG in 2022 associated with the sale of the Kipling Site. It was further agreed that the same treatment would apply to any after-tax gain on this sale recognized by OPG during the 2023-2026 period.[62] Since 2022, OPG recognized such an after-tax gain of $21.5M in 2023, resulting in a credit entry of $2.5M during that year. No additions will be required to the account as of the effective date of the payment amounts order in this proceeding.

5.26 Earnings Sharing Deferral Account

The Earnings Sharing Deferral Account was approved in EB-2020-0290, effective January 1, 2022, 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, assessed over a cumulative 5-year period from January 1, 2022 to December 31, 2026. No entries will be recorded in this account until following the completion of the above five-year period, if applicable.

As discussed in Ex. A1-3-2, Section 4.1, OPG proposes to continue the earnings sharing mechanism for its facilities for the 2027-2031 period. Consistent with the mechanism approved in EB-2020-0290, OPG proposes to base the earnings sharing mechanism on its combined regulated nuclear and regulated hydroelectric business on an asymmetrical basis, with a 100-basis point deadband to the OEB-approved ROE rate and 50/50 sharing above the deadband, assessed over a cumulative 5-year period from 2027-2031.

[62] Decision and Order, EB-2023-0336, June 13, 2024, p.5.

To effectuate the proposed earnings sharing mechanism, OPG proposes to continue the Earnings Sharing Deferral Account. No entries will be recorded in the account with respect to the 2027-2031 period, if applicable, until following the completion of the five-year period.

5.27 Impact of IFRS Deferral Account (OPG)

The Impact for IFRS Deferral Account (OPG) was approved in EB-2020-0290, effective January 1, 2022, to record financial impacts of transition to and implementation of International Financial Reporting Standard ("IFRS") from US GAAP in the event that OPG adopts IFRS for financial reporting purposes to meet the requirements of the *Securities Act* (Ontario). To date, no entries have been recorded in this account as OPG has continued to apply US GAAP to report its consolidated financial statements.

As discussed in Ex. A2-1-1, OPG's financial statements are prepared in accordance with US GAAP, as required by Ontario Regulation 395/11 under *Financial Administration Act* (Ontario), which takes precedence over the continuous disclosure obligations under the *Securities Act* (Ontario). However, these requirements do not take precedence over the equivalent continuous disclosure requirements of other provincial securities regulators. This applies where OPG is also a reporting issuer by virtue of its Medium-Term Notes issued pursuant to a short form base shelf prospectus filed in these jurisdictions and subject to the requirements of *National Instrument 44-101 – Short Form Prospectus Distributions*. OPG currently receives exemptive relief from the OSC and other provincial securities regulators from the requirements of *National Instrument 52-107* ("NI 52-107") that allows OPG to file its financial statements using US GAAP instead of IFRS for continuous disclosure purposes, thereby allowing it to meet the requirements of the other provincial securities laws. Although this exemptive relief is time limited, OPG is not planning for adoption of IFRS for continuous disclosure purposes. OPG is planning to register with the U.S. Securities and Exchange Commission ("SEC") as a Foreign Private Issuer, subject to final approval by OPG's Board of Directors, to facilitate access to U.S. debt capital markets. As an SEC registered issuer, OPG would retain the ability to meet its continuous disclosure requirements in Canada by continuing to file its financial statements using US GAAP as permitted under the ongoing exemptions in NI 52-107 available for SEC registered issuers. As OPG's efforts toward SEC registration are expected to continue

at least partway through the IR term, the Application proposes to continue the deferral account as of the effective date of the payment amounts order in this proceeding and as necessary to reassess this matter in the next payment amounts proceeding.

No interest is recorded on the balance of the account pursuant to the EB-2020-0290 Payment Amounts Order.

5.28 Pickering B Variance Account

The Pickering B Variance Account was established in accordance with section 5.7(1) of O. Reg. 53/05, effective January 1, 2023. The account records the difference between (a) the revenues generated from the output of Pickering B (i.e., Pickering Units 5-8) during the period from January 1, 2026 to September 30, 2026, and (b) the sum of (i) any foregone revenues related to forgone output from these units arising from any Pickering B extension, (ii) the revenue requirement impacts from actual non-capital and capital costs incurred in relation to any Pickering B extension activities undertaken by OPG, and (iii) the revenue requirement impacts arising from actual non-capital and capital costs incurred since January 1, 2024 for Pickering B preservation activities before the effective date of the OEB's first payment amounts order for OPG's nuclear facilities that becomes effective on or after January 1, 2027.[63] Pickering B extension activities represent any activities OPG undertakes 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. Pickering B preservation activities represent any activities undertaken by OPG to preserve its ability to operate Pickering Units 5-8 following the PRP, regardless of whether the project proceeds. Costs incurred for the preservation activities include but are not limited to costs payable for staffing, training, corporate support or administrative functions. Pursuant to the above provisions, no additions will be recorded to the account as of the effective date of the payment amounts order in this proceeding.

[63] O. Reg. 53/05 was initially amended on December 9, 2022 to establish this account as the Pickering B Extension Variance Account, effective January 1, 2023. That amendment did not include item (iii) in the list of amounts to be recorded in the account. O. Reg. 53/05 was subsequently amended on June 27, 2025 to add item (iii) to the list of amounts to be recorded in the account and to rename the account as the Pickering B Variance Account.

The account has a debit balance of $131.1M as of December 31, 2024, representing the impacts to date of foregone revenues related to forgone output from Pickering Units 5-8 arising from the Pickering B extension activities and the costs of such activities.[64] OPG proposes to defer the clearance of this balance to a future application, which would allow for the complete impact of operating Pickering Units 5- 8 from January 1, 2026 to September 30, 2026 and undertaking the preservation activities to be considered at the same time. In particular, once the revenues generated from operating Pickering Units 5-8 during the period from January 1, 2026-December 31, 2026 are credited to the account, the resulting balance is expected to be a net credit position.

5.29 Incremental Cloud Computing Implementation Costs Deferral Account

The Incremental Cloud Computing Implementation Costs Deferral Account was established by the OEB on a generic basis through accounting order 003-2023, effective December 1, 2023, to record incremental cloud computing implementation costs incurred and any related offsetting savings, if applicable. There were no entries recorded to the account as of December 31, 2024.

The OEB's accounting order establishing the above account indicated that a utility may propose the regulatory treatment of any material cloud computing implementation costs expected during its rate-setting term, including consideration of a new deferral account or other approaches. The Application proposes that the Incremental Cloud Computing Implementation Costs Deferral Account be terminated for OPG as of the effective date of the payment amounts order in this proceeding, with any cloud computing implementation costs reflected on a forecast basis as part of the revenue requirements requested in this Application.

[64] Ex. H1-1-1, Table 1, line 45, col. (c).

5.30 Pickering B Refurbishment Project Variance Account

The Pickering B Refurbishment Project Variance Account is established in accordance with section 5.8(1) of O. Reg. 53/05, effective January 1, 2026. The account will record the difference between: (a) the amount calculated by multiplying the 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 (b) 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. Exhibit I1-1-3, Section 5.0 presents such forecast interest amounts that the Application seeks to recover during the IR term in respect of the PRP, including the underpinning calculation methodology, and explains how the actual interest amounts will be determined. There are no such interest amounts in respect of the PRP reflected in the EB-2020-0290 nuclear payment amount in effect during 2026; as such, the full actual interest amount for 2026 will be recorded in the account pursuant to O. Reg. 53/05.

Section 6(2)12.1(ii) of O. Reg 53/05 stipulates that the OEB shall ensure that OPG recovers the balance recorded in the account in the year following which such balance was recorded in the account, to the extent the OEB is satisfied that the balance has been accurately recorded. The Application's proposal for the implementation of this annual requirement can be found at Ex. I1-1-3, Section 6.0.

Section 5.8(3) of O. Reg. 53/05 stipulates that the variance account shall record interest on the balance of the account at OPG's long-term debt rate as approved by the OEB, compounded annually.

5.31 Darlington New Nuclear Project Variance Account

The Darlington New Nuclear Project Variance Account is established in accordance with section 5.4.1(1) of O. Reg. 53/05, effective January 1, 2026.

If necessary, the account will record the difference between: (a) the amount calculated by multiplying the 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 (b) 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.

As set out in section 5.4.1(2)(a), the account shall not include amounts respecting capital costs incurred on or after the OEB issues an order specifying satisfaction with certain conditions set out in section 8 of the regulation. The Application expects that these requirements will be met at the end of 2025 and, thus, is not expecting that entries will be made to this account. The Application expects related entries to be made to the Darlington New Nuclear Project Variance Account re Capital Cost Amounts (established in accordance with section 12(1) of O. Reg. 53/05 and described in Section 6.3 below).

Exhibit I1-1-3, Section 4.0 presents forecast interest amounts that the Application seeks to recover during the IR term in respect of the DNNP, including the underpinning calculation methodology, and explains how the actual interest amounts will be determined. There are no such interest amounts in respect of the DNNP reflected in the EB-2020-0290 nuclear payment amount in effect during 2026; as such, the full actual interest amount for 2026 could be eligible to be recorded in the account pursuant to O. Reg. 53/05, if necessary.

Section 6(2)11.1(ii) of O. Reg 53/05 stipulates that the OEB shall ensure that OPG recovers the balance recorded in the account in the year following which such balance was recorded in the account, to the extent the OEB is satisfied that the balance has been accurately recorded. The Application's proposal for the implementation of this annual requirement can be found at Ex. I1-1-3, Section 6.0.

Section 5.4.1(3) of O. Reg. 53/05 stipulates that the variance account shall record interest on the balance of the account at OPG's long-term debt rate as approved by the OEB, compounded annually.

6.0 DNNP LP'S ACCOUNT DESCRIPTIONS

This section provides a description and sets out the purpose of DNNP LP's existing deferral and variance accounts and describes how additions to the accounts will be determined.

6.1 Darlington New Nuclear Project Variance Account re Development

The Darlington New Nuclear Project Variance Account re Development is established in accordance with section 11(1) of O. Reg. 53/05. Effective January 1, 2026[65], this account will record the differences between the revenue requirement impacts arising from the actual non-capital and capital costs incurred and firm financial commitments made for the DNNP and such forecast amounts reflected in the payment amounts approved by the OEB. This includes but is not limited to the costs of planning, preparation and technology identification for the DNNP facilities, as well as design, development, construction, and commissioning of the DNNP facilities.[66]

The Application proposes that the above variance recorded in the account 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 DNNP LP's corresponding annual revenue requirement approved by the OEB. Prior to the effective date of the payment amounts order in this proceeding, such forecast amounts are zero. Refer to Attachment 9 for the capital-related DNNP revenue requirement underpinning the IR term forecasts that would form the basis of the corresponding capital reference amounts for the DNNPVARD. As discussed in Ex. F2-2-1, the Application proposes to include the following DNNP Operational Readiness OM&A costs in the revenue requirements during the IR term, which would form the basis of the corresponding non-capital reference amounts for the DNNPVARD during the IR term: $45.9M in 2027, $46.3M in 2028, $40.0M in 2029, $40.2M in 2030, and $0.0M in 2031.[67]

The revenue requirement impact of actual capital costs for the DNNP will include the impact of any CEITCs associated with the project, as discussed further in Ex. A1-3-2, Section 2.3.5 and Ex. F4-2-1, Section 3.5.

[65] Subject to conditions set out in in O. Reg. 53/05 section 8, which the Application expects to satisfy at the end of 2025.
[66] 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 (subsection 14(2)(3)), to the extent the OEB is satisfied that the costs were prudently incurred and the firm financial commitment were prudently made.
[67] Ex. F2-1-1, Table 1b, line 3.

In accordance with section 11(1) of O. Reg. 53/05, the account will also record any net revenues earned (section 11(1)b(ii)) or foregone (section 11(1)a(ii)) 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. For the IR term, the forecasted DNNP Unit 1 in-service date is October 17, 2030, as discussed in Ex. D2-4-6. For this component, the account is expected to produce a credit entry should the actual in-service date be earlier than the OEB-approved forecast date and a debit entry should the actual in-service date be later than the OEB-approved forecast date.

The Application proposes that 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 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 for DNNP LP by the OEB, holding all other variables constant (including outage plans relative to the in-service date). Deviations from the forecast would 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 deviation recorded in the account would be determined by multiplying the deviation from the OEB-approved forecast by the approved nuclear payment amount then in effect.

The Application further proposes that the account record, as part of net revenue, the impact of a different in-service date on the forecast nuclear fuel expense (in the form of the nuclear fuel service fees) and outage OM&A expenses. To calculate the nuclear fuel expense deviation, it is proposed that the production deviation, as determined above, be multiplied by the corresponding nuclear fuel consumption cost rate ($/MWh), as reflected in the OEB-approved revenue requirement based on the OEB-approved production forecast for the DNNP facilities. The outage OM&A expense deviation is proposed to be calculated by comparing the expenses that would have been forecast for this proceeding based on the outage timing consistent with the calculated production forecast, holding all other variables constant, and the outage OM&A expense forecast approved by the OEB.

6.2 DNNP Generator Capital Structure Variance Account

The DNNP Generator Capital Structure Variance Account ("DGCSVA") is established in accordance with section 13(1) of O. Reg. 53/05. The account records, effective January 1, 2026[68] and until the effective date of the OEB's first payment amounts order in respect of DNNP LP following the DNNP construction period, 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 impacts arising from the capital structure and the cost of debt reflected in the payment amounts approved by the OEB.[69] The Application's proposals with respect to DNNP LP's capital structure for the IR term are discussed in Ex. C1-1-1.

The manner in which the account entries are calculated needs to consider the interaction with the DNNPVARD, which will record the revenue requirement impact of differences between actual and forecast capital costs for the DNNP (i.e., measured as the difference between the actual and forecast rate base values) using the forecast cost of capital parameters approved by the OEB. Accordingly, for the DGCSVA, the Application proposes that the revenue requirement impacts arising from item (i) above be calculated by applying a debt component (and interest cost) equal to the actual amount of DNNP LP's debt outstanding (and interest cost) at the time to the actual rate base value (i.e., the same actual rate base value used in the DNNPVARD variance calculation), with the remaining portion of such actual rate base value representing the equity component. Item (ii) above would be calculated by applying the forecast cost of capital parameters (including percentage capital structure) approved by the OEB to the actual rate base value.

[68] Subject to conditions set out in in O. Reg. 53/05 section 8, which the Application expects to satisfy at the end of 2025.

[69] 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 (subsection 14(2)5), to the extent the OEB is satisfied that the costs associated with the borrowing were prudently incurred.

6.3 Darlington New Nuclear Project Variance Account re Capital Cost Amounts

The Darlington New Nuclear Project Variance Account re Capital Cost Amounts is established in accordance with section 12(1) of O. Reg. 53/05, effective January 1, 2026.[70] The account records the difference between: (a) the amount calculated by multiplying the actual cumulative capital costs incurred by DNNP LP in respect of the DNNP by OPG's long-term debt rate as approved by the OEB; and (b) 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. Exhibit I1-1-3, Section 4.0 presents such forecast interest amounts that the Application seeks to recover during the IR term in respect of the DNNP, including the underpinning calculation methodology, and explains how the actual interest amounts will be determined. There are no such interest amounts in respect of the DNNP reflected in the EB-2020-0290 nuclear payment amount in effect during 2026; as such, the full actual interest amount for 2026 will be recorded in the account pursuant to O. Reg. 53/05.

Section 14(2)4(ii) of O. Reg. 53/05 stipulates that the OEB shall ensure that DNNP LP recovers the balance recorded in the account in the year following which such balance was recorded in the account, to the extent the OEB is satisfied that the balance has been accurately recorded. The Application's proposal for the implementation of this annual requirement can be found at Ex. I1-1-3, Section 6.0.

Section 12(3) of O. Reg. 53/05 stipulates that the variance account shall record interest on the balance of the account at a long-term debt rate reflecting OPG's long-term term debt rate, as approved by the OEB, compounded annually.

7.0 PROPOSED NEW ACCOUNTS FOR OPG

This section sets out the details of new deferral and variance accounts proposed for OPG as of the effective date of the payment amounts order in this proceeding.

[70] Subject to conditions set out in in O. Reg. 53/05 section 8, which the Application expects to satisfy at the end of 2025.

7.1 Change of Laws Deferral Account (OPG)

OPG operates in a dynamic legal and regulatory landscape governed by a wide range of provincial and federal statutes that prescribe detailed compliance requirements, including with respect to environment, labour and safety.[71] Operating in this complex legislative framework creates considerable uncertainty in terms of forecasting the company's costs and revenues over the five-year term of this Application. As demonstrated by the historical and forecast case studies presented below, changes in laws are outside of the company's control can significantly alter compliance requirements and can have a material impact on OPG's forecasted costs and revenues. To address these risks, OPG proposes a Change of Laws Deferral Account which would record material impacts to regulated hydroelectric and nuclear costs and revenues over the IR term resulting from changes in legal and regulatory requirements, as discussed below.

7.1.1 Historical Case Study re Change in Laws

During the recent historical period, a material change in laws presented itself in the context of *Protecting a Sustainable Public Sector for Future Generations Act, 2019* ("Bill 124"), which restricted both union and non-union provincial public sector wage and total compensation increases to 1% annually for a three-year moderation period. OPG relied on Bill 124 to forecast the compensation costs which were included in its 2022-2026 nuclear payments application (EB-2020-0290). In November 2022, after OPG's application and payments were approved by the OEB, the Ontario Superior Court overturned Bill 124, rendering the company's nuclear payment amounts deficient by approximately $188 million over the five-year rate term.[72]

In response to this material change in law, in EB-2023-0098, OPG filed an accounting order application requesting OEB approval to establish a variance account to record the nuclear revenue requirement impacts resulting from Bill 124 being overturned. The OEB denied the request, concluding that Bill 124 was a foreseeable and material risk to the OPG's forecast employee compensation costs in the 2022-2026 payment amounts application.[73] This decision was upheld by the OEB on a motion to review and vary the prior decision (EB-2023-0209), in

[71] The legislative and regulatory framework and other government requirements that govern OPG and apply to OPG's prescribed facilities are discussed in Ex. A1-6-1.
[72] Decision and Order, EB-2023-0098, June 27, 2023, pp. 7-8.
[73] Decision and Order, EB-2023-0098, June 27, 2023.

which the OEB found that it was not appropriate for OPG to recover the costs of a known risk during the multi-year rate framework, if OPG did not provide "evidence on the record about this known material risk to its compensation forecast so as to give parties an opportunity to factor that evidence into settlement discussions."[74]

7.1.2 Forecast Case Study re Change in Laws

Consistent with the OEB's findings in EB-2023-0209, OPG notes that its 2025-2031 Business Plan and the proposed forecasts in this Application do not include any changes in laws that may occur over the IR term. As such, OPG proposes to establish a deferral account to capture material cost and revenue impacts to OPG's regulated hydroelectric and nuclear facilities arising from provincial and/or federal legislative or regulatory changes (collectively "change in law(s)"), to the extent these impacts are not already recorded in other deferral and variance accounts.

The paragraphs that follow provide an example of prospective changes in environmental laws with respect to the provincial *Endangered Species Act, 2007* ("ESA") and the federal *Species at Risk Act* ("SARA"). OPG is providing this example as a case study to illustrate the material impacts of a prospective change in law that was not included in its application forecasts. It is a foreseeable risk that these and other changes in laws may impact OPG's compliance requirements over the IR term. To the extent this happens, OPG proposes that material cost and revenue impacts arising from any changes in laws would be captured in the proposed account.

Potential Changes to Provincial and Federal Legislation

Ontario legislation concerning the American eel is evolving. The *Endangered Species Act, 2007*, where American eels were previously classified as "Endangered" under Ontario Regulation 242/08, was proposed for repeal by Bill 5 on April 17, 2025 and is expected to be eventually replaced by the *Species Conservation Act, 2025* ("SCA"). Specific requirements or changes that will be established under the new SCA are unknown. Under the former ESA, OPG maintains a formal agreement with the Ministry of the Environment, Conservation and

[74] Decision and Order, EB-2023-0209, October 24, 2023, p. 9.

Parks ("MECP") scheduled to expire in 2029, which includes an obligation to conduct research initiatives aimed at improving downstream passage for migrating eels. OPG expects to continue to operate under the existing ESA agreement until the SCA is enacted and requirements are known.[75]

In April 2024, the Fisheries and Oceans Canada ("DFO") made a recommendation to the Minister of Environment and Climate Change of Canada ("ECCC") whether to uplist American eels from "Special Concern" to "threatened" species. On December 2, 2025, the Government of Canada announced that the American Eel was not to be listed, and that the best way to conserve the species was to manage the species and its habitat under the *Fisheries Act* through "adaptive management approaches". Given the current uncertainty of the DFO's potential adaptive management requirements, OPG has not made any adjustments to its production or cost forecasts for the regulated hydroelectric facilities. Potential outcomes of DFO compliance activities could include additional capital expenditures not contemplated in the business plan, or production impacts at stations during migratory periods.

Prospective Use of the Change in Laws Deferral Account related to the American eels

As discussed above, the specific actions that OPG may be required to undertake in the IR term as a result of such regulations remain uncertain, as provincial and federal legislation continues to evolve. The potential impacts that could arise include capital and non-capital costs as well as foregone hydroelectric production.

OPG's 2025-2031 Business Plan and the forecasts in this Application do not include the costs or revenue impacts arising from potential compliance activities related to changes in provincial and/or federal regulations concerning the American eel. Thus, if OPG's regulated hydroelectric facilities are faced with compliance activities related to such changes over the 2027-2031 IR

[75] Ongoing research efforts under the existing ESA agreement are focused on the use of a "light array" to guide eels to designated locations, enabling their collection and translocation downstream of hydroelectric facilities on the St. Lawrence River. Following a pilot project to assess the success of a small-scale light array that is scheduled for 2027/2028, the MECP may require the full-scale design and deployment of the light array and eel collection system, provided it remains a priority within the incoming SCA. Cost impacts associated with such a full system are not included in OPG's forecasts for the regulated hydroelectric facilities.

term, OPG would use the proposed Change of Laws Deferral Account (OPG) to record the revenue requirement impact of costs associated with these compliance activities, as well as the impact of foregone production revenue, net of changes in GRC costs, at OPG's regulated hydroelectric facilities.

For clarity, OPG provided the American eel example noted above to illustrate the need for and impact of a prospective change in law over the 2027-2031 IR term. OPG requests, however, that the proposed account would be applicable to all changes in laws that may have a material impact on the company's regulated hydroelectric and nuclear costs or revenues over the upcoming term.

7.2 Global Hydroelectric Capital Variance Account

The Application proposes to establish the Global Hydroelectric Capital Variance Account to record the difference in revenue requirement attributed to actual total ("global") hydroelectric capital in-service amounts and the forecast CRRR amounts underpinning the capital factor calculation presented in Ex. I1-2-1, Table 2, as assessed after the 2028-2031 period. The proposed account would be asymmetric in that an amount could be credited to ratepayers in the event the CRRR determined based on actual capital in-service additions over the period is less than the CRRR underpinning the capital factor calculation. In the event the CRRR based on actual capital in-service additions is greater than the CRRR underpinning the C-factor, there would be no recovery from ratepayers through this account. Further details on the proposed operation of the account are discussed in Ex. A1-3-2, Section 2.3.5.

7.3 Clean Electricity ITC Variance Account (OPG)

The federal government has proposed a 15% refundable CEITC with respect to investments in certain clean electricity property and certain refurbishment projects, which is proposed to be available to certain entities including OPG. At the time of filing the Application, no legislation implementing this credit is in place and the CEITCs are not reflected in OPG's 2025-2031 Business Plan or the proposed revenue requirements in this Application. In accordance with US GAAP, OPG will account for such credits, once received, as a reduction in the capital costs of the underlying eligible projects. The revenue requirement savings from the CEITCs will

therefore be realized through a reduction in the capital related revenue requirement once these assets are in service.

The Application proposes to establish the Clean Electricity ITC Variance Account (OPG) to record the revenue requirement differences as between the actual CEITCs received for eligible projects and those attributed to corresponding forecast CEITCs reflected in the OEB-approved payment amounts, if any, for OPG's regulated hydroelectric and nuclear facilities. This account would record such differences only to the extent they are not captured by an existing account, such as the NDVA or the CRVA.

For OPG's nuclear facilities, the variances will be recorded relative to the corresponding forecast amounts included in OPG's annual nuclear revenue requirements approved by the OEB. For the regulated hydroelectric facilities, the Application proposes that any variances be determined with reference to the corresponding 2027-2031 annual forecast amounts. This approach reflects the proposed hydroelectric rate-setting framework for the 2027-2031 term, whereby the forecast CRRR underpins the proposed C-factor. The hydroelectric rate-setting proposal is discussed in Ex. A1-3-2, Section 2.0, with the potential resulting interaction between the Clean Electricity ITC Variance Account (OPG) and the Global Hydroelectric Capital Variance Account addressed in Ex. A1-3-2, Section 2.3.5.[76]

Further details on the CEITCs, including the details of their capital related revenue requirement impact, are discussed in Ex. F4-2-1, Section 3.5.

7.4 Payment Amount Shaping Deferral Account

The Application proposes to establish the Payment Amount Shaping Deferral Account to record, during the IR term, the difference between: (i) OPG's total annual nuclear revenue requirement approved by the OEB; and (ii) the portion of that revenue requirement in (i) that is used in connection with setting the nuclear payment amounts in each year ("the deferral amount"). An annual deferral amount as determined by the OEB would be recorded in the

[76] Any additions to the Clean Electricity ITC Variance Account (OPG) will be calculated without duplication with other accounts that may be impacted.

account from January 1, 2027 until December 31, 2031. As described in Ex. I1-3-2, this account is proposed in conjunction with OPG's payment amount shaping proposal to help manage the 2027 ratepayer impact while balancing OPG's financing needs over the period.

OPG is proposing offsetting debit and credit entries to the Payment Amount Shaping Deferral Account during the 2027-2031 period such that a nil balance remains in the account at December 31, 2031, before interest.

As discussed at Ex. I1-3-2, OPG proposes to set the annual deferral amounts as follows for the IR term, to be recorded on a monthly straight-line basis: $500.0M in 2027, -$500.0M in 2028, $0.0M in 2029, $0.0M in 2030, and $0.0 in 2031.

Consistent with the treatment of the Rate Smoothing Deferral Account, OPG proposes to record interest on the balance of the account at a long-term debt rate reflecting OPG's cost of long-term borrowing, as approved by the OEB, compounded annually.

7.5 DNNP Nuclear Liability Deferral Account

OPG will be responsible for the nuclear waste management and decommissioning obligations arising from the DNNP facilities. Pursuant to section 6(2)10.1 of O. Reg. 53/05, the Application proposes to establish the DNNP Nuclear Liability Deferral Account to record the difference between: (i) the costs of OPG's nuclear waste management and decommissioning liabilities ("nuclear liabilities costs") 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 nuclear liabilities costs with respect to the DNNP facilities reflected in OPG's nuclear revenue requirement approved by the OEB.

Effective January 1, 2026, amendments to O. Reg. 53/05 provide for the recovery of nuclear liability costs. In section 0.1 of O. Reg. 53/05 defines "nuclear decommissioning liability" as follows:

> "nuclear decommissioning liability" means the liability of Ontario Power Generation Inc. for,
>
> (a) decommissioning the nuclear facilities, the Bruce Nuclear Generating Stations and, on and after the DNNP transition date, the DNNP Nuclear Generating Station, and
>
> (b) the management of Ontario Power Generation Inc.'s nuclear waste and used fuel.

Section 6(2)10.1 of O. Reg. 53/05 states:

> The Board shall ensure that Ontario Power Generation Inc. recovers all the costs it incurs in relation to its nuclear decommissioning liability with respect to the Bruce Nuclear Generating Stations and the DNNP Nuclear Generating Station as reflected in the audited financial statements approved by the board of directors of Ontario Power Generation Inc., to the extent that those costs are not otherwise recovered under this subsection.

The above provisions have the effect of requiring OPG to recover its nuclear liabilities costs with respect to the DNNP facilities as they are reflected in OPG's audited financial statements. This will result in OPG recovering these costs using the same methodology that the OEB has approved for the Bruce facilities, and this would be the methodology for recording entries in this account. This methodology is described in Ex. C2-1-1, Section 4.2.[77]

As discussed in Ex. C2-1-1, Section 8.0, the comprehensive cost estimates for these future nuclear liabilities have not yet been recorded in OPG's financial statements and the Application does not reflect any corresponding amounts in the proposed IR term nuclear revenue requirements. At such time as the costs of the nuclear liabilities with respect to the DNNP

[77] Amendments made to section 6(2)10.1 of O. Reg. 53/05 requiring the OEB to ensure that OPG recovers all costs it incurs in relation to its nuclear liabilities with respect to the Bruce facilities as reflected in the audited financial statements approved by OPG's Board of Directors, to the extent that those costs are not otherwise recovered under section 6(2) of the regulation, have the effect of confirming the current recovery methodology for OPG's nuclear liabilities' costs for the Bruce facilities.

facilities are recognized in OPG's financial statements during the IR term, they would be recorded in the account as reflected in those financial statements.

The Application proposes that no interest be recorded on the balance of this account, consistent with the treatment of similar accounts for OPG.

8.0 PROPOSED NEW ACCOUNTS FOR DNNP LP

This section sets out the details of new deferral and variance accounts proposed for DNNP LP as of the effective date of the payment amounts order in this proceeding. Given the similarity of operations between DNNP LP and OPG as nuclear generators, the common cost structure between the two entities by virtue of OPG's role as project manager and operator of the DNNP facilities and the blended nuclear payment amount, the requested accounts mirror the applicable existing and proposed new accounts for OPG.

8.1 Pension and OPEB Cost Variance Account (DNNP)

The Application proposes to establish the Pension and OPEB Cost Variance Account (DNNP) to record the differences between: (i) the pension and OPEB costs reflected in the DNNP LP's revenue requirement approved by the OEB; and (ii) DNNP LP's actual pension and OPEB costs for the DNNP facilities.[78]

As discussed in Ex. F4-3-2, DNNP LP's pension and OPEB costs represent the portion of OPG's pension and OPEB accrual costs attributed to the DNNP facilities and to be charged to DNNP LP under the respective agreements with OPG. Following the transfer of the DNNP assets to DNNP LP, these costs would not be eligible for the Pension and OPEB Cost Variance Account (OPG) and are proposed to be captured in this new deferral account. Actual pension and OPEB costs used in the calculation of the account entries would be calculated on an

[78] Unlike OPG's prescribed facilities, the DNNP facilities will not experience a difference between pension and OPEB accrual costs and pension and OPEB cash amounts, due to the fact that once charged to DNNP LP, any pension and OPEB costs become cash expenditures to DNNP LP (i.e., payable to OPG). Accordingly, there is no such timing difference expected in the regulatory tax calculations for DNNP LP (Ex. F4-2-1) and no regulatory tax impact to be recorded in the proposed Pension and OPEB Cost Variance Account (DNNP). Also for this reason, there will be no amounts to record in the Pension and OPEB Forecast Accrual versus Actual Cash Payment Differential Variance Account for DNNP LP.

accrual basis using the same accounting standards as those used to derive the reference amount. The same methodology for recording entries in the account would be used as for the Pension and OPEB Cost Variance Account (OPG).

The Application proposes that no interest be recorded on the balance of this account, consistent with the treatment of the Pension and OPEB Cost Variance Account (OPG).

8.2 Nuclear Deferral and Variance Over/Under Recovery Variance Account (DNNP)

The Application proposes to establish the Nuclear Deferral and Variance Over/Under Recovery Variance Account (DNNP) to record the difference between the amounts approved for recovery or repayment in nuclear deferral and variance accounts and the actual amounts recovered or repaid based on the actual nuclear production and approved riders. Pursuant to the OEB's orders, the account would also capture the transfer of balances remaining in other DNNP LP accounts as they expire from time to time. The same methodology for recording entries in the account would be used as for the Nuclear Deferral and Variance Over/Under Recovery Variance Account (OPG).

8.3 SR&ED ITC Variance Account (DNNP)

The Application proposes to establish the SR&ED ITC Variance Account (DNNP) to record the difference between actual SR&ED ITCs attributed to the DNNP facilities as determined after any tax audits and the forecast SR&ED ITCs reflected in the DNNP LP's revenue requirement approved by the OEB, including the tax on the difference. The same methodology for recording entries in the account would be used as for the SR&ED ITC Variance Account (OPG). The reasons for maintaining such accounts for OPG's regulated facilities and the DNNP facilities are discussed in Ex. F4-2-1, Section 3.5.

8.4 Income and Other Taxes Variance Account (DNNP)

The Application proposes to establish the Income and Other Taxes Variance Account (DNNP) to record the financial impact on the DNNP LP's revenue requirement of the following:

- 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 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 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 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 facilities or changes in assessing or administrative policy including those arising from court decisions on other taxpayers).

The same methodology for recording entries in the account would be used as for the Income and Other Taxes Variance Account (OPG). Entries in the account would be recorded relative to the income tax provision and the underlying inputs reflected in the approved revenue requirement for DNNP LP for the corresponding year. The account would not record the impact of any of the above in relation to SR&ED ITCs and the income taxes payable thereon. The forecast annual income tax provision for the DNNP facilities for the IR term is detailed in Ex. F4-2-1, Table 3g.[79]

The account is not proposed to include the revenue requirement impact of the CEITCs that may be available to DNNP LP and its partners. Instead, the Application proposes to record any such revenue requirement impacts in applicable accounts as follows: the DNNPVARD for the DNNP and the proposed new Clean Electricity ITC Variance Account (DNNP) for the remaining eligible

[79] Any additions to the Income and Other Taxes Variance Account (DNNP) will be calculated without duplication with other accounts that may be impacted such as the DNNPVARD.

expenditures (Section 8.6). Clean Electricity Investment Tax Credits are discussed in Ex. F4-2-1, Section 3.5.

8.5 Impact for IFRS Deferral Account (DNNP)

The Application proposes to establish the Impact for IFRS Deferral Account (DNNP) to record financial impacts of transition to and implementation of International Financial Reporting Standard ("IFRS") from US GAAP in the event that DNNP LP adopts IFRS for financial reporting purposes.

As discussed in Section 5.27, OPG is proposing to continue the Impact for IFRS Deferral Account (OPG) as it moves forward with its efforts toward SEC registration, which would allow OPG to retain an ongoing ability to meet continuous disclosure requirements in Canada by continuing to file its financial statements using US GAAP. Should OPG's account be continued, the proposed equivalent account for DNNP LP would facilitate ongoing alignment of the regulatory accounting framework between the two entities.

The Application proposes that no interest be recorded on the balance of this account, consistent with the treatment of the Impact for IFRS Deferral Account (OPG).

8.6 Clean Electricity ITC Variance Account (DNNP)

The federal government has proposed a 15% refundable CEITC with respect to investments in certain clean electricity property and certain refurbishment projects, which is proposed to be available to certain entities including OPG. At the time of filing the Application, no legislation implementing this credit is in place and the CEITCs are not reflected in OPG's 2025-2031 Business Plan or this Application. In accordance with US GAAP, such credits will be accounted as a reduction in the capital costs of the underlying eligible projects. The revenue requirement savings from the CEITCs will therefore be realized through a reduction in the capital related revenue requirement once the assets are in service.

The Application proposes to establish the Clean Electricity ITC Variance Account (DNNP) to record the revenue requirement differences as between the actual CEITCs received for eligible

projects and those attributed to corresponding forecast CEITCs reflected in the OEB-approved payment amounts, if any, for the DNNP facilities. This account would record such differences only to the extent they are not captured by an existing account, such as the DNNPVARD. The variances will be recorded relative to the corresponding forecast amounts included in the DNNP LP's annual nuclear revenue requirements approved by the OEB.

Further details on the CEITCs, including their details of the capital related revenue requirement impact, are discussed in Ex. F4-2-1, Section 3.5.

8.7 Impact of Change in Tax Status Variance Account (DNNP)

As discussed in Ex. F4-2-1, regulatory income taxes that form part of the proposed revenue requirement for DNNP LP are determined by applying the statutory tax rates to the portion of the regulatory taxable income or loss attributable to the taxable partners of the partnership. Accordingly, any regulatory taxable income or loss attributable to the tax-exempt partners of DNNP LP result in no associated regulatory income taxes to be recovered in the revenue requirement.

As a result of the above, any changes to the tax status (i.e., taxable or tax-exempt) of current and future partners of DNNP LP can impact the partnership's revenue requirement. The Application proposes to establish the Impact of Change in Tax Status Variance Account to record the impact on the forecast regulatory income taxes reflected in revenue requirement approved by the OEB from any changes to the tax status of DNNP LP's partners.[80] For further discussion on the determination of regulatory income taxes for DNNP LP, refer to Ex. F4-2-1, Section 3.1.

8.8 Change of Laws Deferral Account (DNNP)

Changes in laws are outside of DNNP LP's control and can significantly alter compliance requirements and can have a material impact on DNNP LP's forecasted costs and revenues.

[80] Any additions to the Impact of Change in Tax Status Variance Account (DNNP) will be calculated without duplication with other accounts that may be impacted such as the Income & Other Taxes Variance Account (DNNP) and the Clean Electricity ITC Variance Account (DNNP)..

To address these risks, and for the same reasons that an equivalent account is proposed for OPG in Section 7.1, the Application proposes to establish the Change of Laws Deferral Account (DNNP) which would record material impacts to costs and revenues of DNNP LP over the IR term resulting from changes in legal and regulatory requirements to the extent these impacts are not already recorded in other deferral and variance accounts.

9.0 INTEREST

OPG proposes to record interest on all existing and new deferral and variance accounts, unless specified otherwise in the account descriptions above. For these accounts, OPG proposes to apply interest to the monthly opening balances of these accounts at the interest rate set by the OEB from time to time pursuant to its interest policy for deferral and variance accounts, unless specified otherwise in the account descriptions above.

The above approach was used to apply interest to deferral and variance account balances in determining the December 31, 2024 audited balances in the accounts pursuant to the OEB's decisions and orders, as applicable.

LIST OF ATTACHMENTS

Attachment 1:	Independent Auditors' Report prepared by Ernst & Young LLP Chartered Professional Accountants
Attachment 2:	Schedule of Regulatory Balances as at December 31, 2024
Attachment 3:	Supporting Info for SBGVA Clearance re: EB-2023-0336, Ex. L-H-SEC-04, Attachment 1 (filed in Excel format)
Attachment 4:	Supporting Info for SBGVA Clearance re: EB-2023-0336, Ex. L-H-SEC-05, Attachment 1 (filed in Excel format)
Attachment 5:	Hydroelectric CRVA Revenue Requirement (Capital Component)
Attachment 6:	PRP Revenue Requirement (Capital Component)
Attachment 7:	DRP Revenue Requirement (Capital Component)
Attachment 8:	Nuclear CRVA (Excluding DRP and PRP) Revenue Requirement (Capital Component)
Attachment 9:	DNNP Revenue Requirement

Building a better working world

Ernst & Young LLP
EY Tower
100 Adelaide Street West, PO Box 1
Toronto ON, M5H 0B3

Tel: +1 416 864 1234
Fax: +1 416 864 1174
ey.com/ca

INDEPENDENT AUDITOR'S REPORT

To the management of
Ontario Power Generation Inc.

Opinion

We have audited the schedule of regulatory balances of Ontario Power Generation Inc. as at December 31, 2024 (the "Schedule").

In our opinion, the accompanying schedule, which presents the balances of the deferral and variance accounts authorized for Ontario Power Generation Inc. by the decisions and orders of the Ontario Energy Board, is prepared, in all material respects in accordance with the basis of accounting as described in Note 1 to the Schedule.

Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the Schedule* section of our report. We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the Schedule in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Emphasis of matter – Basis of accounting and restriction on use

We draw attention to Note 1 of the Schedule, which describes the basis of accounting. The Schedule is prepared to assist the Company in filing with the Ontario Energy Board as part of the regulatory process. As a result, the Schedule may not be suitable for another purpose. Our report is intended solely for the information and use of the Company and for filing with the Ontario Energy Board as part of the regulatory process. Our opinion is not modified in respect of this matter.

Responsibilities of management for the Schedule

Management is responsible for the preparation and fair presentation of the Schedule in accordance with the basis of accounting as described in Note 1 of the Schedule; this includes determining that the basis of accounting is an acceptable basis for the preparation of the Schedule in the circumstances, and for such internal control as management determines is necessary to enable the preparation of the Schedule that are free from material misstatement, whether due to fraud or error.

In preparing the Schedule, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters relating to going concern, and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's responsibilities for the audit of the Schedule

Our objectives are to obtain reasonable assurance about whether the Schedule as a whole is free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can

Building a better working world

Ernst & Young LLP
EY Tower
100 Adelaide Street West, PO Box 1
Toronto ON, M5H 0B3

Tel: +1 416 864 1234
Fax: +1 416 864 1174
ey.com/ca

arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the Schedule.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the Schedule, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the Schedule or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the Schedule, including the disclosures, and whether the Schedule represents the underlying transactions and events in a manner that achieves fair presentation.

- Obtain sufficient appropriate audit evidence to express an opinion on the Schedule. We are responsible for the direction, supervision and performance of the audit. We remain solely responsible for our audit opinion.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

Ernst & Young LLP

Toronto, Canada
November 28th, 2025

Chartered Professional Accountants
Licensed Public Accountants

SCHEDULE OF REGULATORY BALANCES
AS AT DECEMBER 31, 2024

The *Ontario Energy Board Act, 1998* and *Ontario Regulation 53/05* provide that Ontario Power Generation Inc. (OPG or the Company) receives regulated prices for electricity generated from most of the Company's hydroelectric generating facilities and all of the nuclear generating facilities that the Company operates. OPG's regulated prices for the generation from these facilities are determined by the Ontario Energy Board (OEB).

The OEB's decisions and orders have authorized OPG to establish certain variance and deferral accounts, including those authorized pursuant to *Ontario Regulation 53/05*. The balances in these accounts are calculated in accordance with the OEB's decisions and orders and *Ontario Regulation 53/05*. In accordance with United States generally accepted accounting principles ("US GAAP"), OPG's consolidated financial statements recognize regulatory assets and regulatory liabilities for balances in the variance and deferral accounts.

Through its August 2021 oral decision approving a settlement between OPG and intervenors on OPG's application for new regulated prices under case number EB-2020-0290 and its November 2021 written decision on the same, the OEB approved balances as at December 31, 2019 in all of the Company's variance and deferral accounts for which clearance was sought, as adjusted by the OEB's decisions, and less amounts previously approved for recovery or repayment in these accounts under case numbers EB-2016-0152 and EB-2018-0243. The OEB's 2021 decision and related settlement agreement also deferred recovery of a portion of the balance in the Hydroelectric Surplus Baseload Generation Variance Account to a future proceeding. Certain account balances were excluded from OPG's application. To effect the recovery and repayment of the balances approved in the EB-2020-0290 proceeding, the OEB established rate riders for OPG's regulated generation for the period from January 1, 2022 to December 31, 2026.

Through its June 2024 decision approving a settlement between OPG and intervenors on OPG's application for disposition of variance and deferral account balances and other matters under case number EB-2023-0336, the OEB approved the balances as at December 31, 2022 in all such accounts brought forward for disposition in that proceeding, as adjusted by the results of the approved settlement, and less amounts previously approved for recovery or repayment under case numbers EB-2020-0290 and EB-2018-0243. This approval included the portion of the balance in the Hydroelectric Surplus Baseload Generation Variance Account deferred as a result of the EB-2020-0290 proceeding. Certain account balances were excluded from OPG's application. To effect the recovery and repayment of the balances approved in the EB-2023-0336 proceeding, the OEB established incremental rate riders for OPG's regulated generation for the period from July 1, 2024 to December 31, 2026.

For the period from January 1, 2023 to December 31, 2024, OPG recognized additions to the variance and deferral accounts and amortized the balances in the accounts as authorized by the OEB in the EB-2020-0290 Payment Amounts Order and the EB-2023-0336 Decision and Order. Where applicable, OPG also recognized additions to variance and deferral account during this period in accordance with the requirements of *Ontario Regulation 53/05*. Where authorized by the OEB, OPG recorded interest on the unamortized balances in the applicable variance and deferral accounts at the OEB-prescribed rate ranging from 4.40 percent per annum to 5.49 percent per annum during the period from January 1, 2023 to December 31, 2024.

As at December 31, 2024, the balances to be recovered from (refunded to) ratepayers in the variance and deferral accounts authorized for OPG were as follows:

(millions of dollars)	**2024**
Regulated Hydroelectric	
Hydroelectric Surplus Baseload Generation Variance Account	**306**
Capacity Refurbishment Variance Account – Hydroelectric	**162**
Pension & OPEB Cash Versus Accrual Differential Deferral Account – Hydroelectric – Post-2017 Additions – EB-2020-0290 Approved	**18**
Pension & OPEB Cash Versus Accrual Differential Deferral Account – Hydroelectric – Registered Pension Plan (RPP) – EB-2018-0243 Approved	**16**
Pension & OPEB Cash Versus Accrual Differential Deferral Account – Hydroelectric – Post-2019 Additions	**(8)**
Pension & OPEB Cash Payment Variance Account – Hydroelectric	**(76)**
Pension and OPEB Forecast Accrual versus Actual Cash Payment Differential Variance Account – Carrying Charges Sub-Account – Hydroelectric	**(9)**
Hydroelectric Deferral and Variance Over/Under Recovery Variance Account	**17**
Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account	**9**
Income and Other Taxes Variance Account – Hydroelectric	**(17)**
Ancillary Services Net Revenue Variance Account – Hydroelectric	**(22)**
Hydroelectric Water Conditions Variance Account	**(173)**
Gross Revenue Charge Variance Account	**-**
Impact for IFRS Deferral Account – Hydroelectric	**-**
Hydroelectric Incentive Mechanism Variance Account	**-**
Incremental Cloud Computing Implementation Costs Deferral Account – Hydroelectric	**-**
Total – Regulated Hydroelectric	**223**
Nuclear	
Rate Smoothing Deferral Account	**677**
Nuclear Liability Deferral Account	**527**
Capacity Refurbishment Variance Account – Nuclear – Darlington Refurbishment Program (DRP) – Excluding Heavy Water Storage and Drum Handling Facility Project (D2O Storage Project)	**170**
Capacity Refurbishment Variance Account – Nuclear – Non-DRP	**174**
Capacity Refurbishment Variance Account – Nuclear – Accelerated Investment Incentive CCA-DRP – EB-2020-0290/EB-2023-0336 Approved	**(17)**
Capacity Refurbishment Variance Account – Nuclear – D2O Storage Project – EB-2023-0336 Approved	**70**
Pension and OPEB Cost Variance Account – Nuclear – Post 2021 Additions	**(411)**
Pension & OPEB Cash Versus Accrual Differential Deferral Account – Nuclear – RPP – EB-2018-0243 Approved	**107**
Pension & OPEB Cash Versus Accrual Differential Deferral Account – Nuclear – Post-2017 Additions – EB-2020-0290 Approved	**111**
Pension & OPEB Cash Versus Accrual Differential Deferral Account – Nuclear – Post-2019 Additions – EB-2023-0336 Approved	**132**
Pension & OPEB Cash Payment Variance Account – Nuclear – EB-2020-0290/EB-2023-0336 Approved	**(245)**
Pension and OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance Account – Carrying Charges Sub-Account – Nuclear	**(42)**
Pickering B Variance Account	**131**
Bruce Lease Net Revenues Variance Account	**(60)**
Nuclear Deferral and Variance Over/Under Recovery Variance Account	**(61)**
Income and Other Taxes Variance Account – Nuclear	**(10)**
Nuclear Development Variance Account – Darlington New Nuclear Project (DNNP)	**62**
Nuclear Development Variance Account – Non-DNNP	**23**
Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account – December 31, 2020	**66**
Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account – December 31, 2023	**(2)**
Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account – EB-2020-0290/EB-2023-0336 Approved	**85**

Ancillary Services Net Revenue Variance Account – Nuclear	**(14)**
SR&ED ITC Variance Account	**(25)**
Fitness for Duty Deferral Account	**3**
Pickering Closure Costs Deferral Account	**8**
Clarington Corporate Campus Deferral Account	**8**
Impact for IFRS Deferral Account – Nuclear	**-**
Incremental Cloud Computing Implementation Costs Deferral Account – Nuclear	**-**
Total – Nuclear	**1,467**
Earnings Sharing Deferral Account	**-**
Sale of Unprescribed Kipling Site Deferral Account	**(13)**
Grand Total	**1,677**

This schedule of regulatory balances has been prepared solely for the use of OPG's management and for filing with the OEB, and is considered by OPG's management to be a fair and reasonable representation of the balances in the authorized variance and deferral accounts as at December 31, 2024. These balances have been determined in accordance with the basis of accounting described in Note 1 to this schedule.

On behalf of Ontario Power Generation Inc.



Aida Cipolla
Chief Financial Officer and Chief Administrative Officer
November 28, 2025

See accompanying note to the schedule

NOTE TO THE SCHEDULE OF REGULATORY BALANCES AS AT DECEMBER 31, 2024

1. BASIS OF ACCOUNTING

The schedule of regulatory balances presents the balances as at December 31, 2024 in all variance and deferral accounts authorized for OPG, with the exception of the Pension and OPEB Forecast Accrual Versus Actual Cash Differential Variance Account – Primary and Contra sub-accounts which are offsetting by definition. The balances presented represent the regulatory assets and regulatory liabilities for these accounts recorded by OPG in accordance with US GAAP for the purposes of its consolidated financial statements, as modified to include a return on equity amount as part of cost of capital additions recorded in the accounts for recovery from, or refund to, ratepayers and to include the full amount of additions recorded in the Capacity Refurbishment Variance Account – Hydroelectric effective June 1, 2017. The Pension and OPEB Forecast Accrual Versus Actual Cash Differential Variance Account – Primary and Contra sub-accounts have a net zero balance at all times pursuant to the Report of the Ontario Energy Board under case number EB-2015-0040. All dollar amounts are presented in Canadian dollars.

For the purposes of its consolidated financial statements prepared in accordance with US GAAP, as required by FASB Accounting Standards Codification Topic 980, *Regulated Operations*, OPG limits the portion of cost of capital additions recognized as a regulatory asset to the amount calculated using the average rate of capitalized interest applied by OPG to construction and development in progress balances. The amortization expense related to the regulatory assets for variance and deferral accounts that include cost of capital additions are correspondingly limited in OPG's consolidated financial statements to amounts calculated using the average rate of capitalized interest applied to OPG's construction and development in progress balances.

In the EB-2016-0152 Payment Amounts Order issued on March 23, 2018, the OEB stipulated that OPG will be entitled to future recovery of additions recorded in the Capacity Refurbishment Variance Account – Hydroelectric effective June 1, 2017 to the extent that OPG's total capital in-service additions for the regulated hydroelectric facilities over the 2017-2021 period exceed the funding for capital expenditures for these facilities implicit in the hydroelectric payment amounts over that period, as calculated pursuant to the EB-2016-0152 Payment Amounts Order. In the EB-2020-0290 Payment Amounts Order issued on January 27, 2022, the OEB stipulated that OPG will be entitled to future recovery of additions recorded in the Capacity Refurbishment Variance Account – Hydroelectric effective January 1, 2022 to the extent that OPG's total capital in-service additions for the regulated hydroelectric facilities over the 2022-2026 period exceed the funding for capital expenditures for these facilities implicit in the hydroelectric payment amounts over that period, as calculated pursuant to the EB-2020-0290 Payment Amounts Order. In accordance with US GAAP, OPG's consolidated financial statements recognize a regulatory asset for additions recorded in the Capacity Refurbishment Variance Account – Hydroelectric effective June 1, 2017 when OPG assesses there is sufficient assurance that these amounts will be recoverable in the future based on the above condition.

US GAAP recognizes that rate regulation can create economic benefits and obligations that are required to be obtained from, or settled with, the ratepayers. When OPG assesses that there is sufficient assurance that incurred costs in respect of its regulated facilities will be recovered in the future, those costs are deferred and reported as a regulatory asset in the Company's consolidated financial statements. When OPG is required to refund amounts in respect of its regulated facilities to ratepayers in the future, including amounts related to costs that have not been incurred and for which the OEB has provided recovery through regulated prices, the Company records a regulatory liability in its consolidated financial statements. The measurement of regulatory assets and regulatory liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of *Ontario Regulation 53/05* and the OEB's decisions. The estimates and assumptions made in the interpretation of the regulation and the OEB's decisions are reviewed as part of the OEB's regulatory process.

OPG's most recent annual consolidated financial statements filed with the Ontario Securities Commission are as at and for the year ended December 31, 2024. OPG's most recent interim consolidated financial statements filed with the Ontario Securities Commission are as at and for the nine months ended September 30, 2025.

Attachment 5
Regulated Hydroelectric CRVA Projects - Revenue Requirement (Capital Component) ($M)

Shown below is the derivation of amounts for the regulated hydroelectric CRVA projects capital component that are reflected in the proposed revenue requirements for OPG's regulated hydroelectric facilities in this proceeding and proposed to form the corresponding reference amounts for the Capacity Refurbishment Variance Account.

Line No.	Category	Note	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
			(a)	(b)	(c)	(d)	(e)
	Rate Base						
1	Regulated Hydroelectric CRVA Projects Rate Base	1	794.3	1,230.1	2,237.3	2,800.7	3,262.6
2	Weighted Average Cost of Capital	2	6.94%	7.03%	7.09%	7.12%	7.13%
3	**Cost of Capital** (line 1 x line 2)		**55.1**	**86.5**	**158.6**	**199.3**	**232.5**
	Depreciation						
4	Regulated Hydroelectric CRVA Projects	1	13.5	21.0	38.3	48.4	57.0
	Regulatory Taxable Income Impacts						
5	ROE (line 1 x 52% x 9.11%)		37.6	58.3	106.0	132.7	154.6
6	Depreciation (line 4)		13.5	21.0	38.3	48.4	57.0
7	CCA (Ex. F4-2-1, Table 3c, Note 3)		(277.4)	(212.0)	(220.2)	(231.0)	(246.4)
8	**Net Decrease in Regulatory Taxable Income**		**(226.3)**	**(132.7)**	**(76.0)**	**(49.9)**	**(34.8)**
9	**Income Tax Rate**		25%	25%	25%	25%	25%
10	**Income Tax Impact** (line 8 x line 9/(1 - line 9))		**(75.4)**	**(44.2)**	**(25.3)**	**(16.6)**	**(11.6)**
11	**Total Regulated Hydroelectric CRVA Projects Capital Revenue Requirement** (line 3 + line 4 + line 10)		**(6.8)**	**63.3**	**171.6**	**231.1**	**277.9**

Notes: Refer to Attachment 5a.

Attachment 5a
Notes to Table 5
Regulated Hydroelectric - CRVA Projects Revenue Requirement (Capital Component) ($M)

Notes:

1 The amounts in line 1 are determined as follows:

Line No.		2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1a	Gross Plant Opening Balance	-	211.6	512.9	1,020.5	1,820.5	2,585.8	3,263.8
1b	In-Service Additions*	211.6	301.3	507.6	800.0	765.3	678.0	311.9
1c	Gross Plant Closing Balance (line 1a + line 1b)	211.6	512.9	1,020.5	1,820.5	2,585.8	3,263.8	3,575.7
1d	Gross Plant Rate Base Amount (line 1a + line 1c)/2**	82.6	362.2	808.4	1,261.5	2,298.4	2,905.1	3,419.8
1e	Accumulated Depreciation Opening Balance	-	1.4	7.4	20.9	41.9	80.2	128.6
1f	Depreciation	1.4	6.0	13.5	21.0	38.3	48.4	57.0
1g	Accumulated Depreciation Closing Balance (line 1e + line 1f)	1.4	7.4	20.9	41.9	80.2	128.6	185.6
1h	Accumulated Depreciation Rate Base Amount (line 1d + line 1g)/2	0.7	4.4	14.2	31.4	61.1	104.4	157.1
1i	Net Plant Rate Base Amount (line 1d - line 1h)	81.9	357.8	794.3	1,230.1	2,237.3	2,800.7	3,262.6

* Proposed reference amounts for the IR term reflects revenue requirement impacts from expected in-service amounts related to eligible projects beginning January 1, 2025 - shown above in line 1b - since such amounts in the bridge years will form part of the forecast underpinning the proposed 2027-2031 revenue requirement for the account. Cascading variances in the IR term from revenue requirement differences between the forecast and actual in-service additions during the bridge years would be recorded in the account.

CRVA-eligible projects with expected in-service amounts in the 2025-2031 period which form part of the proposed 2027-2031 capital related revenue requirement are identified in Ex. D1-1-2, Tables 1, 2a, 2b, 5a and 5b.

** For years including impacts from in-service additions exceeding $50.0M, the month in which the addition is reflected is used to determine the gross plant rate base amount, instead of a mid-year average.

2 Col. (a) is calculated as: Ex. C1-1-1, Table 5, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).
Col. (b) is calculated as: Ex. C1-1-1, Table 4, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).
Col. (c) is calculated as: Ex. C1-1-1, Table 3, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).
Col. (d) is calculated as: Ex. C1-1-1, Table 2, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).
Col. (e) is calculated as: Ex. C1-1-1, Table 1, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).

Numbers may not add due to rounding.
Privileged and confidential. Prepared in contemplation of litigation.

Attachment 6
Pickering Refurbishment Program - Revenue Requirement (Capital Component) ($M)

Shown below is the derivation of amounts for the Pickering Refurbishment Program capital component that are reflected in the proposed revenue requirements for OPG's nuclear facilities in this proceeding and proposed to form the corresponding reference amounts for the Capacity Refurbishment Variance Account.

Line No.	Category	Note	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
			(a)	(b)	(c)	(d)	(e)
	Rate Base						
1	PRP Rate Base (Ex. B3-1-1, Table 2, lines 6 and 18)		166.4	172.8	168.7	164.7	6,139.3
2	Weighted Average Cost of Capital	1	6.94%	7.03%	7.09%	7.12%	7.13%
3	**Cost of Capital** (line 1 x line 2)		**11.6**	**12.2**	**12.0**	**11.7**	**437.5**
	Depreciation						
4	PRP (Ex. F4-1-1, Table 2, line 6)		3.8	4.1	4.1	4.1	156.7
	Regulatory Taxable Income Impacts						
5	ROE (line 1 x 52% x 9.11%)		7.9	8.2	8.0	7.8	290.8
6	Depreciation (line 4)		3.8	4.1	4.1	4.1	156.7
7	CCA (Ex. F4-2-1, Table 3f, Note 3)		(275.9)	(572.1)	(953.7)	(1,169.4)	(1,241.9)
8	**Net Decrease in Regulatory Taxable Income**		**(264.2)**	**(559.8)**	**(941.7)**	**(1,157.5)**	**(794.3)**
9	**Income Tax Rate**		25%	25%	25%	25%	25%
10	**Income Tax Impact** (line 8 x line 9/(1 - line 9))		**(88.1)**	**(186.6)**	**(313.9)**	**(385.8)**	**(264.8)**
11	**Total PRP Capital Revenue Requirement** (line 3 + line 4 + line 10)		**(72.7)**	**(170.4)**	**(297.9)**	**(370.1)**	**329.5**

Notes:

1 Col. (a) is calculated as: Ex. C1-1-1, Table 5, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).
Col. (b) is calculated as: Ex. C1-1-1, Table 4, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).
Col. (c) is calculated as: Ex. C1-1-1, Table 3, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).
Col. (d) is calculated as: Ex. C1-1-1, Table 2, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).
Col. (e) is calculated as: Ex. C1-1-1, Table 1, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).

Attachment 7
Darlington Refurbishment Program - Revenue Requirement (Capital Component) ($M)

Shown below is the derivation of amounts for the Darlington Refurbishment Program capital component, excluding D2O Storage, that are reflected in the proposed revenue requirements for OPG's nuclear facilities in this proceeding and proposed to form the corresponding reference amounts for the Capacity Refurbishment Variance Account.

Line No.	Category	Note	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
			(a)	(b)	(c)	(d)	(e)
	Rate Base						
1	DRP Rate Base, excluding D2O Storage (Ex. B3-1-1, Table 2, lines 2 and 14)		9,906.7	9,508.2	9,109.8	8,711.6	8,313.6
2	Weighted Average Cost of Capital	1	6.94%	7.03%	7.09%	7.12%	7.13%
3	**Cost of Capital** (line 1 x line 2)		**687.8**	**668.7**	**645.8**	**619.9**	**592.5**
	Depreciation						
4	DRP, excluding D2O Storage (Ex. F4-1-1, Table 2, line 2)		398.5	398.5	398.4	398.0	398.0
	Regulatory Taxable Income Impacts						
5	ROE (line 1 x 52% x 9.11%)		469.3	450.4	431.5	412.7	393.8
6	Depreciation (line 4)		398.5	398.5	398.4	398.0	398.0
7	CCA (Ex. F4-2-1, Table 3f, Note 3)		(484.4)	(445.8)	(410.4)	(377.8)	(348.0)
8	**Net Increase in Regulatory Taxable Income**		**383.4**	**403.1**	**419.6**	**432.8**	**443.8**
9	**Income Tax Rate**		25%	25%	25%	25%	25%
10	**Income Tax Impact** (line 8 x line 9/(1 - line 9))		**127.8**	**134.4**	**139.9**	**144.3**	**147.9**
11	**Total DRP Capital Revenue Requirement** (line 3 + line 4 + line 10)		**1,214.1**	**1,201.5**	**1,184.0**	**1,162.2**	**1,138.4**

Notes:

1 Col. (a) is calculated as: Ex. C1-1-1, Table 5, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).
Col. (b) is calculated as: Ex. C1-1-1, Table 4, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).
Col. (c) is calculated as: Ex. C1-1-1, Table 3, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).
Col. (d) is calculated as: Ex. C1-1-1, Table 2, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).
Col. (e) is calculated as: Ex. C1-1-1, Table 1, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).

Attachment 8
Non-DRP/Non-PRP Nuclear CRVA Projects - Revenue Requirement (Capital Component) ($M)

Shown below is the derivation of amounts for the Non-DRP/Non-PRP Nuclear CRVA Projects capital component that are reflected in the proposed revenue requirements for OPG's nuclear facilities in this proceeding and proposed to form the corresponding reference amounts for the Capacity Refurbishment Variance Account.

Line No.	Category	Note	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
			(a)	(b)	(c)	(d)	(e)
	Rate Base						
1	Non-DRP/Non-PRP Nuclear CRVA Projects Rate Base	1	220.1	677.7	785.0	1,426.6	2,287.2
2	Weighted Average Cost of Capital	2	6.94%	7.03%	7.09%	7.12%	7.13%
3	**Cost of Capital** (line 1 x line 2)		**15.3**	**47.7**	**55.7**	**101.5**	**163.0**
	Depreciation						
4	Non-DRP/Non-PRP Nuclear CRVA Projects	1	8.6	27.8	33.5	63.1	105.7
	Regulatory Taxable Income Impacts						
5	ROE (line 1 x 52% x 9.11%)		10.4	32.1	37.2	67.6	108.3
6	Depreciation (line 4)		8.6	27.8	33.5	63.1	105.7
7	CCA (Ex. F4-2-1, Table 3f, Note 3)		(60.5)	(89.8)	(135.2)	(164.9)	(200.2)
8	**Net Increase (Decrease) in Regulatory Taxable Income**		**(41.4)**	**(29.9)**	**(64.5)**	**(34.2)**	**13.8**
9	**Income Tax Rate**		25%	25%	25%	25%	25%
10	**Income Tax Impact** (line 8 x line 9/(1 - line 9))		**(13.8)**	**(10.0)**	**(21.5)**	**(11.4)**	**4.6**
11	**Total Non-DRP/Non-PRP Nuclear CRVA Projects Capital Revenue Requirement** (line 3 + line 4 + 10)		**10.1**	**65.5**	**67.7**	**153.2**	**273.3**

Notes: Refer to Attachment 8a.

Attachment 8a
Notes to Table 8
Non-DRP/Non-PRP Nuclear CRVA Projects - Revenue Requirement (Capital Component) ($M)

Notes:

1 The amounts in line 1 are determined as follows:

Line No.		2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1a	Gross Plant Opening Balance	-	108.0	209.8	399.1	785.8	1,426.2	2,211.9
1b	In-Service Additions*	108.0	101.8	189.3	386.7	640.4	785.8	536.9
1c	Gross Plant Closing Balance (line 1a + line 1b)	108.0	209.8	399.1	785.8	1,426.2	2,211.9	2,748.9
1d	Gross Plant Rate Base Amount (line 1a + line 1c)/2**	76.3	131.8	231.7	707.6	845.6	1,535.5	2,480.4
1e	Accumulated Depreciation Opening Balance	-	2.5	7.3	15.9	43.7	77.3	140.4
1f	Depreciation	2.5	4.8	8.6	27.8	33.5	63.1	105.7
1g	Accumulated Depreciation Closing Balance (line 1e + line 1f)	2.5	7.3	15.9	43.7	77.3	140.4	246.0
1h	Accumulated Depreciation Rate Base Amount (line 1e + line 1g)/2	1.3	4.9	11.6	29.8	60.5	108.8	193.2
1i	Net Plant Rate Base Amount (line 1d - line 1h)	75.1	126.9	220.1	677.7	785.0	1,426.6	2,287.2

* Proposed reference amounts for the IR term reflects revenue requirement impacts from expected in-service amounts related to eligible projects beginning January 1, 2025 - shown above in line 1b - since such amounts in the bridge years will form part of the forecast underpinning the proposed 2027-2031 revenue requirement for the account. Cascading variances in the IR term from revenue requirement differences between the forecast and actual in-service additions during the bridge years would be recorded in the account.

CRVA-eligible projects with expected in-service amounts in the 2025-2031 period which form part of the proposed 2027-2031 capital related revenue requirement for the CRVA are identified in Ex. D2-1-3, Tables 1a-1c, 2a-2g, and 5a-5d.

** All years include impacts from in-service additions exceeding $50.0M, hence the month in which the addition is reflected is used to determine the gross plant rate base amount, instead of a mid-year average.

2 Col. (a) is calculated as: Ex. C1-1-1, Table 5, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).
Col. (b) is calculated as: Ex. C1-1-1, Table 4, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).
Col. (c) is calculated as: Ex. C1-1-1, Table 3, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).
Col. (d) is calculated as: Ex. C1-1-1, Table 2, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).
Col. (e) is calculated as: Ex. C1-1-1, Table 1, line 4, col. (b) x col. (c) plus line 5b, col. (b) x line 5a, col. (c).

Attachment 9
Darlington New Nuclear Program Revenue Requirement ($M)

Shown below is the derivation of amounts for the Darlington New Nuclear Program that are reflected in the proposed revenue requirements for DNNP facilities in this proceeding and proposed to form the corresponding reference amounts for the Darlington New Nuclear Project Variance Account re Development.

Line No.	Category	Note	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
			(a)	(b)	(c)	(d)	(e)
	Rate Base						
1	DNNP Rate Base (Ex. B3-1-1, Table 2, lines 12 and 24)		0.0	0.0	0.0	1,360.5	6,507.4
2	Weighted Average Cost of Capital	1	0.00%	0.00%	0.00%	9.11%	9.11%
3	**Cost of Capital** (line 1 x line 2)		**0.0**	**0.0**	**0.0**	**123.9**	**592.8**
	Depreciation						
4	DNNP (Ex. F4-1-1, Table 2, line 12)		0.0	0.0	0.0	22.6	109.7
	Regulatory Taxable Income Impacts						
5	ROE (line 1 x 100% x 9.11%)		0.0	0.0	0.0	123.9	592.8
6	Depreciation (line 4)		0.0	0.0	0.0	22.6	109.7
7	CCA (Ex. F4-2-1, Table 3g, line 8)		(195.5)	(311.1)	(345.0)	(365.6)	(377.3)
8	**Net Increase (Decrease) in Regulatory Taxable Income**		**(195.5)**	**(311.1)**	**(345.0)**	**(219.0)**	**325.3**
9	**Income Tax Rate**		25%	25%	25%	25%	25%
10	**Income Tax Impact** (line 8 x line 9/(1 - line 9))		**(65.2)**	**(103.7)**	**(115.0)**	**(73.0)**	**108.4**
11	**Total DNNP Capital Revenue Requirement** (line 3 + line 4 + line 10)		**(65.2)**	**(103.7)**	**(115.0)**	**73.6**	**811.0**

Notes:
1 Col. (d) is calculated as: Ex. C1-1-1, Table 14, line 4, col. (b) x col. (c)
Col. (e) is calculated as: Ex. C1-1-1, Table 13, line 4, col. (b) x col. (c)

Numbers may not add due to rounding.

Table 1
Deferral and Variance Accounts
Closing Account Balances - 2022, 2023 and 2024 ($M)

Line No.	Account	Note	Actual Year End Balance 2022	Actual Year End Balance 2023	Actual Year End Balance 2024
			(a)	(b)	(c)
			Note 1	Note 2	Note 3
	Regulated Hydroelectric:				
1	**Hydroelectric Water Conditions Variance**		(172.4)	(185.6)	(172.6)
2	**Ancillary Services Net Revenue Variance - Hydroelectric**		(34.3)	(31.5)	(22.2)
3	**Hydroelectric Incentive Mechanism Variance**		0.0	0.0	0.0
4	**Hydroelectric Surplus Baseload Generation Variance**		401.8	393.3	305.6
5	**Income and Other Taxes Variance - Hydroelectric**		(13.3)	(17.3)	(17.3)
6	**Capacity Refurbishment Variance - Hydroelectric**		80.4	95.7	162.1
7	**Niagara Tunnel Project Pre-December 2008 Disallowance Variance**		8.0	8.8	8.6
8	**Pension and OPEB Cost Variance - Hydroelectric - Future Recovery (Dec. 31, 2012 Balance)**		2.1	1.1	0.0
9	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Registered Pension Plan (RPP) - EB-2018-0243 Approved**		33.0	24.8	16.5
10	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Non-RPP - EB-2018-0243 Approved**		14.0	7.0	0.0
11	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Post-2017 Additions - EB-2020-0290 Approved**		35.3	26.5	17.7
12	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Post-2019 Additions**		28.1	8.4	(8.0)
13	**Pension & OPEB Cash Payment Variance - Hydroelectric**		(77.0)	(83.5)	(76.3)
14	**Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Variance - Carrying Charges - Hydroelectric**	4	(2.0)	(4.9)	(8.5)
15	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**		16.1	17.3	16.7
16	**Regulated Hydroelectric Subtotal**		319.9	260.0	222.3
	Nuclear:				
17	**Nuclear Liability Deferral**		188.3	377.5	527.3
18	**Nuclear Development Variance - DNNP**		110.9	106.7	61.8
19	**Nuclear Development Variance - Non-DNNP**		0.0	7.8	23.5
20	**Ancillary Services Net Revenue Variance - Nuclear**		(13.6)	(15.1)	(13.5)
21	**Capacity Refurbishment Variance - Nuclear - DRP - Excluding D2O Storage Project**		(47.6)	121.4	170.2
22	**Capacity Refurbishment Variance - Nuclear - Non-DRP**		49.7	146.5	173.7
23	**Capacity Refurbishment Variance - Nuclear - Accelerated Investment Incentive CCA - DRP - EB-2020-0290/EB-2023-0336 Approved**		(30.9)	(25.8)	(16.8)
24	**Capacity Refurbishment Variance - Nuclear - D2O Storage Project - EB-2023-0336 Approved**		79.4	83.3	70.1
25	**Bruce Lease Net Revenues Variance - EB-2018-0243/EB-2016-0152 Approved**		84.2	63.2	42.1
26	**Bruce Lease Net Revenues Variance - Post 2017 Additions**		17.1	(4.2)	(102.0)
27	**Income and Other Taxes Variance - Nuclear**		(18.8)	(15.6)	(9.5)
28	**Pension and OPEB Cost Variance - Nuclear - Future Recovery (Dec. 31, 2012 Balance)**		42.9	21.5	0.0
29	**Pension and OPEB Cost Variance - Nuclear - Post 2021 Additions**		(122.6)	(341.3)	(411.1)
30	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Registered Pension Plan (RPP) - EB-2018-0243 Approved**		212.8	159.6	106.4
31	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Non-RPP - EB-2018-0243 Approved**		88.2	44.1	0.0
32	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Post-2017 Additions - EB-2020-0290 Approved**		222.5	166.9	111.3
33	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Post-2019 Additions - EB-2023-0336 Approved**		164.8	164.8	131.9
34	**Pension & OPEB Cash Payment Variance - Nuclear - EB-2020-0290/EB-2023-0336 Approved**		(383.4)	(342.1)	(244.4)
35	**Pension & OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance - Carrying Charges - Nuclear**	4	(12.3)	(26.9)	(42.1)
36	**Nuclear Deferral and Variance Over/Under Recovery Variance**		(74.7)	(76.5)	(61.5)
37	**Fitness for Duty Deferral**		1.6	2.0	2.5
38	**SR&ED ITC Variance**		(8.6)	(23.3)	(25.7)
39	**Rate Smoothing Deferral**		568.9	653.8	677.4
40	**Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral - EB-2020-0290/EB-2023-0336 Approved**		(57.5)	24.4	85.1
41	**Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral - December 31, 2020**		(45.0)	9.6	66.1
42	**Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral - December 31, 2023**		0.0	0.0	(2.3)
43	**Pickering Closure Costs Deferral**		2.8	6.4	7.6
44	**Clarington Corporate Campus Deferral Account**		0.0	7.3	7.7
45	**Pickering B Variance**	5	0.0	26.5	131.1
46	**Nuclear Subtotal**		1,019.1	1,322.3	1,466.8
47	**Sale of Unprescribed Kipling Site Deferral**		0.0	(15.1)	(12.6)
48	**Total** (line 16 + line 46 + line 47)	6	1,339.0	1,567.1	1,676.5

Notes:
1 From EB-2023-0336 Decision and Order, App. A, Table 1, col. (a) for regulated hydroelectric and Table 2, col. (a) for nuclear unless otherwise noted.
2 From Ex. H1-1-1, Table 1a, col. (h).
3 From Ex. H1-1-1, Table 1b, col. (g).
4 The Pension and OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance Account has three subaccounts: (i) Carrying Charges Sub-Account; (ii) Primary Sub-Account; and (iii) Contra Sub-Account. Only the Carrying Charges Sub-Account is presented in the table as the Primary and Contra account balances always net to zero.
5 Established by *Ontario Regulation 53/05* , effective January 1, 2023 and as amended effective July 1, 2025.
6 The following accounts have a zero balance and no activity during the period from January 1, 2023 to December 31, 2024 and are not shown in the table: Gross Revenue Charge Variance Account, Impact for IFRS Deferral Account, Incremental Cloud Computing Arrangement Implementation Costs Deferral Account, and Earnings Sharing Deferral Account.

Numbers may not add due to rounding.

Table 1a
Deferral and Variance Accounts
Continuity of Account Balances - Year Ended December 31, 2023 ($M)

Line No.	Account	Note	Actual Year End Balance 2022	EB-2023-0336 Settlement Adjustments	(a)+(b) EB-2023-0336 Year-End Balance 2022	Actual 2023				(c)+(d)+(e)+(f)+(g) Actual Year End Balance 2023
						Transactions	Amortization EB-2020-0290	Interest	Transfers	
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
			Note 1	Note 2			Note 3	Note 4		
	Hydroelectric:									
1	**Hydroelectric Water Conditions Variance**		(172.4)	0.0	(172.4)	(41.3)	36.4	(8.3)	0.0	(185.6)
2	**Ancillary Services Net Revenue Variance - Hydroelectric**		(34.3)	0.0	(34.3)	(6.7)	11.1	(1.6)	0.0	(31.5)
3	**Hydroelectric Incentive Mechanism Variance**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	**Hydroelectric Surplus Baseload Generation Variance**		401.8	0.0	401.8	29.7	(56.1)	17.9	0.0	393.3
5	**Income and Other Taxes Variance - Hydroelectric**		(13.3)	0.0	(13.3)	(4.2)	0.9	(0.7)	0.0	(17.3)
6	**Capacity Refurbishment Variance - Hydroelectric**	5	80.4	(4.7)	75.7	16.2	0.0	3.8	0.0	95.7
7	**Niagara Tunnel Project Pre-December 2008 Disallowance Variance**		8.0	0.0	8.0	1.7	(1.3)	0.4	0.0	8.8
8	**Pension and OPEB Cost Variance - Hydroelectric - Future Recovery (Dec. 31, 2012 Balance)**		2.1	0.0	2.1	0.0	(1.1)	0.0	0.0	1.1
9	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Registered Pension Plan (RPP) - EB-2018-0243 Approved**		33.0	0.0	33.0	0.0	(8.3)	0.0	0.0	24.8
10	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Non-RPP - EB-2018-0243 Approved**		14.0	0.0	14.0	0.0	(7.0)	0.0	0.0	7.0
11	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Post-2017 Additions - EB-2020-0290 Approved**		35.3	0.0	35.3	0.0	(8.8)	0.0	0.0	26.5
12	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Post-2019 Additions**		28.1	0.0	28.1	(19.7)	0.0	0.0	0.0	8.4
13	**Pension & OPEB Cash Payment Variance - Hydroelectric**		(77.0)	0.0	(77.0)	(15.6)	12.9	(3.7)	0.0	(83.5)
14	**Pension & OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance - Carrying Charges - Hydroelectric**	6	(2.0)	0.0	(2.0)	(2.9)	0.0	0.0	0.0	(4.9)
15	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**		16.1	0.0	16.1	1.6	(1.1)	0.7	0.0	17.3
16	**Regulated Hydroelectric Subtotal**		319.9	(4.7)	315.1	(41.2)	(22.4)	8.4	0.0	260.0
	Nuclear:									
17	**Nuclear Liability Deferral**	9	188.3	0.0	188.3	189.14	0.0	0.0	0.0	377.5
18	**Nuclear Development Variance - DNNP**		110.9	(0.1)	110.8	(8.1)	(1.2)	5.3	0.0	106.7
19	**Nuclear Development Variance - Non-DNNP**		0.0	0.0	0.0	7.6	0.0	0.2	0.0	7.8
20	**Ancillary Services Net Revenue Variance - Nuclear**		(13.6)	0.0	(13.6)	(2.0)	1.2	(0.7)	0.0	(15.1)
21	**Capacity Refurbishment Variance - Nuclear - DRP - Excluding D2O Storage Project**	9	(47.6)	0.0	(47.6)	168.1	0.0	0.9	0.0	121.4
22	**Capacity Refurbishment Variance - Nuclear - Non-DRP**	9	49.7	(4.2)	45.6	64.2	32.0	4.6	0.0	146.5
23	**Capacity Refurbishment Variance - Nuclear - Accelerated Investment Incentive CCA - DRP - EB-2020-0290/EB-2023-0336 Approved**		(30.9)	0.0	(30.9)	0.0	6.4	(1.3)	0.0	(25.8)
24	**Capacity Refurbishment Variance - Nuclear - D2O Storage Project - EB-2023-0336 Approved**		79.4	0.0	79.4	0.0	(0.0)	3.9	0.0	83.3
25	**Bruce Lease Net Revenues Variance - EB-2018-0243/EB-2016-0152 Approved**		84.2	0.0	84.2	0.0	(21.1)	0.0	0.0	63.2
26	**Bruce Lease Net Revenues Variance - Post 2017 Additions**	9	17.1	0.0	17.1	(16.9)	(7.7)	3.3	0.0	(4.2)
27	**Income and Other Taxes Variance - Nuclear**		(18.8)	0.0	(18.8)	(1.0)	4.8	(0.7)	0.0	(15.6)
28	**Pension and OPEB Cost Variance - Nuclear - Future Recovery (Dec. 31, 2012 Balance)**		42.9	0.0	42.9	0.0	(21.5)	0.0	0.0	21.5
29	**Pension and OPEB Cost Variance - Nuclear - Post 2021 Additions**		(122.6)	0.0	(122.6)	(218.7)	0.0	0.0	0.0	(341.3)
30	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Registered Pension Plan (RPP) - EB-2018-0243 Approved**		212.8	0.0	212.8	0.0	(53.2)	0.0	0.0	159.6
31	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Non-RPP - EB-2018-0243 Approved**		88.2	0.0	88.2	0.0	(44.1)	0.0	0.0	44.1
32	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Post-2017 Additions - EB-2020-0290 Approved**		222.5	0.0	222.5	0.0	(55.6)	0.0	0.0	166.9
33	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Post-2019 Additions - EB-2023-0336 Approved**		164.8	0.0	164.8	0.0	0.0	0.0	0.0	164.8
34	**Pension & OPEB Cash Payment Variance - Nuclear - EB-2020-0290/EB-2023-0336 Approved**		(383.4)	0.0	(383.4)	0.0	58.1	(16.8)	0.0	(342.1)
35	**Pension & OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance - Carrying Charges - Nuclear**	6	(12.3)	0.0	(12.3)	(14.8)	0.2	0.0	0.0	(26.9)
36	**Nuclear Deferral and Variance Over/Under Recovery Variance**		(74.7)	0.0	(74.7)	(6.1)	8.4	(4.1)	0.0	(76.5)
37	**Fitness for Duty Deferral**	11	1.6	0.0	1.6	0.4	0.0	0.1	0.0	2.0
38	**SR&ED ITC Variance**		(8.6)	0.0	(8.6)	(18.0)	4.0	(0.7)	0.0	(23.3)
39	**Rate Smoothing Deferral**	10	568.9	0.0	568.9	64.0	0.0	20.9	0.0	653.8
40	**Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral - EB-2020-0290/EB-2023-0336 Approved**		(57.5)	0.0	(57.5)	0.0	81.9	0.0	0.0	24.4
41	**Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral - December 31, 2020**		(45.0)	0.0	(45.0)	54.6	0.0	0.0	0.0	9.6
42	**Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral - December 31, 2023**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
43	**Pickering Closure Costs Deferral**	12	2.8	0.0	2.8	3.4	0.0	0.2	0.0	6.4
44	**Clarington Corporate Campus Deferral Account**		0.0	0.0	0.0	7.0	0.0	0.3	0.0	7.3
45	**Pickering B Variance**		0.0	0.0	0.0	26.2	0.0	0.3	0.0	26.5
46	**Nuclear Subtotal**		1,019.1	(4.3)	1,014.8	299.1	(7.3)	15.7	0.0	1,322.3
47	**Sale of Unprescribed Kipling Site Deferral**	7	0.0	(12.7)	(12.7)	(2.5)	0.0	0.0	0.0	(15.1)
48	**Total** (line 16 + line 46 + line 47)	8	1,339.0	(21.7)	1,317.3	255.4	(29.7)	24.1	0.0	1,567.1

Notes:

1 From EB-2023-0336 Decision and Order, App. A, Table 1, col. (a) for regulated hydroelectric and Table 2, col. (a) for nuclear unless otherwise noted.

2 From EB-2023-0336 Decision and Order, App. A, Table 1, col. (c1) for regulated hydroelectric and Table 2, col. (c1) for nuclear.

3 From EB-2020-0290 Payment Amounts Order, App. C, Table 1, col. (i) for Regulated Hydroelectric, and App. D, Table 1, col. (i) for Nuclear.

4 Per EB-2020-0290 Payment Amounts Order, no interest is recorded on the Pension & OPEB Cash Versus Accrual Differential Deferral Account, Pension and OPEB Cost Variance Account, Nuclear Liability Deferral Account, Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account, and Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account. Per EB-2023-0336 Decision and Order, no interest is recorded on the Sale of Unprescribed Kipling Site Deferral Account.

5 The year-end 2022 balance has been updated from that presented in EB-2023-0336 to reflect changes identified in the course of preparing this application.

6 The Pension and OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance Account has three subaccounts: (i) Carrying Charges Sub-Account; (ii) Primary Sub-Account; and (iii) Contra Sub-Account. Only the Carrying Charges Sub-Account is presented in the table as the Primary and Contra account balances always net to zero.

7 The year-end 2022 balance has been updated from that presented in EB-2023-0336 pursuant to EB-2023-0336 Decision and Order, June 13, 2024, p.5. Account transactions in 2023 recorded pursuant to EB-2023-0336 Decision and Order, June 13, 2024, p.5, and represent 50% of the 23% of an incremental $21.5M after-tax gain recognized by OPG in 2023 associated with the sale of the Kipling Site.

8 The following accounts have a zero balance and no activity during the period from January 1, 2023 to December 31, 2024 and are not shown in the table: Gross Revenue Charge Variance Account, Impact for IFRS Deferral Account, Incremental Cloud Computing Arrangement Implementation Costs Deferral Account, and Earnings Sharing Deferral Account.

9 Includes the following adjustments, presented as part of 2023 transactions in col. (d): (i) reduction of $4.1M in line 17 and addition of $2.1M in line 26 to reflect the 2022 impact of updated calculations to the dollar per cubic metre cost rates for low and intermediate level waste ("L&ILW") based on the 2022 ONFA Reference Plan ("Reference Plan"); (ii) net addition of $0.8M in line 21, reflecting the combined impact of $1.4M reduction for updated calculations to the dollar per cubic metre cost rates for L&ILW in 2022 and $2.2M addition to correct minor discrepancies identified for years prior to 2023 in the course of preparing this application; and (iii) reduction of $0.4M in line 22 to correct minor discrepancies identified for years prior to 2023 in the course of preparing this application.

10 The year-end 2022 balance comprises deferral amounts recorded from 2017 to 2021 per EB-2016-0152 Payment Amounts Order, App. H, p. 1: 2017 - $0M, 2018 - $0M, 2019 - $102.2M, 2020 - $390.6M, 2021 - $0M; deferral amount of $19.0M recorded in 2022 per EB-2020-0290 Payment Amounts Order, App. B, Table 1; and interest on the account balance recorded at the following OPG long-term debt rates, compounded annually: 2019 - 4.52%, 2020 - 4.49%, 2021 - 4.48% (EB-2016-0152 Payment Amounts Order, App. H, p. 2) and 3.61% in 2022 (EB-2020-0290 Payment Amounts Order, App. E, p. 19). Transactions in 2023 represent the deferral amount, if any, pursuant to EB 2020-0290 Payment Amounts Order, App. B, Table 1, line 5.

11 The account records the full amount of eligible costs, as there were no corresponding forecast costs reflected in the OEB-approved revenue requirements. The year-end 2022 balance comprises costs incurred as follows: 2017 - $0.1M, 2018 - $0.1M, 2019 - $0.3M, 2020 - $0.1M, 2021 - $0.5M and 2022 - $0.4M, plus interest on the account balance at the OEB's prescribed interest rate.

12 The account records the full amount of eligible costs, as there were no corresponding forecast costs reflected in the OEB-approved revenue requirements. The year-end 2022 balance comprises costs incurred as follows: 2021 - $1.0M and 2022 - $1.8M, plus interest on the account balance at the OEB's prescribed interest.

Numbers may not add due to rounding.

Table 1b
Deferral and Variance Accounts
Continuity of Account Balances - Year Ended December 31, 2024 ($M)

Line No.	Account	Note	Actual Year End Balance 2023	Actual 2024					(c)+(d)+(e)+(f)+(g)
				Transactions	Amortization EB-2020-0290	Amortization EB-2023-0336	Interest	Transfers	Audited Year End Balance 2024
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
			Note 1		Note 2	Note 3	Note 4		
	Hydroelectric:								
1	**Hydroelectric Water Conditions Variance**		(185.6)	(35.1)	36.4	19.9	(8.2)	0.0	(172.6)
2	**Ancillary Services Net Revenue Variance - Hydroelectric**		(31.5)	(3.0)	11.1	2.4	(1.2)	0.0	(22.2)
3	**Hydroelectric Incentive Mechanism Variance**		0.0	0.0	(0.0)	(0.0)	0.0	0.0	0.0
4	**Hydroelectric Surplus Baseload Generation Variance**		393.3	10.6	(56.1)	(57.9)	15.7	0.0	305.6
5	**Income and Other Taxes Variance - Hydroelectric**		(17.3)	(2.3)	0.9	2.3	(0.8)	0.0	(17.3)
6	**Capacity Refurbishment Variance - Hydroelectric**		95.7	72.0	0.0	(10.3)	4.7	0.0	162.1
7	**Niagara Tunnel Project Pre-December 2008 Disallowance Variance**		8.8	1.7	(1.3)	(1.1)	0.4	0.0	8.6
8	**Pension and OPEB Cost Variance - Hydroelectric - Future Recovery (Dec. 31, 2012 Balance)**		1.1	0.0	(1.1)	0.0	0.0	0.0	0.0
9	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Registered Pension Plan (RPP) - EB-2018-0243 Approved**		24.8	0.0	(8.3)	0.0	0.0	0.0	16.5
10	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Non-RPP - EB-2018-0243 Approved**		7.0	0.0	(7.0)	0.0	0.0	0.0	0.0
11	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Post-2017 Additions - EB-2020-0290 Approved**		26.5	0.0	(8.8)	0.0	0.0	0.0	17.7
12	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric - Post-2019 Additions**		8.4	(10.8)	0.0	(5.6)	0.0	0.0	(8.0)
13	**Pension & OPEB Cash Payment Variance - Hydroelectric**		(83.5)	(12.1)	12.9	10.3	(3.8)	0.0	(76.3)
14	**Pension and OPEB Forecast Accrual versus Actual Cash Payment Differential Variance - Carrying Charges - Hydroelectric**	5	(4.9)	(4.0)	0.0	0.4	0.0	0.0	(8.5)
15	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**		17.3	2.6	(1.1)	(2.8)	0.7	0.0	16.7
16	**Regulated Hydroelectric Subtotal**		260.0	19.6	(22.4)	(42.5)	7.6	0.0	222.3
	Nuclear:								
17	**Nuclear Liability Deferral**		377.5	187.5	0.0	(37.7)	0.0	0.0	527.3
18	**Nuclear Development Variance - DNNP**		106.7	(26.5)	(1.2)	(21.7)	4.5	0.0	61.8
19	**Nuclear Development Variance - Non-DNNP**		7.8	15.1	0.0	0.0	0.6	0.0	23.5
20	**Ancillary Services Net Revenue Variance - Nuclear**		(15.1)	(1.1)	1.2	2.3	(0.7)	0.0	(13.5)
21	**Capacity Refurbishment Variance - Nuclear - DRP - Excluding D2O Storage Project**		121.4	41.5	0.0	0.0	7.3	0.0	170.2
22	**Capacity Refurbishment Variance - Nuclear - Non-DRP**		146.5	9.3	32.0	(22.4)	8.3	0.0	173.7
23	**Capacity Refurbishment Variance - Nuclear - Accelerated Investment Incentive CCA - DRP - EB-2020-0290/EB-2023-0336 Approved**		(25.8)	0.0	6.4	3.6	(1.0)	0.0	(16.8)
24	**Capacity Refurbishment Variance - Nuclear - D2O Storage Project - EB-2023-0336 Approved**		83.3	0.0	(0.0)	(15.9)	2.8	0.0	70.1
25	**Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - EB-2018-0243/EB-2016-0152 Approved**		63.2	0.0	(21.1)	0.0	0.0	0.0	42.1
26	**Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - Post 2017 Additions**		(4.2)	(89.2)	(7.7)	(0.3)	(0.7)	0.0	(102.0)
27	**Income and Other Taxes Variance - Nuclear**		(15.6)	0.0	4.8	1.8	(0.5)	0.0	(9.5)
28	**Pension and OPEB Cost Variance - Nuclear - Future Recovery (Dec. 31, 2012 Balance)**		21.5	0.0	(21.5)	0.0	0.0	0.0	0.0
29	**Pension and OPEB Cost Variance - Nuclear - Post 2021 Additions**		(341.3)	(94.4)	0.0	24.5	0.0	0.0	(411.1)
30	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Registered Pension Plan (RPP) - EB-2018-0243 Approved**		159.6	0.0	(53.2)	0.0	0.0	0.0	106.4
31	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Non-RPP - EB-2018-0243 Approved**		44.1	0.0	(44.1)	0.0	0.0	0.0	0.0
32	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Post-2017 Additions - EB-2020-0290 Approved**		166.9	0.0	(55.6)	0.0	0.0	0.0	111.3
33	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear - Post-2019 Additions - EB-2023-0336 Approved**		164.8	0.0	0.0	(33.0)	0.0	0.0	131.9
34	**Pension & OPEB Cash Payment Variance - Nuclear - EB-2020-0290/EB-2023-0336 Approved**		(342.1)	0.0	58.1	53.5	(13.8)	0.0	(244.4)
35	**Pension and OPEB Forecast Accrual versus Actual Cash Payment Differential Variance - Carrying Charges - Nuclear**	5	(26.9)	(17.8)	0.2	2.4	0.0	0.0	(42.1)
36	**Nuclear Deferral and Variance Over/Under Recovery Variance**		(76.5)	(1.2)	8.4	11.6	(3.7)	0.0	(61.5)
37	**Fitness for Duty Deferral**	8	2.0	0.4	0.0	0.0	0.1	0.0	2.5
38	**SR&ED ITC Variance**		(23.3)	(5.5)	4.0	0.1	(1.0)	0.0	(25.7)
39	**Rate Smoothing Deferral**	7	653.8	0.0	0.0	0.0	23.6	0.0	677.4
40	**Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral - EB-2020-0290/EB-2023-0336 Approved**		24.4	0.0	81.9	(21.3)	0.0	0.0	85.1
41	**Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral - December 31, 2020**		9.6	47.4	0.0	9.0	0.0	0.0	66.1
42	**Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral - December 31, 2023**		0.0	(2.3)	0.0	0.0	0.0	0.0	(2.3)
43	**Pickering Closure Costs Deferral**	8	6.4	0.9	0.0	0.0	0.3	0.0	7.6
44	**Clarington Corporate Campus Deferral Account**		7.3	0.0	0.0	0.0	0.4	0.0	7.7
45	**Pickering B Variance**		26.5	101.4	0.0	0.0	3.3	0.0	131.1
46	**Nuclear Subtotal**		1,322.3	165.4	(7.3)	(43.4)	29.9	0.0	1,466.8
47	**Sale of Unprescribed Kipling Site Deferral**		(15.1)	0.0	0.0	2.5	0.0	0.0	(12.6)
48	**Total** (line 16 + line 46 + line 47)	6	1,567.1	184.9	(29.7)	(83.3)	37.5	0.0	1,676.5

Notes:

1 From Ex. H-1-1-1, Table 1a, col. (h).

2 From EB-2020-0290 Payment Amounts Order, App. C, Table 1, col. (j) for Regulated Hydroelectric and App. D, Table 1, col. (j) for Nuclear.

3 From EB-2023-0336 Decision and Order, App. A, Table 1, col. (g) for Regulated Hydroelectric and Table 2, col. (g) for Nuclear.

4 Per EB-2020-0290 Payment Amounts Order, no interest is recorded on the Pension & OPEB Cash Versus Accrual Differential Deferral Account, Pension and OPEB Cost Variance Account, Nuclear Liability Deferral Account, Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account, and Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account. Per EB-2023-0336 Decision and Order, no interest is recorded on the Sale of Unprescribed Kipling Site Deferral Account.

5 The Pension and OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance Account has three subaccounts: (i) Carrying Charges Sub-Account; (ii) Primary Sub-Account; and (iii) Contra Sub-Account. Only the Carrying Charges Sub-Account is presented in the table as the Primary and Contra account balances always net to zero.

6 The following accounts have a zero balance and no activity during the period from January 1, 2023 to December 31, 2024 and are not shown in the table: Gross Revenue Charge Variance Account, Impact for IFRS Deferral Account, Incremental Cloud Computing Arrangement Implementation Costs Deferral Account, and Earnings Sharing Deferral Account.

7 Transactions in 2024 represent the deferral amount, if any, pursuant to EB 2020-0290 Payment Amounts Order, App. B, Table 1, line 5.

8 Account records the full amount of eligible costs, as there were no corresponding forecast costs reflected in the OEB-approved revenue requirements.

Numbers may not add due to rounding.

Table 2
Hydroelectric Water Conditions Variance Account
Summary of Account Transactions - 2023 and 2024 ($M)

Line No.	Particulars	Note	Actual 2023	Actual 2024
			(a)	(b)
	Regulated Hydroelectric:			
1	**Forecast Production (GWh)**	1	32,432	32,432
2	**Actual Calculated Production (GWh)**		33,898	33,650
3	**Difference (GWh)** (line 1 - line 2)		(1,466)	(1,218)
4	**Payment Amount ($/MWh)**	2	43.88	43.88
5	**Revenue Impact ($M)** (line 3 x line 4 / 1000)		(64.3)	(53.5)
6	**GRC/Water Rental Costs ($M)**		23.1	18.4
7	**Total Addition to Variance Account ($M)** (line 5 + line 6)		(41.3)	(35.1)

Notes:

1 Cols. (a) and (b) as set out in EB-2020-0290 Payment Amounts Order, App. E, pp. 3-4.

2 Cols. (a) and (b) from EB-2020-0290 Payment Amounts Order, p. 4.

Numbers may not add due to rounding.

Table 3
Ancillary Services Net Revenue Variance Account
Summary of Account Transactions - 2023 and 2024 ($M)

Line No.	Particulars	Note	Actual 2023	Actual 2024
			(a)	(b)
	Regulated Hydroelectric:			
1	**Forecast Revenue**	1	55.5	55.5
2	**Actual Revenue**	2	62.3	58.5
3	**Regulated Hydroelectric Addition to Variance Account** (line 1 - line 2)		(6.7)	(3.0)
	Nuclear:			
4	**Forecast Revenue**	1	6.3	6.1
5	**Actual Revenue**	2	8.3	7.3
6	**Nuclear Addition to Variance Account** (line 4 - line 5)		(2.0)	(1.1)

Notes:

1 Cols. (a) and (b) as per EB-2020-0290 Payment Amounts Order, App. E, pp. 4-5.

2 As shown in G1-1-1, Table 1, line 1, cols. (h) and (i) for regulated hydroelectric. As shown in G2-1-1, Table 1, line 6, cols. (d) and (e) for nuclear.

Numbers may not add due to rounding.

Table 4
Hydroelectric Incentive Mechanism Variance Account
Summary of Account Transactions - 2023 and 2024 ($M)

Line No.	Particulars	Note	Actual 2023	Actual 2024
			(a)	(b)
1	**Total Actual Regulated Hydroelectric Incentive Mechanism Net Revenue**	1	14.8	28.4
2	**Threshold**	2	54.5	54.5
3	**Actual Hydroelectric Incentive Mechanism Net Revenue In Excess of Threshold** (line 1 - line 2; nil if line 1 < line 2)		0.0	0.0
4	**Percentage**	2	50%	50%
5	**Total Addition to Variance Account** (line 3 x line 4)		0.0	0.0

Notes:
1 Annual values as reported in OPG's 2024 Management's Discussion & Analysis (p. 51) for 2023 and 2024.
2 Annual threshold and percentage per EB-2014-0370 Payment Amounts Order, App. B, pp. 8-9.

Numbers may not add due to rounding.

Table 5
Hydroelectric Surplus Baseload Generation Variance Account
Summary of Account Transactions - 2023 and 2024 ($M)

Line No.	Particulars	Note	Actual 2023	Actual 2024
			(a)	(b)
	Regulated Hydroelectric:			
1	**Actual Foregone Production Due to SBG Conditions (GWh)**	1	977	350
2	**Payment Amount ($/MWh)**	2	43.88	43.88
3	**Revenue ($M)** (line 1 x line 2 / 1000)		42.9	15.3
4	**GRC/Water Rental Costs ($M)**		(13.2)	(4.7)
5	**Total Addition to Variance Account ($M)** (line 3 + line 4)		29.7	10.6

Notes:

1 Annual values are reported in OPG's 2024 Management's Discussion & Analysis (p.14) for 2023 and 2024.

2 Cols. (a) and (b) from EB-2020-0290 Payment Amounts Order, p.5.

Numbers may not add due to rounding.

Updated: 2026-03-10
EB-2025-0297
Exhibit H1
Tab 1
Schedule 1
Table 6

Table 6
Income and Other Taxes Variance Account
Summary of Account Transactions - 2023 and 2024 ($M)

Line No.	Particulars	Note	Actual 2023			Actual 2024		
			Regulated Hydroelectric	Nuclear	(a) + (b) Total	Regulated Hydroelectric	Nuclear	(d) + (e) Total
			(a)	(b)	(c)	(d)	(e)	(f)
	Entry (i): CCA Accelerated Investment Incentive Property Impact	1						
1	**2023 CCA differences**		(11.2)	0.0	(11.2)	0.0	0.0	0.0
2	**2024 CCA differences**		0.0	0.0	0.0	(6.4)	0.0	(6.4)
3	**Income Tax Impact for 2023** (line 1 x 25%)		(2.8)	0.0	(2.8)	0.0	0.0	0.0
4	**Income Tax Impact for 2024** (line 2 x 25%)		0.0	0.0	0.0	(1.6)	0.0	(1.6)
5	**Addition to Variance Account** (line 3 + line 4) / (1-25%)		(3.7)	0.0	(3.7)	(2.1)	0.0	(2.1)
	Entry (ii) Increase of SR&ED ITCs Recognition Percentage from 75% to 100% in 2023 for 2017	2						
6	**Forecast SR&ED ITCs, net of Tax on ITCs, at 75%**		(0.7)	(2.9)	(3.7)	0.0	0.0	0.0
7	**Forecast SR&ED ITCs, net of Tax on ITCs, at 100%** (line 6 x 4/3)		(1.0)	(3.9)	(4.9)	0.0	0.0	0.0
8	**Addition to Variance Account** (line 7 - line 6)		(0.2)	(1.0)	(1.2)	0.0	0.0	0.0
	Entry (iii) Increase of SR&ED ITCs Recognition Percentage from 75% to 100% in 2023 for 2018	3						
9	**Forecast SR&ED ITCs, net of Tax on ITCs, at 75%**		(0.7)	0.0	(0.7)	0.0	0.0	0.0
10	**Forecast SR&ED ITCs, net of Tax on ITCs, at 100%** (line 9 x 4/3)		(1.0)	0.0	(1.0)	0.0	0.0	0.0
11	**Addition to Variance Account** (line 10 - line 9)		(0.2)	0.0	(0.2)	0.0	0.0	0.0
	Entry (iv) Increase of SR&ED ITCs Recognition Percentage from 75% to 100% in 2024 for 2019	4						
12	**Forecast SR&ED ITCs, net of Tax on ITCs, at 75%**		0.0	0.0	0.0	(0.7)	0.0	(0.7)
13	**Forecast SR&ED ITCs, net of Tax on ITCs, at 100%** (line 12 x 4/3)		0.0	0.0	0.0	(1.0)	0.0	(1.0)
14	**Addition to Variance Account** (line 13 - line 12)		0.0	0.0	0.0	(0.2)	0.0	(0.2)
	Entry (v): Ontario Research and Development Tax Credit (ORDTC) Reduction from 4.5% to 3.5% Effective June 1, 2016							
15	**Addition to Variance Account - Reduction in ORDTC Rate**		0.0	0.0	0.0	0.0	0.0	0.0
16	**Total Addition to Variance Account** (line 5 + line 8 + line 11 + line 14 + line 15)		(4.2)	(1.0)	(5.2)	(2.3)	0.0	(2.3)

Notes:

1 Recorded to reflect the impact of changes in Capital Cost Allowance (CCA) rules, whereby taxpayers can claim higher first-year CCA deductions on eligible capital assets acquired after November 20, 2018, for assets other than those subject to the Capacity Refurbishment Variance Account (CRVA) and the Nuclear Development Variance Account (NDVA). The impact of this rule change for assets subject to the CRVA and NDVA are recorded in the respective accounts as part of the total CCA variances for eligible projects. No entries have been recorded for the nuclear facilities beginning January 1, 2022 as the impact of this rule change was reflected in the EB-2020-0290 nuclear revenue requirements.

2 Recorded in 2023 following the resolution, during 2023, of the 2017 taxation year audit. Amount at line 7 represents SR&ED ITCs, net of tax on ITCs, for 2017 previously credited to ratepayers at 75% through the EB-2013-0321 payment amounts. For the nuclear facilities, the amount at line 7 represents the January 1 to May 31, 2017 portion of said credit. The June 1 to December 31, 2017 portion for the nuclear facilities is recorded in the SR&ED ITC Variance Account.

3 Recorded in 2023 following the resolution, during 2023, of the 2018 taxation year audit. Amount at line 10 represents SR&ED ITCs, net of tax on ITCs, for 2018 previously credited to ratepayers at 75% through the EB-2013-0321 payment amounts for the regulated hydroelectric facilities. The impact for the nuclear facilities is recorded in the SR&ED ITC Variance Account.

4 Recorded in 2024 following the resolution, during 2024, of the 2019 taxation year audit. Amount at line 13 represents SR&ED ITCs, net of tax on ITCs, for 2019 previously credited to ratepayers at 75% through the EB-2013-0321 payment amounts for the regulated hydroelectric facilities. The impact for the nuclear facilities is recorded in the SR&ED ITC Variance Account.

Numbers may not add due to rounding.

Table 7
Pension & OPEB Cash Payment Variance Account and Pension & OPEB Cash Versus Accrual Differential Deferral Account
Summary of Account Transactions - 2023 and 2024 ($M)

Line No.	Particulars	Note	Actual 2023			Actual 2024		
			Regulated Hydroelectric	Nuclear[4]	(a)+(b) Total	Regulated Hydroelectric	Nuclear[4]	(d)+(e) Total
			(a)	(b)	(c)	(d)	(e)	(f)
1	**Forecast Pension Contributions**	1	45.1	0.0	45.1	45.1	0.0	45.1
2	**Forecast OPEB Payments**	1	12.8	0.0	12.8	12.8	0.0	12.8
3	**Total Forecast Pension and OPEB Cash Amounts** (line 1 + line 2)		58.0	0.0	58.0	58.0	0.0	58.0
4	**Actual Pension Contributions**	2	23.1	0.0	23.1	27.6	0.0	27.6
5	**Actual OPEB Payments**	2	19.2	0.0	19.2	18.2	0.0	18.2
6	**Total Actual Pension and OPEB Cash Amounts** (line 4 + line 5)		42.3	0.0	42.3	45.8	0.0	45.8
7	**Total Addition to Pension & OPEB Cash Payment Variance Account** (line 6 - line 3)		(15.6)	0.0	(15.6)	(12.1)	0.0	(12.1)
8	**Actual Pension - Registered Pension Plan (RPP) Accrual Costs**	3	(5.0)	0.0	(5.0)	8.1	0.0	8.1
9	**Actual OPEB - Non-RPP Accrual Costs**	3	27.7	0.0	27.7	27.0	0.0	27.0
10	**Total Actual Pension and OPEB Accrual** (line 8 + line 9)		22.6	0.0	22.6	35.1	0.0	35.1
11	**Addition to Pension & OPEB Cash Versus Accrual Differential Deferral Account - RPP** (line 8 - line 4)		(28.1)	0.0	(28.1)	(19.6)	0.0	(19.6)
12	**Addition to Pension & OPEB Cash Versus Accrual Differential Deferral Account - Non-RPP** (line 9 - line 5)		8.4	0.0	8.4	8.8	0.0	8.8
13	**Total Addition to Pension & OPEB Cash Versus Accrual Differential Deferral Account** (line 11 + line 12)		(19.7)	0.0	(19.7)	(10.8)	0.0	(10.8)

Notes:

1 Cols. (a) and (d) are per EB-2020-0290 Payment Amounts Order, App. E, p. 12.

2 Represents the portion of OPG's actual pension contributions and OPEB payments for the corresponding years, as set out in Ex. F4-3-2, Attachment 2, pp.9-10, attributed to the regulated hydroelectric facilities.

3 Represents the portion of OPG's actual pension and OPEB costs for the corresponding years, as set out in Ex. F4-3-2, Attachment 2, pp. 9-10, attributed to the regulated hydroelectric facilities.

4 As per the EB-2020-0290 Payment Amounts Order, App. E, p. 12, no additions are recorded to the Pension & OPEB Cash Payment Variance Account or the Pension & OPEB Cash Versus Accrual Differential Deferral Account for the nuclear facilities beginning in 2022 as the nuclear revenue requirements approved in that proceeding reflected pension and OPEB costs calculated on an accrual basis.

Numbers may not add due to rounding.

Table 7a

Pension & OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance Account - Primary, Contra and Carrying Charges Sub-Accounts

Summary of Account Transactions - 2023 and 2024 ($M)

Line No.	Particulars	Note	Actual 2023			Actual 2024		
			Regulated Hydroelectric	Nuclear	(a)+(b) Total	Regulated Hydroelectric	Nuclear	(d)+(e) Total
			(a)	(b)	(c)	(d)	(e)	(f)
1	**Amortization of Pension & OPEB Cash Versus Accrual Differential Deferral - Registered Pension Plan (RPP) - EB-2018-0243 Approved**	1	8.3	53.2	61.5	8.3	53.2	61.5
2	**Amortization of Pension & OPEB Cash Versus Accrual Differential Deferral - Non-RPP - EB-2018-0243 Approved**	1	7.0	44.1	51.1	7.0	44.1	51.1
3	**Amortization of Pension & OPEB Cash Versus Accrual Differential Deferral - Post-2017 Additions - EB-2020-0290 Approved**	1	8.8	55.6	64.5	8.8	55.6	64.5
4	**Amortization of Pension & OPEB Cash Versus Accrual Differential Deferral - Post-2019 Additions**	2	0.0	0.0	0.0	5.6	33.0	38.6
5	**Actual Pension and OPEB Accrual Costs - Nuclear**	3	0.0	125.6	125.6	0.0	205.2	205.2
6	**Actual Pension and OPEB Cash Amounts - Nuclear**	4	0.0	234.9	234.9	0.0	268.2	268.2
7	**Total Addition to Primary Sub-Account Tracking Balance** (line 1 + line 2 + line 3 + line 4 + line 5 - line 6)		24.1	43.6	67.6	29.7	122.8	152.5
8	**Total Addition to Contra Sub-Account Tracking Balance** (line 7 x -1)		(24.1)	(43.6)	(67.6)	(29.7)	(122.8)	(152.5)
9	**Net Total Addition to Primary and Contra Sub-Accounts Tracking Balances**		0.0	0.0	0.0	0.0	0.0	0.0
10	**Primary Sub-Account Tracking Credit Balance - Opening**	5	45.0	267.4	312.4	69.1	310.9	380.0
11	**Primary Sub-Account Tracking Credit Balance - Closing** (line 7 + line 10)		69.1	310.9	380.0	98.7	433.8	532.5
12	**Total Addition to Carrying Charges Sub-Account**	6	(2.9)	(14.8)	(17.6)	(4.0)	(17.8)	(21.9)

Notes:

1 Col. (a) and (d) per EB-2020-0290 Payment Amounts Order, App. C, Table 1, lines 10-12, col. (i) and (j), respectively. Cols. (b) and (e) per EB-2020-0290 Payment Amounts Order, App. D, Table 1, lines 15-17, col. (i) and (j), respectively.

2 Col. (d) per EB-2023-0336 Decision and Order, App. A, Table 1, line 12, col. (g). Col. (e) per EB-2023-0336 Decision and Order, App. A, Table 2, line 16, col. (g).

3 Cols. (b) and (e) from Ex. H1-1-1, Table 7b, line 6, cols. (a) and (b), respectively.

4 Cols. (b) and (e) represents the portion of OPG's actual pension contributions and OPEB payments for 2023 and 2024 respectively, as set out in Ex. F4-3-2, Attachment 2, pp. 9-10, attributed to the nuclear facilities.

5 Cols. (a) and (b) from EB-2023-0336, Ex. H1-1-1, Table 8a, line 10, cols. (g) and (h), respectively. Cols. (d) and (e) are equal to line 11 of the preceding year.

6 Carrying charges are calculated on the monthly opening cumulative balance in the Primary Sub-Account (when in a credit position) using the OEB's prescribed Construction Work in Progress rate, as follows: 2023 - 5.01% for Q1 to Q3 and 5.48% for Q4; 2024 - 5.48% for Q1, 4.98% for Q2 to Q3 and 4.55% for Q4.

Numbers may not add due to rounding.

Table 7b
Pension and OPEB Cost Variance Account - Nuclear
Summary of Account Transactions - 2023 and 2024 ($M)

Line No.	Particulars	Note	Actual 2023	Actual 2024
			(a)	(b)
1	**Forecast Accrual Pension Costs**	1	134.3	111.7
2	**Forecast Accrual OPEB Costs**	1	159.9	161.0
3	**Total Forecast Accrual Pension and OPEB Costs** (line 1 + line 2)	2	294.1	272.7
4	**Actual Accrual Pension Costs**	3	(27.9)	47.2
5	**Actual Accrual OPEB Costs**	3	153.5	158.0
6	**Total Actual Accrual Pension and OPEB Costs** (line 4 + line 5)		125.6	205.2
7	**Addition to Variance Account - Pension Costs** (line 4 - line 1)		(162.2)	(64.5)
8	**Addition to Variance Account - OPEB Costs** (line 5 - line 2)		(6.3)	(3.0)
9	**Addition to Variance Account - Income Tax Impact**	4	(50.2)	(26.8)
10	**Total Addition to Variance Account** (line 7 + line 8 + line 9)		(218.7)	(94.4)

Notes:

1 From EB-2020-0290, Ex. F4-3-2, Chart 1.

2 From EB-2020-0290 Payment Amounts Order, App. E, p.10, line 27.

3 Represents the portion of OPG's actual pension and OPEB costs in 2023 and 2024, as set out in Ex. F4-3-2, Attachment 2, pp. 9-10, attributed to the nuclear facilities.

4 Table to Note 4 - The income tax impact of the pension and OPEB cost additions to the account is calculated as follows ($M):

Line No.		Note	Actual 2023	Actual 2024
			(a)	(b)
1a	Forecast Income Tax Impact	*	13.7	5.8
	Actual Additions to / Deductions from Regulatory Earnings Before Tax:			
2a	Actual Accrual Pension Costs (line 4)		(27.9)	47.2
3a	Actual Accrual OPEB Costs (line 5)		153.5	158.0
4a	Less: Actual Pension Contributions	**	128.2	161.7
5a	Less: Actual OPEB Payments	**	106.8	106.5
6a	Net Additions to Regulatory Earnings Before Tax (line 2a + line 3a - line 4a - line 5a)		(109.3)	(63.0)
7a	Actual Income Tax Impact (line 6a x 25% / (1 - 25%))		(36.4)	(21.0)
8a	Addition to Variance Account - Income Tax Impact (line 7a - line 1a)		(50.2)	(26.8)

* From EB-2020-0290 Payment Amounts Order, App. E, p. 11, line 2.

** Represents the portion of OPG's actual pension contributions and OPEB payments in 2023 and 2024, as set out in Ex. F4-3-2, Attachment 2, pp. 9-10, attributed to the nuclear facilities.

Numbers may not add due to rounding.

Table 8
Hydroelectric Deferral and Variance Over/Under Recovery Variance Account
Summary of Account Transactions - 2023 and 2024 ($M)

Line No.	Particulars	Note	Actual 2023	Actual 2024
			(a)	(b)
1	**Regulated Hydroelectric Rider ($/MWh)-EB-2020-0290**	1	1.03	1.03
2	**Regulated Hydroelectric Rider ($/MWh)-EB-2023-0336**	2		2.61
3	**Regulated Hydroelectric Production Forecast Used to Set Rider (TWh) EB-2020-0290**	3	33.0	33.0
4	**Regulated Hydroelectric Production Forecast Used to Set Rider (TWh) EB-2023-0336**	4		16.5
5	**Regulated Hydroelectric Actual Production (TWh)**	5	31.4	32.5
6	**Regulated Hydroelectric Actual Production (TWh) - For Six Months Beginning July 1, 2024**			15.7
7	**Production Variance for Regulated Hydroelectric Rider (TWh) EB-2020-0290** (line 3 - line 5)		1.6	0.5
8	**Production Variance for Regulated Hydroelectric Rider (TWh) EB-2023-0336** (line 4 - line 6)			0.8
9	**Addition to Variance Account ($M) - Regulated Hydroelectric Rider-EB-2020-0290** (line 7 x line 1)		1.6	0.5
10	**Addition to Variance Account ($M) - Regulated Hydroelectric Rider-EB-2023-0336** (line 8 x line 2)			2.1
11	**Addition to Variance Account ($M)** (line 9 + line 10)		1.6	2.6

Notes:

1 From EB-2020-0290 Payment Amounts Order, App. C, Table 1, line 23, cols. (i) and (j).
2 From EB-2023-0336 Decision and Order, App. A, Table 1, line 21, col. (g).
3 From EB-2020-0290 Payment Amounts Order, App. C, Table 1, line 22, cols. (i) and (j).
4 From EB-2023-0336 Decision and Order, App. A, Table 1, line 20, col. (g).
5 From Ex. E1-1-1, Table 1, line 4, cols. (h) and (i).

Table 9
Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account
Summary of Account Transactions - 2023 and 2024 ($M)

Line No.	Particulars	Note	Actual 2023	Actual 2024
			(a)	(b)
	Capital Addition to Variance Account:			
1	**Actual Net Plant Rate Base Amount**	1	19.3	19.0
2	**Weighted Average Cost of Capital**	2	6.85%	6.85%
3	**Actual Cost of Capital Amount** (line 1 x line 2)		1.3	1.3
4	**Cost of Capital Variance**		1.3	1.3
5	**Forecast Depreciation**		0.0	0.0
6	**Actual Depreciation**		0.2	0.2
7	**Depreciation Variance** (line 6 - line 5)		0.2	0.2
	Income Tax Impact:			
8	**Forecast Capital Cost Allowance Deduction**		0.0	0.0
9	**Actual Capital Cost Allowance Deduction**		0.6	0.6
10	**Difference** (line 8 - line 9)		(0.6)	(0.6)
11	**Net Increase in Regulatory Taxable Income**	3	0.4	0.5
12	**Income Tax Rate**	4	25%	25%
13	**Income Tax Impact** (line 11 x line 12 / (1 - line 12))		0.1	0.2
14	**Total Addition to Variance Account** (line 4 + line 7 + line 13)		1.7	1.7

Notes:

1 The continuity of the variation between the original Niagara Tunnel Project rate base disallowance of $28M and the varied disallowance of $6.4M is as follows:

	Table to Note 1 - Niagara Tunnel Project Disallowance Continuity ($M)		
Line No.		2023	2024
		(a)	(b)
1a	Opening Balance (col. (a) from EB-2023-0336, Ex. H1-1-1, Table 10, line 4a, col. (c))	19.4	19.1
2a	In-Service	0.0	0.0
3a	Depreciation Expense (line 6)	(0.2)	(0.2)
4a	Closing Balance	19.1	18.9
5a	Actual Net Plant Rate Base Amount (lines 1a+ 4a)/ 2	19.3	19.0

2 From EB-2013-0321 Payment Amounts Order, App. A, Table 6b, line 6, col. (c).

3 The change in regulatory taxable income is calculated as the sum of lines 7 and 10, plus the ROE component of the cost of capital variance at line 4. The ROE component of the variance is equal to line 1 multiplied by the OEB-approved equity portion (45%) of the capital structure, multiplied by the EB-2013-0321 OEB-approved ROE rate of 9.30%.

4 From EB-2013-0321 Payment Amounts Order, App. A, Table 8, line 31, col. (c).

Numbers may not add due to rounding.

Table 10
Bruce Lease Net Revenues Variance Account
Summary of Account Transactions - 2023 and 2024 ($M)

Line No.	Particulars	Note	Actual 2023	Actual 2024
			(a)	(b)
1	**Actual Total Bruce Lease Net Revenues ($M)**	1	(25.8)	42.5
2	**Forecast Bruce Lease Net Revenue**	2	(38.7)	(48.1)
3	**Forecast Nuclear Production (TWh)**	3	31.2	34.0
4	**Rate Credited to (Recovered from) Customers ($/MWh)** (line 2 / line 3)	4	(1.24)	(1.42)
5	**Actual Nuclear Production (TWh)**	5	36.1	33.0
6	**Amount Credited to (Recovered from) Customers ($M)** (line 4 x line 5)		(44.8)	(46.7)
7	**Total Addition to Variance Account ($M)** (line 6 - line 1)		(19.0)	(89.2)

Notes:

1 From Ex. G2-2-1, Table 1, line 3, cols. (d) and (e).
2 Cols. (a) and (b) from EB-2020-0290 Payment Amounts Order, App. E, p. 17.
3 Cols. (a) and (b) from EB-2020-0290 Payment Amounts Order, App. B, Table 1, line 2, cols. (b) and (c), respectively.
4 Cols. (a) and (b) from EB-2020-0290 Payment Amounts Order, App. E, p. 17.
5 From Ex. E2-1-1, Table 1, line 3, cols. (d) and (e).

Numbers may not add due to rounding.

Table 11
Nuclear Deferral and Variance Over/Under Recovery Variance Account
Summary of Account Transactions - 2023 and 2024 ($M)

Line No.	Particulars	Note	Actual 2023	Actual 2024
			(a)	(b)
1	**Nuclear Rider ($/MWh)-EB-2020-0290**	1	1.25	1.15
2	**Nuclear Rider ($/MWh)-EB-2023-0336**	2		3.13
3	**Nuclear Production Forecast Used to Set Nuclear Rider (TWh)-EB-2020-0290**	3	31.2	34.0
4	**Nuclear Production Forecast Used to Set Nuclear Rider (TWh)-EB-2023-0336**	4		17.0
5	**Actual Nuclear Production (TWh)**	5	36.1	33.0
6	**Actual Nuclear Production (TWh) - For Six Months Beginning July 1, 2024**			17.7
7	**Production Variance for Nuclear Rider (TWh) EB 2020-0290** (line 3 - line 5)		(4.9)	1.03
8	**Production Variance for Nuclear Rider (TWh) EB 2023-0336** (line 4 - line 6)			(0.8)
9	**Addition To Variance Account - Nuclear Rider-EB-2020-0290** (line 7 x line 1)		(6.1)	1.2
10	**Addition To Variance Account - Nuclear Rider-EB-2023-0336** (line 8 x line 2)			(2.4)
11	**Addition To Variance Account** (line 9 + line 10)		(6.1)	(1.2)

Notes:
1 From EB-2020-0290 Payment Amounts Order, App. D, Table 1, line 32, cols. (i) and (j).
2 From EB-2023-0336 Decision and Order, App. A, Table 2, line 31, col. (g)
3 From EB-2020-0290 Payment Amounts Order, App. D, Table 1, line 31, cols. (i) and (j).
4 From EB-2023-0336 Decision and Order, App. A, Table 2, line 30, col. (g).
5 From Ex. E2-1-1, Table 1, line 3, cols. (d) and (e).

Table 12
SR&ED ITCs Variance Account
Summary of Account Transactions - 2023 and 2024 ($M)

Line No.	Particulars	Note	Actual 2023	Actual 2024
			(a)	(b)
	Entry (i): Additions Based on Current Year Tax Provision			
1	**Forecast Annual SR&ED ITCs**	1	16.3	16.4
2	**Less: Tax on Provincial Portion Taxable in Current Year**		(0.8)	(0.8)
3	**Less: Tax on Federal ITC in Prior Year**		(3.3)	(3.3)
4	**Forecast Annual SR&ED ITCs, net of Tax**		12.2	12.3
5	**Actual Annual SR&ED ITCs Recorded in the Year**		19.7	15.0
6	**Less: Tax on Provincial Portion Taxable in Current Year**		(1.0)	(0.7)
7	**Less: Tax on Federal ITC in Prior Year**		(4.0)	(4.4)
8	**Actual Annual SR&ED ITCs Recorded, net of Tax**		14.8	9.9
9	**Addition to Variance Account based on Current Year Tax Provision** ((line 4 - line 8) / (1-25%))		(3.4)	3.2
	Entry (ii): True Up Adjustments Based on Prior Year's Income Tax Return			
10	**Actual Annual SR&ED ITCs Recorded, net of Tax**	2	13.5	14.8
11	**Prior Year Actual Annual SR&ED ITCs per Income Tax Return Completed in Current Year**		19.7	21.6
12	**Less: Tax on Provincial Portion Taxable in Current Year**		(1.0)	(1.1)
13	**Less: Tax on Federal ITC in Prior Year**		(4.1)	(4.0)
14	**Prior Year Actual Annual SR&ED ITCs Finalized in Current Year, net of Tax**		14.7	16.6
15	**True-Up Adjustment Based on Prior Year Actual Annual SR&ED ITCs Finalized in Current Year, net of tax** (line 10 - line 14)	3	(1.2)	(1.8)
16	**Addition to Variance Account based on True-Up Adjustments based on Prior Year's Income Tax Return** (line 15 / (1-25%))		(1.6)	(2.4)
	Entry (iii): Increase of SR&ED ITCs Recognition Percentage from 75% to 100% in 2023 for 2017 from June 1 to December 31, 2017	4		
17	**Actual Annual SR&ED ITCs per Income Tax Return, net of Tax on ITCs, at 75%**		(12.1)	0.0
18	**Actual Annual SR&ED ITCs per Income Tax Return, net of Tax on ITCs, at 100%** (line 17 x 4/3)		(16.2)	0.0
19	**Addition to Variance Account** ((line 18 - line 17) / (1-25%))		(5.4)	0.0
	Entry (iv): Increase of SR&ED ITCs Recognition Percentage from 75% to 100% in 2023 for 2018	5		
20	**Actual Annual SR&ED ITCs per Income Tax Return, net of Tax on ITCs, at 75%**		(16.9)	0.0
21	**Actual Annual SR&ED ITCs per Income Tax Return, net of Tax on ITCs, at 100%** (line 20 x 4/3)		(22.6)	0.0
22	**Addition to Variance Account** ((line 21 - line 20) / (1-25%))		(7.5)	0.0
	Entry (v): Increase of SR&ED ITCs Recognition Percentage from 75% to 100% in 2024 for 2019	6		
23	**Actual Annual SR&ED ITCs per Income Tax Return, net of Tax on ITCs, at 75%**		0.0	(14.2)
24	**Actual Annual SR&ED ITCs per Income Tax Return, net of Tax on ITCs, at 100%** (line 23 x 4/3)		0.0	(18.9)
25	**Addition to Variance Account** ((line 24 - line 23) / (1-25%))		0.0	(6.3)
26	**Total Addition to Variance Account** (line 9 + line 16 + line 19 + line 22+ line 25)		(18.0)	(5.5)

Notes:

1 Cols. (a) and (b) per EB-2020-0290 Payment Amounts Order, App. E, p. 18.

2 Col. (a) from EB-2023-0336, Ex. H1-1-1, Table 14, line 8, col (c). Col. (b) from line 8, col. (a).

3 Represents the adjustment based on the final ITC values determined in 2023 and 2024 as part of the filing of the 2022 and 2023 income tax returns and trued up as part of the 2023 and 2024 entries to the variance account, respectively.

4 Recorded in 2023 following the resolution, during 2023, of the 2017 taxation year audit. Amount in line 17 represents the June 1 to December 31, 2017 portion of SR&ED ITCs, net of tax on ITCs, for the nuclear faciliites for 2017 previously credited to ratepayers at 75% through the EB-2016-0152 payment amounts and the SR&ED ITC Variance Account (i.e., 7/12 x EB-2020-0290, Ex. H1-1-1, Table 14, line 11, col. (a)) . The SR&ED ITC Variance Account became effective on June 1, 2017.

5 Recorded in 2023 following the resolution, during 2023, of the 2018 taxation year audit. Amount in line 20 represents the SR&ED ITCs, net of tax on ITCs, for nuclear facilities for 2018 previously credited to ratepayers at 75% through the EB-2016-0152 payment amounts and the SR&ED ITC Variance Account (i.e., EB-2020-0290, Ex. H1-1-1, Table 14, line 11, col. (b)).

6 Recorded in 2024 following the resolution, during 2024, of the 2019 taxation year audit. Amount in line 23 represents actual SR&ED ITCs, net of tax on ITCs, for nuclear facilities for 2019 previously credited to ratepayers at 75% through EB-2016-0152 payment amounts and the SR&ED ITC Variance Account (i.e., EB 2023-0336, Ex. H1-1-1, Table 14, line 11, col. (a)).

Table 13
Capacity Refurbishment Variance Account - Nuclear - Non-Capital Portion - Non DRP
Summary of Account Transactions 2023 and 2024 ($M)

Line No.	Particulars	Note	Actual 2023	Actual 2024
			(a)	(b)
	Non-Capital Addition to Variance Account - Non-DRP			
	Forecast Non-Capital Costs:			
1	**Pickering Extended Operations**	1	0.0	0.0
2	**Fuel Channel Life Extension Project**	1	0.0	0.0
3	**FCLE Related Ongoing Costs**	1	18.7	1.1
4	**Darlington U3 Fuel Channel Component Retrieval Project**	1	0.0	0.0
5	**Darlington Annulus Spacer Life Management Project**		0.0	0.0
6	**Pickering B Refurbishment Feasibility Assessment**		0.0	0.0
7	**Darlington Steam Generator Primary Moisture Separators Replacement**		0.0	0.0
8	**Optimization of Pickering Shutdown**	1	4.9	18.4
9	**Fuel Channel Life Management Phase V Project**		0.0	0.0
10	**Total** (lines 1 through 9)	2	23.6	19.4
	Actual Non-Capital Costs:	3		
11	**Pickering Extended Operations**		0.4	0.0
12	**Fuel Channel Life Extension Project**		3.0	(0.1)
13	**FCLE Related Ongoing Costs**		46.8	1.9
14	**Darlington U3 Fuel Channel Component Retrieval Project**		0.1	0.0
15	**Darlington Annulus Spacer Life Management Project**		0.4	0.0
16	**Pickering B Refurbishment Feasibility Assessment**		17.8	0.0
17	**Darlington Steam Generator Primary Moisture Separators Replacement**		4.5	3.8
18	**Optimization of Pickering Shutdown**		11.6	15.0
19	**Fuel Channel Life Management Phase V Project**		1.1	5.3
20	**Total** (lines 11 through 19)		85.7	25.9
	Non-Capital Addition to Variance Account:			
21	**Pickering Extended Operations** (line 11 - line 1)		0.4	0.0
22	**Fuel Channel Life Extension Project** (line 12 - line 2)		3.0	(0.1)
23	**FCLE Related Ongoing Costs** (line 13 - line 3)		28.0	0.8
24	**Darlington U3 Fuel Channel Component Retrieval Project** (line 14 - line 4)		0.1	0.0
25	**Darlington Annulus Spacer Life Management Project** (line 15 - line 5)		0.4	0.0
26	**Pickering B Refurbishment Feasibility Assessment** (line 16 - line 6)		17.8	0.0
27	**Darlington Steam Generator Primary Moisture Separators** (line 17 - line 7)		4.5	3.8
28	**Optimization of Pickering Shutdown** (line 18 - line 8)		6.7	(3.4)
29	**Fuel Channel Life Management Phase V Project** (line 19 - line 9)		1.1	5.3
30	**Non-Capital Addition to Variance Account** (lines 21 through 29)		62.1	6.5

Notes:
1 Cols. (a) and (b) from EB-2020-0290, Ex. L-H1-01-Staff-328, Chart 1.
2 Cols. (a) and (b) from EB-2020-0290 Payment Amounts Order, App. E, p. 9.
3 Details for actual non-capital costs can be found at Ex. F2-1-1, Table 1a, F2-2-1, Table 1a, F2-3-1, Table 1, and Ex. F2-4-1, Table 1.

Table 14
Capacity Refurbishment Variance Account - Nuclear - Capital Portion - Non-DRP
Summary of Account Transactions - 2023 and 2024 ($M)

Line No.	Particulars	Note	Actual 2023	Actual 2024
			(a)	(b)
	Capital Addition to Variance Account:			
1	**Forecast Cost of Capital Amount**	1	0.8	0.3
2	**Actual Net Plant Rate Base Amount**	2	68.5	151.5
3	**Weighted Average Cost of Capital**	1	5.83%	5.90%
4	**Actual Cost of Capital Amount** (line 2 x 3)		4.0	8.9
5	**Cost of Capital Variance** (line 4 - line 1)		3.2	8.6
6	**Forecast Depreciation**	1	8.8	8.8
7	**Actual Depreciation**	2	11.5	9.9
8	**Depreciation Variance** (line 7 - line 6)		2.7	1.1
	Income Tax Impact			
9	**Forecast Capital Cost Allowance Deduction**	1	1.9	1.7
10	**Actual Capital Cost Allowance Deduction**		12.0	14.6
11	**Actual SR&ED Qualifying Capital Expenditures**		4.8	14.7
12	**Difference** (line 9 - line 10 - line 11)		(14.9)	(27.5)
13	**Net Increase (Decrease) in Regulatory Taxable Income**	3	(10.1)	(20.8)
14	**Income Tax Rate**		25.0%	25.0%
15	**Income Tax Impact** (line 13 x line 14 / (1 - line 14))		(3.4)	(6.9)
16	**Capital Addition to Variance Account - Non-DRP** (line 5 + line 8 +line 15)		2.5	2.7

For notes see Table 14a

Table 14a
Notes to Table 14
Capacity Refurbishment Variance Account - Nuclear - Capital Portion - Non-DRP ($M)

Notes:

1 The amounts in line 1 are determined as follows:

Table to Note 1 - Capacity Refurbishment Variance Account - Forecast Capital Amounts for Nuclear Projects - EB-2020-0290 ($M)

Line No.		2023	2024
		(a)	(b)
1a	Forecast Net Plant Rate Base Amount*	14.4	5.6
2a	Weighted Average Cost of Capital**	5.83%	5.90%
3a	Forecast Cost of Capital Amount (line 1a x line 2a)^	0.8	0.3
4a	ROE Component of Forecast Cost of Capital Amount	0.6	0.2
5a	Forecast Depreciation^	8.8	8.8
6a	Forecast Capital Cost Allowance Deduction^	1.9	1.7

* Represents the EB-2020-0290 forecast for the Pickering Extended Operations projects.

** Col. (a) is calculated as EB-2020-0290 Payment Amounts Order, App. A, Table 12: line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b). Col. (b) is calculated as EB-2020-0290 Payment Amounts Order, App. A, Table 13: line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).

^ For lines 5a and 6a, cols. (a) and (b) as shown in EB-2020-0290, Ex. L-H1-01-Staff-328, Chart 3. The sum of the following in cols. (a) and (b) equals $12.1M and $11.6M respectively, per EB-2020-0290 Payment Amounts Order, App. E, p. 9: (i) line 3a; (ii) line 5a; and (iii) the result of the following, multiplied by 25% / (1-25%): line 4a plus line 5a minus line 6a.

2 The amounts in line 2 are determined as follows:

Table to Note 2 - Capacity Refurbishment Variance Account - Actual Net Plant Rate Base Amounts for Nuclear Projects ($M)

Line No.		2023	2024
		(a)	(b)
1b	Gross Plant Opening Balance (col. (a) from EB-2023-0336, Ex. H1-1-1, Table 16a, line 3b, col. (c))	38.1	121.0
2b	In-service Addition - Darlington Steam Generator Primary Moisture Separators Replacement+	82.2	87.9
2bb	In-service Addition - Pickering Extended Operations	0.6	0.0
3b	Gross Plant Closing Balance (line 1b + line 2b + line 2bb)	121.0	208.9
4b	Gross Plant Rate Base Amount (line 1b + line 3b)/2 ++	93.2	186.9
5b	Accumulated Depreciation Opening Balance (col. (a) from EB-2023-0336, Ex. H1-1-1, Table 16a, line 7b, col. (c))	18.9	30.5
6b	Depreciation - Darlington Steam Generator Primary Moisture Separators Replacement	2.1	5.1
6bb	Depreciation - Pickering Extended Operations	9.5	4.8
7b	Accumulated Depreciation Closing Balance (line 5b + line 6b + line 6bb)	30.5	40.4
8b	Accumulated Depreciation Rate Base Amount (line 5b + line 7b)/2	24.7	35.4
9b	Net Plant Rate Base Amount (line 4b - line 8b)	68.5	151.5

\+ Col. (a) as shown in Ex. B3-3-1, Table 1a, Note 1 and Ex. D2-1-3, Table 4a, line 13, col. (l). Col. (b) as shown in Ex. B3-3-1 Table 1a, Note 1 and Ex. D2-1-3 Table 4a, line 38, col. (c).

++ In-service additions in 2023 and 2024 for Darlington Steam Generator Primary Moisture Separator exceed $50M, hence the month in which the addition is reflected is used to determine the gross plant rate base amount, instead of a mid-year average.

3 The change in regulatory taxable income is calculated as the sum of lines 8 and 12, plus the ROE component of the cost of capital variance at line 5. The ROE component of the variance is equal to the difference between (i) line 2 multiplied by the OEB-approved equity portion (45%) of the capital structure and the OEB-approved ROE rate of 8.66% for 2023 and 2024, and (ii) line 4a, for the corresponding year.

Numbers may not add due to rounding.

Updated: 2026-03-10
EB-2025-0297
Exhibit H1
Tab 1
Schedule 1
Table 15

Table 15
Capacity Refurbishment Variance Account - Nuclear - Non-Capital Portion - DRP
Summary of Account Transactions 2016, 2017, 2018, 2019, 2020, 2021, 2022, 2023 and 2024 ($M)

Line No.	Particulars	Note	Actual 2016	Actual Jan - May 2017	Actual Jun - Dec 2017	(b) + (c) Actual 2017	Actual 2018	Actual 2019	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Actual 2024	(a)+(d)+(e)+(f)+(g)+(h)+(i)+(j)+(k) Total	Budget 2025	Budget 2026
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	Non-Capital Addition to Variance Account:															
1	**Forecast Non-Capital Costs**	1	12.4	5.2	24.2	29.4	13.8	3.5	48.4	19.7	24.2	23.6	29.3		25.0	8.4
2	**Actual Non-Capital Costs**	2	3.1	12.1	24.0	36.1	31.3	1.7	19.0	35.6	22.3	39.0	59.7		10.5	1.8
3	**Non-Capital Addition to Variance Account Before Adjustments** (line 2 - line 1)		(9.3)	6.9	(0.2)	6.7	17.6	(1.8)	(29.4)	15.8	(1.9)	15.4	30.4		(14.5)	(6.6)
4	**Less: EB-2013-0321 Impact Statement (Ex. N1) Adjustment - DRP**	3	1.1	0.4	0.0	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0
5	**Less: EB-2016-0152 DRP L&ILW Variable Expenses Adjustment**	5	0.0	0.0	2.3	2.3	2.1	3.2	4.6	5.3	0.0	0.0	0.0		0.0	0.0
6	**Less: DRP-Related Impact Recorded in Nuclear Liability Deferral Account**	4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5	15.7	15.9		1.9	0.3
7	**Non-Capital Addition to Variance Account - DRP** (line 3 - line 4 - line 5 - line 6)		(10.4)	6.4	(2.5)	3.9	15.5	(5.0)	(33.9)	10.6	(6.4)	(0.3)	14.5	(11.5)	(16.4)	(6.9)

Notes:

1 The forecast amounts are determined as follows:

Table to Note 1 - Capacity Refurbishment Variance Account - Forecast Non-Capital Amounts for the Darlington Refurbishment Program ($M)

Line No.		2014	2015	((a)+(b)) / 2 Reference Amount	equals col. (c) 2016	col. (d)/12*5 Jan 1 2017- May 31 2017	col. (g)/12*7 Jun 1 2017 - Dec 31 2017	EB-2016-0152 Full Year 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1a	EB-2013-0321 Forecast Costs*	6.6	18.2	12.4	12.4	5.2											
2a	EB-2016-0152 Forecast Costs**						24.2	41.5	13.8	3.5	48.4	19.7					
3a	EB-2020-0290 Forecasts Costs***												24.2	23.6	29.3	25.0	8.4

* Col. (a) from EB-2013-0321, Ex. F2-7-1, Table 1, line 3, col. (e) less EB-2013-0321, Ex. N2-1-1, p. 8, line 2. Col. (b) from EB-2013-0321, Ex. F2-7-1, line 3, col. (f).
** Cols. (g) to (k) from EB-2016-0152, Ex. F2-1-1, line 5, cols. (e) to (i), as per EB-2016-0152 Payment Amounts Order, App. G, p. 10, Note 12.
*** Cols. (l) to (n) from EB-2020-0290 Payment Amounts Order, App. E, p.9.

2 Cols. (a). (d\. (e) and (f) from EB-2020-0290. Ex. F2-7-1. Table 1. line 4.
Cols. (g) to (k) and cols. (m) and (n) from Ex. F2-7-1, Table 1, line 4 for 2020 to 2024.

3 Col. (a) amount is from EB-2016-0152, Ex. H1-1-1, Table 11a, line 9a and col. (b) is calculated as 5/12 of that value.

4 Reflects the impact on the Darlington Refurbishment Program L&ILW variable expenses recorded in the Nuclear Liability Deferral Account as a result of the 2022 ONFA Reference Plan. This adjustment avoids duplication across the Capacity Refurbishment Variance Account and the Nuclear Liability Deferral Account.

5 Represents a credit adjustment recognized by OPG, in connection with low and intermediate level waste (L&ILW) expenses incurred by the DRP, related to the reference plan amounts against which variances in the DRP non-capital costs were being determined during the period from June 1, 2017 to December 31, 2021 pursuant to the EB-2016-0152 Payment Amounts Order. The adjustment was made to correct an error made by OPG in the draft payment amounts order submission in EB-2016-0152, which was subsequently reproduced in the final EB-2016-0152 Payment Amounts Order. In particular, such reference amounts were based on EB-2016-0152, Ex. F2-7-1, line 4, cols. (e) to (i) of OPG's pre-filed evidence and did not reflect the nuclear liability revenue requirement updates approved by the OEB on account of the 2017 ONFA Reference Plan – as summarized in EB-2016-0152, Ex. J21.2 – which included an increase to the forecast DRP L&ILW expenses. The adjustment is necessary to accurately match the reference amounts to such forecasts included in the OEB-approved revenue requirements and payment amounts in EB-2016-0152. The adjustment has the effect of lowering amounts that would otherwise be recorded as recoverable from customers in the Capacity Refurbishment Variance Account.

Table 16
Capacity Refurbishment Variance Account - Nuclear - Capital Portion - DRP - Excluding D2O Storage Project
Summary of Account Transactions - 2016, 2017, 2018 , 2019, 2020, 2021, 2022, 2023 and 2024 ($M)

Line No.	Particulars	Note	Actual 2016	Actual Jan - May 2017	Actual Jun - Dec 2017	(b) + (c) Actual 2017	Actual 2018	Actual 2019	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Actual 2024	(a)+(d)+(e)+(f)+(g)+(h)+(i)+(j)+(k) Total	Budget 2025	Budget 2026
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(j)	(k)
	Capital Addition to Variance Account:															
1	**Forecast Cost of Capital Amount**	1	10.3	4.3	23.2		38.2	37.1	301.7	330.5	293.2	280.7	419.7		484.9	524.1
2	**Actual Net Plant Rate Base Amount**	2	340.8	594.6	594.6		693.6	684.7	3,398.0	5,238.0	5,059.1	5,883.0	7,013.5		8,316.2	9,620.3
3	**Weighted Average Cost of Capital**	1	6.85%	6.85%	6.65%		6.50%	6.46%	6.44%	6.43%	5.89%	5.83%	5.90%		5.92%	5.92%
4	**Actual Cost of Capital Amount**		23.3	17.0	23.1	40.0	45.1	44.2	218.8	336.8	298.0	343.0	413.8		492.3	569.5
5	**Cost of Capital Variance** (line 4 - line 1)		13.1	12.6	(0.2)	12.4	6.9	7.1	(82.9)	6.3	4.8	62.2	(5.9)		7.4	45.4
6	**Forecast Depreciation**	1	4.0	1.7	11.1	12.7	19.2	19.3	148.5	166.9	163.4	163.4	249.8		298.9	334.6
7	**Actual Depreciation**	2	16.1	9.9	17.6	27.5	33.9	34.4	123.2	184.6	184.7	226.1	271.8		311.4	373.3
8	**Depreciation Variance** (line 7 - line 6)		12.2	8.2	6.6	14.8	14.7	15.1	(25.3)	17.7	21.3	62.7	22.0		12.5	38.7
	Income Tax Impact:															
9	**Forecast Capital Cost Allowance Deduction**	1	66.8	27.8	106.8	134.6	283.7	354.4	380.8	383.2	523.6	550.7	540.3		538.9	520.2
10	**Actual Capital Cost Allowance Deduction**	6	118.7	78.8	104.3	183.1	243.6	412.4	431.6	454.0	489.5	527.3	525.5		540.7	526.5
11	**SR&ED Qualifying Capital Expenditures**		62.4	0.0	20.7	20.7	18.8	0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0
12	**Difference** (line 9 - line 10 - line 11)		(114.3)	(51.0)	(18.2)	(69.1)	21.3	(58.0)	(50.8)	(70.8)	34.0	23.4	14.8		(1.7)	(6.3)
13	**Net (Decrease) Increase in Regulatory Taxable Income**	3	(94.2)	(35.0)	(11.7)	(46.7)	40.2	(38.5)	(127.0)	(49.3)	58.6	127.7	32.9		15.6	62.3
14	**Income Tax Rate**		25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	0.3	25.0%	25.0%	25.0%		0.3	0.3
15	**Income Tax Impact** (line 13 x line 14 / (1 - line 14))		(31.4)	(11.7)	(3.9)	(15.6)	13.4	(12.8)	(42.3)	(16.4)	19.5	42.6	11.0		5.2	20.8
16	**Capital Addition to Variance Account** (line 5 + line 8 + line 15)		(6.2)	9.2	2.5	11.6	35.0	9.4	(150.5)	7.5	45.6	167.6	27.0		25.1	104.8
17	**Less: EB-2013-0321 Impact Statement (Ex. N1) Adjustment**	5	5.1	2.1		2.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0
18	**Addition to Variance Account-Capital Portion DRP** (line 16 - line 17)		(11.2)	7.1	2.5	9.5	35.0	9.4	(150.5)	7.5	45.6	167.6	27.0		25.1	104.8
19	**Less: Accelerated Investment Incentive CCA - DRP**	4						(18.9)	(19.9)	3.1						
20	**Total Capital Additon to Variance Account - Capital Portion DRP** (line 18 - line 19)		(11.2)	7.1	2.5	9.5	35.0	28.3	(130.6)	4.4	45.6	167.6	27.0	175.6	25.1	104.8

For notes see Table 16a

Numbers may not add due to rounding.

Updated: 2026-03-10
EB-2025-0297
Exhibit H1
Tab 1
Schedule 1
Table 16a

Table 16a
Notes to Table 16
Capacity Refurbishment Variance Account - Nuclear - Capital Portion - DRP - Excluding D2O Storage Project

Notes:

1 The amounts in line 1 are determinded as follows:

Table to Note 1 - Capacity Refurbishment Variance Account - Forecast Capital Amounts for the Darlington Refurbishment Program ($M)

Line No.		2014	2015	((a)+(b)) / 2 Reference Amount	equals to col. (c) 2016	col. (d) / 12*5 Jan 1 2017- May 31 2017	col. (g) / 12*7 June 1 2017- Dec 31 2017	EB-2016-0152 Full Year 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1a	Forecast Net Plant Rate Base Amount*	116.0	184.3					598.1	587.7	572.9	4,685.3	5,140.7	4,978.0	4,815.3	7,114.2	8,191.7	8,853.7
2a	Weighted Average Cost of Capital**	6.86%	6.85%					6.65%	6.50%	6.46%	6.44%	6.43%	5.89%	5.83%	5.90%	5.92%	5.92%
3a	Forecast Cost of Capital Amount (line 1a x line 2a)	8.0	12.6	10.3	10.3	4.3	23.2	39.8	38.2	37.1	301.7	330.5	293.2	280.7	419.7	484.9	524.1
4a	ROE Component of Forecast Cost of Capital Amount***	4.9	7.7	6.3	6.3	2.6	13.8	23.6	23.2	22.6	185.1	203.1	194.0	187.7	277.2	319.2	345.0
5a	Forecast Depreciation*	3.0	5.0	4.0	4.0	1.7	11.1	19.0	19.2	19.3	148.5	166.9	163.4	163.4	249.8	298.9	334.6
6a	Forecast Capital Cost Allowance Deduction****	39.3	94.3	66.8	66.8	27.8	106.8	183.1	283.7	354.4	380.8	383.2	523.6	550.7	540.3	538.9	520.2

* Cols. (a) and (b) from EB-2013-0321, Ex. L-4.9-1-Staff-048, Chart 1, "Total" line less "Heavy Water & Drum Handling Facility" line.
Cols. (g) to (k) from EB-2016-0152, Ex. L-2.2-1-Staff-009, Attachment 1, "Total" line less "Heavy Water Storage & Drum Handling Facility" line.
Line 1a cols. (l) to (p) from EB-2020-0290 Payment Amounts Order, App. E, Attachment 1, line 1, cols. (a) to (e). Line 5a cols. (l) to (p) from EB-2020-0290 Payment Amounts Order, App. E, Attachment 1, line 6, cols. (a) to (e).

** Cols. (a) and (b) from EB-2013-0321 Payment Amounts Order, App. A, Tables 5b and 6b: line 6, col. (c).
Cols. (g) to (k) from EB-2016-0152 Payment Amounts Order, App. A, Tables 11 to 15: line 6, col. (c).
Cols. (l) to (p) from EB-2020-0290 Payment Amounts Order, App. A, Tables 11 to 15: line 4, col. (b) x col. (c), plus line 5a, col. (c) x line 5b, col. (b).

*** The ROE component of the cost of capital forecast is equal to line 1a mulitiplied by the OEB-approved equity portion (45%) of the capital structure and the OEB-approved ROE rates as follows: 2016 and Jan 1, 2017 to May 31, 2017 - 9.30%; June 1, 2017 to Dec 31, 2021 - 8.78%; 2022 to 2026 - 8.66%.

**** Cols. (a) and (b) from EB-2013-0321, Ex. D2-2-1, p. 29, Note 2.
Cols. (g) to (k) from EB-2016-0152, Ex. F4-2-1, Table 3b, Note 3.
Cols. (l) to (p) from EB-2020-0290 Payment Amounts Order, App. E, Attachment 1, line 11, cols. (a) to (e).

2 The amounts in line 2 are determined as follows:

Table to Note 2 - Capacity Refurbishment Variance Account - Actual Net Plant Rate Base Amounts for the Darlington Refurbishment Program ($M)

Line No.		2016	Jan 1 2017- May 31 2017	June 1 2017- Dec 31 2017	(b) + (c) Total 2017	2018	2019	2020	2021	2022	2023	2024	Budget 2025	Budget 2026
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1b	Gross Plant Opening Balance (col. (a) from EB-2020-0290, Ex. B3-3-1, Table 1, line 2, col. (a))	280.1			444.5	750.4	784.9	800.9	5,575.1	5,582.9	5,586.5	7,826.6	9,568.5	9,607.1
2b	In-service Addition - Darlington Refurbishment - Unit Refurbishments	0.0			0.0	0.0	0.0	4,765.0	6.2	(2.5)	2,240.1	1,739.6	38.6	2,297.7
3b	In-service Addition - Darlington Refurbishment - Early In-Service	103.4			44.9	22.5	7.6	2.2	1.5	2.9	0.0	0.0	0.0	1.7
4b	In-service Addition - Darlington Refurbishment - Facilities & Infrastructure Projects	43.0			16.9	0.9	0.1	10.0	(1.4)	(0.9)	0.0	0.0	0.0	0.0
5b	In-service Addition - Darlington Refurbishment - Safety Improvement Opportunities	17.9			244.1	11.1	8.2	(3.0)	1.5	4.2	0.0	2.3	0.0	0.0
6b	Total In-Service Additions (line 2b + line 3b + line 4b + line 5b)*	164.4	241.0	64.9	305.9	34.5	16.0	4,774.1	7.8	3.7	2,240.1	1,741.9	38.6	2,299.4
7b	Gross Plant Closing Balance (line 1b + line 6b)	444.5			750.4	784.9	800.9	5,575.1	5,582.9	5,586.5	7,826.6	9,568.5	9,607.1	11,906.5
8b	Gross Plant Rate Base Amount (line 1b + line 7b)/2**	362.3			638.0	767.7	792.9	3,585.1	5,579.0	5,584.7	6,614.0	7,993.4	9,587.8	11,234.2
9b	Accumulated Depreciation Opening Balance (col. (a) from EB-2020-0290, Ex. B3-4-1, Table 1, line 2, col. (a))	13.5			29.6	57.1	91.0	125.5	248.6	433.3	618.0	844.1	1,115.9	1,427.3
10b	Depreciation*	16.1	9.9	17.6	27.5	33.9	34.4	123.2	184.6	184.7	226.1	271.8	311.4	373.3
11b	Accumulated Depreciation Closing Balance (line 9b + line 10b)	29.6			57.1	91.0	125.5	248.6	433.3	618.0	844.1	1,115.9	1,427.3	1,800.6
12b	Accumulated Depreciation Rate Base Amount (line 9b + line 11b)/2 ***	21.5			43.4	74.1	108.2	187.0	341.0	525.6	731.0	980.0	1,271.6	1,614.0
13b	Net Plant Rate Base Amount (line 8b - line 12b)	340.8			594.6	693.6	684.7	3,398.0	5,238.0	5,059.1	5,883.0	7,013.5	8,316.2	9,620.3

\+ In-service additions - Cols. (a), (d), (e) and (f) from EB-2020-0290, Ex. D2-2-9, Table 5a, excluding the D2O Storage Project. Cols. (g) to (m) from Ex. D2-2-3, Table 5a, excluding the D2O Storage Project.
Depreciation - Cols. (a), (d), (e) and (f) from EB-2020-0290, Ex. F4-1-1, Table 2, line 2, cols. (a) to (d). Cols. (g) to (m) from Ex. F4-1-1, Table 2, line 2, cols. (a) to (g).

++ Total in-service additions include the following amounts over $50M: 2016 - $88.1M for R&FR - Tooling, 2017 - $191.2 for Safety Improvement Opportunities, 2020 - $4,765.0M for Unit 2, 2023 - $2,221.8M for Unit 3, 2024 - $1,689.9M for Unit 1, and 2026 - $2,291.5M for Unit 4. For these in-service additions, the month in which the addition is reflected is used to determine the gross plant rate base amount, instead of a mid-year average. Amounts at line 8b can also be found as follows -- Cols. (a), (d), (e) and (f) from EB-2020-0290, Ex. B3-3-1, Table 1, col. (f), lines 2, 10, 18 and 26. Cols. (g) to (m) from Ex. B3-3-1, Table 1, col. (f), lines 2, 11, 20, 29, 38, 47 and 59.

+++ Amouns at line 12b can also be found as follows -- Cols. (a), (d), (e) and (f) from EB-2020-0290, Ex. B3-4-1, Table 1, col. (e), lines 2, 10, 18 and 26. Cols. (g) to (k) from Ex. B3-4-1, Table 1, col. (e), lines 2, 11, 20, 29 and 38. Cols. (l) and (m) from Ex. B3-4-1, Table 2, col. (f), lines 2 and 14.

3 The change in regulatory taxable income is calculated as the sum of lines 8 and 12, plus the ROE component of the cost of capital variance at line 5 . The ROE component of the variance is equal to the difference between: (i) line 2 multiplied by the OEB-approved equity portion (45%) of the capital structure and the following OEB-approved ROE rates: 2016 and Jan 1 to May 31, 2017 - 9.30%; June 1, 2017 to Dec 31, 2021 - 8.78%; 2022 to 2026 - 8.66%; and (ii) line 4a, cols. (d) to (f), (h) to (p).

4 Accelerated Investment Incentive CCA is included within the total CCA at line 10, and such amounts for Darlington Refurbishment Program recorded in the Capacity Refuribshment Variance Account have been separately approved for disposition in EB-2020-0290 Payment Amounts Order, Appendix D, Table 1, line 7, col. (f) and EB-2023-0336 Decision and Order, Attachment A, Table 2, line 6, col. (e).

5 Col. (a) amount is from EB-2016-0152 Ex. H1-1-1, Table 11, line 33 and col. (b) is calculated as 5/12 of that value.

6 Amounts are net of impacts to capital cost allowance from the permanent rate base disallowance applied to the D2O Storage Project by the OEB in the EB-2020-0290 Decision and Order.

Table 17
Nuclear Liability Deferral Account
Summary of Account Transactions - 2023 and 2024 ($M)

Line No.	Particulars	Note	Actual 2023	Actual 2024	Budget 2025	Budget 2026
			(a)	(b)	(c)	(d)
	Revenue Requirement Impact of Current Approved ONFA Reference Plan Effective January 1, 2022:					
1	**Depreciation Expense**	1	80.5	80.5	1.1	1.1
	Return on Rate Base					
2	**Average Asset Retirement Costs**	2	151.8	71.2	30.4	29.3
3	**Weighted Average Cost of Capital**	3	5.83%	5.90%	5.92%	5.92%
4	**Return on Rate Base** (line 2 x line 3)		8.8	4.2	1.8	1.7
	Variable Expenses					
5	**Used Fuel Storage and Disposal Variable Expenses**	5	0.3	0.7	1.0	1.5
6	**Low & Intermediate Level Waste Management Variable Expenses**	5	28.8	29.4	12.3	7.9
7	**Total Variable Expenses** (line 5 + line 6)		29.1	30.1	13.3	9.4
	Income Tax Impact					
8	**Forecast Contributions to Segregated Funds**	6	100.6	100.6	0.0	0.0
9	**Contributions to Segregated Funds based on Current Approved ONFA Reference Plan**	7	200.1	200.1	116.4	39.2
10	**Increase in Contributions to Segregated Funds** (line 8 - line 9)		(99.5)	(99.5)	(116.4)	(39.2)
11	**Return on Rate Base - ROE Component** (line 2 x 45% x 8.66%)		5.9	2.8	1.2	1.1
12	**Net Increase in Regulatory Taxable Income** (line 1 + line 7 + line 10 + line 11)		16.1	14.0	(100.8)	(27.6)
13	**Income Tax Rate**		25.0%	25.0%	25.0%	25.0%
14	**Income Tax Impact** (line 12 x line 13 / (1 - line 13))		5.4	4.7	(33.6)	(9.2)
15	**Addition to Deferral Account - Year-End 2021 ARO / ARC Adjustment** (lines 1 + 4 + 7 + 14)		123.9	119.5	(17.4)	3.0
16	**Addition to Deferral Account - Change in Pickering Station End-of-Life Dates (December 31, 2020 End-of-Life Extension)**	4	69.4	67.9	19.6	19.6
17	**Total Addition to Deferral Account** (line 15 + line 16)		193.3	187.5	2.2	22.6

Notes:

1 The depreciation expense component of the addition to the deferral account is calculated as follows:

Table to Note 1 - Change in Depreciation Expense ($M)

Line No.		Pickering Units 1 & 4	Pickering Units 5 - 8	Darlington	(a) + (b) + (c) Total
		(a)	(b)	(c)	(d)
	Incremental Asset Retirement Cost ("ARC") Continuity:				
1a	ARC Adjustment at December 31, 2021 (EB-2023-0336, Ex. H1-1-1, Table 18a, line 7b, cols. (a) to (d))**	254.8	(16.5)	34.2	272.6
2a	Remaining Useful Life as at December 31, 2021 (years)*	3.0	3.0	31.0	
3a	2022 Annual Incremental Depreciation (line 1a / line 2a)	84.9	(5.5)	1.1	80.5
4a	Incremental ARC at December 31, 2022 (EB-2023-0336, Ex. H1-1-1, Table 18, Note 1, line 4a)	169.9	(11.0)	33.1	192.0
5a	Remaining Useful Life as at December 31, 2022 (years)*	2.0	2.0	30.0	
6a	2023 Annual Incremental Depreciation (line 4a / line 5a)	84.9	(5.5)	1.1	80.5
7a	Incremental ARC at December 31, 2023 (line 4a - line 6a)	84.9	(5.5)	32.0	111.5
8a	Remaining Useful Life as at December 31, 2023 (years)*	1.0	1.0	29.0	
9a	2024 Annual Incremental Depreciation (line 7a / line 8a)	84.9	(5.5)	1.1	80.5
10a	Incremental ARC at December 31, 2024 (line 7a - line 9a)	0.0	0.0	30.9	30.9
11a	Remaining Useful Life as at December 31, 2024 (years)*	0.0	0.0	28.0	
12a	2025 Annual Incremental Depreciation (line 10a / line 11a)	0.0	0.0	1.1	1.1
13a	Incremental ARC at December 31, 2025 (line 10a - line 12a)	0.0	0.0	29.8	29.8
14a	Remaining Useful Life as at December 31, 2025 (years)*	0.0	0.0	27.0	
15a	2026 Annual Incremental Depreciation (line 13a / line 14a)	0.0	0.0	1.1	1.1
16a	Incremental ARC at December 31, 2026 (line 13a - line 15a)	0.0	0.0	28.7	28.7

* A common end of life date of December 31, 2024 was used to depreciate ARC for Pickering Units 1 & 4 due to the integrated nature of Unit operations.

** Cols. (a) through (d) from Ex. C2-1-1, Table 4, line 14, cols. (a) through (d), respectively.

2 Col. (a) calculated as (line 4a, col. (d) + line 7a, col. (d)) / 2. Col. (b) calculated as (line 7a, col.(d) + line 10a, col. (d)) / 2. Col. (c) calculated as (line 10a, col.(d) + line 13a, col. (d)) / 2. Col. (d) calculated as (line 13a, col.(d) + line 16a, col. (d)) / 2.

3 Col. (a) WAAC: calculated as EB-2020-0290 Payment Amounts Order, Appendix A, Table 12, line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).
Col. (b) WACC: calculated as EB-2020-0290 Payment Amounts Order, Appendix A, Table 13, line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).
Col. (c) WAAC: calculated as EB-2020-0290 Payment Amounts Order, Appendix A, Table 14, line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).
Col. (d) WACC: calculated as EB-2020-0290 Payment Amounts Order, Appendix A, Table 15, line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).

4 From Ex. H1-1-1, Table 18, line 22, cols. (a) through (d). Represents the nuclear liabilities component of the revenue requirement impacts arising from the extension of station end-of-life dates for Pickering Units 1 and 4 to December 31, 2024, effective December 31, 2020. As the current approved ONFA Reference Plan reflects this change effective January 1, 2022, this impact is recorded in the Nuclear Liability Deferral Account beginning in 2022. Prior to 2022, the impact was recorded in the Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account as this change in end-of-life dates was not yet reflected in the current approved ONFA Reference Plan.

5 Values are calculated as the difference between: (A) the product of (i) corresponding year unit cost rates for the Used Fuel Storage and Disposal Programs and the Low and Intermediate Level Waste ("L&ILW") Storage and Disposal Programs arising from the current approved ONFA Reference Plan and (ii) the forecast used fuel bundles and L&ILW volumes reflected for the corresponding year in the EB-2020-0290 nuclear revenue requirements, and (B) the product of (i) the corresponding year unit cost rates for the Used Fuel Storage and Disposal Programs and the L&ILW Storage and Disposal Programs applicable following the changes in nuclear liabilities as a result of the extension of station end-of-life dates for Pickering Units 1 and 4 effective December 31, 2020, and (ii) the forecast used fuel bundles and L&ILW volumes reflected for the corresponding years in the EB-2020-0290 nuclear revenue requirements.

6 Per EB-2020-0290, Ex. C2-1-1, Table 2, line 15, cols. (h) through (k).

7 Cols (a) through (d) from Ex. C2-1-1, Table 2, line 14, cols. (d) through (f), respectively.

Table 18

Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account - December 31, 2020 End-of-Life Extension[1]
Summary of Account Transactions - 2023 and 2024 ($M)

Line No.	Description	Note	Actual 2023	Actual 2024	Budget 2025	Budget 2026
			(a)	(b)	(c)	(d)
	Cost of Capital					
1	**Asset Retirement Cost ("ARC") Rate Base** (Note 4, line 4h)		2.3	0.6	(0.3)	(0.2)
2	**Non-ARC Rate Base** (Note 5, line 5f)		3.1	1.0	0.0	0.0
3	**Total Return on Rate Base Impact** (line 1 + line 2)		5.5	1.6	(0.3)	(0.2)
	Depreciation Expense:					
4	**Asset Retirement Costs** (Note 2, col. (f))		29.7	29.7	(0.2)	(0.2)
5	**Non-Asset Retirement Costs** (Note 3, line 3c)		38.1	34.6	0.0	0.0
6	**Total Depreciation Expense Impact** (line 4 + line 5)		67.8	64.3	(0.2)	(0.2)
	Other Expenses:					
7	**Used Fuel Storage and Disposal Variable Expenses**	6	19.4	19.9	14.5	14.6
8	**Low & Intermediate Level Waste Management Variable Expenses**	6, 7	0.8	0.8	0.6	0.4
9	**Total Variable Expenses Impact** (line 7 + line 8)		20.2	20.7	15.1	15.1
	Income Taxes:					
10	**Return on Rate Base - Non-ARC Impact - ROE Component** (Note 5, line 5g x (25%/75%))		0.7	0.2	0.0	0.0
11	**Depreciation Expense on Non-Asset Retirement Costs** (line 5 x (25%/75%))		12.7	11.5	0.0	0.0
12	**Total Non-ARC Income Tax Impact** (line 10 + line 11)		13.4	11.8	0.0	0.0
13	**Return on Rate Base - ARC Impact** (Note 4, line 4k x (25%/75%))		0.5	0.1	(0.1)	(0.1)
14	**Depreciation Expense on Asset Retirement Costs** (line 4 x (25%/75%))		9.9	9.9	(0.1)	(0.1)
15	**Used Fuel Storage and Disposal Variable Expenses** (line 7 x (25%/75%))		6.5	6.6	4.8	4.9
16	**Low & Intermediate Level Waste Management Variable Expenses** (line 8 x (25%/75%))		0.3	0.3	0.2	0.1
17	**Total Nuclear Liabilities Income Tax Impact** (line 13 + line 14 + line 15 + line 16)		17.2	16.9	4.9	4.9
18	**Total Income Tax Impact** (line 12 + line 17)		30.5	28.7	4.9	4.9
19	**Revenue Requirement Impact - Nuclear Liabilities** (line 1 + line 4 + line 9 + line 17)		69.4	67.9	19.6	19.6
20	**Revenue Requirement Impact - Non-ARC** (line 2 + line 5 + line 12)		54.6	47.4	0.0	0.0
21	**Total Revenue Requirement Impact** (line 19 + line 20)		124.0	115.4	19.6	19.6
22	**Less: Revenue Requirement Impact Recorded in Nuclear Liability Deferral Account Beginning Jan. 1, 2022** (line 19)	8	69.4	67.9	19.6	19.6
23	**Total Addition to Deferral Account** (line 21 - line 22)		54.6	47.4	0.0	0.0

For notes see Tables 18a and 18b.

Table 18a
Notes to Table 18
Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account - December 31, 2020 End-of-Life Extension ($M)

1 Calculations follow the methodology in EB-2020-0290 Payment Amounts Order, App. F, p.1. Amounts are as set out in EB-2020-0290 Ex. L-F-01-Staff-271, Att. 1, Table 2, other than those that reflect changes between the EB-2020-0290 proposed and OEB approved revenue requirement for the corresponding year, subject to rounding differences.

2 The ARC depreciation expense component of the addition to the deferral account is calculated as follows:

Table to Note 2 - ARC Depreciation Expense ($M)

Line No.		Pickering Units 1 & 4	Pickering Units 5-8	Darlington	(a)+(b)+(c) Total	ARC Depreciation per EB-2020-0290***	(d) - (e) Impact of Year-End 2020 Adjustment
		(a)	(b)	(c)	(d)	(e)	(f)
2a	Asset Retirement Cost as at December 31, 2020 Before Pickering Units 1 & 4 End-of-Life Adjustment*	63.3	187.8	113.9	365.2		
2b	Asset Retirement Cost Adjustment as at December 31, 2020 (Cols. (a) through (d) from Ex. C2-1-1, Table 4, line 7, cols. (a) through (d).)	50.4	5.6	(4.8)	51.1		
2c	Unamortized Asset Retirement Cost as at December 31, 2020 (line 2a + line 2b)	113.6	193.4	109.1	416.2		
2d	Remaining Useful Life as at December 31, 2020 (years)**	4.0	4.0	32.0			
2e	Annual Depreciation (line 2c / line 2d)	28.4	48.3	3.4	80.2	82.2	(2.0)
2f	Unamortized Asset Retirement Cost as at December 31, 2021 (line 2c - line 2e)	85.2	145.0	105.7	336.0		
2g	Remaining Useful Life as at December 31, 2021 (years)**	3.0	3.0	31.0			
2h	2022 Annual Depreciation (line 2f / line 2g)	28.4	48.3	3.4	80.2	82.2	(2.0)
2i	Unamortized Asset Retirement Cost as at December 31, 2022* (line 2f - line 2h)	56.8	96.7	102.3	255.8		
2j	Remaining Useful Life as at December 31, 2022 (years)**	2.0	2.0	30.0			
2k	2023 Annual Depreciation (line 2i / line 2j)	28.4	48.3	3.4	80.2	50.5	29.7
2l	Unamortized Asset Retirement Cost as at December 31, 2023 (line 2i - line 2k)	28.4	48.3	98.9	175.7		
2m	Remaining Useful Life as at December 31, 2023 (years)**	1.0	1.0	29.0			
2n	2024 Annual Depreciation (line 2l / line 2m)	28.4	48.3	3.4	80.2	50.5	29.7
2o	Unamortized Asset Retirement Cost as at December 31, 2024 (line 2l - line 2n)	0.0	0.0	95.5	95.5		
2p	Remaining Useful Life as at December 31, 2024 (years)**	0.0	0.0	28.0			
2q	2025 Annual Depreciation (line 2o / line 2p)	0.0	0.0	3.4	3.4	3.6	(0.2)
2r	Unamortized Asset Retirement Cost as at December 31, 2025 (line 2o - line 2q)	0.0	0.0	92.1	92.1		
2s	Remaining Useful Life as at December 31, 2025 (years)**	0.0	0.0	27.0			
2t	2026 Annual Depreciation (line 2r / line 2s)	0.0	0.0	3.4	3.4	3.6	(0.2)
2u	Unamortized Asset Retirement Cost as at December 31, 2026 (line 2r - line 2t)	0.0	0.0	88.7	88.7		

* From EB-2023-0336, Ex. H1-1-1, Table 19a, line 2a, cols. (a) to (d) (differences due to rounding).

** A common end of life date of December 31, 2024 was used to depreciate ARC for Pickering Units 1 & 4 due to the integrated nature of Unit operations.

*** Per EB-2018-0002 OEB Staff Interrogatory #1, Schedule 1-Staff-1, Att. 1, Table 1a, line 1n, col. (d) for 2021 and EB-2020-0290 Payment Amounts Order, App. A, Table 10, col. (b), lines 8, 17, 26, 35 and 44 for 2023 to 2026, respectively.

3 The non-ARC depreciation and amortization expense component of the addition to the deferral account is calculated as follows:

Table to Note 3 - Non-ARC Depreciation Expense ($M)

Line No.		Actual 2023	Actual 2024	Budget 2025	Budget 2026
		(a)	(b)	(c)	(d)
3a	Unadjusted Non-ARC Depreciation and Amortization Expense - December 31, 2022 Pickering Units 1 & 4 End-of-Life+	421.0	528.2	0.4	0.0
3b	Non-ARC Depreciation and Amortization Expense - December 31, 2024 Pickering Units 1 & 4 End-of-Life#	459.1	562.9	0.4	0.0
3c	Impact of Pickering Units 1 & 4 End-of-Life Extension (line 3b less line 3a)	38.1	34.6	0.0	0.0

\+ EB-2020-0290, Ex. B3-4-1: Table 2, cols. (b) to (d), line 30 for 2023 and line 38 for 2024; Table 3, cols. (b) to (d), line 4 for 2025 and line 12 for 2026.

\# Calculated by applying the revised Pickering end-of-life date to the forecast non-ARC Pickering gross plant including forecast in-service additions reflected in the corresponding year nuclear revenue requirement (EB-2020-0290 for 2023 to 2026) and holding all other variables constant, effective January 1, 2022 onwards.

4 Cost of capital for ARC Rate Base component of the addition to the deferral account is calculated as follows:

Table to Note 4 - Cost of Capital for ARC Rate Base ($M)

Line No.		Actual 2023	Actual 2024	Budget 2025	Budget 2026
		(a)	(b)	(c)	(d)
4a	Average ARC: Note 2, col. (d); (opening ARC + closing ARC for corresponding year)/2	215.7	135.6	93.8	90.4
4b	Average UNL++++	(107.0)	(290.8)	(452.1)	(547.2)
4c	Weighted Average Accretion Rate+	4.86%	4.86%	4.86%	4.86%
4d	Return on Rate Base at Weighted Average Accretion Rate ((lesser of line 4a or 4b) x line 4c)++	0.0	0.0	0.0	0.0
4e	Return on Rate Base at Weighted Average Cost of Capital (line 4a x WACC, as line 4b < 0)+++	12.6	8.0	5.6	5.4
4f	EB-2020-0290 Return on Rate Base at Weighted Average Accretion Rate^	0.0	0.0	0.0	0.0
4g	EB-2020-0290 Return on Rate Base at Weighted Average Cost of Capital^^	10.2	7.4	5.8	5.6
4h	Impact of Pickering Units 1 & 4 End-of-Life Extension ((line 4d + line 4e) - (line 4f + line 4g))	2.3	0.6	(0.3)	(0.2)
4i	ROE Component of Line 4e Cost of Capital ((line 4a x 45% x 8.66%), as line 4b < 0)	8.4	5.3	3.7	3.5
4j	ROE Component of Line 4g Cost of Capital^^^	6.8	4.9	3.8	3.7
4k	Impact of Pickering Units 1 & 4 End-of-Life Extension on Cost of Capital for Income Tax Calculation ((line 4d - line 4f) + (line 4i - line 4j))	1.6	0.4	(0.2)	(0.2)

\+ From EB-2020-0290, Ex. L-A1-2-Staff-002, Att. 1, Table 5, line 7, col. (c).

++ When UNL is a negative value, no return on rate base at weighted average accretion is recorded and the return at rate base is limited to average ARC at line 4a multiplied by the OEB-approved weighted average cost of capital (WACC), as shown in line 4e.

+++ Col. (a) WACC : EB-2020-0290 Payment Amounts Order, App. A, Table 12, line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).
Col. (b) WACC : EB-2020-0290 Payment Amounts Order, App. A, Table 13, line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).
Col. (c) WACC : EB-2020-0290 Payment Amounts Order, App. A, Table 14, line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).
Col. (d) WACC : EB-2020-0290 Payment Amounts Order, App. A, Table 15, line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).

++++ From EB-2020-0290, Ex. L-F-01-Staff-271, Att. 1, Table 2b, line 4b, cols. (b)-(e) for the corresponding years.

^ EB-2020-0290 Payment Amounts Order, App. A: Table 12, line 7, col. (d) for 2023, Table 13, line 7, col. (d) for 2024, Table 14, line 7, col. (d) for 2025 and Table 15, line 7, col. (d) for 2026.

^^ Col. (a): EB-2020-0290, Ex. C2-1-1, Table 1a, line 8a, col. (c) multiplied by WACC (see note +++).
Col. (b): EB-2020-0290, Ex. C2-1-1, Table 1a, line 9a, col. (c) multiplied by WACC (see note +++).
Col. (c): EB-2020-0290, Ex. C2-1-1, Table 1a, line 10a, col. (c) multiplied by WACC (see note +++).
Col. (d): EB-2020-0290, Ex. C2-1-1, Table 1a, line 11a, col. (c) multiplied by WACC (see note +++).

^^^ Col. (a): EB-2020-0290, Ex. C2-1-1, Table 1a, line 8a, col. (c) x 45% OEB-apporved equity ratio x 8.66% OEB-approved ROE.
Col. (b): EB-2020-0290, Ex. C2-1-1, Table 1a, line 9a, col. (c) x 45% OEB-apporved equity ratio x 8.66% OEB-approved ROE.
Col. (c): EB-2020-0290, Ex. C2-1-1, Table 1a, line 10a, col. (c) x 45% OEB-apporved equity ratio x 8.66% OEB-approved ROE.
Col. (d): EB-2020-0290, Ex. C2-1-1, Table 1a, line 11a, col. (c) x 45% OEB-apporved equity ratio x 8.66% OEB-approved ROE.

Table 18b

Notes to Table 18 - Continued

Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account - December 31, 2020 End-of-Life Extension ($M)

5 Cost of Capital for Non-ARC Rate Base component of the addition to the deferral account is calculated as follows:

Table to Note 5 - Cost of Capital for Non-ARC Rate Base ($M)

Line No.		Actual 2023	Actual 2024	Budget 2025	Budget 2026
		(a)	(b)	(c)	(d)
5a	Opening Non-ARC Net Plant Balance Impact[##]	72.7	34.6	0.0	0.0
5b	Non-ARC Depreciation and Amortization Expense Impact (Note 3, line 3c x -1)	(38.1)	(34.6)	0.0	0.0
5c	Ending Non-ARC Net Plant Balance Impact (line 5a + line 5b)	34.6	0.0	0.0	0.0
5d	Non-ARC Rate Base Impact (line 5a + line 5c)/2	53.7	17.3	0.0	0.0
5e	Weighted Average Cost of Capital[###]	5.83%	5.90%	5.92%	5.92%
5f	Total Cost of Capital (line 5d x line 5e)	3.1	1.0	0.0	0.0
5g	ROE Component of Cost of Capital (line 5d x 45% x 8.66%)	2.1	0.7	0.0	0.0

Col. (a) from EB-2023-0336, Ex. H1-1-1, Table 19b, line 5c., col. (b).

See Ex. H1-1-1, Table 18a, Note +++.

6 The variable expense component of the addition to the deferral account is determined by multiplying the differences between (i) and (ii) by the corresponding forecast used fuel bundles and low and intermediate level waste ("L&ILW") volumes reflected in the EB-2020-0290 nuclear revenue requirements for the corresponding year, where:
(i) is the corresponding year unit cost rates for the Used Fuel Storage and Disposal Programs and the L&ILW Storage and Disposal Programs reflecting the 2.01% discount rate used to determine the year-end 2020 ARO adjustment reflecting the Pickering Units 1 and 4 end-of-life extension, and (ii) is the equivalent corresponding year unit cost rates reflected in the corresponding variable expenses included in the EB-2020-0290 nuclear revenue requirements.

7 Actual 2023 and 2024 amounts exclude $1.3M and $1.1M of low & intermediate level waste management variable expenses related to the Darlington Refurbishment Project as these impacts are captured in the Capacity Refurbishment Variance Account. The amount recorded in the Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account has been calculated to avoid duplication. Budget 2025 and 2026 amounts of $0.4M and $0.1M, respectively, are excluded for the same reason.

8 Refer to Ex. H1-1-1, Table 17, Note 4.

Numbers may not add due to rounding.

Table 19

Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account - December 31, 2023 End-of-Life Extension[1]

Summary of Account Transactions - 2024 ($M)

Line No.	Description	Note	Actual 2024	Budget 2025	Budget 2026
			(a)	(b)	(c)
	Cost of Capital:				
1	**Asset Retirement Cost ("ARC") Rate Base** (Note 4, line 4j)		18.5	17.4	17.1
2	**Non-ARC Rate Base** (Note 5, line 5f)		1.9	3.6	3.1
3	**Total Return on Rate Base Impact** (line 1 + line 2)		20.5	21.0	20.2
	Depreciation Expense:				
4	**Asset Retirement Costs** (Note 2, col. (h))		78.1	6.8	6.8
5	**Non-Asset Retirement Costs** (Note 3, line 3c)		(65.5)	8.9	8.7
6	**Total Depreciation Expense Impact** (line 4 + line 5)		12.6	15.7	15.6
	Other Expenses:				
7	**Used Fuel Storage and Disposal Variable Expenses**	6	(29.9)	(21.9)	(21.8)
8	**Low & Intermediate Level Waste Management Variable Expenses**	6,7	(5.8)	(4.4)	(3.1)
9	**Total Variable Expenses Impact** (line 7 + line 8)		(35.7)	(26.2)	(24.9)
	Income Taxes:				
10	**Return on Rate Base - Non-ARC Impact - ROE Component** (Note 5, line 5g x (25%/75%))		0.4	0.8	0.7
11	**Depreciation Expense on Non-Asset Retirement Costs** (line 5 x (25%/75%))		(21.8)	3.0	2.9
12	**Total Non-ARC Income Tax Impact** (line 10 + line 11)		(21.4)	3.7	3.6
13	**Return on Rate Base - ARC Impact** (Note 4, line 4o x (25%/75%))		7.6	6.6	6.5
14	**Depreciation Expense on Asset Retirement Costs** (line 4 x (25%/75%))		26.0	2.3	2.3
15	**Used Fuel Storage and Disposal Variable Expenses** (line 7 x (25%/75%))		(10.0)	(7.3)	(7.3)
16	**Low & Intermediate Level Waste Management Variable Expenses** (line 8 x (25%/75%))		(1.9)	(1.5)	(1.0)
17	**Total Nuclear Liabilities Income Tax Impact** (line 13 + line 14 + line 15 + line 16)		21.7	0.2	0.5
18	**Total Income Tax Impact** (line 12 + line 17)		0.3	3.9	4.1
19	**Revenue Requirement Impact - Nuclear Liabiilties** (line 1 + line 4 + line 9 + line 17)		82.6	(1.9)	(0.4)
20	**Revenue Requirement Impact - Non-ARC** (line 2 + line 5 + line 12)		(84.9)	16.2	15.4
21	**Total Addition to Deferral Account** (line 19 + line 20)		(2.3)	14.4	15.0

For notes see Tables 19a and 19b.

Table 19a
Notes to Table 19
Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account - December 31, 2023 End-of-Life Extension ($M)

1 Calculations follow the methodology in EB-2020-0290 Payment Amounts Order, App. F, p.1.

2 The ARC depreciation expense component of the addition to the deferral account is calculated as follows:

Table to Note 2 - ARC Depreciation Expense ($M)

Line No.		Pickering Units 1 & 4	Pickering Units 5-8	Darlington	(a)+(b)+(c) Total	ARC Depreciation per EB-2020-0290 *	Impact of Year-End 2020 Adjustment**	Impact of 2022 ONFA Reference Plan (Year-End 2021) Adjustment***	(d) - (e) - (f) - (g) Impact of Year-End 2023 Adjustment
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
2a	Asset Retirement Cost as at December 31, 2023 Before Pickering Units 5-8 End-of-Life Adjustment (Col. (d) from Ex. C2-1-1, Table 2, line 23, col. (d).)	113.1	42.7	130.9	286.7				
2b	Asset Retirement Cost Adjustment as at December 31, 2023 (Cols. (a) through (d) from Ex. C2-1-1, Table 4, line 22, cols. (a) through (d).)	114.3	490.7	(130.9)	474.1				
2c	Unamortized Asset Retirement Cost as at December 31, 2023 (line 2a + line 2b)	227.4	533.4	0.0	760.8				
2d	Remaining Useful Life as at December 31, 2023 (years) #	1.0	47.0	29.0					
2e	2024 Annual Depreciation (line 2c / line 2d) (Col. (d) from Ex. C2-1-1, Table 2, line 22, col. (e) and from Ex. F4-1-1, Table 2, line 9, col. (e).)	227.4	11.3	0.0	238.8	50.5	29.7	80.5	78.1
2f	Unamortized Asset Retirement Cost as at December 31, 2024 (line 2c - line 2e)	0.0	522.0	0.0	522.0				
2g	Remaining Useful Life as at December 31, 2024 (years) #	0.0	46.0	28.0					
2h	2025 Annual Depreciation (line 2f / line 2g)	0.0	11.3	0.0	11.3	3.6	(0.2)	1.1	6.8
2i	Unamortized 2025 Asset Retirement Cost as at December 31, 2025 (line 2f - line 2h)	0.0	510.7	0.0	510.7				
2j	Remaining Useful Life as at December 31, 2025 (years) #	0.0	45.0	27.0					
2k	2026 Annual Depreciation (line 2i / line 2j)	0.0	11.3	0.0	11.3	3.6	(0.2)	1.1	6.8
2l	Unamortized 2026 Asset Retirement Cost as at December 31, 2026 (line 2i - line 2k)	0.0	499.3	0.0	499.3				

* Per EB-2020-0290 Payment Amounts Order, App. A, Table 10, col. (b), lines 26, 35 and 44 for 2024 to 2026, respectively.

** From Ex. H1-1-1, Table 18, line 4, cols. (b) through (d) for 2024 to 2026, respectively.

*** Ex. H1-1-1, Table 17, line 1, cols. (b) through (d) for 2024 to 2026, respectively.

A common end of life date of December 31, 2024 is used to depreciate ARC for Pickering Units 1 & 4 due to the integrated nature of Unit operations. An end of life date of December 31, 2070 is used to depreciate ARC for Pickering Units 5-8.

3 The non-ARC depreciation and amortization expense component of the addition to the deferral account is calculated as follows:

Table to Note 3 - Non-ARC Depreciation Expense ($M)

Line No.		Actual 2024	Budget 2025	Budget 2026
		(a)	(b)	(c)
3a	Unadjusted non-ARC Depreciation and Amortization Expense - December 31, 2024 Pickering Units 5-8 End of Life+	562.9	0.4	0.0
3b	Non-ARC Depreciation and Amortization Expense - December 31, 2070 Pickering Units 5-8 End-of Life++	497.4	9.2	8.7
3c	Impact of Pickering End-of-Life Extension (line 3b less line 3a)	(65.5)	8.9	8.7

\+ Cols. (a) through (c) from Ex. H1-1-1, Table 18a, line 3b, cols. (b) through (d), respectively.

++ Calculated by applying the revised Pickering end-of-life date to the forecast non-ARC Pickering gross plant including forecast in-service additions reflected in the corresponding year nuclear revenue requirement (EB-2020-0290 for 2024-2026) and holding all other variables constant, effective January 1, 2022.

Table 19b

Notes to Table 19 - Continued

Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account (December 31, 2023 End-of-Life Extension) ($M)

4 Cost of capital for ARC Rate Base component of the addition to the deferral account is calculated as follows:

Table to Note 4 - Cost of Capital for ARC Rate Base ($M)

Line No.		Actual 2024	Budget 2025	Budget 2026
		(a)	(b)	(c)
4a	Average ARC: Note 2, col. (d); (opening ARC + closing ARC for corresponding year)/2	641.4	516.4	505.0
4b	Average UNL	774.0	640.3	567.0
4c	Weighted Average Accretion Rate (Ex. C1-1-1, Table 9, line 7, col. (c))	4.79%	4.79%	4.79%
4d	Return on Rate Base at Weighted Average Accretion Rate ((lesser of line 4a or 4b) x line 4c)	30.7	24.7	24.2
4e	Return on Rate Base at Weighted Average Cost of Capital ((line 4a - line 4b) x WACC), if line 4a > line 4b)[#]	0.0	0.0	0.0
4f	EB-2020-0290 Return on Rate Base at Weighted Average Accretion Rate (from Ex. H1-1-1, Table 18a, line 4f)	0.0	0.0	0.0
4g	EB-2020-0290 Return on Rate Base at Weighted Average Cost of Capital (from Ex. H1-1-1, Table 18a, line 4g)	7.4	5.8	5.6
4h	Impact of Year-End 2020 ARO Adjustment (from Ex. H1-1-1, Table 18a, line 4h, cols. (b) to (d))	0.6	(0.3)	(0.2)
4i	Impact of 2022 ONFA Reference Plan (Year-End 2021) ARO Adjustment (from Ex. H1-1-1, Table 17, line 4, cold. (b) to (d))	4.2	1.8	1.7
4j	Impact of Pickering Units 5-8 End-of-Life Extension ((line 4d + line 4e) - (line 4f + line 4g) - (line 4h + line 4i))	18.5	17.4	17.1
4k	ROE Component of Line 4e Cost of Capital (((line 4a-4b) x 45% x 8.66%), if line 4a > line 4b)	0.0	0.0	0.0
4l	ROE Component of Line 4g Cost of Capital (from Ex. H1-1-1, Table 18a, line 4j, cols. (b) to (d))	4.9	3.8	3.7
4m	ROE Component of Impact of Year-End 2020 ARO Adjustment (from Ex. H1-1-1, Table 18a, line 4k, cols. (b) to (d))	0.4	(0.2)	(0.2)
4n	ROE Component of Impact of 2022 ONFA Reference Plan (Year-End 2021) ARO Adjustment[^]	2.8	1.2	1.1
4o	Impact of Pickering Units 5-8 End-of-Life Extension on Cost of Capital for Income Tax Calculation ((line 4d - line 4f) + (line 4k - line 4l) - line 4m - line 4n)	22.7	19.9	19.5

[#] Col. (a) WACC : EB-2020-0290 Payment Amounts Order, App. A, Table 13, line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).
Col. (b) WACC : EB-2020-0290 Payment Amounts Order, App. A, Table 14, line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).
Col. (c) WACC : EB-2020-0290 Payment Amounts Order, App. A, Table 15, line 4, col. (b) x col. (c) plus line 5a, col. (c) x line 5b, col. (b).

[^] Col. (a) Ex. H1-1-1, Table 17, line 2, col. (b) x 45% OEB-approved equity ratio x 8.66% OEB-approved ROE.
Col. (b) Ex. H1-1-1, Table 17, line 2, col. (c) x 45% OEB-approved equity ratio x 8.66% OEB-approved ROE.
Col. (c) Ex. H1-1-1, Table 17, line 2, col. (d) x 45% OEB-approved equity ratio x 8.66% OEB-approved ROE.

5 Cost of Capital for non-ARC Rate Base component of the addition to the deferral account is calculated as follows:

Table to Note 5 - Cost of Capital for Non-ARC Rate Base ($M)

Line No.		Actual 2024	Budget 2025	Budget 2026
		(a)	(b)	(c)
5a	Opening Non-ARC Net Plant Balance Impact	0.0	65.5	56.6
5b	Non-ARC Depreciation and Amortization Expense Impact (Note 3, line 3c x -1)	65.5	(8.9)	(8.7)
5c	Ending Non-ARC Net Plant Balance Impact (line 5a + line 5b)	65.5	56.6	47.9
5d	Non-ARC Rate Base Impact (line 5a + line 5c)/2	32.7	61.0	52.2
5e	Weighted Average Cost of Capital[+]	5.90%	5.92%	5.92%
5f	Total Cost of Capital (line 5d x line 5e)	1.9	3.6	3.1
5g	ROE Component of Cost of Capital (line 5d x 45% x 8.66%)	1.3	2.4	2.0

[+] For calculation of WACC, see note [##]

6 The variable expense component of the addition to the deferral account is determined by multiplying the differences between (i) and (ii) by the corresponding forecast used fuel bundles and low and intermediate level waste ("L&ILW") volumes reflected in the EB-2020-0290 nuclear revenue requirement for the corresponding year, where:
(i) is the corresponding year unit cost rates for the Used Fuel Storage and Disposal Programs and the L&ILW Storage and Disposal Programs reflecting the 3.93% discount rate used to determine the year-end 2023 ARO adjustment reflecting the Pickering Units 5-8 end-of-life extension, and(ii) is the equivalent corresponding year unit cost rates reflected in the corresponding variable expenses reflecting the 2.45% discount rate used to record variable expenses during 2022 and 2023, following the year-end 2021 ARO adjustment reflecting the impact of the 2022 ONFA Reference Plan.

7 Actual 2024 amount excludes $7.5M of low & intermediate level waste management variable expenses related to the Darlington Refurbishment Project as these impacts are captured in the Capacity Refurbishment Variance Account. The amount recorded in the Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account has been calculated to avoid duplication. Budget 2025 and 2026 amounts of $1.7M and $0.2M, respectively, are excluded for the same reason.

Numbers may not add due to rounding.

Table 20
Nuclear Development Variance Account - Darlington New Nuclear Program
Summary of Account Transactions - 2023 and 2024 ($M)

Line No.	Particulars	Note	Actual 2023	Actual 2024
			(a)	(b)
	Capital Addition to Variance Account:			
	Income Tax Impact:			
1	**Forecast Capital Cost Allowance Deduction**		0.0	0.0
2	**Actual Capital Cost Allowance Deduction**		0.0	23.9
3	**Actual SR&ED Qualifying Expenditures**		21.1	56.0
4	**Difference** (line 1 - line 2 - line 3)		(21.1)	(79.9)
5	**Net Decrease in Regulatory Taxable Income** (line 4)		(21.1)	(79.9)
6	**Income Tax Rate**		25%	25%
7	**Income Tax Impact** (line 5 x line 6 / (1 - line 6))		(7.0)	(26.6)
8	**Capital Addition to Variance Account** (line 7)		(7.0)	(26.6)
	Non-Capital Addition to Variance Account:			
9	**Forecast Costs**	2	2.2	2.3
10	**Actual Costs**	3	1.1	2.3
11	**Difference** (line 10 - line 9)		(1.1)	0.1
12	**Non-Capital Addition to Variance Account** (line 11)		(1.1)	0.1
13	**Total Addition to Variance Account** (line 8 + line 12)		(8.1)	(26.5)

Notes:

1 From EB-2020-0290 Payment Amounts Order, App. E, p.16.

2 From Ex. F2-1-1, Table 1a, line 8, cols. (d) and (e).

SUMMARY OF REVENUE REQUIREMENT AND REVENUE DEFICIENCY

1.0 PURPOSE

This evidence provides a summary of the 2027-2031 revenue requirements for:

- OPG's nuclear facilities;
- OPG's regulated hydroelectric facilities; and
- DNNP LP's facility.

This evidence also includes the revenue deficiency amounts for the same period for OPG's nuclear and regulated hydroelectric facilities.

2.0 REVENUE REQUIREMENT

For OPG's regulated hydroelectric facilities, this Application is seeking approval of a proposed 2027 revenue requirement of $1,668.3M, as presented in Ex. I1-1-1, Table 1.

For OPG's nuclear facilities, this Application is seeking approval of proposed revenue requirements, net of the stretch factor, of $4,062.8M for 2027, $4,257.4M for 2028, $4,677.0M for 2029, $4,882.4M for 2030, and $5,737.6M for 2031, as presented in Ex. I1-1-1, Table 2.

For the DNNP facilities, this Application is seeking approval of proposed revenue requirements of $301.0M for 2027, $378.8M for 2028, $404.9M for 2029, $559.3M for 2030, and $1,042.0M for 2031, as presented in Ex. I1-1-1, Table 2a.

The revenue requirement amounts above do not include the recovery of deferral and variance account balances. OPG is seeking to clear certain deferral and variance accounts using a hydroelectric payment rider and a nuclear payment rider as discussed in Ex. H1-2-1.

3.0 REVENUE DEFICIENCY

Exhibit I1-1-1, Table 3a compares:

a) OPG's forecast revenues determined using the 2026 regulated hydroelectric payment amount set in EB-2020-0290 (i.e., 2026 regulated hydroelectric payment amount multiplied by the regulated hydroelectric production forecast for 2027 proposed in this Application); and
b) the regulated hydroelectric revenue requirement for 2027 proposed in this Application.

OPG's revenue deficiency for the regulated hydroelectric facilities is $243.9M for 2027.

Exhibit I1-1-1, Table 3b compares:

a) Forecast revenues determined using the 2026 nuclear payment amount approved in EB-2020-0290 (i.e., 2026 nuclear payment amount multiplied by the production forecast for 2027-2031 for the OPG nuclear facilities); and
b) the OPG nuclear revenue requirements net of stretch factor proposed in this Application.

The revenue deficiency for the nuclear facilities is $1,981.8M for 2027, $1,285.8M for 2028, $1,886.3M for 2029, $1,896.1M for 2030, and $2,515.3M for 2031.

Exhibit I1-1-1, Tables 4 and 5 present the determination of OPG's 2025 and 2026 forecast regulated return on equity ("ROE") at current payment amounts. Chart 1 below provides these forecast ROE for 2025 and 2026, along with the actual ROE for 2022-2024 as well as the expected average ROE for the 2022-2026 period.

Chart 1 - Actual and Forecast ROE

	2022	2023	2024	2025	2026	Average
OPG ROE	12.7%	13.8%	5.8%	12.2%	4.7%	9.84%
OEB-approved[1]	8.93%	8.93%	8.93%	8.93%	8.93%	8.93%

[1] 8.93% is a rate-base-weighted average of the 8.66% ROE approved for the nuclear business in EB-2020-0290 and 9.33% ROE approved for the hydroelectric business in EB-2013-0321.

4.0 REVENUE REQUIREMENT WORK FORM

A Revenue Requirement Work Form ("RRWF") is attached as Attachment 1 to this exhibit and has also been filed in MS Excel worksheet format. The OEB provides a proprietary RRWF model as a filing requirement for transmission and distribution applications, intended to support the calculation of revenue deficiency or sufficiency. The Application includes a RRWF customized to OPG and DNNP LP's circumstances in order to provide a mechanism to support the Application for 2027-2031 payment amounts for the prescribed nuclear facilities and the 2027 payment amount for the prescribed hydroelectric facilities. This is consistent with the approach taken in EB-2020-0290.

Similar to the OEB RRWF, adjustments are entered in a single worksheet with the effect of these adjustments presented in subsequent worksheets.

LIST OF ATTACHMENTS

Attachment 1: Revenue Requirement Work Form

Table 1
Summary of Revenue Requirement - Regulated Hydroelectric ($M)
Year Ending December 31, 2027

Line No.	Description	Note	2027
			(a)
	Rate Base		
1	**Net Fixed Assets**	1	9,115.6
2	**Working Capital**	1	0.3
3	**Cash Working Capital**	1	19.3
4	**Total Rate Base**		9,135.1
	Capitalization		
5	**Short-Term Debt**	2	152.4
6	**Long-Term Debt**	2	4,232.4
7	**Common Equity**	2	4,750.3
8	**Total Capital**		9,135.1
	Cost of Capital		
9	**Short-Term Debt**	3	7.7
10	**Long-Term Debt**	3	193.8
11	**Common Equity**	3	432.8
12	**Total Cost of Capital**		634.2
	Expenses:		
13	**OM&A**	4	499.3
14	**GRC**	5	352.2
15	**Depreciation & Amortization**	6	215.4
16	**Property Tax**	7	2.1
17	**Total Expenses**		1,069.0
	Less:		
	Other Revenues		
18	**Ancillary and Other Revenue**	8	62.2
19	**Total Other Revenues**		62.2
20	**Income Tax**	9	27.3
21	**Revenue Requirement** (line 12 + line 17 - line 19 + line 20)		1,668.3
22	**Amortization of Variance & Deferral Account Amounts**	10	(37.9)
23	**Revenue Requirement Plus Variance & Deferral Account Amounts** (line 21 + line 22)		1,630.4

Notes:

1 Per Ex. B1-1-1 Table 1.

2 Regulated hydroelectric portion of totals from Ex. C1-1-1 Table 5, (col. (a)). Capitalization is allocated to regulated hydroelectric and OPG's nuclear facilities using rate base financed by capital structure.

3 Regulated hydroelectric portion of totals from Ex. C1-1-1 Table 5, (col. (d)). Cost of Capital is allocated to regulated hydroelectric and OPG's nuclear facilities using rate base financed by capital structure.

4 Per Ex. F1-1-1, Table 1, line 6.

5 Per Ex. F1-1-1, Table 1, line 7.

6 Per Ex. F4-1-1, Table 1, line 10.

7 Per Ex. F4-2-1, Table 1, line 5.

8 Per Ex. G1-1-1, Table 1, line 7.

9 Per Ex. F4-2-1, Table 1, line 1.

10 Per Ex. H1-2-1 Table 1, col. (h), line 19.

Numbers may not add due to rounding.

Updated: 2026-03-10
EB-2025-0297
Exhibit I1
Tab 1
Schedule 1
Table 2

Table 2
Summary of Revenue Requirement - OPG Nuclear Facilities ($M)
Years Ending December 31, 2027 to 2031

Line No.	Description	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
	Rate Base						
1	**Net Fixed Assets**	1	14,920.0	15,375.4	15,247.3	15,769.2	22,435.9
2	**Working Capital**	1	897.1	975.3	1,040.2	1,120.8	1,174.5
3	**Cash Working Capital**	1	(22.5)	(22.4)	(22.5)	(22.5)	(22.5)
4	**Total Rate Base**		15,794.7	16,328.3	16,265.0	16,867.5	23,587.9
	Capitalization						
5	**Short-Term Debt**	2	261.9	259.9	248.9	246.6	274.6
6	**Long-Term Debt**	2	7,271.5	7,566.6	7,558.3	7,849.8	11,047.6
7	**Common Equity**	2	8,087.3	8,412.7	8,398.2	8,717.2	12,216.1
7a	**EB-2020-0290 Settlement Adjustment for Equity at Long-Term Debt Rate**	13	73.9	66.1	59.6	53.9	49.6
8	**Adjustment for Lesser of UNL or ARC**	2	100.1	23.0	0.0	0.0	0.0
9	**Total Capital**		15,794.7	16,328.3	16,265.0	16,867.5	23,587.9
	Cost of Capital						
10	**Short-Term Debt**	3	13.3	12.2	12.0	11.4	13.2
11	**Long-Term Debt**	3	332.9	362.0	370.4	389.9	550.5
12	**Common Equity**	3	736.8	766.4	765.1	794.1	1,112.9
12a	**EB-2020-0290 Settlement Adjustment for Equity at Long-Term Debt Rate**	13	3.4	3.2	2.9	2.7	2.5
13	**Adjustment for Lesser of UNL or ARC**	3	4.7	1.1	0.0	0.0	0.0
14	**Total Cost of Capital**		1,091.0	1,144.9	1,150.5	1,198.1	1,679.0
	Expenses:						
15	**OM&A**	4	1,863.7	1,756.0	1,917.4	1,856.3	2,153.5
16	**Fuel**	5	150.9	221.7	223.6	261.2	306.1
17	**Depreciation & Amortization**	6	663.3	708.5	730.3	779.8	992.6
18	**Property Tax**	7	14.0	14.2	14.5	14.8	15.0
19	**Total Expenses**		2,691.9	2,700.5	2,885.7	2,912.1	3,467.2
	Less:						
	Other Revenues						
20	**Bruce Lease Revenues Net of Direct Costs**	8	(5.2)	11.5	(18.1)	7.3	(17.1)
21	**Ancillary and Other Revenue**	9	6.3	32.7	13.8	13.5	23.6
22	**Total Other Revenues**		1.1	44.2	(4.3)	20.8	6.5
22a	**Concurrent Cost Recovery - Pickering Refurbishment Program**	14	297.6	479.9	667.7	832.0	646.2
23	**Income Tax**	10	(16.6)	(16.6)	(16.6)	(16.6)	(16.6)
24	**Revenue Requirement Before Stretch Factor** (line 14 + line 19 - line 22 + Line 22a + line 23)		4,062.8	4,264.4	4,691.6	4,904.8	5,769.3
25	**Cumulative Nuclear Stretch Dollars**	11	0.0	7.0	14.6	22.5	31.7
26	**Revenue Requirement Net of Stretch Factor** (line 24 - line 25)		4,062.8	4,257.4	4,677.0	4,882.4	5,737.6
27	**Amortization of Variance & Deferral Account Amounts**	12	134.5	134.5	134.5	67.7	67.7
28	**Revenue Requirement Net of Stretch Factor Plus Variance & Deferral Account Amounts** (line 26 + line 27)		4,197.3	4,391.9	4,811.5	4,950.1	5,805.3

Notes:

1 Per Ex. B1-1-1 Table 2.
2 OPG's nuclear facilities portion of totals from Ex. C1-1-1 Tables 1 through 5, (col. (a)). Capitalization is allocated to regulated hydroelectric and OPG's nuclear facilities using rate base financed by capital structure.
3 OPG's nuclear facilities portion of totals from Ex. C1-1-1 Tables 1 through 5, (col. (d)). Cost of Capital is allocated to regulated hydroelectric and OPG's nuclear facilities using rate base financed by capital structure.
4 Per Ex. F2-1-1, Table 1a, line 16.
5 Per Ex. F2-1-1, Table 1a, line 17.
6 Per Ex. F4-1-1, Table 2, line 11.
7 Per Ex. F4-2-1, Table 2, line 4.
8 Per Ex. G2-2-1, Table 1, line 3.
9 Per Ex. G2-1-1, Table 1, line 7.
10 Per Ex. F4-2-1, Table 2, line 1.
11 Per Ex. I1-3-1, Table 2, line 23.
12 Per Ex. H1-2-1 Table 2, col. (h)-(l), line 32.
13 Per Ex. C1-1-1, Tables 1-5, line 5. Represents the portion of rate base financed by common equity that is subject to return at the long-term debt rate until 2036 per the OEB-approved settlement proposal in EB-2020-0290 (Settlement Proposal, p. 23).
14 Per Ex. I1-1-1, Table 7, line 7.

Numbers may not add due to rounding.

Updated: 2026-03-10
EB-2025-0297
Exhibit I1
Tab 1
Schedule 1
Table 2a

Table 2a
Summary of Revenue Requirement - DNNP Facilities ($M)
Years Ending December 31, 2027 to 2031

Line No.	Description	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
	Rate Base						
1	**Net Fixed Assets**	1	0.0	0.0	0.0	1,360.5	6,507.4
2	**Working Capital**	1	0.0	0.0	2.1	11.1	25.0
3	**Cash Working Capital**	1	0.0	0.0	0.0	(0.6)	(2.4)
4	**Total Rate Base**		0.0	0.0	2.1	1,371.1	6,530.0
	Capitalization						
5	**Short-term Debt**	2	0.0	0.0	0.0	0.0	0.0
6	**Long-Term Debt**	2	0.0	0.0	0.0	0.0	0.0
7	**Common Equity**	2	0.0	0.0	2.1	1,371.1	6,530.0
8	**Total Capital**		0.0	0.0	2.1	1,371.1	6,530.0
	Cost of Capital						
9	**Short-term Debt**	3	0.0	0.0	0.0	0.0	0.0
10	**Long-Term Debt**	3	0.0	0.0	0.0	0.0	0.0
11	**Common Equity**	3	0.0	0.0	0.2	124.9	594.9
12	**Total Cost of Capital**		0.0	0.0	0.2	124.9	594.9
	Expenses:						
13	**OM&A**	4	77.0	80.1	70.8	118.7	259.3
14	**Fuel**		9.1	13.8	12.7	18.1	49.8
15	**Depreciation & Amortization**	5	0.0	0.0	0.0	22.6	109.7
16	**Property Tax**	6	0.0	0.0	0.0	0.8	3.7
17	**Total Expenses**		86.1	93.9	83.5	160.2	422.5
	Less:						
	Other Revenues						
18	**Ancillary and Other Revenue**		0.0	0.0	0.0	0.0	0.0
19	**Total Other Revenues**		0.0	0.0	0.0	0.0	0.0
20	**Concurrent Cost Recovery - DNNP**	7	214.9	284.8	321.2	274.2	24.6
21	**Income Tax**	8	0.0	0.0	0.0	0.0	0.0
22	**Revenue Requirement** (line 12 + line 17 - line 19 + line 20 + line 21)		301.0	378.8	404.9	559.3	1,042.0
23	**Amortization of Variance & Deferral Account Amounts**		n/a	n/a	n/a	n/a	n/a
24	**Revenue Requirement Plus Variance & Deferral Account Amounts** (line 22)		301.0	378.8	404.9	559.3	1,042.0

Notes:
1 Per Ex. B1-1-1 Table 3.
2 Per Ex. C1-1-1 Tables 14 through 18 (col. (a)).
3 Per Ex. C1-1-1 Tables 14 through 18 (col. (d)).
4 Per Ex. F2-1-1, Table 1b, line 9.
5 Per Ex. F4-1-1, Table 2, line 12.
6 Per Ex. F4-2-1, Table 2a, line 2.
7 Per Ex. I1-1-1, Table 6, line 7.
8 Per Ex. F4-2-1, Table 2a, line 1.

Table 3a
Summary of Revenue Deficiency - Regulated Hydroelectric
January 1, 2027 to December 31, 2027

Line No.	Description	Note	2027
			(a)
1	**Forecast Production (TWh)**	1	32.5
2	**2026 Payment Amount per EB-2020-0290 ($/MWh)**	2	43.88
3	**Indicated Production Revenue ($M)** (line 1 x line 2)		1,424.4
4	**Revenue Requirement ($M)**	3	**1,668.3**
5	**Revenue Requirement Deficiency ($M)** (line 4 - line 3)		**243.9**

Notes:

1 Ex. E1-1-1, Table 1, line 4.
2 EB-2020-0290 Payment Amounts Order, p. 4.
3 Ex. I1-1-1, Table 1, line 21.

Numbers may not add due to rounding.

Updated: 2026-03-10
EB-2025-0297
Exhibit I1
Tab 1
Schedule 1
Table 3b

Table 3b
Summary of Revenue Deficiency - OPG Nuclear Facilities
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	18.7	26.7	25.1	26.8	28.9
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)		2,081.0	2,971.6	2,790.6	2,986.3	3,222.2
4	**Revenue Requirement Net of Stretch Factor ($M)**	3	**4,062.8**	**4,257.4**	**4,677.0**	**4,882.4**	**5,737.6**
5	**Revenue Requirement Deficiency ($M)** (line 4 - line 3)		**1,981.8**	**1,285.8**	**1,886.3**	**1,896.1**	**2,515.3**

Notes:
1 Ex. E2-1-1, Table 1, line 3.
2 EB-2020-0290 Payment Amounts Order, App. B, Table 1, line 3, col. (e).
3 Ex. I1-1-1, Table 2, line 26.

Numbers may not add due to rounding.

Updated: 2026-03-10
EB-2025-0297
Exhibit I1
Tab 1
Schedule 1
Table 4

Table 4
Determination of 2025 Forecast Return on Equity ($M)

Line No.	Description	Note	2025 Forecast		
			Regulated Hydroelectric	Nuclear	Total
			(a)	(b)	(c)
1	**Forecast Production (TWh)**	1	33.0	36.9	69.9
2	**Payment Amount ($/MWh)**	2	47.18	111.61	n/a
3	**Indicated Production Revenue ($M)** (line 1 x line 2)		1,556.2	4,119.0	5,675.2
	Expenses:				
4	**OM&A**	3	427.9	2,044.5	2,472.4
5	**Fuel and GRC**	4	357.2	255.1	612.3
6	**Depreciation**	5	190.8	540.3	731.0
7	**Property Taxes**	6	1.1	12.2	13.3
8	**Total Expenses**		977.0	2,852.1	3,829.0
9	**Ancillary and Other Revenue**	7	70.9	46.6	117.5
	Cost of Capital Excluding Return on Equity				
10	**Short-term Debt**	8	4.6	7.3	12.0
11	**Long-Term Debt**	9	177.8	281.8	459.6
12	**Adjustment for Lesser of UNL or ARC**	10	0.0	15.5	15.5
13	**Cost of Capital Excluding Return on Equity**		182.4	304.6	487.0
	Deferral and Variance Account Adjustments				
14	**Amortization of Previously Approved Amounts**	11	(99.5)	(214.1)	(313.6)
15	**Transactions Excluding Income Tax Components**	12	46.6	261.3	307.9
16	**Total Deferral and Variance Account Adjustments**		(52.9)	47.2	(5.7)
17	**Revenue Requirement Excluding Income Tax and Return on Equity, Plus Deferral and Variance Account Amounts Excluding Income Tax Components and Concurrent Cost Recovery** (line 8 - line 9 + line 13 - line 16)		1,141.4	3,062.9	4,204.3
18	**2025 Forecast Regulatory Earnings Before Tax** (line 3 - line 17)		414.7	1,056.2	1,470.9
19	**Income Tax**	13	68.8	170.7	239.5
20	**Deferral and Variance Account Transactions - Income Tax Variance Components**	14	14.3	37.8	52.1
21	**Income Tax Benefit of EB-2020-0290 Tax Losses Carried Forward**	15	0.0	(6.0)	(6.0)
22	**Total Income Tax** (line 19 + line 20 + line 21)		83.1	202.5	285.6
23	**2026 Forecast Return on Equity** (line 18 - line 22)		331.6	853.6	1,185.2
24	**ROE as a Percent of Equity Financed by Capital Structure (line 23 / Ex. C1-1-1, Table 7, col. (a), line 5)**				12.46%

Notes:
Refer to Table 4a

Table 4a
Notes to Ex. I1-1-1 Table 4

Notes:

1 Col. (a) from Ex. E1-1-1, Table 1, line 4, col. (j). Col. (b) from Ex. E2-1-1, Table 1, line 3, col. (f).

2 Col. (a) is the sum of the regulated hydroelectric payment amount of $43.88/MWh (EB-2020-0290 PAO, p. 4), regulated hydroelectric payment rider of $0.69/MWh (EB-2020-0290 PAO, App. C, Table 1, col. (k), line 23 and regulated hydroelectric payment rider of $2.61/MWh (EB-2023-0336 Payment Amounts Order, App. A, Table 1, col. (h), line 21.
Col. (b) is the sum of the nuclear payment amount of $102.85/MWh (EB-2020-0290 PAO, p. 5), nuclear payment rider of $5.34/MWh (EB-2020-0290 PAO, App. D, Table 1, col. (k), line 32 and nuclear payment rider of $3.42/MWh (EB-2023-0336 Payment Amounts Order, App. A, Table 2, col. (h), line 31.

3 Col. (a) from Ex. F1-1-1 Table 1, line 6, col. (j). Col. (b) from Ex. F2-1-1 Table 1a, line 16, col. (f).

4 Col. (a) from Ex. F1-1-1 Table 1, line 7, col. (j). Col. (b) from Ex. F2-1-1 Table 1a, line 17, col. (f).

5 Col. (a) from Ex. F1-1-1 Table 1, line 8, col. (j). Col. (b) from Ex. F2-1-1 Table 1a, line 18, col. (f).

6 Col. (a) from Ex. F1-1-1 Table 1, line 10, col. (j). Col. (b) from Ex. F2-1-1 Table 1a, line 20, col. (f).

7 Col. (a) from Ex. G1-1-1, Table 1, col. (j), line 7. Col. (b) from Ex. G2-1-1, Table 1, col. (f), line 7.

8 Col. (c) from Ex. C1-1-1, Table 7, col. (d), line 1.
Col. (a) equal to col. (c) multiplied by ratio of regulated hydroelectric rate base to total regulated rate base. Col. (b) equal to col. (c) multiplied by ratio of nuclear rate base to total regulated rate base.
Regulated hydroelectric ratio determined by dividing Ex. B1-1-1, Table 1, col. (d), line 12 by Ex. C1-1-1, Table 7, line 8, col. (a).
Nuclear ratio determined by dividing Ex. B1-1-1, Table 2, col. (f), line 7 by Ex. C1-1-1, Table 7, line 8, col. (a).

9 Col. (c) from Ex. C1-1-1, Table 7, col. (d): line 2 plus line 3.
Col. (a) equal to col. (c) multiplied by ratio of regulated hydroelectric rate base to total regulated rate base. Col. (b) equal to col. (c) multiplied by ratio of nuclear rate base to total regulated rate base.
Regulated hydroelectric ratio determined by dividing Ex. B1-1-1, Table 1, col. (d), line 12 by Ex. C1-1-1, Table 7, line 8, col. (a).
Nuclear ratio determined by dividing Ex. B1-1-1, Table 2, col. (f), line 7 by Ex. C1-1-1, Table 7, line 8, col. (a).

10 From Ex. C1-1-1, Table 7, col. (d), line 7.

11 Col. (a) is the sum of EB-2020-0290 PAO, App. C, Table 1, line 16, col. (k) and EB-2023-0336 PAO, App. A, Table 1, col. (h), line 16.

12 Forecast 2025 Transactions Excluding Income Tax Components are computed as follows:

Table to Note 12 ($M)

Line No.	Description	Amount ($M)
	Regulated Hydroelectric:	
12a	Total Transactions Impacting Calculation of Regulatory Return on Equity	45.4
12b	Less: Tax Gross-up Components of Transactions in:	13.1
	Income and Other Taxes Variance	
	Capacity Refurbishment Variance Account	
	Niagara Tunnel Project Pre-December 2008 Disallowance Variance	
12c	Less: Tax Variance Components of Transactions in:	(14.3)
	Income and Other Taxes Variance	
	Capacity Refurbishment Variance Account	
	Niagara Tunnel Project Pre-December 2008 Disallowance Variance	
12d	Transactions Excluding Income Tax Components	46.6
	Nuclear :	
12e	Total Transactions Impacting Calculation of Regulatory Return on Equity	217.7
12f	Less: Tax Gross-up Components of Transactions in:	(5.8)
	Nuclear Liability Deferral	
	Nuclear Development Variance Account	
	Capacity Refurbishment Variance Account	
	SR&ED ITC Variance	
	Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral	
	Pension and OPEB Cost Variance - Nuclear - Post 2021 Additions	
12g	Less: Tax Variance Components of Transactions in:	(37.8)
	Nuclear Liability Deferral	
	Nuclear Development Variance Account	
	Capacity Refurbishment Variance Account	
	SR&ED ITC Variance	
	Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral	
	Pension and OPEB Cost Variance - Nuclear - Post 2021 Additions	
12h	Transactions Excluding Income Tax Components	261.3

13 Col. (a) from Ex. F4-2-1 Table 1, line 1, col. (j). Col. (b) from Ex. F4-2-1 Table 2, line 1, col. (f).

14 Regulated Hydroelectric: Sum of Note 12, line 12c. Nuclear: line 12g.

15 EB-2020-0290 PAO, Table 22, col. (d) (line 2 + line 3) x 25%

Table 5
Determination of 2026 Forecast Return on Equity ($M)

Line No.	Description	Note	2026 Forecast		
			Regulated Hydroelectric	Nuclear	Total
			(a)	(b)	(c)
1	**Forecast Production (TWh)**	1	32.8	32.5	65.2
2	**Payment Amount ($/MWh)**	2	47.18	123.76	n/a
3	**Indicated Production Revenue ($M)** (line 1 x line 2)		1,545.8	4,016.8	5,562.6
	Expenses:				
4	**OM&A**	3	439.4	2,118.2	2,557.6
5	**Fuel and GRC**	4	354.3	239.2	593.5
6	**Depreciation**	5	194.8	617.7	812.4
7	**Property Taxes**	6	1.0	13.5	14.5
8	**Total Expenses**		989.5	2,988.6	3,978.0
9	**Ancillary and Other Revenue**	7	76.0	39.4	115.4
	Cost of Capital Excluding Return on Equity				
10	**Short-term Debt**	8	5.9	10.2	16.1
11	**Long-Term Debt**	9	200.7	346.3	547.1
12	**Adjustment for Lesser of UNL or ARC**	10	0.0	9.6	9.6
13	**Cost of Capital Excluding Return on Equity**		206.6	366.1	572.7
	Deferral and Variance Account Adjustments				
14	**Amortization of Previously Approved Amounts**	11	(99.5)	(214.1)	(313.6)
15	**Transactions Excluding Income Tax Components and Concurrent Cost Recovery**	12	84.8	(308.4)	(223.6)
16	**Total Deferral and Variance Account Adjustments**		(14.7)	(522.5)	(537.2)
17	**Revenue Requirement Excluding Income Tax and Return on Equity, Plus Deferral and Variance Account Amounts Excluding Income Tax Components and Concurrent Cost Recovery** (line 8 - line 9 + line 13 - line 16)		1,134.8	3,837.7	4,972.6
18	**2026 Forecast Regulatory Earnings Before Tax** (line 3 - line 17)		411.0	179.0	590.0
19	**Income Tax**	13	(3.3)	(36.9)	(40.2)
20	**Deferral and Variance Account Transactions - Income Tax Variance Components**	14	37.1	27.2	64.3
21	**Income Tax Benefit of EB-2020-0290 Tax Losses Carried Forward**	15	0.0	(24.7)	(24.7)
22	**Total Income Tax** (line 19 + line 20 + line 21)		33.8	(34.4)	(0.5)
23	**2026 Forecast Return on Equity** (line 18 - line 22)		377.1	213.4	590.5
24	**ROE as a Percent of Equity Financed by Capital Structure (line 23 / Ex. C1-1-1, Table 6, col. (a), line 5)**				5.64%

Notes:
Refer to Table 5a

Table 5a
Notes to Ex. I1-1-1 Table 5

Notes:

1 Col. (a) from Ex. E1-1-1, Table 1, line 4, col. (k). Col. (b) from Ex. E2-1-1, Table 1, line 5, col. (g).

2 Col. (a) is the sum of the regulated hydroelectric payment amount of $43.88/MWh (EB-2020-0290 PAO, p. 4), regulated hydroelectric payment rider of $0.69/MWh (EB-2020-0290 PAO, App. C, Table 1, col. (l), line 23 and regulated hydroelectric payment rider of $2.61/MWh (EB-2023-0336 Payment Amounts Order, App. A, Table 1, col. (i), line 21.
Col. (b) is the sum of the nuclear payment amount of $111.33/MWh (EB-2020-0290 PAO, p. 5), nuclear payment rider of $7.58/MWh (EB-2020-0290 PAO, App. D, Table 1, col. (l), line 32 and nuclear payment rider of $4.85/MWh (EB-2023-0336 Payment Amounts Order, App. A, Table 2, col. (i), line 31.

3 Col. (a) from Ex. F1-1-1 Table 1, line 6, col. (k). Col. (b) from Ex. F2-1-1 Table 1a, line 16, col. (g).

4 Col. (a) from Ex. F1-1-1 Table 1, line 7, col. (k). Col. (b) from Ex. F2-1-1 Table 1a, line 17, col. (g).

5 Col. (a) from Ex. F1-1-1 Table 1, line 8, col. (k). Col. (b) from Ex. F2-1-1 Table 1a, line 18, col. (g).

6 Col. (a) from Ex. F1-1-1 Table 1, line 10, col. (k). Col. (b) from Ex. F2-1-1 Table 1a, line 20, col. (g).

7 Col. (a) from Ex. G1-1-1, Table 1, col. (k), line 7. Col. (b) from Ex. G2-1-1, Table 1, col. (g), line 7.

8 Col. (c) from Ex. C1-1-1, Table 6, col. (d), line 1.
Col. (a) equal to col. (c) multiplied by ratio of regulated hydroelectric rate base to total regulated rate base. Col. (b) equal to col. (c) multiplied by ratio of nuclear rate base to total regulated rate base.
Regulated hydroelectric ratio determined by dividing Ex. B1-1-1, Table 1, col. (e), line 12 by Ex. C1-1-1, Table 6, line 8, col. (a). Nuclear ratio determined by dividing Ex. B1-1-1, Table 2, col. (g), line 7) by Ex. C1-1-1, Table 6, line 8, col. (a).

9 Col. (c) from Ex. C1-1-1, Table 6, col. (d): line 2 plus line 3.
Col. (a) equal to col. (c) multiplied by ratio of regulated hydroelectric rate base to total regulated rate base. Col. (b) equal to col. (c) multiplied by ratio of nuclear rate base to total regulated rate base.
Regulated hydroelectric ratio determined by dividing Ex. B1-1-1, Table 1, col. (e), line 12 by Ex. C1-1-1, Table 6, line 8, col. (a). Nuclear ratio determined by dividing Ex. B1-1-1, Table 2, col. (g), line 7) by Ex. C1-1-1, Table 6, line 8, col. (a).

10 From Ex. C1-1-1, Table 6, col. (d), line 7.

11 Col. (a) is the sum of EB-2020-0290 PAO, App. C, Table 1, line 16, col. (l) and EB-2023-0336 PAO, App. A, Table 1, col. (i), line 16.
Col. (b) is the sum of EB-2020-0290 PAO, App. D, Table 1, col. (l), line 25 and EB-2023-0336 PAO, App. A, Table 2, col. (i), line 26.

12 Forecast 2026 Transactions Excluding Income Tax Components are computed as follows:

Table to Note 12 ($M)

Line No.	Description	Amount ($M)
	Regulated Hydroelectric:	
12a	Total Transactions Impacting Calculation of Regulatory Return on Equity	57.8
12b	Less: Tax Gross-up Components of Transactions in:	10.2
	Income and Other Taxes Variance	
	Capacity Refurbishment Variance Account	
	Niagara Tunnel Project Pre-December 2008 Disallowance Variance	
12c	Less: Tax Variance Components of Transactions in:	(37.1)
	Income and Other Taxes Variance - Hydroelectric	
	Capacity Refurbishment Variance Account - Hydroelectric	
	Niagara Tunnel Project Pre-December 2008 Disallowance Variance	
12d	Transactions Excluding Income Tax Components	84.8
	Nuclear :	
12e	Total Transactions Impacting Calculation of Regulatory Return on Equity	(289.0)
12f	Less: Tax Gross-up Components of Transactions in:	46.6
	Nuclear Liability Deferral	
	Nuclear Development Variance Account	
	Capacity Refurbishment Variance Account	
	SR&ED ITC Variance	
	Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral	
	Pension and OPEB Cost Variance - Nuclear - Post 2021 Additions	
	Pickering B Variance	
12g	Less: Tax Variance Components of Transactions in:	(27.2)
	Nuclear Liability Deferral	
	Nuclear Development Variance Account	
	Capacity Refurbishment Variance Account	
	SR&ED ITC Variance	
	Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral	
	Pension and OPEB Cost Variance - Nuclear - Post 2021 Additions	
12h	Transactions Excluding Income Tax Components	(308.4)

13 Col. (a) from Ex. F4-2-1 Table 1, line 1, col. (k). Col. (b) from Ex. F4-2-1 Table 2, line 1, col. (g).

14 Regulated Hydroelectric: Note 12, line 12c. Nuclear: Note 12, line 12g.

15 EB-2020-0290 PAO, Table 22, col. (e) (line 2 + line 3) x 25%

Numbers may not add due to rounding.

Table 6
Calculation of Forecast Concurrent Cost Recovery - Darlington New Nuclear Program
January 1, 2026 to December 31, 2031 ($M)

Line No.	Description	Note	2026	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)	(f)
1	**Opening Balance**	1	2,250.5	3,884.0	5,504.7	6,401.4	6,706.1	494.3
2	**Capital Expenditures**	1	1,633.5	1,620.7	896.7	304.7	373.2	0.0
3	**In-Service**	2	0.0	0.0	0.0	0.0	6,584.9	0.0
4	**Closing Balance** (line 1 + line 2 - line 3)		3,884.0	5,504.7	6,401.4	6,706.1	494.3	494.3
5	**Capital Costs for Purposes of Calculating CCR** ((line 1 + line 4) / 2	2	3,067.2	4,694.3	5,953.0	6,553.7	5,520.8	494.3
6	**OPG Cost of Long-Term Borrowing**	3	3.65%	4.58%	4.78%	4.90%	4.97%	4.98%
7	**Concurrent Cost Recovery** (line 5 x line 6)	4	112.0	214.9	284.8	321.2	274.2	24.6

Notes

1 Per Ex. D2-4-8, Table 1, line 3. Opening balance in col. (a) per Ex. D2-4-8, Table 1, sum of line 3, col. (a) through col. (f).

2 In-service additions exceeding $50M are reflected in the month of the addition instead of using mid-year average (see Ex. B1-1-1, p. 9). 2030 in-service is weighted 2.5/12 months based on in-service date of October 17, 2030. Per Ex. B3-3-1, Table 2a, Note 1.

3 Per Ex. C1-1-1, Tables 1-5: line 2, col. (c).

4 Over the 2027-2031 period, concurrent cost recovery amounts of $1,004.9M relate to Unit 1 and $114.9M relate to Units 2 through 4.

Table 7
Calculation of Forecast Concurrent Cost Recovery - Pickering Refurbishment Program
January 1, 2026 to December 31, 2031 ($M)

Line No.	Description	Note	2026	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)	(f)
1	**Opening Balance**	1	1,887.0	4,773.3	8,225.9	11,833.5	15,411.7	18,093.2
2	**Capital Expenditures**	1	3,045.6	3,473.2	3,607.6	3,578.3	2,681.4	1,860.5
3	**In-Service**	2	159.3	20.6	0.0	0.0	0.0	9,688.0
4	**Closing Balance** (line 1 + line 2 - line 3)		4,773.3	8,225.9	11,833.5	15,411.7	18,093.2	10,265.7
5	**Capital Costs for Purposes of Calculating CCR** ((line 1 + line 4) / 2	2	3,303.6	6,499.6	10,029.7	13,622.6	16,752.5	12,968.4
6	**OPG Cost of Long-Term Borrowing**	3	3.65%	4.58%	4.78%	4.90%	4.97%	4.98%
7	**Concurrent Cost Recovery**		120.6	297.6	479.9	667.7	832.0	646.2

Notes

1 Per Ex. D2-3-8, Table 1, line 4. Opening balance in col. (a) per Ex. D2-3-10, Table 1, sum of line 4: col. (a) through col. (f).

2 In-service additions exceeding $50M are reflected in the month of the addition instead of using mid-year average (see Ex. B1-1-1, p. 9). The 2031 in-service is weighted 7.5/12 based on in-service date of May 15, 2031. See Ex. B3-3-1 Table 2a, Note 1 for further details.

3 Per Ex. C1-1-1, Tables 1-5: line 2, col. (c).

CONSUMER IMPACT

1.0 PURPOSE

This evidence describes the estimated impact of the proposed payment amounts and payment rider changes on a residential electricity consumer consuming at the 750 kWh per month level (the "typical consumer").

2.0 CONSUMER IMPACT

The Application has calculated the weighted average of regulated hydroelectric and shaped nuclear payment amounts and payment amount riders, weighted by forecast production to be $110.03/MWh for 2027, $118.62/MWh for 2028, $123.42/MWh for 2029, $125.83/MWh for 2030, and $141.02/MWh for 2031.[1,2]

The annual change in weighted average payment amounts and riders is applied to the typical consumer's usage of OPG's regulated hydroelectric and regulated nuclear facilities and the DNNP facilities, after adjusting for line losses and accounting for these facilities' share of the province's generation. Typical consumer data is based on the average electricity distributor bill information provided on the OEB's website at:
https://www.oeb.ca/consumer-protection/energy-contracts/bill-calculator

The estimated monthly consumer bill impacts associated with the revenue requirements and clearance of deferral and variance accounts are reflected in Chart 1, as calculated in Ex. I1-1-2, Table 1.

Chart 1 - Annualized Residential Consumer Impact

	2027	2028	2029	2030	2031
Typical Bill ($/Month)	$142.10	$142.10	$142.10	$142.10	$142.10
Typical Bill Impact ($/Month)	$7.93	$2.44	$1.33	$0.69	$4.62
Typical Bill Impact (%)	5.6%	1.7%	0.9%	0.5%	3.3%

[1] Includes shaped 2027-2031 nuclear payment amounts applicable to OPG's nuclear facilities and the DNNP facilities, as illustrated in Ex. I1-3-1, Table 1. An illustrative regulated hydroelectric payment amount is used for the 2028-2031 period, using the proposed ratemaking methodology, as per Ex. I1-2-1.
[2] Determination of weighted average payment amounts per Ex. I-1-2, Table 2.

Numbers may not add due to rounding.

Updated: 2026-03-10
EB-2025-0297
Exhibit I1
Tab 1
Schedule 2
Table 1

Table 1
Annualized Residential Consumer Impact
EB-2020-0290/EB-2023-0336 to EB-2025-0297

Line No.	Description	2027 Amount	2028 Amount	2029 Amount	2030 Amount	2031 Amount	2027-2031 Average
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Typical Consumption[1] (kWh/Month)**	787	787	787	787	787	787
2	**Typical Usage of OPG and DNNP LP Generation (kWh/Month)** (line 1 x line 11)	246	284	276	287	304	280
3	**Typical Bill[1] ($/Month)**	142.10	142.10	142.10	142.10	142.10	142.10
4	**Typical Bill Impact ($/Month)** (line 2 x line 8 / 1000)	7.93	2.44	1.33	0.69	4.62	3.40
5	**Typical Bill Impact (%)** (line 4 / line 3)	5.6%	1.7%	0.9%	0.5%	3.3%	2.4%
6	Prior Year weighted average rate with proposed payment amounts and riders[2,3] ($/MWh)	77.75	110.03	118.62	123.42	125.83	
7	Current Year weighted average rate with proposed payment amounts and riders[2,3] ($/MWh)	110.03	118.62	123.42	125.83	141.02	
8	Change in weighted average rate ($/MWh) (line 7 - line 6)	32.28	8.59	4.80	2.41	15.19	
9	Total Regulated Production[4] (TWh)	51.2	59.2	57.5	59.8	63.3	
10	Forecast of 2027 Provincial Demand[5] (TWh)	163.9	163.9	163.9	163.9	163.9	
11	OPG and DNNP LP Proportion of Consumer Usage (line 9 / line 10)	31.2%	36.1%	35.1%	36.5%	38.6%	

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 From Ex. I1-1-2 Table 2, line 9.

3 Per Ex. I1-3-1 Table 1.

4 From Ex. I1-1-2 Table 2, line 3 + line 6.

5 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.

Updated: 2026-03-10
EB-2025-0297
Exhibit I1
Tab 1
Schedule 2
Table 2

Table 2
Computation of Percent 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	Note 2	Note 2	Note 2	Note 2	Note 2
1	**Hydroelectric Payment Amount (HPA) ($/MWh)**	3	43.88	51.39	54.97	59.20	62.02	64.21
2	**Hydroelectric Payment Rider (HPR) ($/MWh)**	4	3.30	(1.17)	(1.17)	(1.17)	0.00	0.00
3	**Hydroelectric Production Forecast (HPF) TWh**	5	33.0	32.5	32.5	32.5	32.5	32.5
4	**Nuclear Payment Amount (NPA) ($/MWh)**	6	111.33	206.70	192.42	202.74	199.16	219.60
5	**Nuclear Payment Rider (NPR) ($/MWh)**	7	12.43	7.19	5.04	5.36	2.48	2.19
6	**Nuclear Production Forecast (NPF) TWh**	8	21.9	18.7	26.7	25.1	27.3	30.9
7	**Regulated Hydroelectric Portion of Weighted Average Payment Amount ($/MWh)** (HPA + HPR) x HPF / (NPF+HPF)		28.35	31.87	29.52	32.75	33.68	32.91
8	**Nuclear Portion of Weighted Average Payment Amount ($/MWh)** (NPA + NPR) x NPF / (NPF+HPF)		49.41	78.16	89.10	90.67	92.15	108.11
9	**Weighted Average Payment Amount ($/MWh)** (((NPA + NPR) x NPF) + (HPA + HPR) x HPF) / (NPF + HPF)		77.75	110.03	118.62	123.42	125.83	141.02
10	**Percentage Change in Weighted Average Payment Amount (Year over Year)**			41.5%	7.8%	4.0%	2.0%	12.1%

Notes:

1 Payment amounts, riders and production forecasts approved in EB-2020-0290 Payment Amounts Order plus payment riders approved in EB-2023-0336.
2 Payment amounts and payment riders proposed in this application.
3 Per Ex. I1-2-1, Table 1. Cols. (c) to (f) are illustrative only.
4 Per Ex. H1-2-1, Table 1, line 21.
5 For 2027: Per Ex. E1-1-1, Table 1, col. (l), line 4.
6 Per Ex. I1-3-1, Table 1, line 9. Shaped payment amounts are based on the combined revenue requirements of the OPG nuclear facilities and the DNNP facilities.
7 Per Ex. H1-2-1, Table 2, line 34.
8 For 2027-2031: Per Ex. E2-1-1, Table 1, line 5. Includes production forecasts of the OPG nuclear facilities and DNNP facilities.

NUCLEAR PAYMENT AMOUNTS

1.0 PURPOSE

This evidence presents the blended payment amounts requested by OPG and DNNP LP for OPG's nuclear facilities and the DNNP facilities for 2027, 2028, 2029, 2030, and 2031.

2.0 PAYMENT AMOUNT

The Application is seeking approval of the following shaped payment amounts:

- $206.70/MWh for the nuclear facilities effective January 1, 2027;
- $192.42/MWh for the nuclear facilities effective January 1, 2028;
- $202.74/MWh for the nuclear facilities effective January 1, 2029;
- $199.16/MWh for the nuclear facilities effective January 1, 2030; and
- $219.60/MWh for the nuclear facilities effective January 1, 2031.

The basis for the requested payment amounts is presented in Ex. I1-3-1, Table 1.

Numbers may not add due to rounding.

Updated: 2026-03-10
EB-2025-0297
Exhibit I1
Tab 3
Schedule 1
Table 1

Table 1
Payment Amounts - Combined 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 - OPG Nuclear Facilities	1	4,062.8	4,257.4	4,677.0	4,882.4	5,737.6
2	Revenue Requirement - DNNP Facilities	2	301.0	378.8	404.9	559.3	1,042.0
3	**Combined Nuclear Revenue Requirement Net of Stretch Factor ($M)**		4,363.8	4,636.2	5,081.9	5,441.7	6,779.6
4	**OPG Nuclear Revenue Requirement Shaping Adjustment ($M)**	3	(500.0)	500.0	0.0	0.0	0.0
5	**Combined Nuclear Revenue Requirement After Shaping Adjustment ($M)** (line 3 + line 4)		3,863.8	5,136.2	5,081.9	5,441.7	6,779.6
6	Production Forecast - OPG Nuclear Facilities	4	18.7	26.7	25.1	26.8	28.9
7	Production Forecast - DNNP Facilities	5	0.0	0.0	0.0	0.5	1.9
8	**Combined Nuclear Forecast Production (TWh)**		18.7	26.7	25.1	27.3	30.9
9	**Blended Nuclear Payment Amount ($/MWh)** (line 5 / line 8)	6	206.70	192.42	202.74	199.16	219.60

Notes:

1 From Ex. I1-1-1 Table 2, line 26.
2 From Ex. I1-1-1, Table 2a, line 22.
3 The Application's payment amount shaping proposal is discussed in Ex. I1-3-2.
4 From Ex. E2-1-1 Table 1, line 3.
5 From Ex. E2-1-1 Table 1, line 4.
6 From Ex. I1-1-2 Table 2, line 4.

Numbers may not add due to rounding.

Updated: 2026-03-10
EB-2025-0297
Exhibit I1
Tab 3
Schedule 1
Table 2

Table 2
Calculation of OPG Nuclear Facilities Stretch Factor
January 1, 2027 to December 31, 2031 ($M)

Line No.	Description	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
	Stretch Factor Applicable Nuclear OM&A Expenses						
	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	214.6	222.4
5	**Darlington Total OM&A Expenses Subject to Stretch Factor** (line 1 through line 4)			1,082.5	1,232.9	1,138.7	1,158.2
	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		-	-	-	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** (line 6 through line 10)			524.7	559.7	589.0	864.4
12	Asset Service Fees			73.9	89.5	99.0	99.4
	Stretch Factor Applicable Nuclear Capital Related Revenue Requirement						
	Darlington and Operations & Project Support Capital Related Revenue Requirement						
13	Cost of Capital	10		318.8	337.9	391.3	457.1
14	Depreciation Expense	10		256.0	277.6	320.0	372.9
15	Income Tax Expense on Cost of Capital and Depreciation Expense	10		156.6	167.5	193.3	225.4
16	**Total Darlington and Operations & Project Support Capital Related Revenue Requirement Subject to Stretch Factor** (line 13 + line 14 + line 15)			731.4	783.1	904.6	1,055.4
	Pickering Capital Related Revenue Requirement						
17	Cost of Capital	11		24.1	29.3	45.0	59.4
18	Depreciation Expense	11		26.6	26.8	34.4	41.6
19	Income Tax Expense on Cost of Capital and Depreciation Expense	11		14.3	15.5	21.5	27.0
20	**Total Pickering Capital Related Revenue Requirement Subject to Stretch Factor** (line 18 + line 19 + line 20)			65.0	71.6	100.9	128.1
21	Income Tax Expense- Capital Cost Allowance	13		(159.4)	(193.6)	(207.4)	(226.2)
22	**Total Revenue Requirement Amount Subject to Stretch Factor** (line 5 + line 11 + line 12 + line 16 + line 20 + line 21)			2,318.1	2,543.1	2,624.8	3,079.4
23	OPG Nuclear Facilities Stretch Factor	12		0.30%	0.30%	0.30%	0.30%
24	**OPG Nuclear Facilities Stretch Factor Revenue Requirement Adjustment ($M)** (line 22_t * line 23_t) + line 24_{t-1}	14		**7.0**	**14.6**	**22.5**	**31.7**

Notes:
Refer to Table 2a

Table 2a
Notes to Ex. I1-3-1 Table 2

Notes:

1 Col. (b) from Ex. F2-2-1, Table 11, line 13, col.(a); Col.(c) from Ex. F2-2-1, Table 12, line 13, col.(a); Col.(d) from Ex. F2-2-1, Table 13, line 13, col.(a); Col.(e) from Ex. F2-2-1, Table 14, line 13, col.(a).

2 From Ex. F2-3-1, Table 1: line 1 + line 3a + line 3d.

3 From Ex. F2-4-1,Table 1, line 3.

4 From Ex. F3-1-1, Table 3a, line 10.

5 Col. (b) from Ex. F2-2-1, Table 11, line 13, col.(b). Col.(c) from Ex. F2-2-1, Table 12, line 13, col.(b). Col.(d) from Ex. F2-2-1, Table 13, line 13, col.(b). Col.(e) from Ex. F2-2-1, Table 14, line 13, col.(b).

6 From Ex. F2-3-1, Table 1: line 2 + line 3b + line 3e.

7 From Ex. F2-4-1_Table 1, line 6.

8 From Ex. F2-4-1, Table 1, line 14.

9 From Ex. F3-1-1, Table 3b, line 10.

10 Cost of capital component of Darlington and Operations & Project Support Capital Related Revenue Requirement for 2028-2031 is calculated as follows:

		2027	2028	2029	2030	2031
10a	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: Ex. B3-3-1, Table 2, col. (f), lines 13 and 20 less Ex. B3-4-1 Table 2, col. (f), lines 37 and 44. Less line 10b. 2029: Ex. B3-3-1, Table 2, col. (f), lines 25 and 32 less Ex. B3-4-1 Table 2, col. (f), lines 49 and 56. Less line 10b. 2030: Ex. B3-3-1, Table 2, col. (f), lines 37 and 44 less Ex. B3-4-1 Table 2, col. (f), lines 61 and 68. Less line 10b. 2031: Ex. B3-3-1, Table 2, col. (f), lines 49 and 56 less Ex. B3-4-1 Table 2, col. (f), lines 73 and 80. Less line 10b.		4,447.4	4,687.9	5,426.9	6,347.4
10b	Darlington GS and Operations & Project Support Net Fixed Asset Rate Base for which common equity is subject to return at long-term debt rate.		127.1	114.6	103.7	95.5
10c	Return on Equity at ROE Rate (line 10a x 52% x 9.11%)		210.7	222.1	257.1	300.7
10d	Return on Equity at Long-Term Debt Rate (line 10b x 52% x Ex. C1-1-1, Tables 1-4, col. (c), line 3)		3.2	2.9	2.7	2.5
10e	Cost of Debt ((line 10a + line 10b) x 48% x Ex. C1-1-1, Tables 1-4, col. (c), line 4)		105.0	112.9	131.6	154.0
10f	Total Cost of Capital (lines 10c + 10d + 10e)		**318.8**	**337.9**	**391.3**	**457.1**
10g	Depreciation Expense (Ex. B3-4-1, Table 2, col. (b) plus col. (c): lines 37 & 44; lines 49 & 56; lines 61 & 68; lines 73 & 80)		256.0	277.6	320.0	372.9
10h	Net Regulatory Taxable Income Increase / (Decrease) (line 10c + line 10d + line 10g)		469.8	502.6	579.8	676.1
10i	Income Tax Expense (line 10h x 25% / (1 - 25%))		**156.6**	**167.5**	**193.3**	**225.4**

11 Cost of capital component of Pickering Capital Related Revenue Requirement for 2028-2031 is calculated as follows:

11a	Pickering GS 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: Ex. B3-3-1, Table 2, col. (f), line 17 less Ex. B3-4-1 Table 2, col. (f), line 41. Less line 11b. 2029: Ex. B3-3-1, Table 2, col. (f), line 29 less Ex. B3-4-1 Table 2, col. (f), line 53. Less line 11b. 2030: Ex. B3-3-1, Table 2, col. (f), line 41 less Ex. B3-4-1 Table 2, col. (f), line 65. Less line 11b. 2031: Ex. B3-3-1, Table 2, col. (f), line 53 less Ex. B3-4-1 Table 2, col. (f), line 77. Less line 11b.		343.2	412.9	632.4	833.5
11b	Pickering GS Net Fixed Asset Rate Base for which Common Equity is Subject to Return at Long-Term Debt Rate.		-	-	-	-
11c	Return on Equity at ROE Rate (line 10a x 52% x 9.11%)		16.3	19.6	30.0	39.5
11d	Return on Equity at Long-Term Debt Rate (line 10b x 52% x Ex. C1-1-1, Tables 1-4, col. (c), line 3)		-	-	-	-
11e	Cost of Debt ((line 10a + line 10b) x 48% x Ex. C1-1-1, Tables 1-4, col. (c), line 4)		7.9	9.7	15.0	19.9
11f	Total Cost of Capital (lines 10c + 10d + 10e)		**24.1**	**29.3**	**45.0**	**59.4**
11g	Depreciation Expense (Ex. B3-4-1, Table 2, col. (b) plus col. (c): lines 41, 53, 65, 77)		**26.6**	**26.8**	**34.4**	**41.6**
11h	Net Regulatory Taxable Income Increase / (Decrease) (line 10c + line 10d + line 10g)		42.8	46.4	64.4	81.1
11i	Income Tax Expense (line 10h x 25% / (1 - 25%))		**14.3**	**15.5**	**21.5**	**27.0**

12 Per Ex. A1-3-2, Section 3.2.1.

13 Income tax component of CCA-related revenue requirement for 2028-2031 is calculated as follows:

		2027	2028	2029	2030	2031
(a)	Capital Cost Allowance (Ex. F4-2-1 Table 3d, line 15 less DRP and PRP amounts per Ex. F4-2-1 Table 3f Note 3)		(478.2)	(580.9)	(622.3)	(678.5)
(b)	Income Tax Expense (line (a) x 25% / (1 - 25%))		**(159.4)**	**(193.6)**	**(207.4)**	**(226.2)**

14 The nuclear stretch factor revenue requirement adjustment can be further broken down as follows:

		2027	2028	2029	2030	2031
14a	OM&A Stretch Factor Adjustment ((line 5 + line 11 + line 12) * line 23)		5.0	10.7	16.2	22.5
14b	Capital-related Stretch Factor Adjustment (line 16 + line 20 + line 21) * line 23)		1.9	3.9	6.3	9.2
14c	Total Nuclear Stretch Factor Revenue Requirement Adjustment (line 14a + line 14b)		7.0	14.6	22.5	31.7

PAYMENT AMOUNT SHAPING

1.0 PURPOSE

This evidence sets out the Application's proposal for shaping payment amounts during the 2027-2031 IR term.

2.0 OVERVIEW

OPG proposes a payment amount shaping approach intended to help manage the 2027 ratepayer impacts, while balancing the company's financing needs over the 2027-2031 period. To enable payment amount shaping, the Application proposes to establish a Payment Amount Shaping Deferral Account ("PASDA") to record the difference between: (1) OPG's total annual nuclear revenue requirement approved by the OEB; and (2) the portion of that revenue requirement in (1) that is used in connection with setting the nuclear payment amounts in each year.[1]

For the 2027-2031 IR term, OPG proposes to defer $500M of its proposed 2027 nuclear revenue requirement to 2028, with resulting PASDA entries[2] of $500M in 2027, $(500)M in 2028, $0M in 2029, $0M in 2030, and $0M in 2031 and resulting weighted average payment amounts ("WAPA")[3] of $110.03/MWh in 2027, $118.62/MWh in 2028, $123.42/MWh in 2029, $125.83/MWh in 2030, and $141.02/MWh in 2031. This proposal is consistent with customer feedback received during OPG's customer engagement (See Attachment 1).

The estimated average residential customer bill impact of the weighted average payment amounts proposed in this Application inclusive of the payment amount shaping proposal is 2.4% annually or approximately $3.40 on a typical monthly residential customer bill each year.[4]

[1] Ex. H1-1-1 Section 7.4.
[2] Ex. I1-3-1 Table 1, line 2.
[3] Ex. I1-1-2 Table 2, line 9.
[4] Ex. I1-1-2 Table 1, lines 4 and 5, col. (f).

Section 3.0 describes the calculation of the WAPA and the resulting WAPA and bill impacts in this Application, before rate shaping. Section 4.0 sets out the Application's rate shaping proposal and OPG's customer engagement efforts.

3.0 WEIGHTED AVERAGE PAYMENT AMOUNTS AND BILL IMPACTS

3.1 Calculation of the Weighted Average Payment Amount

OPG determines WAPA for a year through the following formula:

$$\frac{((BNPA + BNPR) \times TNPF) + ((HPA + HPR) \times HPF)}{(TNPF + HPF)}$$

BNPA (**Blended Nuclear Payment Amount**) is the pre-shaping blended payment amount for the year in respect of the OPG nuclear facilities and the DNNP facilities[5]

BNPR (**Blended Nuclear Payment Riders**) represents any payment amount riders for the year in respect of the recovery (or repayment) of balances recorded in the deferral accounts and variance accounts established for the OPG nuclear facilities and the DNNP facilities

TNPF (**Total Nuclear Production Forecast**) is the sum of the production forecasts for the year for the OPG nuclear facilities and the DNNP nuclear facilities

HPA (**Hydroelectric Payment Amount**) is the payment amount for the year in respect of OPG's prescribed hydroelectric facilities

HPR (**Hydroelectric Payment Riders**) represents any payment amount riders for the year in respect of the recovery (or repayment) of balances

[5] Further description of the blended payment amount can be found in Ex. A1-3-2, Section 3.1.

recorded in the deferral accounts and variance accounts established for OPG's prescribed hydroelectric facilities

HPF (**Hydroelectric Production Forecast**) is the production forecast for OPG's prescribed hydroelectric facilities for the year

3.2 WAPA and Bill Impacts without Shaping

This section lays out the WAPA and estimated customer bill impacts resulting from the revenue requirements and production forecasts proposed in this Application.

Blended Nuclear Payment Amount ("BNPA"):

The nuclear revenue requirements for OPG's nuclear facilities and the DNNP facilities proposed in this application are summarized in Chart 1 below and the production forecasts for OPG's nuclear facilities and the DNNP facilities are summarized in Chart 2 below.

Chart 1 - Nuclear Revenue Requirements Before Shaping[6]

	2027	2028	2029	2030	2031
OPG Nuclear Revenue Requirement Net of Stretch Factor ($M)	4,062.8	4,257.4	4,677.0	4,882.4	5,737.6
DNNP Revenue Requirement ($M)	301.0	378.8	404.9	559.3	1,042.0

Chart 2 - Nuclear Production Forecasts[7]

	2027	2028	2029	2030	2031
OPG Nuclear Production Forecast (TWh)	18.7	26.7	25.1	26.8	28.9
DNNP Production Forecast (TWh)	0.0	0.0	0.0	0.5	1.9

Based on the information provided in Chart 1 and Chart 2, the proposed pre-shaping BNPA amounts are $233.45/MWh in 2027, $173.69/MWh in 2028, $202.74/MWh in 2029, $199.16/MWh in 2030, and $219.60/MWh in 2031.

[6] Ex. I1-3-1 Table 1, lines 1 and 2.
[7] Ex. E2-1-1 Table 1, line 3 and line 4.

Hydroelectric Payment Amount ("HPA"): Per Ex. I1-2-1 Table 1, line 11, the proposed HPA is $51.39/MWh in 2027. Final payment amounts beyond 2027 will be determined annually using the approved ratemaking methodology, proposed in Ex. A1-3-2. The illustrative hydroelectric payment amounts calculated using the proposed methodology and included in Ex. I1-2-1 Table 1 are $54.97/MWh in 2028, $59.20/MWh in 2029, $62.02/MWh in 2030, and $64.21/MWh in 2031. These illustrative HPAs are based on the proposed Gross Revenue Charge Factor, Custom Capital Factor, Stretch Factor, and the most recently published I Factor, to be updated annually.

Blended Nuclear Payment Rider ("BNPR") and Hydroelectric Payment Rider ("HPR"): Per Ex. H1-2-1, OPG is requesting recovery or repayment of certain audited December 31, 2024 balances in the deferral and variance accounts, adjusted for 2025-2026 amortization amounts approved in EB-2020-0290 and EB-2023-0336, through nuclear payment riders and hydroelectric payment riders over the January 1, 2027 to December 31, 2031 period. The proposed blended nuclear payment rider[8] is $7.19/MWh in 2027, $5.04/MWh in 2028, $5.36/MWh in 2029, $2.48/MWh in 2030, and $2.19/MWh in 2031. The proposed hydroelectric payment rider[9] is $(1.17)/MWh in 2027, $(1.17)/MWh in 2028, $(1.17)/MWh in 2029, $0.00/MWh in 2030, and $0.00/MWh in 2031.

Determination of WAPA: Chart 3 lays out the calculation of WAPA absent payment amount shaping, based on the proposals in this Application.

[8] Ex. H1-2-1, Table 2, Line 34
[9] Ex. H1-2-1, Table 1, Line 21.

Chart 3 – Determination of WAPA

Line No.	Description	2027	2028	2029	2030	2031
1.	**BNPA ($/MWh)**	$233.45/MWh	$173.69/MWh	$202.74/MWh	$199.16/MWh	$219.60/MWh
2.	**BNPR ($/MWh)**	$7.19/MWh	$5.04/MWh	$5.36/MWh	$2.48/MWh	$2.19/MWh
3.	**TNPF (TWh)**	18.7TWh	26.7TWh	25.1TWh	27.3TWh	30.9TWh
4.	**HPA ($/MWh)**[10]	$51.39/MWh	$54.97/MWh	$59.20/MWh	$62.02/MWh	$64.21/MWh
5.	**HPR ($/MWh)**	$(1.17)/MWh	$(1.17)/MWh	$(1.17)/MWh	$0.00/MWh	$0.00/MWh
6.	**HPF (TWh)**	32.5TWh	32.5TWh	32.5TWh	32.5TWh	32.5TWh
7.	**WAPA ($/MWh)** Pre-shaping	$119.80/MWh	$110.17/MWh	$123.42/MWh	$125.83/MWh	$141.02/MWh
8.	**WAPA (% y/y change)**	54.1%	-8.0%	12.0%	2.0%	12.1%
9.	**Typical Residential Monthly Bill Impact (%)**[11]	7.3%	-1.9%	2.6%	0.5%	3.3%

The year-over-changes in WAPA (line 8) and typical residential consumer residential monthly bills (line 9) show that the highest increase is in 2027, followed by a decrease in 2028 and increases in 2029, 2030, and 2031.

4.0 PAYMENT AMOUNT SHAPING PROPOSAL AND CUSTOMER ENGAGEMENT

To help manage the 2027 customer bill impacts and the associated volatility in year-over-year changes, OPG proposes to defer recovery of a portion of its 2027 nuclear revenue requirement to subsequent years in the IR term.

[10] Regulated hydroelectric payment amounts beyond 2027 are for illustrative purposes only.
[11] Further discussion on OPG's methodology for determining the impact of proposed payment amounts and payment riders on a typical residential electricity consumer monthly bill is found in Ex. I1-1-2.

4.1 Payment Amount Shaping Criteria

In determining the shaping amounts in each year, the Application was guided by two principles: customer bill impact and financial viability.

Customer Bill Impact: The primary objective of the payment amount shaping approach is to reduce the 2027 customer bill impact, and this is accomplished by deferring recovery of $500M of OPG's proposed nuclear revenue requirement from 2027. As a secondary objective, the analysis considered the trajectory of bill impacts over the remaining four years in the 2027-2031 period. This is addressed by varying how the $500M deferred from 2027 is recovered over the remaining years in the IR term.

Financial Viability: As discussed in Ex. A2-2-1 Section 3.3, OPG closely monitors credit metrics used by rating agencies (S&P, Moody's and DBRS), as these metrics significantly influence assigned credit ratings, which in turn affect the cost and availability of debt financing. As OPG undertakes substantial capital investments in support of Ontario's energy needs, all three rating agencies' reports have identified increasing pressure on the credit metrics as a risk.

In considering payment amount shaping options, OPG determined that deferring recovery of more than approximately $500M from 2027 could adversely affect its key credit metrics. Maintaining the current credit ratings is important to OPG's ability to access effective debt financing and, thus, OPG did not consider payment amount shaping options that deferred recovery of more than $500M from 2027.[12]

4.2 Payment Amount Shaping Options

OPG considered three options for payment amount shaping, as summarized in Chart 4, below. Approach A is a status quo scenario with no shaping of proposed payment amounts. Approach B reduces recovery by $500M in 2027 and increases recovery by $500M in 2028. Approach C reduces recovery by $500M in 2027 and increases recovery by $250M in 2028, $50M in 2029,

[12] See Ex. A2-2-1, Section 3.3 for further discussion OPG's credit metrics and credit ratings.

and $200M in 2030. The figures are stated before interest costs that would be associated with the deferral.

Chart 4 – Estimated Residential Monthly Bill Impacts Under Payment Amount Shaping Options

Line No.	Scenario	2027	2028	2029	2030	2031
1	**Approach A**	$10.33 7.3%	$(2.74) -1.9%	$3.66 2.6%	$0.69 0.5%	$4.62 3.3%
2	**Approach B**	$7.93 5.6%	$2.44 1.7%	$1.33 0.9%	$0.69 0.5%	$4.62 3.3%
3	**Approach C**	$7.93 5.6%	$1.24 0.9%	$2.73 1.9%	$1.40 1.0%	$3.61 2.5%

OPG presented these scenarios to customers as part of a customer engagement process conducted by Innovative Research Group Inc. ("INNOVATIVE"), as discussed below in Section 4.3.[13]

4.3 Customer Engagement Feedback

OPG engaged INNOVATIVE to conduct a customer engagement process that included seeking feedback on OPG's approach to payment amount shaping.

INNOVATIVE sought customer input on the value proposition that different payment amount shaping options present for customers. INNOVATIVE presented payment amount shaping as "[smoothing] out the annual change in rates by deferring a portion of 2027 costs to subsequent years, making the 2027 rate increase lower and spreading out the cost over future years' rates". The workbook presented customers with three illustrative scenarios with varying degrees of shaping. These scenarios were generally aligned with those presented in Chart 4 above.

[13] In the customer engagement process, these payment amount shaping scenarios were presented in terms of the portion of a monthly bill paid to OPG over the period rather than in terms of the bill impact dollars and percentages shown in Chart 4.

The results of the customer engagement survey show that a plurality of customers supported at least some degree of rate shaping, with a combined 48% of panellists preferring Approach B or C.[14] Managing the volatility present in the pre-shaping payment amounts comes at a cost. In providing additional feedback in the customer engagement survey, the two most common types of responses related to concerns about future interest costs, and increases in costs more generally.[15] Customer preferences are discussed further in the INNOVATIVE report, filed as Attachment 1 to this schedule.

The Application's payment amount shaping proposal considered these customer preferences, while also balancing the Customer Bill Impact and Financial Viability criteria outlined in Section 4.1.

4.4 Payment Amount Shaping Proposal

The Application proposes Approach B, as it best reflects customer preferences collected through the customer engagement process as summarized above. This proposal helps to manage the 2027 increase and results in a lower amount of interest recorded to the PASDA as compared to Approach C.

Based on this analysis, the proposed nuclear payment amounts presented in Ex. I1-3-1 have been determined based on Approach B. The Application therefore proposes to defer the collection of $500M in OPG's nuclear revenue requirement from 2027 to 2028, as shown in Ex. I-1-3-1, Table 1 and reproduced in Chart 5, below.

[14] Attachment 1, p. 20.
[15] *Ibid.*, p. 21.

Chart 5 - Proposed Combined Nuclear Revenue Requirement and Payment Amounts[16]

	2027	2028	2029	2030	2031
Proposed Combined Revenue Requirement Before Shaping ($M)	$4,363.8	$4,636.2	$5,081.9	$5,441.7	$6,779.6
OPG Revenue Requirement Shaping Adjustment ($M)	$(500.0)	$500.0	$0.0	$0.0	$0.0
Proposed Shaped Combined Revenue Requirement ($M)	$3,863.8	$5,136.2	$5,081.9	$5,441.7	$6,779.6
Total Nuclear Production Forecast (TWh)	18.7	26.7	25.1	27.3	30.9
Blended Nuclear Payment Amount After Shaping ($/MWh)	$206.70	$192.42	$202.74	$199.16	$219.60

[16] Includes OPG nuclear facilities and DNNP facilities.

LIST OF ATTACHMENTS

Attachment 1: *2025 Customer Engagement Report*, Innovative Research Group Inc.

INNOVATIVE RESEARCH GROUP

Online Survey
2025 Customer Engagement Report

ONTARIO POWER GENERATION



This report and all of the information and data contained within it may not be released, shared or otherwise disclosed to any other party, without the prior, written consent of Ontario Power Generation.

November 2025

Introduction & Methodology

Innovative Research Group Inc. (INNOVATIVE) was engaged by Torys LLP on behalf of its client Ontario Power Generation Inc. (Ontario Power Generation or OPG) to help design, execute and document the results of OPG's customer engagement in support of its 2027 to 2031 rate application.

Unlike other utility rate applications in Ontario, much of OPG's plan and are determined as a matter of system planning and cannot be influenced by customer preferences. As such, this customer engagement survey focuses on 3 key principles:

1. Focus on customer, not company outcomes
2. Do not expect customers to be subject-matter experts
3. Provide customers with the necessary background/context to make informed decisions

Method: A random sample of online panellists were invited to complete the survey from a set of partner panels based on the Lucid exchange platform. These partners are typically double opt-in survey panels, blended to manage potential skews in the data from a single source.

Sample Size: This survey was conducted online among a representative sample of n=2,524 (weighted to n=2,500) Ontarians, 18 years or older who at least share responsibility for paying their household electricity bill.

Field Dates: **November 12th to November 18th, 2025**

Weighting: Results are weighted by age, gender, region, and education to ensure that the overall sample's composition reflects that of the actual population according to Census data; in order to provide results that are intended to approximate a probability sample.

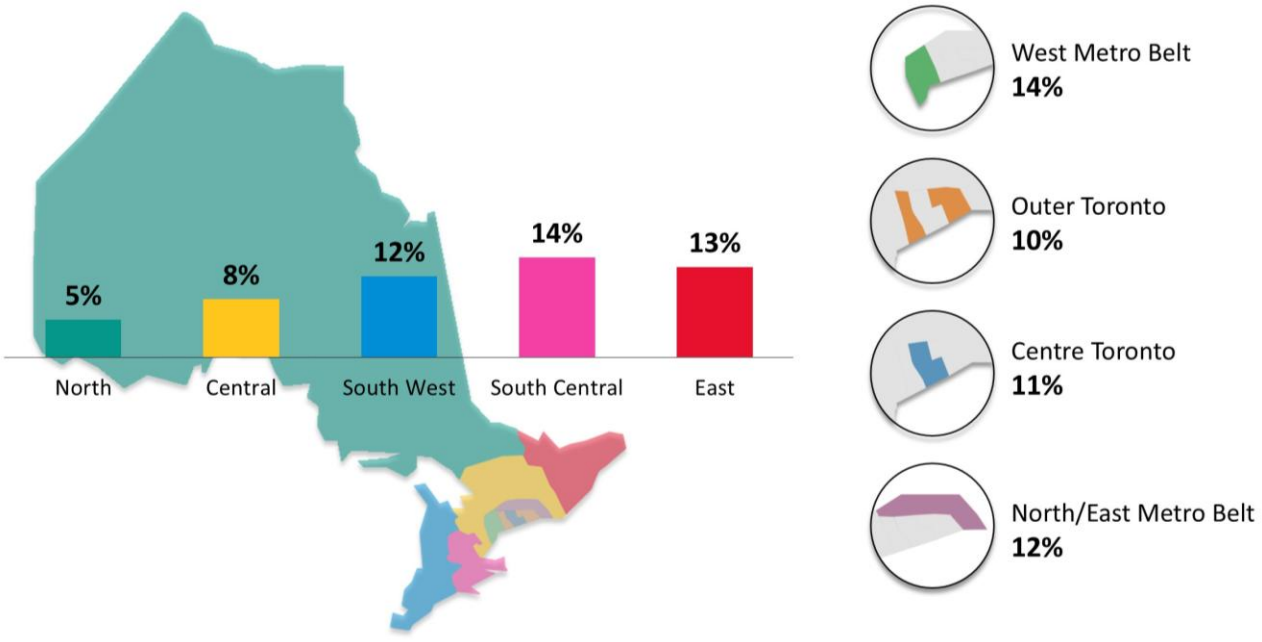
Margin of Error: This is a representative sample. However, since the online survey was not a random probability-based sample, a margin of error cannot be calculated. Statements about margins of sampling error or population estimates do not apply to most online panels.

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

Regional Segmentation

To ensure that the survey results are regionally representative of the Ontario population, respondents are categorized into 9 Ontario regions based on the first three characters of their postal code.

As shown below, the 9 regions are then further combined into 4 regions: **Toronto** (Outer Toronto + Centre Toronto), **Rest of GTA** (the Metro Belts), **South/West** (South West + South Central), and **North/East** (East + Central + North).



The table below summarizes the unweighted and weighted (in brackets) sample breakdown by age, gender, and region. Totals may not correspond with cell values as some respondents prefer to self-describe their gender. Weights are calculated based on all available information for a given respondent.

Region	Age-Gender						Total
	Men 18-34	Men 35-54	Men 55+	Women 18-34	Women 35-54	Women 55+	
Toronto	70 (69)	100 (90)	109 (79)	99 (86)	75 (98)	75 (89)	528 (510)
Rest of GTA	87 (84)	135 (117)	140 (115)	92 (82)	98 (138)	101 (124)	653 (660)
South/West	114 (80)	117 (113)	162 (129)	66 (82)	86 (109)	118 (142)	665 (656)
North/East	83 (65)	113 (111)	175 (152)	76 (72)	100 (122)	131 (151)	678 (673)
Total	354 (298)	465 (430)	586 (475)	333 (321)	359 (467)	425 (505)	2,524 (2,500)

Understanding Segmentation

In addition to segmenting electricity customers based on where they reside in Ontario, it is important to be able to identify factors that may influence customer preferences and distinguish between what is within and what is outside of OPG's influence or control.

Segmentation has been used throughout this report to look beyond the topline numbers to analyze the results for key segments:

Region: As mentioned earlier, the first three characters of a respondent's postal code are used to split Ontario ratepayers into one of four regions for analysis.

Bill Impact on Finances: Segmentation that INNOVATIVE refers to as "Bill Impact on Finances" is provided. This segment is determined based on the extent to which customers agree with the following statement: *The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.*

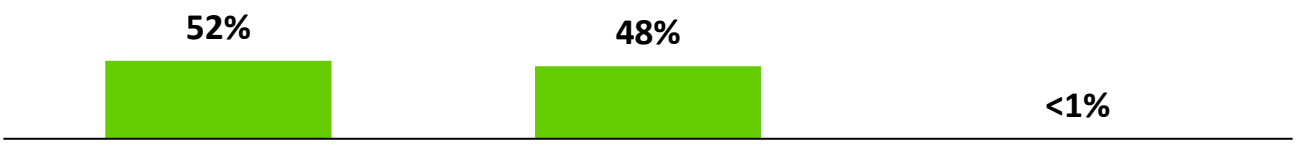
Vulnerable Consumers: Using a combination of household size and combined household income, the report identifies customers who would be eligible for financial assistance programs. The methodology used to calculate this segmentation is based on the OEB's Ontario Electricity Support Program (OESP) criteria.

Understanding Segmentation

Segmentation is an effective way of looking past the topline numbers and digging deeper into the needs and preferences of the customer segments above. For instance, while it is valuable to know, overall, how many Ontarians are satisfied with OPG, it is also important to understand whether satisfaction differs based on region or based on perceptions that may be outside of the OPG's influence or control. Segmentation allows readers of this report to quickly look past the topline numbers and understand how various segments of customers feel about various issues.

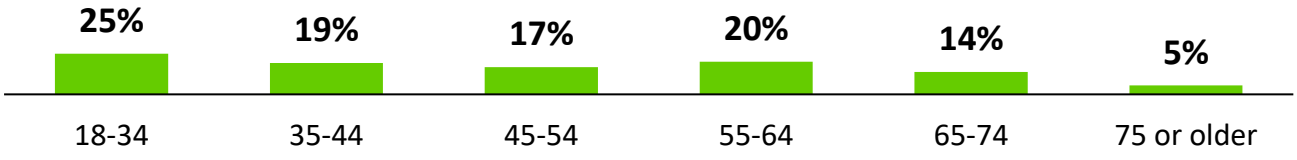
Demographic Breakdown

Q Gender



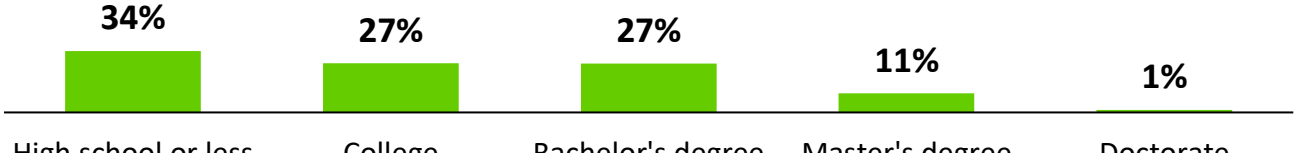
n=2,500

Q Age



n=2,500

Q Education



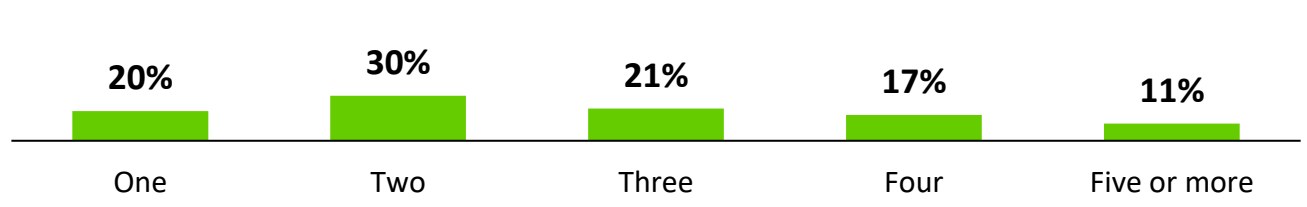
"Other" (1%) and "Prefer not to say" (<1%) not shown.

n=2,500

INNOVATIVE RESEARCH GROUP

Demographic Breakdown

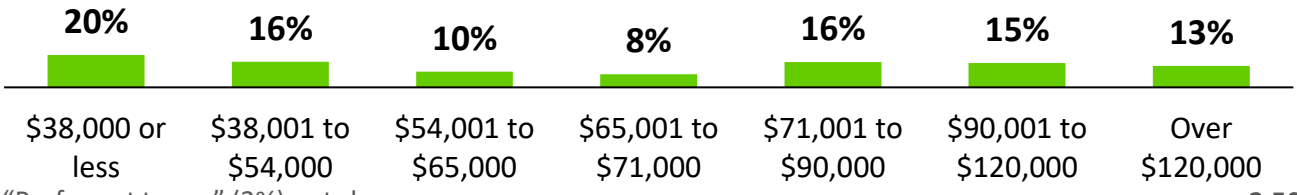
Q Household Size



"Prefer not to say" (<1%) not shown.

n=2,500

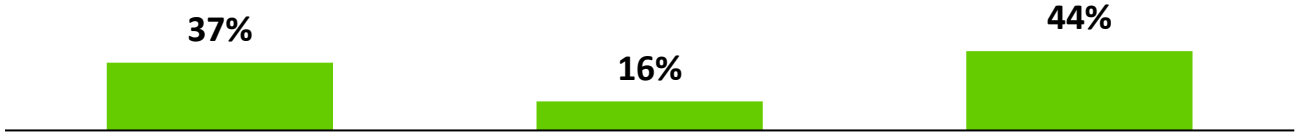
Q After Tax Household Income



"Prefer not to say" (3%) not shown.

n=2,500

Q LEAP/OESP Qualification (based on household size and income)



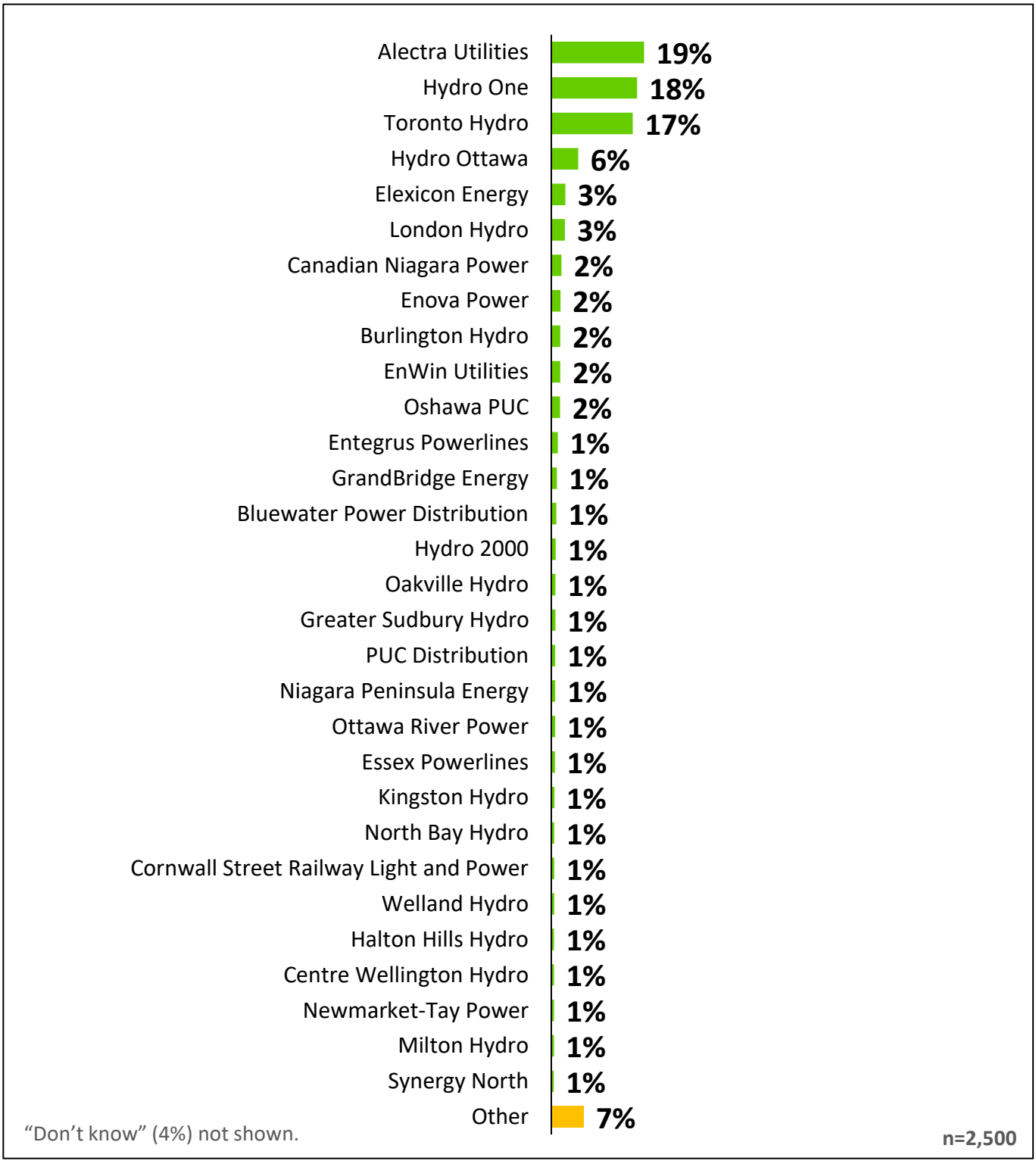
"Prefer not to say" (3%) not shown.

n=2,500

INNOVATIVE RESEARCH GROUP

Demographic Breakdown

Q Electricity Provider



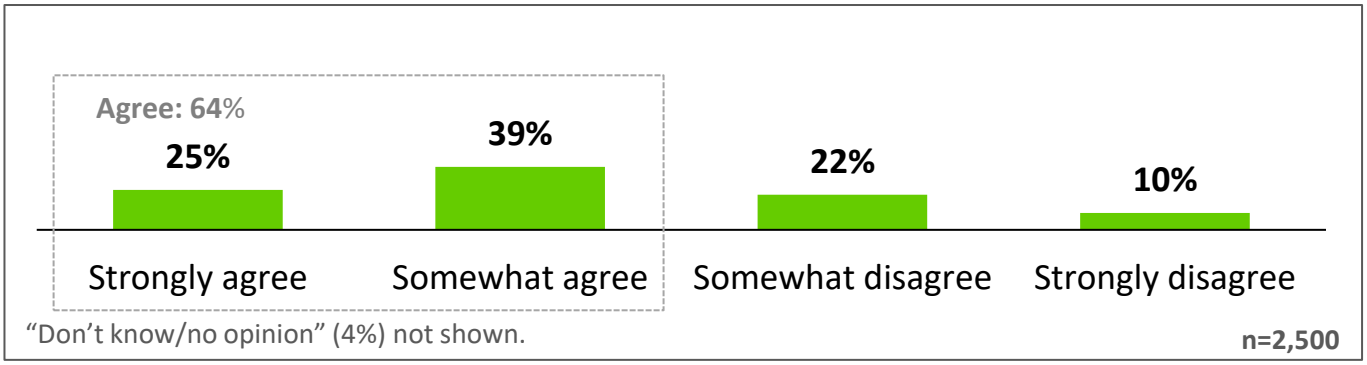
"Don't know" (4%) not shown.

n=2,500

Environmental Controls

To what extent do you agree or disagree with the following statements?

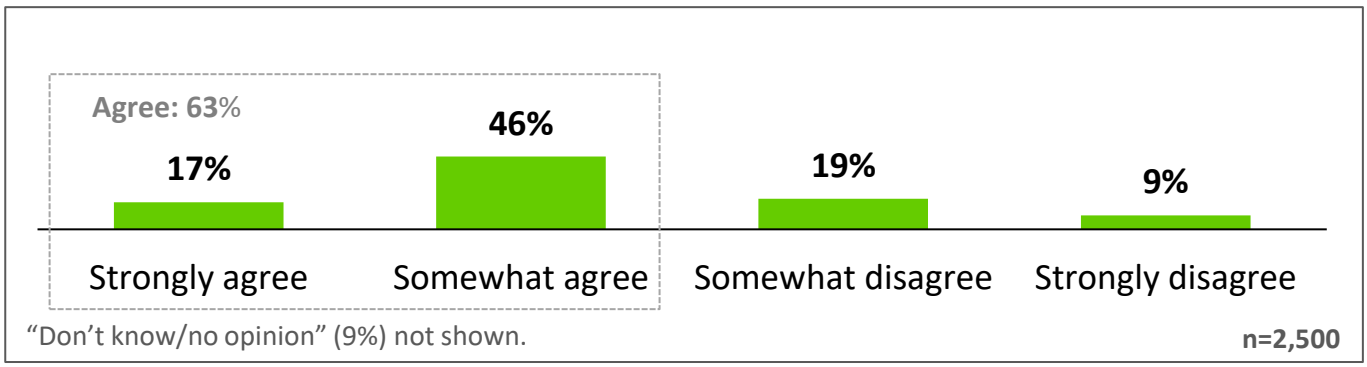
Q The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.



"Don't know/no opinion" (4%) not shown.

n=2,500

Q Consumers are well-protected with respect to prices and the reliability and quality of electricity service in Ontario.



"Don't know/no opinion" (9%) not shown.

n=2,500

INNOVATIVE RESEARCH GROUP

Residential Ratepayers

Familiarity & Experience

Preamble:

Ontario Power Generation's (OPG), Ontario's largest electricity generator, is looking for input into choices that will impact the rates Ontarians pay for electricity.

The goal of this survey is to understand your point of view as a **residential** ratepayer.

Familiarity & Experience

Bill Familiarity

How much of your electricity bill goes to OPG?

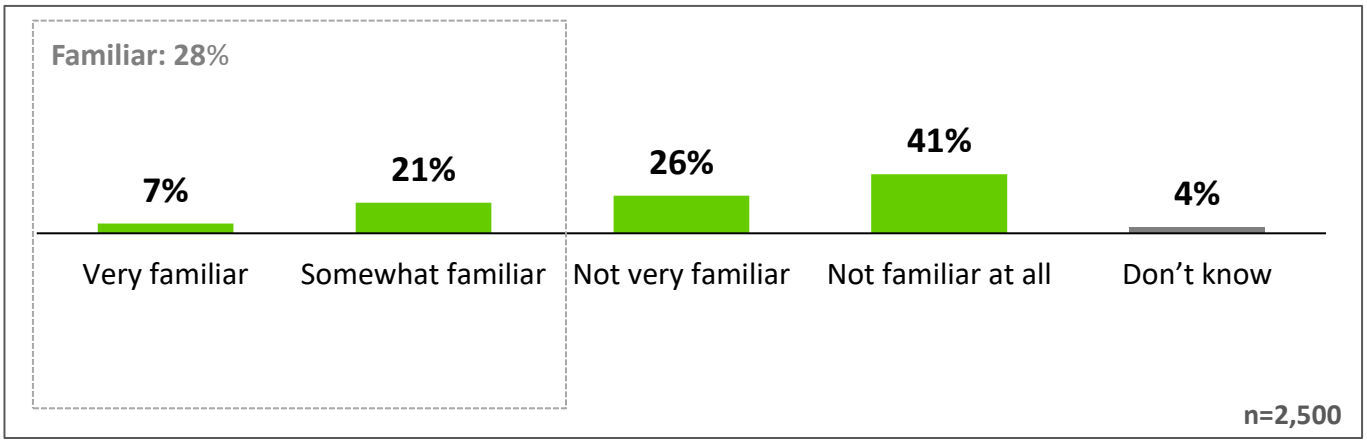
Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board, the provincial energy regulator.

As of **August 1st, 2025**, the average monthly bill for a typical residential customer consuming 750 kWh is about $135 after taxes and the Ontario Electricity Rebate.

On average, **about 15% or approximately $20 of the monthly electricity bill for a typical residential ratepayer** goes to OPG to pay for the power they generate. However, OPG's share of the bill depends on your consumption level and can be higher or lower in any given month.

The rest of the bill goes to pay for other generators, transmission companies, distribution companies, regulatory agencies, and government taxes.

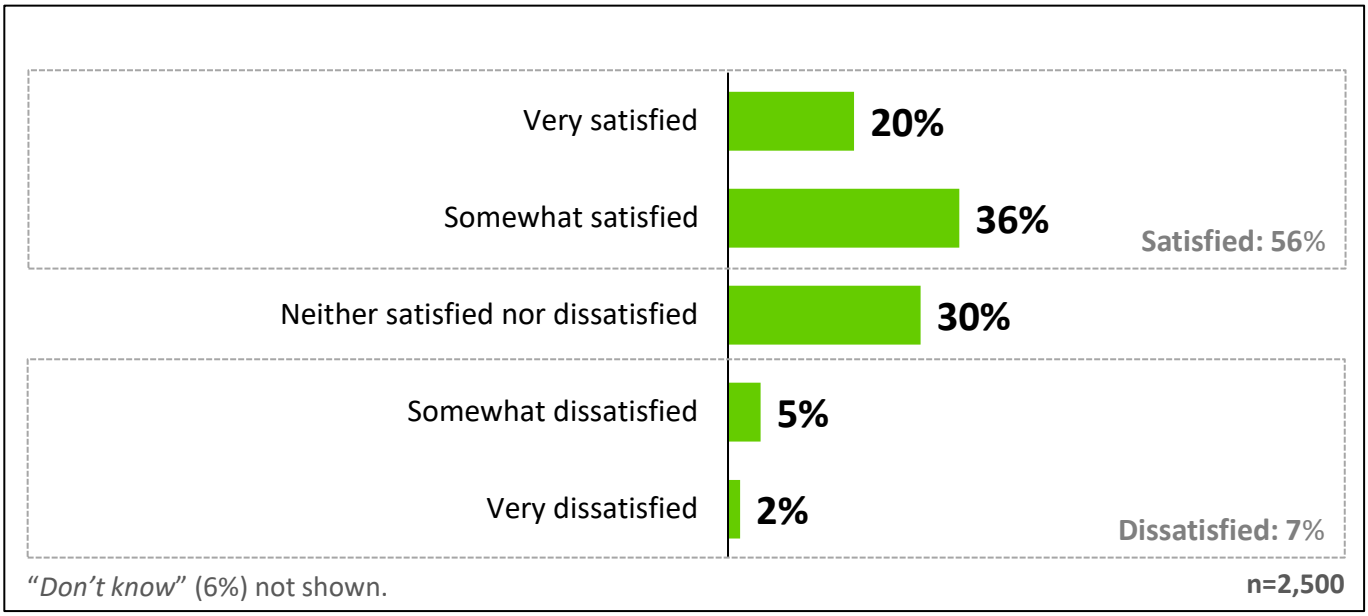
Q Before this survey, how familiar were you with the amount of your electricity bill that went to **OPG** for the generation of electricity?



Familiarity & Experience

Overall Satisfaction with OPG

Q Now that you've read a bit more about **OPG** and how it fits into Ontario's electricity system, how satisfied are you with **OPG's** performance?



"*Don't know*" (6%) not shown.

n=2,500

Region

	Toronto	Rest of GTA	South/ West	North/ Central/ East
Very satisfied	22%	20%	17%	21%
Somewhat satisfied	37%	41%	34%	34%
Neither	29%	27%	33%	32%
Somewhat dissatisfied	5%	5%	6%	4%
Very dissatisfied	1%	2%	2%	2%
Don't know	6%	4%	8%	8%
Satisfied (Very + Somewhat)	**59%**	**61%**	**51%**	**55%**
Dissatisfied (Very + Somewhat)	**6%**	**8%**	**8%**	**6%**

Familiarity & Experience

Overall Satisfaction with OPG

Q Now that you've read a bit more about **OPG** and how it fits into Ontario's electricity system, how satisfied are you with **OPG's** performance?

		LEAP/OESP Qualification			Bill Impact	
	Overall	**Qualified**	**<$71k Not Qualified**	**>$71k Not Qualified**	**Major Impact**	**No Major Impact**
Very satisfied	20%	17%	20%	22%	19%	22%
Somewhat satisfied	36%	34%	35%	40%	37%	35%
Neither	30%	33%	29%	27%	30%	31%
Somewhat dissatisfied	5%	5%	6%	4%	6%	3%
Very dissatisfied	2%	2%	3%	1%	3%	1%
Don't know	6%	8%	8%	4%	5%	8%
Satisfied (Very + Somewhat)	**56%**	**51%**	**55%**	**63%**	**56%**	**57%**
Dissatisfied (Very + Somewhat)	**7%**	**7%**	**9%**	**6%**	**9%**	**4%**

Familiarity & Experience

How can OPG do better?

Q Is there anything in particular that **OPG** could do better for you?

Response	%
Lower rates/reduce costs	11.7%
Improve communication or transparency	2.2%
No improvements needed/satisfied as is	1.8%
Help public better understand OPG's role/don't know what they do	1.4%
Increase investment in renewable energy/energy alternatives/green options	1.0%
Clearer information on bills/what goes to OPG	0.8%
Provide energy-saving incentives, programs, or guidance	0.7%
Upgrade/better maintain infrastructure	0.5%
Improve reliability	0.4%
Support low-income or vulnerable customers	0.2%
Improve environmental/wildlife protection practices	0.1%
Other	1.4%
None/Don’t know	77.9%

Note: Only responses >0.1% shown

INNOVATIVE RESEARCH GROUP

OPG's 2027-2031 Proposed Plan



Preamble:

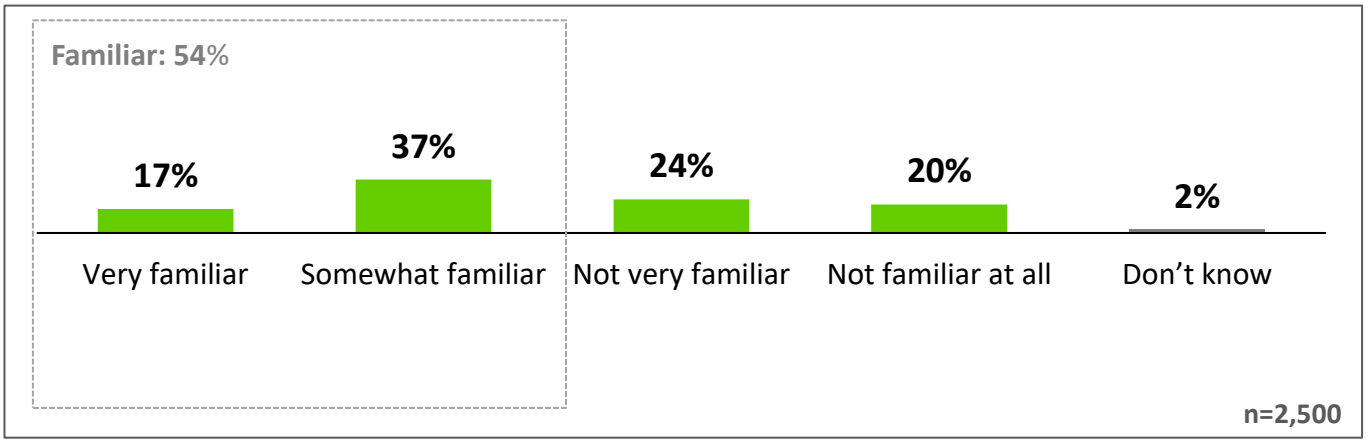
Now, let's talk about OPG's upcoming draft plan for 2027 to 2031.

OPG's 2027-2031 Proposed Plan

Familiarity with Future Electricity Demand

According to the **Independent Electricity System Operator (IESO)**, Ontario's independent electricity planning expert, annual electricity demand in the province is anticipated to grow significantly by 2050.

Q Before this survey, how familiar were you with the fact that Ontario's electricity demand is anticipated to increase in the next 25 years?



INNOVATIVE RESEARCH GROUP

OPG's 2027-2031 Proposed Plan

Familiarity with OPG's Hydroelectric/Nuclear Operations

As the company that is responsible for generating about half of Ontario's electricity, OPG's 2027 to 2031 plan will play an important role in meeting future electricity demand in Ontario.

OPG plans its investments in Ontario's electricity generating stations using a variety of inputs from Provincial system planners to independent experts and OPG's own engineers and asset managers.

However, much of OPG's plan and objectives are set by the Ontario government.

What's in OPG's plan for 2027 to 2031?

Hydroelectric power currently provides about 24 per cent of Ontario's electricity, and OPG's 2027 to 2031 plan includes significant investments in refurbishing hydroelectric generating stations across the province, which have an average age of 90 years. Costs associated with operating and investing in **the hydroelectric fleet account for 30% of OPG's 2027-2031 plan**.

OPG's two **nuclear generating stations** play a significant role in Ontario's energy mix. Darlington and Pickering Stations operate continuously to produce a steady and reliable supply of electricity, providing a foundation for the province's power needs. Costs associated with operating and investing in **the nuclear fleet account for 65% of OPG's 2027-2031 plan**.

A significant portion of OPG's 2027-2031 nuclear budget will fund the refurbishment of the Pickering nuclear plant, pending approvals. Once refurbished, this plant would continue to provide over 2,000 MW of baseload generating capacity for more than 30 years, the equivalent of powering approximately two million homes.

Finally, roughly **5%** of OPG's proposed 2027-2031 budget will fund development of the first grid-scale **Small Modular Reactor (SMR)** project in North America, if approved. An SMR is smaller and designed to simplify construction by using modular components, which can shorten construction times, reduce costs, and promote simplified and safe operation.

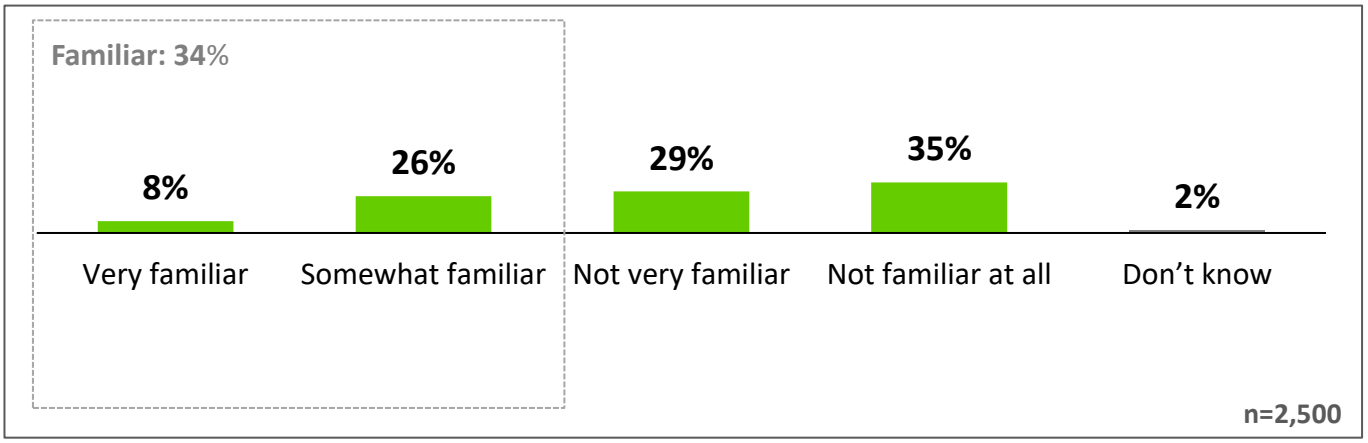
OPG's budget also goes toward meeting safety, legal, and regulatory requirements and all other aspects of running a large business.

SURVEY PAGE

OPG's 2027-2031 Proposed Plan

Familiarity with OPG's Hydroelectric/Nuclear Operations

Q Before this survey, how familiar were you that **OPG** manages both a hydroelectric and nuclear fleet?



INNOVATIVE RESEARCH GROUP

Rate Shaping



Rate Shaping

Approaches to OPG's Proposed Plan

OPG has calculated the cost of their proposed plan.

Under its plan, depending on customer feedback, for a typical residential customer consuming 750 kWh per month, the portion of their monthly bill that goes to OPG could increase by up to $17, over the course of five years, from the start of 2027 to the end of 2031*, to fund the investments described on the preceding pages to maintain existing generation and build new projects to meet growing electricity demand which will support stable baseload generation.

OPG has developed three representative approaches for how these rate increases could potentially be rolled out over the 2027 to 2031 period. OPG is seeking customer feedback on these approaches before they submit their plan to the Ontario Energy Board, the provincial energy regulator, for review.

How much of a typical customer's monthly bill would go to OPG:

	2026	2027	2028	2029	2030	2031
Approach A	$20.00	$30.00	$27.00	$31.00	$32.00	$36.50
Approach B	$20.00	$27.50	$30.00	$31.50	$32.50	$37.00
Approach C	$20.00	$27.50	$29.00	$31.50	$33.50	$37.50

* Based on a point-in-time average for the typical residential customer with an average monthly bill of ~$135; annual changes are based on OPG impacts only, and do not consider the Ontario Electricity Rebate (OER).

Approach A represents the true cost of OPG's investments. This approach would result in a roughly $10 increase on the monthly bill in the first year of the plan (2027) and an average annual increase of about $2 in each of the following 4 years (2028-2031).

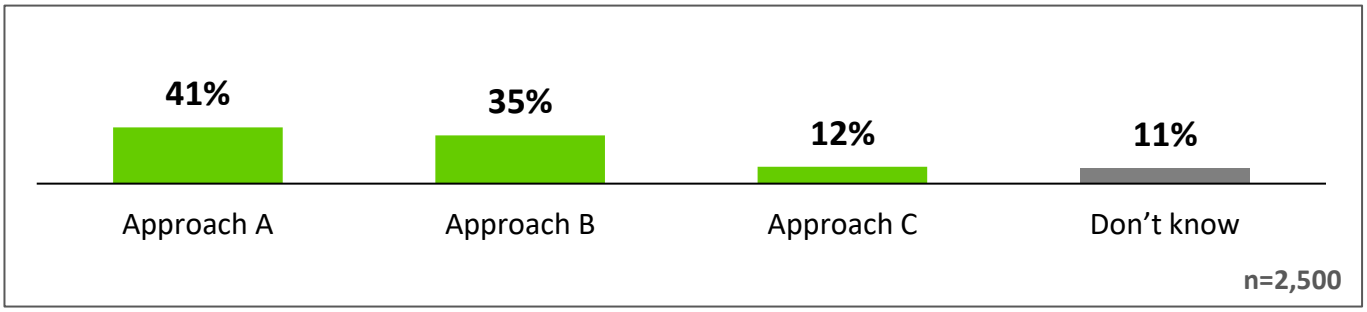
Approach B and **Approach C** "smooth out" the annual change in rates by deferring a portion of 2027 costs to subsequent years, making the 2027 rate increase lower and spreading out the cost over future years' rates.

In both **Approach B** and **Approach C,** to pay for the work in the short term, OPG would borrow more money instead of raising it through rates, incurring interest costs that would be paid by customers in later years.

SURVEY IMAGE

Rate Shaping
Approaches to OPG's Proposed Plan

Q Which of the following approaches do you prefer?



Summary of Findings: Overall, 48% of Ontario electricity ratepayers prefer some degree of rate shaping (Approach B or C). 41% of electricity ratepayers prefer Approach A, which includes no rate shaping. The remaining 11% don't know which of the three approaches they prefer.

This sentiment is consistent across both region and among more financially vulnerable customers.

Region

	Toronto	Rest of GTA	South/ West	North/ Central/ East
Approach A	37%	44%	40%	42%
Approach B	36%	36%	37%	33%
Approach C	16%	12%	11%	11%
Don't know	11%	9%	12%	13%

LEAP/OESP Qualification **Bill Impact**

	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Approach A	39%	39%	43%	39%	44%
Approach B	34%	35%	36%	37%	32%
Approach C	13%	12%	12%	13%	11%
Don't know	13%	13%	8%	10%	13%

Rate Shaping
Additional Feedback

Q Do you have any additional feedback on the approaches above that you would like to share?

Response	%
Support for upfront payment/concern about future interest costs (A)	4.4%
Increase is too high/lower costs	2.9%
No preference/all options are fine	1.9%
Preference for more gradual increase (B or C)	1.7%
Need for transparency/more information	1.5%
Affordability/cost of living concerns (low-income, seniors, fixed income)	0.8%
Distrust in OPG/perception of mismanagement/profit-driven motives	0.7%
OPG should find their own efficiencies/cost savings	0.6%
Confusion/difficulty understanding the approaches	0.1%
Include programs to support low-income/vulnerable households	0.1%
Other	1.9%
None/Don’t know	83.3%

Note: Only responses >0.1% shown

INNOVATIVE RESEARCH GROUP

Building Understanding.

Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for Ontario Power Generation. The conclusions drawn and opinions expressed are those of the authors.

Innovative Research Group Inc.

Toronto Office
18 King Street East, Suite 515
Toronto, Ontario M5C 1C4
Tel: 416.642.6340
www.innovativeresearch.ca

Vancouver Office
888 Dunsmuir Street, Suite 350
Vancouver, British Columbia V6C 3K4
Tel: 604.662.4022
www.innovativeresearch.ca