UNDERTAKING JT5.1

Undertaking

Provide a scenario where OPG begins recovering the $500 million proposed deferral amount earlier than the beginning of 2028 so that recovery is more gradual through 2027 and into 2028.

Response

In Attachment 1, OPG presents an illustrative scenario where $500M is deferred to the proposed Payment Amounts Shaping Deferral Account ("PASDA") between January 1, 2027 and June 30, 2027, rather than between January 1, 2027 and December 31, 2027 as proposed in the Application, thus reducing the weighted average payment amount during the January 1, 2027 to June 30, 2027 period. The deferred amount is then recovered between July 1, 2027 and December 31, 2028, rather than between January 1, 2028 and December 31, 2028 as proposed in the Application, thus increasing the weighted average payment amount during the July 1, 2027 to December 31, 2028 period. Specifically, this scenario assumes recovery of $100M during the July 1, 2027 to December 31, 2027 period and $400M during the January 1, 2028 to December 31, 2028 period.

As shown in Attachment 1, Table 1, lines 4 and 5, the resulting impact of the Application on a typical residential customer's monthly bill on January 1, 2027 is $5.53/month, or 3.9% (compared to $7.93/month or 5.6% based on OPG's payment amount shaping proposal), with a further impact on July 1, 2027 of $5.76/month, or 4.1%.

Numbers may not add due to rounding.

Table 1
Annualized Residential Consumer Impact - Ex. JT5.1 Payment Amounts Shaping Scenario
EB-2020-0290/EB-2023-0336 to EB-2025-0297

Line No.	Description	2027 Jan-June Amount	2027 July-Dec Amount	2028 Amount	2029 Amount	2030 Amount	2031 Amount	2027-2031 Average
		(a)	(a1)	(b)	(c)	(d)	(e)	(f)
1	**Typical Consumption[1] (kWh/Month)**	787	787	787	787	787	787	787
2	**Typical Usage of OPG and DNNP LP Generation (kWh/Month)** (line 1 x line 11)	246	246	284	276	287	304	274
3	**Typical Bill[1] ($/Month)**	142.10	142.10	142.10	142.10	142.10	142.10	142.10
4	**Typical Bill Impact ($/Month)** (line 2 x line 8 / 1000)	5.53	5.76	(1.93)	1.79	0.69	4.62	3.29
5	**Typical Bill Impact (%)** (line 4 / line 3)	3.9%	4.1%	-1.4%	1.3%	0.5%	3.3%	2.3%
6	Prior year/half-year weighted average rate with proposed payment amounts and riders[2] ($/MWh)	77.75	100.26	123.72	116.93	123.42	125.83	
7	Current year/half-year weighted average rate with proposed payment amounts and riders[2] ($/MWh)	100.26	123.72	116.93	123.42	125.83	141.02	
8	Change in weighted average rate ($/MWh) (line 7 - line 6)	22.51	23.46	(6.79)	6.49	2.41	15.19	
9	Total Regulated Production[3] (TWh)	51.2	51.2	59.2	57.5	59.8	63.3	
10	Forecast of 2027 Provincial Demand[4] (TWh)	163.9	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%	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. Ex. JT5.1, Att. 1, Table 2, line 9.

3 From Ex. I1-1-2 Table 2: line 3 + line 6.

4 Based on forecast demand for 2027 (163.9 TWh) from Figure 2 of IESO Annual Planning Outlook, released April 2025.

Numbers may not add due to rounding.

Table 2
Computation of Percent Change in Payment Amounts - Ex. JT5.1 Payment Amounts Shaping Scenario
EB-2020-0290/EB-2023-0336 to EB-2025-0297

Line No.	Description	Note	2026	2027 Jan-June	2027 July-Dec	Jan 1 2028	2029	2030	2031
			(a)	(b)	(b1)	(c)	(d)	(e)	(f)
			Note 1	Note 2	Note 2	Note 2	Note 2	Note 2	Note 2
1	**Hydroelectric Payment Amount (HPA) ($/MWh)**	3	43.88	51.39	51.39	54.97	59.20	62.02	64.21
2	**Hydroelectric Payment Rider (HPR) ($/MWh)**	4	3.30	(1.17)	(1.17)	(1.17)	(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	32.5
4	**Nuclear Payment Amount (NPA) ($/MWh)**	6	111.33	179.96	244.15	188.68	202.74	199.16	219.60
5	**Nuclear Payment Rider (NPR) ($/MWh)**	7	12.43	7.19	7.19	5.04	5.36	2.48	2.19
6	**Nuclear Production Forecast (NPF) TWh**	8	21.9	18.7	18.7	26.7	25.1	27.3	30.9
7	**Regulated Hydroelectric Portion of Weighted Average Payment Amount ($/MWh)** (HPA + HPR) x HPF / (NPF+HPF)		28.35	31.87	31.87	29.52	32.75	33.68	32.91
8	**Nuclear Portion of Weighted Average Payment Amount ($/MWh)** (NPA + NPR) x NPF / (NPF+HPF)		49.41	68.39	91.84	87.41	90.67	92.15	108.11
9	**Weighted Average Payment Amount ($/MWh)** (((NPA + NPR) x NPF) + (HPA + HPR) x HPF) / (NPF + HPF)		77.75	100.26	123.72	116.93	123.42	125.83	141.02
10	**Percentage Change in Weighted Average Payment Amount (Year over Year)**			29.0%	23.4%	-5.5%	5.6%	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 the Application, as adjusted for the payment amounts shaping scenario presented in Ex. JT5.1.
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 2026: Per Ex. I1-3-1, Table 1, line 9. 2027-2031: Per Ex. JT5.1, Att. 1, Table 3, line 10.
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.

Numbers may not add due to rounding.

Table 3
Payment Amounts - Combined Nuclear - Ex. JT5.1 Payment Amounts Shaping Scenario
January 1, 2027 to December 31, 2031

Line No.	Description	Note	2027 Jan-June	2027 July-Dec	2028	2029	2030	2031
			(a)	(a1)	(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)	100.0	400.0	0.0	0.0	0.0
5	Production Forecast - OPG Nuclear Facilities	4	18.7		26.7	25.1	26.8	28.9
6	Production Forecast - DNNP Facilities	5	0.0		0.0	0.0	0.5	1.9
7	**Combined Nuclear Forecast Production (TWh)**		18.7		26.7	25.1	27.3	30.9
8	**Blended Nuclear Payment Amount Before Shaping Adjustment ($/MWh)** (line 3 / line 7)		233.45		173.69	202.74	199.16	219.60
9	**Impact of Payment Amount Shaping on Nuclear Payment Amounts ($/MWh)** (line 4 / line 7)		(53.50)	10.70	14.99	0.00	0.00	0.00
10	**Blended Nuclear Payment Amount After Shaping Adjustment ($/MWh)** (line 8 + line 9)		179.96	244.15	188.68	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 Per payment amounts shaping scenario presented in Ex. JT5.1.
4 From Ex. E2-1-1 Table 1, line 3.
5 From Ex. E2-1-1 Table 1, line 4.

UNDERTAKING JT5.2

Undertaking

Make inquiries of Scott Madden as to whether the Candu adjustment referred to on page 3 of F2-Staff-324 is the difference between the average total generation cost of the three Candu facilities and all the other non-Candu facilities.

Response

The following response was prepared by ScottMadden Management Consultants:

Not confirmed. The CANDU adjustment is not the difference between the average total generation cost ("TGC") of the three CANDU facilities and the average TGC of the non-CANDU facilities.

Rather, the CANDU adjustment is the estimated CANDU coefficient from ScottMadden's regression model, which controls for other variables, including site capacity and plant weighted age. Such coefficient indicates that CANDU technology increases predicted TGC by just over $539M per year relative to Boiling Water Reactor technology, as described in Ex. F2-1-1, Attachment 4, pp. 9-10.

UNDERTAKING JT5.3

Undertaking

Advise how the capital stretch factor does or does not come into play for the global hydroelectric capital account.

Response

The proposed Global Hydroelectric Capital Variance Account ("GHCVA") is discussed primarily in Ex. A1-3-2, Section 2.3.5 and Ex. H1-1-1, Section 7.2. OPG confirms that the forecast capital-related revenue requirement amounts against which the actual capital-related revenue requirement amounts would be compared for purposes of determining entries in the GHCVA are after the stretch factor adjustment, such as at line 1 of Ex. A1-3-2, Chart 10. OPG confirms that the proposal does not apply a stretch factor adjustment to the actual capital-related revenue requirement amounts themselves, such as at line 2 of Ex. A1-3-2, Chart 10.

OPG's view is that the above approach appropriately reflects the purpose of the proposed GHCVA, which is to return to ratepayers amounts recovered through the proposed hydroelectric rate-setting framework to the extent the actual capital-related revenue requirements over the IR term are less than such amounts afforded through the payment amounts inclusive of the proposed C-factor.

UNDERTAKING JT5.4

Undertaking

Provide what the EB-2013-0321 CRVA eligible projects were, including the percentage of the total forecast capital in-service additions at the time, and provide any other meaningful additional commentary that can be given.

Response

Capital in-service additions reflected in the EB-2013-0321 regulated hydroelectric revenue requirement for 2014 and 2015 that were eligible for the Capacity Refurbishment Variance Account ("CRVA") were as follows:[1]

- Otto Holden Generating Station – Replace Headgates and Rehabilitate Gains
- Otto Holden Generating Station – Replace Sluicegates & Rehabilitate Sluicegates System
- Des Joachims Generating Station – Replace Main Output Transformers
- Des Joachims Generating Station – Turbine Runner Replacement
- Sir Adam Beck I Generating Station – Unit G10 Upgrade.

These projects represented approximately 16% of the total regulated hydroelectric capital in-service additions forecasted by OPG for years 2014 and 2015 in EB-2013-0321.

Eligibility of expenditures for the CRVA is established by O. Reg. 53/05, Section 6(2)4. Ex. L-D1-Staff-061 and Ex. L-D2-Staff-081 outline certain considerations made by OPG in applying these requirements to its projects. Given that the eligibility for the CRVA depends on the specific scope of the work, that is whether it constitutes work to increase the installed operating capacity of a generating station, increase the output from the station's existing operating capacity (through either efficiency gains or extension of the facility's operating life), and/or refurbish a generating station, the portion of the total regulated hydroelectric in-service additions subject to the CRVA at a given point will vary depending on the nature of the specific projects being undertaken.

Compared to EB-2013-0321, a greater portion of the forecasted regulated hydroelectric in-service additions is identified at CRVA-eligible in this Application. With the project portfolios and programs in the Application developed over ten years after EB-2013-0321, this reflects the evolution of the investment needs for the regulated hydroelectric facilities. As discussed in the pre-filed evidence and the attendant

[1] EB-2023-0336, Ex. H1-1-1, Table 7a, Note 1, Note *.

interrogatories, undertakings and Technical Conference, the current condition of the regulated hydroelectric fleet requires increased capital investment, with a focus on turbine-generator refurbishments, civil infrastructure projects and certain redevelopment projects, among others. These investments will support Ontario's ability to meet future energy needs and align to the Province of Ontario's Integrated Energy Plan. The number and/or relative size of these projects that meet the requirements of O. Reg. 53/05, Section 6(2)4 are such that a larger proportion of the total forecasted regulated hydroelectric in-service additions is eligible for the CRVA treatment compared to the composition of the EB-2013-0321 projects.

The CRVA eligibility of the capital projects identified in this proceeding can be found with reference to the "CRVA Eligible" columns in Ex. D1-1-2, Tables 1, 2a, 2b, 5a and 5b, and the corresponding total in-service additions and reference revenue requirement impacts over the IR term can be found in Ex. H1-1-1, Attachments 5 and 5a. The details of the regulated hydroelectric capital budgets and projects in this proceeding can be found in Ex. F1-1-1, Ex. D1-1-1 and Ex. D1-1-2, among others.

UNDERTAKING JT5.5

Undertaking

To replicate the Table at exhibit A1-Staff-331, Attachment 1, Table 2, isolating the capital-related revenue requirement for the in-service additions during the 2027 to 2031 term.

Response

Refer to Attachment 1.

In OPG's view, this hypothetical calculation is not meaningful because it ignores the existence of a material 2027 opening rate base for the regulated hydroelectric facilities, and therefore is not an appropriate basis for setting payment amounts.

Numbers may not add due to rounding.

Table 1
Hypothetical Calculation of Capital Factor for Regulated Hydroelectric Facilities Based on 2027-2031 In-Service Additions Only
January 1, 2027 to December 31, 2031 ($M)

Line No.	Description	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
			Note 1				
1	**Depreciation**	Ex. JT4.13, Att 1, Table 2, line 1 less Ex. L-A1-Staff-275, Chart 1	27.1	40.0	61.3	75.3	83.4
2	**Cost of Debt**	Note 2	9.9	27.3	58.9	79.7	97.4
3	**Return on Equity**	Note 2	21.3	56.4	118.7	158.7	193.1
4	**Income Taxes**	Ex. JT4.13, Att 1, Table 2, line 4 less Ex. L-A1-Staff-275, Chart 1	(80.2)	(42.9)	(28.8)	(18.2)	(10.4)
5	**Capital Related Revenue Requirement**	Sum lines 1 to 4	(21.9)	80.8	210.1	295.5	363.4
6	**Regulated Hydroelectric Stretch Factor Capital Related Revenue Requirement Adjustment**	0.15% * line 5a (cumulative)		0.1	0.4	0.9	1.4
7	**Capital Related Revenue Requirement after Stretch**	line 5 - line 6	(21.9)	80.7	209.7	294.6	362.0
8	**Capital Afforded through (I-X) Adjustment** (assuming Custom Capital Factor in preceding years)	(line 8_{t-1} + line 9_{t-1}) x (I-X)	(21.9)	(22.5)	83.0	215.5	302.8
9	**Capital Related Revenue Requirement Shortfall**	(line 7 + line 7a) - line 8	-	103.2	126.7	79.1	59.2
10	**Hypothetical Custom Capital Factor (C-Factor)**	line 9_t / line 14_{t-1}		13.4%	16.2%	8.8%	5.7%
11	**OM&A (excluding GRC)**	2028-2031: escalated by (I - X)	501.4	515.4	529.8	544.6	559.8
12	**GRC**	Note 3	352.2	352.2	352.2	352.2	352.2
13	**Other Revenues**	2028-2031: escalated by (I - X)	(62.2)	(64.0)	(65.8)	(67.6)	(69.5)
14	**Hypothetical Total Revenue Requirement**	line 7 + (lines 11 to 13)	769.5	781.2	899.2	1,044.7	1,145.3

Notes:
1 Lines 11, 12 and 13 per Ex. I1-1-1, Table 1.
2 Determination of cost of capital amounts included in the hypothetical C-factor is based on the following:

Line No.	Description	Reference	2027	2028	2029	2030	2031
2a	Rate Base	Ex. JT4.13, Att. 1, Table 2, line 2a less Ex. L-A1-Staff-275, Chart 1	449.8	1,190.0	2,505.3	3,350.7	4,075.3
2b	Short-Term Debt	Ex. JT4.13, Att. 1, Table 2, line 2b less Ex. L-A1-Staff-275, Chart 1	0.4	0.9	1.9	2.3	2.3
2c	Long-Term Debt	Ex. JT4.13, Att. 1, Table 2, line 2c less Ex. L-A1-Staff-275, Chart 1	9.5	26.4	57.1	77.4	95.1
2d	Common Equity	Ex. JT4.13, Att. 1, Table 2, line 2d less Ex. L-A1-Staff-275, Chart 1	21.3	56.4	118.7	158.7	193.1

3 The hypothetical GRC Factor calculated below effectively fixes the underlying GRC amount recovered through payment amounts at the 2027 amount:

Line No.	Description	Reference	2027	2028	2029	2030	2031
3a	GRC Escalated by (I-X)	line 12 x (1+(I-X))	352.2	362.0	362.0	362.0	362.0
3b	Variance to Fixed GRC	line 12 less line 3a	-	(9.8)	(9.8)	(9.8)	(9.8)
3c	Variance as Percentage of Prior Year Hypothetical Revenue Requirement	line 3b, col. b / line 14, col. a	-	(1.3)%	(1.3)%	(1.1)%	(0.9)%

UNDERTAKING JT5.6

Undertaking

Consider whether long-term escalation factor of 4.5 percent remains appropriate based on the current state of affairs and provide commentary in support of that assessment, including context regarding the Kroll forecast.

Response

The long-term construction cost escalation factor of 4.5% per year reflected in OPG's 2025-2031 Business Plan remains reasonable based on current and anticipated market conditions and trends, including in the context of the Kroll analysis (Ex. L-A2-CCC-015, Attachment 2). As shown below, the 2025 market indicators across multiple indices show escalation ranging from 4.1% to 7.3% for general construction, including non-residential construction. Additionally, as discussed in Ex. L-A1-Staff-343, the 4.5% cost escalation factor is based on a long-term normalization principle that already takes into account a moderation of escalation following historical peak levels, averaging as high as 13.1%, observed in 2021 and 2022.

The 2025 market indicators related to construction cost escalation reviewed by OPG in preparing this response include:
The Mortenson Construction Cost (2025) indices, which range between approximately 6.6% and 7.3%,

- The Turner Building Cost Index, which reported escalation of approximately 4.1% (2025),
- A composite of Statistics Canada's 2025 non-residential and factory construction price indices for Toronto, which range between approximately 4.5% and 5.5%, depending on project type. This relates to industrial and equipment-intensive construction, which resembles the Applicants' project types.

These trends are supported by underlying ongoing market considerations, including:

- Labour constraints, particularly in skilled trades required for infrastructure and energy projects (Ex. F4-3-1);
- Supply chain pressures, which, while improved compared to peak disruption, continue to exhibit increased demand in specialized equipment and long-lead components (Ex. F1-1-1, p. 6; Ex. D2-1-2, p.9 and Ex. L-D2-AMPCO-050); and
- Sustained demand for infrastructure and energy investment, including electrification, grid modernization, and nuclear projects (Ex. L-A2-CCC-015, Attachment 2, pp. 14-15).

UNDERTAKING JT5.7

Undertaking

Provide the live spreadsheets for Tables 59 and 60 of F4-CCC-84, Attachment 1.

Response

Refer to Attachment 1 provided in Excel format.

UNDERTAKING JT5.8

Undertaking

Advise whether the audited amount now replaces the value at Exhibit I1, Tab 1, Schedule 1, Table 6.

Response

The opening balance at Ex. I1-1-1, Table 6, which presents the calculation of the forecast concurrent cost recovery interest amounts in respect of the Darlington New Nuclear Program pursuant to Section 14(2)5i of O. Reg. 53/05, reflects the forecast of such cumulative capital expenditures as of January 1, 2026 included in the Application.

Section 14(2)2 of O. Reg. 53/05 requires the OEB to accept certain costs set out in the audited schedule of costs approved by OPG's board of directors, as capital costs of DNNP LP[1]. However, there is no requirement in O. Reg. 53/05 for the opening balance at Ex. I1-1-1, Table 6 to be equal to the amount of costs set out in such audited schedule. As discussed in Ex. H1-1-1, Section 6.3, Section 12 of O. Reg. 53/05 establishes the Darlington New Nuclear Project Variance Account re Capital Cost Amounts to true-up the forecast concurrent cost recovery interest amounts in respect of the DNNP with such amounts based on the actual capital expenditures, which will include the effect of any difference between the forecast and actual opening balance at Ex. I1-1-1, Table 6. Accordingly, it is not necessary to update Ex. I1-1-1, Table 6 for such difference in the course of this proceeding.

[1] For reference, the audited schedule of costs is provided at Ex. L-A1-CCC-010, Att. 8.

UNDERTAKING JT5.9

Undertaking

Provide, for each of the nuclear and hydroelectric businesses, the annual 2027 to 2031 capital and OM&A amounts to which the assumption in Exhibit A2, Tab 2, Schedule 1, Attachment 2 is applied.

Response

Refer to Chart 1 and Chart 2 below for the respective estimates of the forecast OM&A and capital procurement costs over the 2027-2031 period that are subject to the 4.5% escalation assumption outlined in Ex. A2-2-1, Attachment 2 for OPG's nuclear facilities, OPG's regulated hydroelectric facilities and the DNNP facilities, separately showing the DNNP and the PRP. As stated by Mr. Melaragno at Tr. Tech. Conf., June 2, 2026, p. 56, line 11, this response is provided on a best efforts basis.

For the respective categories of OM&A costs, Chart 1 presents procurement costs that are as set out in the following exhibits for OPG nuclear facilities – Ex. F2-2-1, Table 2a, line 5, Ex. F2-4-1, Table 2, line 5 and Ex. F2-4-1, Table 3, line 5; DNNP facilities – Ex. F2-2-1, Table 2, line 5 and Ex. F2-4-1, Table 4, line 5; and OPG's regulated hydroelectric facilities – Ex. F1-2-1, Table 2, line 5. This reflects that OPG is unable to isolate the specific portion of such costs that are subject to the 4.5% escalation assumption without significant effort. However, OPG can confirm that most of these costs were subject to this assumption.

Chart 1 – Estimated OM&A Procurement Costs Subject to 4.5% Escalation Assumption ($M)

	2027	2028	2029	2030	2031
Regulated Hydroelectric Facilities – Base OM&A	21				
Regulated Hydroelectric Facilities – Project OM&A	39				
OPG Nuclear Operations – Base and Outage OM&A	124	87	108	91	124
OPG Nuclear Operations – Project OM&A	22	23	23	22	21
DNNP Facilities – Base & Outage OM&A	0	0	0	3	11
Total	186	92	114	101	143

Numbers may not add due to rounding

Chart 2 – Estimated Capital Procurement Costs Subject to 4.5% Escalation Assumption ($M)

	2027	2028	2029	2030	2031
Regulated Hydroelectric	206	249	239	271	258
OPG Nuclear Operations	228	159	160	173	135
Pickering Refurbishment Program	591	526	279	97	19
Darlington New Nuclear Program	359	163	21	-	-
Total	1,007	760	386	211	136

Numbers may not add due to rounding

UNDERTAKING JT5.10

Undertaking

Provide an explanation of how the provision for accumulated obsolescence is calculated and what dollar value of that provision for each year from 2027 to 2031.

Response

As discussed in Ex. L-B1-CCC-019, OPG is required to hold both lifetime and critical spares at all times in support of nuclear operations safety and continuous operations. As such, over time, it is expected that some parts will become obsolete due to externalities such as changes in the operating systems, reaching shelf-life expiration, or design changes or other technical factors that would preclude inventory use within the stations. An accumulated provision balance for inventory obsolescence is required to address such de-valued materials and supplies as well as inventory losses identified through the cycle count or physical verification process, recognizing the unique nature of the majority of nuclear materials and their limited use outside of OPG. An annual obsolescence provision cost is calculated by allocating (depreciating) the expected residual inventory value (net of accumulated obsolescence) at the end of the respective station life over that station's remaining life, and is recorded as a Base OM&A expense. As discussed in Ex. B1-1-1, Section 3.2.4, the nuclear inventory rate base values are net of accumulated obsolescence amounts.

Chart 1 below shows the annual obsolescence provision costs forecasted by OPG for 2027-2031.

Chart 1 – Annual Nuclear Inventory Obsolescence Provision Contribution

	2027	2028	2029	2030	2031
Annual Provision for Obsolescence ($M)	9.7	10.3	11.2	12.2	13.7

UNDERTAKING JT5.11

Undertaking

Advise if currently there is always a lease versus buy analysis completed for fleet assets and advise what that analysis shows on average and provide a breakdown between capital and OM&A of the fleet costs on an annual basis for both the historical and forecast periods, as necessary on an estimate or best-efforts basis.

Response

Fleet assets are defined as either standard vehicles (e.g., cars, SUVs, vans, light trucks) or non-standard vehicles and material handling equipment (e.g., heavy trucks, ATVs, boats, forklifts). OPG governance (OPG-PROC-0162, Fleet Management) requires a lease versus buy analysis only for non-standard fleet vehicles. Such analyses are performed on a case-by-case basis based on the specific business requirements. OPG is unable to provide an average result of these analyses as they are not maintained in a standardized or centralized manner.

Most fleet costs are planned as OM&A costs, based on historical actual trends. The actual OM&A fleet costs over the 2020-2025 period and the forecast OM&A fleet costs over the 2026-2031 period for OPG's regulated facilities are shown in Charts 1 and 2 below, respectively, inclusive of other related costs such as vehicle parts, fuel and maintenance. The actual capitalized fleet costs over the 2020-2025 period for OPG's regulated facilities are shown in Chart 3 below. OPG is unable to specifically identify the capitalized fleet assets that may be incurred in the forecast period, as these expenditures are planned a part of a broader mix of minor fixed assets (refer to D1-1-1, Table 4, line 17 and Ex. D2-1-2, Table 2, line 21).

Chart 1
Breakdown of Fleet Costs – OM&A Actual 2020-2025 ($M)

	2020	2021	2022	2023	2024	2025
Fleet Costs – OM&A	$8.1	$9.1	$9.8	$11.4	$13.7	$12.8

Chart 2
Breakdown of Fleet Costs – OM&A Budget and Plan 2026-2031 ($M)

	2026	2027	2028	2029	2030	2031
Fleet Costs – OM&A	$10.8	$11.0	$10.6	$10.6	$10.7	$10.7

Chart 3
Breakdown of Fleet Costs – Capital Actual Costs 2020-2025 ($M)

	2020	2021	2022	2023	2024	2025
Fleet Costs – Capital	$0.8	$0.9	$0.9	$1.0	$1.7	$2.7

UNDERTAKING JT5.12

Undertaking

Provide a revised version of the table and notes in H1-1-1, Attachment 5, that only includes 2027 to 2031 in-service additions.

Response

Refer to Attachment 1 for a revised version of Ex. H1-1-1, Attachments 5 and 5a, where the original version provides the proposed 2027-2031 revenue requirement reference amounts for the regulated hydroelectric projects identified as eligible for the Capacity Refurbishment Variance Account ("CRVA") and where the revised version only includes revenue requirement impacts of the forecast 2027-2031 in-service additions for such projects.

As noted at Ex. H1-1-1, Attachment 5a, Note 1, Note * and further explained by OPG's witnesses at Tr. Tech. Conf. June 2, 2026, p. 18, line 24 to 19, line 1 and p. 20, lines 14-21, OPG's proposed 2027-2031 reference amounts for the regulated hydroelectric facilities for the purposes of the CRVA reflect the revenue requirement impacts of the forecast in-service amounts for eligible projects beginning with January 1, 2025, rather than January 1, 2027. This recognizes that the 2027 opening rate base values for such projects underpinning the rebasing of the regulated hydroelectric payment amounts are partly a function of the forecast in-service additions during the 2025 and 2026 bridge years as reflected in the Application. This means that, all else equal, there would be a 2027-2031 IR term revenue requirement impact with respect to these projects should there be a variance between such forecast and actual in-service additions during 2025 and 2026. While the CRVA entries during 2025 and 2026, made with respect to reference amounts established in EB-2020-0290, would true-up for any variances arising from such actual in-service additions with respect to the 2025 and 2026 revenue requirement impacts, excluding the cascading 2027 opening rate base variances from the scope of CRVA entries during the IR term would result in the account no longer providing for recovery of OPG's prudently incurred costs with respect to such projects over the 2027-2031 period. This would be contrary to the intent of the account and its enabling provisions in O. Reg. 53/05, Section 6(2)4.

Table 1
2027-2031 Regulated Hydroelectric CRVA Projects In-Service Additions - Revenue Requirement (Capital Component) ($M)

Shown below is the derivation of amounts for the regulated hydroelectric CRVA projects capital component based on OPG's regulated hydroelectric facilities' 2027 to 2031 in-service additions in this proceeding.

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	293.1	737.5	1,753.2	2,325.2	2,795.6
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)		**20.4**	**51.9**	**124.3**	**165.5**	**199.2**
	Depreciation						
4	Regulated Hydroelectric CRVA Projects	1	4.9	12.5	29.8	39.9	48.4
	Regulatory Taxable Income Impacts						
5	ROE (line 1 x 52% x 9.11%)		13.9	34.9	83.1	110.1	132.4
6	Depreciation (line 4)		4.9	12.5	29.8	39.9	48.4
7	CCA	3	(214.5)	(160.0)	(174.0)	(183.4)	(183.4)
8	**Net Decrease in Regulatory Taxable Income**		**(195.7)**	**(112.6)**	**(61.2)**	**(33.4)**	**(2.5)**
9	**Income Tax Rate**		25%	25%	25%	25%	25%
10	**Income Tax Impact** (line 8 x line 9/(1 - line 9))		**(65.2)**	**(37.5)**	**(20.4)**	**(11.1)**	**(0.8)**
11	**Total Regulated Hydroelectric CRVA Projects Capital Revenue Requirement** (line 3 + line 4 + line 10)		**(40.0)**	**26.8**	**133.6**	**194.2**	**246.9**

Notes: Refer to Table 1a.

Table 1a
Notes to Table 1
2027-2031 Regulated Hydroelectric CRVA Projects In-Service Additions - Revenue Requirement (Capital Component) ($M)

Notes:
1 The amounts in line 1 are determined as follows:

Line No.		**2027 Plan**	**2028 Plan**	**2029 Plan**	**2030 Plan**	**2031 Plan**
		(a)	(b)	(c)	(d)	(e)
1a	Gross Plant Opening Balance	-	507.6	1,307.7	2,072.9	2,750.9
1b	In-Service Additions*	507.6	800.0	765.3	678.0	311.9
1c	Gross Plant Closing Balance (line 1a + line 1b)	507.6	1,307.7	2,072.9	2,750.9	3,062.9
1d	Gross Plant Rate Base Amount (line 1a + line 1c)/2**	295.6	748.6	1,785.5	2,392.3	2,906.9
1e	Accumulated Depreciation Opening Balance	-	4.9	17.4	47.2	87.0
1f	Depreciation	4.9	12.5	29.8	39.9	48.4
1g	Accumulated Depreciation Closing Balance (line 1e + line 1f)	4.9	17.4	47.2	87.0	135.5
1h	Accumulated Depreciation Rate Base Amount (line 1e + line 1g)/2	2.5	11.2	32.3	67.1	111.3
1i	Net Plant Rate Base Amount (line 1d - line 1h)	293.1	737.5	1,753.2	2,325.2	2,795.6

* CRVA-eligible projects with expected in-service amounts in the 2027-2031 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).

3 Includes CCA related to in-service additions beginning on or after January 1, 2027 only.

UNDERTAKING JT5.13

Undertaking

Provide a table showing total annual revenue recovered under proposed and indicative regulated hydroelectric payment amounts and the production forecast confirmed in part a of A1-SEC-11.

Response

The total annual revenue that would be recovered under the proposed 2027 and the illustrative 2028-2031 regulated hydroelectric payment amounts and based on the regulated hydroelectric production forecast confirmed in Ex. L-A1-SEC-011 is presented in Chart 1 below.

Chart 1: Indicative Regulated Hydroelectric Revenue Recovery

				Illustrative Payment Amounts			
	Description	**Note**	**2027**	**2028**	**2029**	**2030**	**2031**
			(a)	(b)	(c)	(d)	(e)
1	**Proposed and Illustrative Regulated Hydroelectric Payment Amounts ($/MWh)**	Ex. JT4.13, Att. 1, Table 1, line 11	51.39	54.89	59.04	61.78	63.88
2	**Regulated Hydroelectric Production Forecast (TWh)**	Ex. L-A1-SEC-011	32.5	32.7	33.0	33.0	32.9
3	**Indicative Revenue Recovery ($M)**		**1,668.2**	**1,794.9**	**1,948.3**	**2,038.7**	**2,101.7**

UNDERTAKING JT5.14

Undertaking

Advise how OPG would propose to make an adjustment to the 2028 to 2031 hydroelectric payment adjustment formula to eliminate any additional recovery of capital costs as a result of the increase in the forecast hydro production.

Response

For the reasons set out in Ex. L-A1-SEC-011, OPG does not believe it is necessary to include an adjustment of the type contemplated by the undertaking as part of its proposed rate-setting framework for the regulated hydroelectric facilities. For purposes of responding to this undertaking, OPG has considered such a hypothetical adjustment to the proposed regulated hydroelectric payment amount adjustment formula, as shown in Chart 1 below. With the annual increases in the forecast regulated hydroelectric production as confirmed in Ex. L-A1-SEC-011, reducing the price cap index by those percentage increases, together with a corresponding adjustment to the GRCF as discussed below, results in the hypothetical regulated hydroelectric payment amounts shown.

As noted in Ex. L-A1-Staff-334, part b), there is a forecast increase in GRC expense associated with higher production during the IR term. As part of the hypothetical adjustments considered in this response, this reduces the GRCF applicable in each year, as recalculated in line 5 of Chart 1 below.

Chart 1 – Regulated Hydroelectric Payment Amounts with Hypothetical Adjustments for Increased Forecast Production

		2027	2028	2029	2030	2031
1	**Production Forecast (TWh)**	32.5	32.7	33.0	33.0	32.9
2	**Production y/y change (%)**		0.7%	0.9%	0.0%	-0.3%
3	**“I-X” (Ex. JT4.13)**		2.78%	2.78%	2.78%	2.78%
4	**Custom Capital Factor (Ex. JT4.13)**		4.63%	5.34%	2.36%	1.11%
5	**GRCF (recalculated)**		-0.45%	-0.50%	-0.58%	-0.46%
6	**Hypothetical “Growth Factor” (%)**		-0.7%	-0.9%	0.0%	+0.3%
7	**Hypothetical Price Cap Index net of “Growth Factor” (%)** (sum of lines 3 to 6)		6.22%	6.70%	4.56%	3.72%
8	**Price Cap and Growth Factor Adjusted Regulated Hydroelectric Payment Amount ($/MWh)**	**51.39**	**54.59**	**58.25**	**60.90**	**63.17**

UNDERTAKING JT5.15

Undertaking

Provide the impact of the following four illustrative scenarios in 2031 showing how base payment amount revenues are allocated between OPG and DNNP LP under section 5.3 of CCC-10, Attachment 5, holding all other assumptions constant per the rate filing:

a) OPG's nuclear production forecast is 10 percent below its approved forecast and DNNP LP is at its forecast;
b) OPG's nuclear production forecast is 10 percent above its approved forecast and DNNP LP is at its forecast;
c) OPG's nuclear production forecast is at its approved forecast and DNNP LP is 10 percent above its approved forecast; and
d) OPG's nuclear production forecast is at its approved forecast and DNNP LP is 10 percent below its approved forecast, using full-year 2031 values for both.

Response

The Applicants understand the undertaking to be for scenarios where actual production differs from the approved forecast production used to set their nuclear payment amounts. Refer to Attachment 1.

Table 1
OPG and DNNP LP - 2031 Nuclear Base Payment Amount Revenue Scenarios

Line No.	Description	Note	2031 Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
	As Filed														
1	**OPG Forecast Nuclear Production (TWh)**	1	2.6	2.2	1.9	1.9	2.1	2.2	2.8	2.8	2.7	2.9	2.5	2.3	28.9
2	**DNNP LP Forecast Production (TWh)**	1	0.2	0.2	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.1	(0.0)	0.2	1.9
3	**Total Base Payment Amount Revenue ($M)**	2	609.4	527.4	467.0	429.3	505.4	516.9	663.5	663.5	642.1	653.8	543.3	558.3	6,779.8
4	**Revenue Allocation to DNNP LP ($M)**	3	110.0	99.4	110.0	50.7	110.0	102.3	105.7	105.7	102.3	46.8	(5.0)	104.2	1,042.0
5	**Revenue Allocation to OPG ($M)**	8	499.4	428.1	357.0	378.6	395.4	414.6	557.8	557.8	539.8	607.0	548.3	454.1	5,737.7
	Scenario a)														
6	**OPG Actual Nuclear Production (-10%)**	4	2.3	2.0	1.7	1.7	1.9	1.9	2.5	2.5	2.5	2.6	2.2	2.1	26.0
7	**DNNP LP Actual Production (= forecast)**	1	0.2	0.2	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.1	(0.0)	0.2	1.9
8	**Total Base Payment Amount Revenue ($M)**	2	552.9	478.7	424.8	388.4	459.4	469.3	601.4	601.4	582.0	590.3	488.8	506.7	6,144.2
9	**Revenue Allocation to DNNP LP ($M)**	3	110.0	99.4	110.0	50.7	110.0	102.3	105.7	105.7	102.3	46.8	(5.0)	104.2	1,042.0
10	**Revenue Allocation to OPG ($M)**	8	442.9	379.4	314.8	337.7	349.4	367.1	495.7	495.7	479.8	543.5	493.8	402.5	5,102.1
	Scenario b)														
11	**OPG Actual Nuclear Production (+10%)**	5	2.8	2.4	2.1	2.0	2.3	2.4	3.1	3.1	3.0	3.2	2.7	2.6	31.8
12	**DNNP LP Actual Production (= forecast)**	1	0.2	0.2	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.1	(0.0)	0.2	1.9
13	**Total Base Payment Amount Revenue ($M)**	2	665.8	576.1	509.2	470.1	551.5	564.4	725.5	725.5	702.1	717.3	597.8	609.9	7,415.4
14	**Revenue Allocation to DNNP LP ($M)**	3	110.0	99.4	110.0	50.7	110.0	102.3	105.7	105.7	102.3	46.8	(5.0)	104.2	1,042.0
15	**Revenue Allocation to OPG ($M)**	8	555.8	476.8	399.2	419.4	441.5	462.1	619.8	619.8	599.8	670.4	602.8	505.7	6,373.3
	Scenario c)														
16	**OPG Actual Nuclear Production (= forecast)**	1	2.6	2.2	1.9	1.9	2.1	2.2	2.8	2.8	2.7	2.9	2.5	2.3	28.9
17	**DNNP LP Actual Production (+10%)**	6	0.2	0.2	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.1	(0.0)	0.2	2.1
18	**Total Base Payment Amount Revenue ($M)**	2	613.8	531.5	471.5	431.3	509.9	521.0	667.8	667.8	646.2	655.7	543.1	562.5	6,822.2
19	**Revenue Allocation to DNNP LP ($M)**	3	114.5	103.4	114.5	52.8	114.5	106.4	110.0	110.0	106.4	48.8	(5.2)	108.4	1,084.4
20	**Revenue Allocation to OPG ($M)**	8	499.4	428.1	357.0	378.6	395.4	414.6	557.8	557.8	539.8	607.0	548.3	454.1	5,737.7
	Scenario d)														
21	**OPG Actual Nuclear Production (= forecast)**	1	2.6	2.2	1.9	1.9	2.1	2.2	2.8	2.8	2.7	2.9	2.5	2.3	28.9
22	**DNNP LP Actual Production (-10%)**	7	0.2	0.2	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.1	(0.0)	0.2	1.7
23	**Total Base Payment Amount Revenue ($M)**	2	604.9	523.4	462.5	427.2	501.0	512.7	659.2	659.2	637.9	651.9	543.5	554.0	6,737.4
24	**Revenue Allocation to DNNP LP ($M)**	3	105.5	95.3	105.5	48.7	105.5	98.1	101.4	101.4	98.1	44.9	(4.8)	100.0	999.7
25	**Revenue Allocation to OPG ($M)**	8	499.4	428.1	357.0	378.6	395.4	414.6	557.8	557.8	539.8	607.0	548.3	454.1	5,737.7

Notes:
1 From Ex. E2-1-1 Table 26.
2 Sum of OPG Nuclear and DNNP LP production, multiplied by Ex. I1-3-1, Table 1, line 9, col. (e).
3 Revenue Allocation to DNNP LP per Ex. L-CCC-010, Att. 5, Section 5.3: DNNP LP's annual revenue requirement allocated to each month based on DNNP LP's monthly production forecast (Section 5.3(i)), plus (or minus) Actual Base Production Surplus (or Shortfall) determined by multiplying the difference between actual and forecast DNNP LP production by the base nuclear payment amount (Section 5.3(ii)).
4 Amounts from line 1 reduced by 10%.
5 Amounts from line 1 increased by 10%.
6 Amounts from line 2 reduced by 10%.
7 Amounts from line 2 increased by 10%.
8 Total Base Payment Amount Revenue less Revenue Allocation to DNNP LP.

UNDERTAKING JT5.16

Undertaking

Provide the materials shared with Elenchus relating to the outputs of the OM&A capital allocation process and the review or confirmation performed in respect of the OM&A capital blend rule.

Response

Following an exchange between representatives of OPG and SEC to clarify the nature of the materials that OPG had shared with Elenchus, parties agreed that in response to the undertaking:

a) Elenchus would explain the steps it took to review the allocation results/logic considering the response to Ex. L-F3-SEC-180 (that the allocation model is embedded within OPG's internal systems as opposed to being a standalone model); and

b) OPG would provide, as an example, a group/department/cost category that uses the OM&A/Capital allocator (which is the primary allocator under OPG's cost allocation methodology), showing the allocation between OPG's regulated facilities and each of the other entities that the costs are allocated to (and all the relevant calculations). Relevant calculations mean the total costs being allocated, the OM&A/capital amounts for each entity (which derives the allocator percentage), and the application of such percentages to the total costs, to arrive at the allocation to each of the entities.

Part a): Response from Elenchus Research Associates ("Elenchus")

a) In support of Elenchus' review of the cost allocation methodology, OPG provided a detailed allocated cost dataset and arranged a series of meetings to support Elenchus' review of both the methodology and its implementation. The dataset OPG shared with Elenchus included a list of OPG's central and common costs, detailing how each cost had been allocated to cost allocation sites in each year of the business plan period. This file included over 200,000 line items, with each line including items such as:

   - A description of whether the cost was allocated or directly assigned
   - A description of the cost allocation site grouped by the respective regulated and unregulated business segments
   - The resource type to identify the nature of the costs (for example, labour, purchased services, etc.)
   - The allocation rule (allocator) to identify the SAP calculated rule applied, where applicable

- The allocation type and client name, to identify if the costs are directly attributable to a cost allocation site or allocated to cost allocation sites, where applicable
- The organizational structure, broken down by Corporate Support Services, Enterprise Operations and Enterprise Projects; including Centrally Held amounts.

This file followed the same structure as a dataset reviewed by Elenchus in EB-2020-0290. As part of its work for the 2025 Cost Allocation Review, Elenchus reviewed and compared the file provided in EB-2020-0290 with the updated file underpinning the EB-2025-0297 rate application.

Elenchus and OPG held meetings to discuss OPG's cost allocation methodology, including meetings dedicated to a detailed review of the dataset. This review included a walkthrough of the SAP software to illustrate the data underlying the allocation results and the derivation of the allocators. OPG walked Elenchus through the additional manual controls put in place to ensure the derivation of the allocators and the calculation of asset service fees are accurate in accordance with the methodology. Review sessions for the dataset ensured Elenchus understood which costs were directly assigned and how the remaining costs were allocated. Elenchus asked clarifying questions regarding various aspects of the cost allocation methodology and OPG responded to Elenchus' satisfaction.

Elenchus also performed high-level calculations and reasonableness checks to assess the application of the allocators against the allocation results contained in the data set provided by OPG. Elenchus calculated the allocation percentages of specific costs allocated to cost allocation sites and found the allocations to be consistent among different costs that are assigned the same allocator. The reasonableness of the application of allocators was also assessed by comparing the annual calculated allocation percentages for a given allocator across each year of the business plan period. Elenchus also compared the allocation percentages against similar allocators within the file underpinning the EB-2025-0297 rate application and the allocations in the file provided in EB-2020-0290.

b) To demonstrate the application of OPG's cost allocation methodology, which is implemented and executed in OPG's SAP business warehouse ("BW"), Supply Chain – Strategic Programs 2027 Base OM&A costs are used as an example. Chart 1 summarizes the total Supply Chain costs by business segment, while the charts that follow show summarized view of the BW data extract for Supply Chain, the derivation of the primary allocator (blended Capital/OM&A) for the group, and the application of that allocator to Supply Chain – Strategic Programs.

Chart 1: Total Supply Chain Corporate Support and Administrative Costs ($M)

Ex. F3 Table Reference	2027 Amount
Total OPG - Ex. F3-1-1 Table 1	52.0
Total Regulated Hydroelectric - Ex. F3-1-1 Table 2	4.1
Total OPG Nuclear Facilities - Ex. F3-1-1 Table 3	44.6
Total DNNP LP - Ex. F3-1-1 Table 3c	1.2

Chart 2 below reflects a summarized BW data extract of Supply Chain's 2027 Base OM&A costs (and the subset of data provided to Elenchus for its review).

Chart 2: Supply Chain Organization Data Extract from BW ($M)
Base OM&A Costs for 2027

Department/Category	Direct Assignment Costs	Allocated Costs	Total Costs
Chief Supply Officer Office	0.0	2.2	2.2
Supply Chain Project Support	0.8	0.3	1.1
Quality Assurance	7.5	1.4	8.9
Category Management	1.9	4.1	6.0
Strategic Programs	0.1	6.3	6.4
Purchasing	5.1	1.7	6.7
Plant Operations	19.6	0.6	20.2
Primary Pay	-	0.5	0.5
Total OPG - Ex. F3-1-1 Table 1	**34.9**	**17.0**	**52.0**

Per Appendix A of Ex. F3-1-4, Attachment 1, Supply Chain's allocated costs applied the blended Capital/OM&A cost driver to determine the amounts for each cost allocation site. Chart 3 shows the underlying calculation of this cost driver. Consistent with EB-2020-0290, the blended Capital/OM&A cost driver is calculated using direct costs planned to each cost allocation site and excludes expenditures for outage and project work resourced by purchased services[1]. The calculation below is OPG's recalculation of the cost driver for 2027 and agrees to BW's calculation of the same. Also consistent with EB-2020-0290, the calculation of the cost driver

[1] EB-2020-0290 Ex. F3-1-4, Attachment 1, Section 4.1.7.

excludes central and common costs and considers only direct costs charged by OPG's Enterprise Operations and Project organizations[2].

Chart 3: Blended Capital/OM&A Cost Driver Calculation ($M)[1]

Business	Regulated / Unregulated	Cost Allocation Site	Total Direct Capital and OM&A – 2027	Capital/OM&A Cost Driver
Nuclear Generation	Regulated	Pickering	1,291.1	40%
		Darlington	999.0	31%
		DNNP	281.5	9%
Renewable Generation	Regulated & Unregulated	Eastern Region	261.6	8%
		Western Region	184.1	6%
		Niagara Region	144.2	4%
Other	Unregulated		51.1	2%
Total			**3,212.6**	**100%**

[1] Numbers may not add due to rounding.

Using Supply Chain – Strategic Programs as the example, the BW data extract summarized in Chart 4 below shows $0.1M in 2027 as directly attributable OM&A costs to non-regulated other business activities, with the remaining planned amounts allocated using the cost driver shown in Chart 3.

[2] EB-2020-0290 Ex. F3-1-4, Attachment 1, Section 4.1.5.

Chart 4: Allocating Supply Chain – Strategic Programs 2027 Base OM&A ($M)

Business	Regulated / Unregulated	Cost Allocation Site	Direct Assigned Costs	Allocated Costs[1,2]
Nuclear Generation	Regulated	Pickering	-	2.5
		Darlington	-	2.0
		DNNP	-	0.6
Renewable Generation	Regulated & Unregulated	Eastern Region	-	0.5
		Western Region	-	0.4
		Niagara Region	-	0.3
Other Business	Unregulated		0.1	0.1
Total			**0.1**	**6.3**

[1] The BW logic applies the percent allocation from Chart 3 to the total $6.3M to determine the allocation to each cost allocation site.
[2] Numbers may not add due to rounding

UNDERTAKING JT5.17

Undertaking

Provide a reconciliation of how the clean electricity investment tax credit adjustments are applied to the DNNP and PRP projects and advise and explain how the hydro numbers in F4-CCC-84, Attachment 1, Table 3, lines 6 and 7 are derived.

Response

Refer to Attachment 1, Tables 1 to 4 for the estimated CEITC adjustments applied to rate base for the PRP, the DNNP, the Matabichuan GS Redevelopment and the Kakabeka Falls GS Redevelopment for the purposes of Ex. L-F4-CCC-084, Attachment 1, Table 8, lines 12 to 14, and Table 3, lines 6 and 7.

The CEITC adjustments applied to rate base amounts for eligible projects – including the PRP, the DNNP, the Matabichuan GS Redevelopment and the Kakabeka Falls GS Redevelopment – are derived based on the general approach described below and further explained in the notes provided with Attachment 1, Tables 1 to 4.

1. Estimate the amount of capital expenditures eligible for CEITCs. Refer to Attachment 1, Tables 1 to 4, Note 1, line 1a.

2. Estimate the eligible CEITC rate. Refer to Attachment 1, Tables 1 to 4, Note 1, line 1b.

3. Estimate CEITCs to be received annually based on the amount of eligible expenditures and corresponding CEITC rate. Refer to Attachment 1, Tables 1 to 4, Note 1, line 1c, for estimated CEITCs to be received annually.

4. Derive CEITC adjustment to reduce amounts otherwise placed in service and added to rate base for eligible projects. Refer to Attachment 1, Tables 1 to 4, Note 2, line 2f.

UNDERTAKING JT5.18

Undertaking

Advise whether a change to the VBO requested by OPG and approved by the CNSC, resulting in material cost or revenue impacts, would be captured under the change of law variance account, and whether cost or revenue impacts results from a CNSC requirement arising from a deficiency in OPG's maintenance practices would also be captured under the account.

Response

The Applicants would not consider a hypothetical scenario where OPG requests, under existing laws and regulations, the approval of the Canadian Nuclear Safety Commission ("CNSC") to change the timing of a Vacuum Building Outage ("VBO") and the CNSC grants such a request, to be within the scope of the proposed Change of Laws Deferral Accounts. Similarly, the Applicants would not consider impacts from a hypothetical scenario where OPG's maintenance practices are found to be deficient by the CNSC under existing laws and regulations, to be eligible for these accounts. Both scenarios would represent an application of existing laws and regulations.

For clarity, should there instead be a change in laws or regulations the compliance with which results in outcomes to the Applicants, such impacts may be eligible for the proposed Changes of Laws Deferral Accounts, on a symmetrical basis. For example, in November 2025, the CNSC published changes to the Nuclear Security Regulations: SOR/2025-219. These regulations may incrementally increase security requirements for high security nuclear sites, potentially resulting in increased infrastructure or staffing costs. The impacts from the new regulations on the regulated business for each of the Applicants are still being assessed, and as such, are not included the Application. Based on the outcome of this assessment, such costs may be subject to the Change of Laws Deferral Accounts.

Further details on the proposed Change of Laws Deferral Accounts can be found in Ex. H1-1-1, Sections 7.1 and 8.8, Ex. L-H1-SEC-214 and EX. L-H1-CCC-106.

UNDERTAKING JT5.19

Undertaking

Advise whether there have been material developments in the projects that would impact the cost forecast reflected in the Application in the context of the interrogatory response at D3-SEC-118.

Response

There have been no material developments with respect to the Enterprise Asset Management projects for DNNP and OPG (discussed in Ex. L-D3-SEC-118) that have impacted the associated cost forecasts reflected in the Application.

UNDERTAKING JT5.20

Undertaking

Provide the built-in 2027 to 2031 amounts that are expected to be received from Laurentis that would be netted out in the OM&A calculation.

Response

As noted in Ex. L-G2-SEC-202, when Laurentis Energy Partners, an unregulated subsidiary of OPG, uses OPG's employees for purposes of providing services, OPG recovers the associated costs from Laurentis Energy Partners, including allocated support costs in accordance with OPG's cost allocation methodology. OPG's 2025-2031 Business Plan underpinning the Application includes such planned recoveries as a net reduction to OPG's OM&A costs of approximately $18M in 2027, $18M in 2028, $19M in 2029, $19M in 2030, and $20M in 2031. This ensures that none of these costs are included in the Applicants' proposed 2027-2031 revenue requirements.

UNDERTAKING JT5.21

Undertaking

Provide the 2022 to 2024 corporate scorecards and the 2026 corporate scorecard.

Response

The year-end results for the 2025 corporate balanced scorecard are provided in Ex.L-F4-AMPCO-124. The year-end results for the 2021-2024 corporate balanced scorecards, and the 2026 corporate balanced scorecard, are provided below in Charts 1-5.

Chart 1: 2021 Corporate Balanced Scorecard - Year-End Results

2021 Corporate Balanced Scorecard					*Actual 2021 Results*			
Weight	**Key Performance Indicators**	**Threshold**	**Target**	**Stretch**	**Actual Results**	**Score**	**Weighted**	**YE Score**
10%	**Social Licence*** - Through building and maintaining public trust, positive Indigenous relations, climate change goals, and an engaged and inclusive workforce							
10%	**Serious Injury Incidence Rate (SIIR)**	0.07	0.02	0.00	0.02	1.00	0.100	Target
40%	**Financial Strength** - Through regulated and non-regulated asset revenue and expansion of our core business, risk management, commercial focus and financial flexibility							
25%	**Earnings Before Tax**, excl. Nuclear Waste Management segment ($M)	$1,166	$1,266	$1,516	$1,662	1.50	0.375	Stretch
15%	**OM&A Expenses from Ongoing Operations** – Total OPG ($M)	$2,958	$2,908	$2,758	$2,864	1.15	0.172	Above Target
20%	**Operational Excellence** - Through efficiencies and optimized asset management in a safe and environmentally responsible manner							
20%	**Production** – Total OPG adjusted for SBG (TWh)	70.9	73.4	75.9	70.7	0.00	0.00	Below Threshold
30%	**Project Excellence** - Through delivering project results on time and on budget and achieving industry leading project management							
10%	**Refurbishment Cost** –** Unit 3 Costs ($M)	N/A	$1,764M	$1,676M	$1,675	1.50	0.150	Stretch
10%	**Refurbishment Schedule** –** Unit 3 Schedule - % Complete	Project is 48% complete overall	Project is 54% complete overall	Project is 60% complete overall	57%	1.25	0.125	Above Target
10%	**Total In-service Capital - ($M)** not including major projects otherwise on scorecard (e.g. DRP)	$875 +/-10% to +/-15%	$875 +/-3% to +/-10%	$875 +/-3%	$763	0.50	0.050	Threshold
100%	**Results**(1)				0.972 (Below BP)			

These measures form the basis on which overall Corporate performance is assessed, but the scores against these measures and overall Corporate Score are not absolute. *In addition to the measures above, the Board includes OPG's reputation risk and ESG considerations including any extraordinary events as part of its assessment of Corporate performance and overall score. The Board and President reserve the right to determine the Corporate Score. In exercising their discretion, the Board and President may choose to make adjustments to the Corporate Score or individual scorecard items. **Figures included in the threshold, target and stretch goals are based on the final baseline Unit 3 Refurbishment Execution Estimate, which was approved by the board on August 13, 2020 and exclusive of COVID-19 impacts.

Chart 2: 2022 Corporate Balanced Scorecard - Year-End Results

2022 Corporate Balanced Scorecard					*Actual 2022 Results*			
Weight	**Key Performance Indicators**	**Threshold**	**Target**	**Stretch**	**Actual Results**	**Score**	**Weighted**	**YE Score**
20%	**Social Licence*** - Through building and maintaining public trust, positive Indigenous relations, climate change goals, and an engaged and inclusive workforce							
10%	**Serious Injury Incidence Rate (SIIR)**	0.05	0.02	0.00	0.03	0.83	0.083	Below Target
5%	**Supply Chain Diversity Program ($M)**	$10	$14	$18	$18.5	1.50	0.075	Stretch
5%	**Procurement from Indigenous Businesses ($M)**	$40	$56	$65	$57.6	1.09	0.054	Above Target
35%	**Financial Strength** - Through regulated and non-regulated asset revenue and expansion of our core business, risk management, commercial focus and financial flexibility							
20%	**Earnings Before Tax**, excl. Nuclear Waste Management segment ($M)	$1,595	$1,720	$2,045	$2,102	1.50	0.300	Stretch
15%	**OM&A Expenses from Ongoing Operations** – Total OPG ($M)	$2,762	$2,712	$2,562	$2,681	1.10	0.166	Above Target
20%	**Operational Excellence** - Through efficiencies and optimized asset management in a safe and environmentally responsible manner							
20%	**Production** – Total OPG adjusted for SBG (TWh)	66.0	68.5	71.0	70.4	1.38	0.276	Above Target
25%	**Project Excellence** - Through delivering project results on time and on budget and achieving industry leading project management							
7.5%	**Refurbishment Cost –** Unit 3, 1 & 4 Costs ($M)	N/A	$3,503	$3,404	$3,391	1.50	0.113	Stretch
7.5%	**Refurbishment Schedule –** Unit 3 Schedule - % Complete	Project is 69% complete overall	Project is 77% complete overall	Project is 86% complete overall	95%	1.50	0.113	Stretch
10%	**Total In-service Capital - ($M)** not including major projects otherwise on scorecard (e.g. Darlington Refurbishment)	$1,346 +/-10% to +/-15%	$1,346 +/-3% to +/-10%	$1,346 +/-3%	$1,297	1.00	0.100	Target
100%	**Results[(1)]**				1.280 (Above BP)			

These measures form the basis on which overall Corporate performance is assessed, but the scores against these measures and overall Corporate Score are not absolute. *The Board will include OPG's reputation risk and Environment, Social, and Governance (ESG) considerations as part of its assessment of Corporate performance. The Board and President reserve the right to determine the Corporate Score. In exercising their discretion, the Board and President may choose to make adjustments to the Corporate Score or individual scorecard items.

1 **Chart 3: 2023 Corporate Balanced Scorecard - Year-End Results**
2

2023 Corporate Balanced Scorecard					*Actual 2023 Results*			
Weight	**Key Performance Indicators**	**Threshold**	**Target**	**Stretch**	**Actual Results**	**Score**	**Weighted**	**YE Score**
20%	**Social Licence*** - Through building and maintaining public trust, positive Indigenous relations, climate change goals, and an engaged and inclusive workforce							
10%	**Serious Injury Incidence Rate (SIIR)**	0.05	0.02	0.00	0.00	1.50	0.15	Stretch
5%	**Supply Chain Diversity Program ($M)**	16	24	32	58.3	1.50	0.075	Stretch
5%	**Indigenous Economic Empowerment ($M)**	59	84	109	142	1.50	0.075	Stretch
35%	**Financial Strength** - Through regulated and non-regulated asset revenue and expansion of our core business, risk management, commercial focus and financial flexibility							
20%	**Earnings Before Tax**, excl. Nuclear Waste Management segment ($M)	2,035	2,160	2,485	2,199	1.06	0.212	Above Target
15%	**OM&A Expenses from Ongoing Operations** – Total OPG ($M)	2,816	2,766	2,616	2,896	0.00	0.000	Below Threshold
20%	**Operational Excellence** - Through efficiencies and optimized asset management in a safe and environmentally responsible manner							
20%	**Production** – Total OPG adjusted for SBG (TWh)	65.8	68.3	70.8	71.1	1.50	0.300	Stretch
25%	**Project Excellence** - Through delivering project results on time and on budget and achieving industry leading project management							
7.5%	**Refurbishment Cost –** Unit 3, 1 & 4 Costs ($M)	N/A	4,793	4,678	4,528	1.50	0.113	Stretch
7.5%	**Refurbishment Schedule –** Unit 3 Schedule - % Complete/Return-to-Service (RTS) Date	Project is 90% complete overall	RTS by Jan 2, 2024 or better	RTS by Sept 5, 2023 or better	July 18, 2023	1.50	0.113	Stretch
10%	**Total In-service Capital - ($M)** not including major projects otherwise on scorecard (e.g. Darlington Refurbishment)	1,292 +/-10% to +/-15%	1,292 +/-3% to +/-10%	1,292 +/-3%	1,286	1.50	0.150	Stretch
100%	**Results**[(1)]				1.188 (Above BP)			

These measures form the basis on which overall Corporate performance is assessed, but the scores against these measures and overall Corporate Score are not absolute. *The Board will include OPG's reputation risk and Environment, Social, and Governance (ESG) considerations as part of its assessment of Corporate performance. The Board and President reserve the right to determine the Corporate Score. In exercising their discretion, the Board and President may choose to make adjustments to the Corporate Score or individual scorecard items.

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Chart 4: 2024 Corporate Balanced Scorecard - Year-End Results

2024 Corporate Balanced Scorecard					*Actual 2024 Results*			
Weight	**Key Performance Indicators**	**Threshold**	**Target**	**Stretch**	**Actual Results**	**Score**	**Weighted**	**YE Score**
20%	**Social Licence*** - Through building and maintaining public trust, positive Indigenous relations, climate change goals, and an engaged and inclusive workforce							
10%	**Serious Injury Incidence Rate (SIIR)**	0.04	0.02	0	0.02	1.00	0.100	Target
5%	**Supply Chain Diversity Program ($M)**	25	36	47	81	1.50	0.075	Stretch
5%	**Indigenous Economic Empowerment ($M)**	78	112	140	171	1.50	0.075	Stretch
35%	**Financial Strength** - Through regulated and non-regulated asset revenue and expansion of our core business, risk management, commercial focus and financial flexibility							
20%	**Earnings Before Tax**, excl. Nuclear Waste Management segment ($M)	1,268	1,348	1,548	1,358	1.03	0.205	Above Target
15%	**OM&A Expenses from Ongoing Operations** – Total OPG ($M)	3,077	3,022	2,862	3,012	1.03	0.155	Above Target
20%	**Operational Excellence** - Through efficiencies and optimized asset management in a safe and environmentally responsible manner							
20%	**Production** – Total OPG adjusted for SBG (TWh)	64.3	66.8	69.3	68.1	1.26	0.252	Above Target
25%	**Project Excellence** - Through delivering project results on time and on budget and achieving industry leading project management							
7.5%	**Refurbishment Cost –** Unit 3, 1 & 4 Costs ($M)	N/A	5,804	5,670	5,459	1.50	0.112	Stretch
7.5%	**Refurbishment Schedule –** Unit 1 Schedule - % Complete/Return-to-Service (RTS) Date	Project is 84% complete overall	Project is 92% complete overall	RTS by Nov 15, 2024 or better	98%	1.37	0.103	Above Target
10%	**Total In-service Capital - ($M)** not including major projects otherwise on scorecard (e.g. Darlington Refurbishment)	1,400 +/-10% to +/-15%	1,400 +/-3% to +/-10%	1,400 +/-3%	1,415	1.50	0.150	Stretch
100%	**Results[(1)]**				1.227 (Above BP)			

These measures form the basis on which OPG's overall Corporate performance will be assessed, but the scores against these measures and overall Corporate Score are not absolute. *The Board will include OPG's reputation risk and Environmental, Social, and Governance (ESG) considerations as part of its assessment of Corporate performance. The Board and President reserve the right to determine the Corporate Score. In exercising their discretion, the Board and President may choose to make adjustments to the Corporate Score or individual scorecard items.
*Operating OM&A forecast includes a Management recommended scorecard adjustment to exclude the impact of the expected PWU retroactive payment and the impact of a discount rate and provision rate changes compared to plan on Low & Intermediate Level Waste.
**Includes a Management recommended scorecard adjustment to exclude the impact of a discount rate and provision rate changes compared to plan on Low & Intermediate Level Waste.
***Earnings Before Tax forecast includes a Management recommended scorecard adjustment to exclude the impact of the [redacted]. OM&A from on-going operations excludes costs covered by our deferral and variance accounts, and costs from large developmental projects. This metric also excludes results from our operating subsidiaries. This view of OM&A strives to help our organization understand how much it takes to run our operations and creates a view of costs that ensures we are working towards keeping costs low for our rate payers.

Chart 5: 2026 Corporate Balanced Scorecard

2026 Corporate Balanced Scorecard					
Weight	**Key Performance Indicators**		**Threshold**	**Target**	**Stretch**
20%	**Social Licence*** - Through building and maintaining public trust, positive Indigenous relations, climate change goals, and an engaged and inclusive workforce.				
10%	**Serious Injury Incidence Rate (SIIR)**		0.03	0.01	0.00
10%	5%	**Supply Chain Diversity Program ($M) Spends**	55	70	90
	5%	**Indigenous Economic Empowerment ($M) Spends**	150	185	200
35%	**Financial Strength** - Through regulated and non-regulated asset revenue and expansion of our core business, risk management, commercial focus and financial flexibility				
20%	**Earnings Before Tax**, excl. Nuclear Waste Management segment ($M)		[redacted]		
15%	**OM&A Expenses from Ongoing Operations** – Total OPG ($M)		[redacted]		
20%	**Operational Excellence** - Through efficiencies and optimized asset management in a safe and environmentally responsible manner				
20%	**Production** – Total OPG adjusted for SBG (TWh)		[redacted]		
25%	**Project Excellence** - Through delivering project results on time and on budget and achieving industry leading project management				
15%	7.5%	DNNP Unit 1 Percent Complete	51%	56%	58%
	7.5%	DNNP LTD Unit 1 Cost	$3.66	$3.41B	$3.39B
10%	**Total In-service Capital - ($M)** not including major projects otherwise on scorecard (e.g., Darlington Refurbishment)		[redacted]		
			+/-10% to +/-15%	+/-3% to +/-10%	+/-3%
100%					

These measures form the basis on which OPG's overall Corporate performance will be assessed, but the scores against these measures and overall Corporate Score are not absolute. *The Board will include OPG's reputation risk and Environmental, Social, and Governance (ESG) considerations as part of its assessment of Corporate performance. The Board and President reserve the right to determine the Corporate Score. In exercising their discretion, the Board and President may choose to make adjustments to the Corporate Score or individual scorecard items.

UNDERTAKING JT5.22

Undertaking

Provide a calculation in excel format underpinning the current metrics in SEC-35 separately showing the concurrent cost recovery line item in a meaningful but sufficiently summarized level of detail that anchors the business plan information for the company.

Response

Refer to Attachment 1 (confidential) (filed in Microsoft excel).

Exhibit JT5.22, Attachment 1

This Attachment was filed as confidential information in its entirety.

UNDERTAKING JT5.23

Undertaking

Describe the risk management policy and, in general terms, how it is applied.

Response

OPG's Enterprise Risk Management Policy (Attachment 1) ensures a consistent, scalable approach to risk management to support decision making and governance responsibilities across the organization. The policy applies to OPG and its subsidiaries, including business plans, activities, processes, policies, procedures, individuals and property. Risk management is the responsibility of all employees as part of their duties at OPG.

OPG applies the policy through a structured and proactive process to assess risks at the enterprise, business unit and project levels, supported by a regular cycle of risk review, escalation, and oversight to ensure that material risks are identified, assessed, monitored and where possible, mitigated.

Enterprise level risks, which are those that may affect the achievement of corporate objectives, strategic priorities, operational performance, and long-term value, are reviewed regularly to ensure they remain current and reflective of changes in the internal and external operating environments. This process supports informed decision-making by senior management and enables appropriate oversight of the organization's overall risk profile by both OPG's Enterprise Leadership Team and Board of Directors.

Business unit level risks are managed by the business areas where such risks arise. Business units are responsible for identifying, assessing, and managing risks within their respective areas, while aligning with OPG's broader enterprise risk management expectations. This helps ensure that operational and department-specific risks are understood in context, appropriately mitigated where possible, and escalated where they may have broader enterprise significance.

At the project level, risks are managed, with a specific focus on cost and schedule uncertainty, through project planning and execution. Such risk management activities are undertaken pursuant to OPG project management governance, scaled based on the overall value and complexity of the project.

The enterprise risk team works with business units and stakeholders across the company to review leading indicators, performance trends, and key risk information. This is designed to enable the organization to identify early warning signals, evaluate whether existing controls and mitigation plans remain effective, and determine whether additional action is required.

OPG continually assesses the external environment to identify emerging risks, trends, and areas of opportunity. This includes consideration of industry developments, regulatory changes, market conditions, technological shifts, stakeholder expectations, and other external factors that could affect the organization. Some of the resources that may be utilized by the risk team in performing the external environmental scan include the World Economic Forum’s Global Risks Report, Gartner resources, reports issued by professional consulting firms, as well as peer industry groups such as Electricity Canada and the Edison Electric Institute.

Title: ENTERPRISE RISK MANAGEMENT POLICY

Policy Statements:

The mandate of Enterprise Risk Management ("ERM") is to promote risk-informed decision making and support the effective execution of OPG's strategic and business plans by implementing a company-wide risk management framework. OPG is committed to managing risks and pursuing opportunities to achieve its strategic objectives and business imperatives.

The purpose of this policy is to ensure a consistent, scalable approach to risk management throughout Ontario Power Generation ("OPG") and its subsidiaries to support decision making and governance responsibilities.

This policy applies to all plans, activities, business processes, policies, procedures, individuals and property that comprise OPG and its subsidiaries. Risk management is the responsibility of all employees as part of their duties at OPG.

Requirements:

Enterprise Risk Management:

- OPG shall implement risk management processes to identify, assess, prioritize, treat, monitor and report risks, as an integral part of its management and governance of its resources, including periodic reporting of risks and risk treatments to the Executive Risk Committee ("ERC") and the Audit and Risk Committee ("ARC") of OPG's Board of Directors ("Board").
- Risk management activities will comply with all applicable legal and regulatory requirements and take into consideration industry leading practices.
- Risk management shall be integrated into strategic planning, asset investment and resource allocation decisions.
- OPG shall provide management and the Board with an assessment of the effectiveness of risk management processes every three years.

Risk Appetite and Tolerance:

Risk appetite is the amount of risk an entity is willing to accept or retain in order to achieve its strategic objectives and business imperatives.

The Board, with recommendations through the ARC, shall consider and approve risk appetite statements defined by management (i.e., the ERC).

Risk tolerance represents the practical application of risk appetite and sets an acceptable range of risk taking, over a given period of time, including limits and triggers, in order to achieve a specific objective or manage a category of risk. Where possible, OPG shall manage risks within the defined acceptable tolerance range. Risk tolerances for enterprise risks shall be established through Key Risk Indicators at the discretion of the ERC.

Risk Reporting:

The Vice President Risk & Audit and Chief Audit Executive shall ensure the following items are reported to the ERC and the ARC as part of quarterly risk reporting:

a) Enterprise risks;
b) Exceptions to risk tolerance levels for KRIs;
c) Developments in risk treatment actions; and
d) Significant risk events that have occurred and the impact.

Market and Trading Limit Exceptions:

Market and Trading activities are governed by the Credit and Market Risk Program (OPG-PROG-0016). Exceptions or changes to the limits set out in that program will be reported to the ERC and ARC by the Senior Vice President & Treasurer.

Accountabilities:

Board of Directors (through the ARC):

- Oversees ERM such that the identification and management of OPG's principal risks to the business are in place and are effective; and
- Approves the ERM Policy and risk appetite statements.

The President & Chief Executive Officer ("CEO"):

- Ensures management and oversight systems are in place as part of an effective ERM program to manage risks within the corporation;
- Approves the membership and mandate of the ERC;
- Has overall accountability of the management of risks in the organization; and
- Endorses and supports a risk-aware culture (tone from the top).

Executive Risk Committee:

- Provides oversight and direction to risk management activities and processes;
- Considers and approves risk management strategies for the top risks of the organization;
- Develops risk appetite statements for Board approval, and establishes risk tolerance levels on KRIs at its discretion;
- Establishes and approves exceptions to trading risk limits in the Credit & Market Risk Program (if required); and
- Reviews the consolidated quarterly risk report, including validating risks, risk updates, risk treatment plans and risk prioritization.

Vice President, Risk & Audit and Chief Audit Executive ("CAE"):

- Oversees the ERM program within OPG and develops and implements an ERM framework and processes to identify, measure, manage, and report on enterprise risks;
- Ensures that the ERM program and processes are effective;
- Participates in risk-related Board Committee meetings, including acting as the Subject Matter Expert ("SME") on risk management and providing risk guidance and support as part of the development of the strategic plan;
- Ensures that appropriate risk appetite statements, tolerances and limits have been established, consistent with the ERM framework;
- Reports the corporation's risk profile on a quarterly basis to the ARC; and
- On an annual basis, reviews compensation policies to ensure that structures do not provide incentives for excessive risk taking by management.

Senior Vice President & Treasurer:

- Independently oversees and assesses risk management within OPG as it relates to Energy Markets, Supply Chain, and Treasury and routinely reporting to the CAE on material changes in the limits and any significant exceptions; and
- Verifies and validates that appropriate risk tolerances and limits have been established consistent with the credit and market risk management framework.

Business Unit Leaders and Management (including Risk Owners):

- Identify, assess, prioritize, manage and monitor risks on a day-to-day basis in their span of control within their established risk tolerances and in compliance with approved risk management policies, procedures and limits;
- Regularly assess and report significant risks, including significant risk events that have occurred, as well as any exceptions to risk management policies, procedures and limits to senior management and to the ERM team; and
- Engage employees in the management of risk and ensures staff are aware of their accountabilities with regards to risk management.

Employees:

- Shall report risks to their supervisor and manage risks within their scope of accountability.

Sponsoring Unit: Corporate Services **Approval:** Board of Directors

Effective Date: May 7, 2026

Document requires CNSC Notification ☐