AMPCO Interrogatory #090

Interrogatory

Reference:
F1-1-1 p.4

Preamble:

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. In December 2024, the OAGO released a Follow-Up Report on its 2022 Value for Money Audit.

Question(s):

a) Please provide a copy of the OAGO's 2022 Value for Money audit of OPG's Management and Maintenance of Hydroelectric Generating Stations.

b) Please provide a copy of the OAGO's December 2024 Follow-Up Report on its 2022 Value for Money Audit.

Response

a) The 2022 Value for Money Audit[1] of OPG's Management and Maintenance of Hydroelectric Generating Stations can be found at: Ontario Power Generation: Management and Maintenance of Hydroelectric Generating Stations

b) The 2024 Follow-Up on the 2022 Value for Money Audit[1] can be found at: Ontario Power Generation: Management and Maintenance of Hydroelectric Generating Stations

[1] As the Office of the Auditor General's reports are locked and cannot be edited, OPG is unable to file in accordance with the OEB's Regulatory Electronic Submission System Document Guide.

Witness Panel: Hydroelectric Operations and Hydroelectric Projects, and Market Renewal Program

AMPCO Interrogatory #091

Interrogatory

Reference:
F1-1-1 p.5

Preamble:

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.

Question(s):

a) For each of the 53 regulated hydroelectric refurbishment projects, please complete the following Table.

2027-2031 Hydroelectric Refurb Projects (capital)	Project #	Capacity Sustained (MW)	Planned MW Capacity Added (MW)	LCOE* $/MWh	Total Project Cost ($M)	Inservice $ 2027-2031
Total		1,500	50			

*Levelized Cost of Electricity (LCOE)

Response

For clarity, there are 39 refurbishment projects associated with 53 hydroelectric generating units at OPG's regulated hydroelectric facilities that are expected to come into service during the 2027-2031 period. Certain projects include multiple hydroelectric generating units.

The requested information regarding the 39 refurbishment projects is presented in Charts 1 to 4 below. Levelized cost of energy ("LCOE") analyses are not performed for refurbishment projects.

Chart 1 - Tier 1 Projects (Allocated)

2027-2031 Hydroelectric Refurbishment Projects (Capital)	Project #	Unit	Capacity Sustained (MW)	Planned MW Capacity Added (MW)	Total Project Cost[1] ($M)	In-Service 2027-2031 ($M)
Abitibi Canyon GS, G1	83148	G1	69.5	0.0	54.7	46.8
R.H. Saunders GS, G16	86937	G16	61.7	4.5	49.3	38.7
Alexander GS, G2	86792	G2	12.6	0.0	49.7	43.5
Alexander GS, G1	82391	G1	12.6	0.0	45.9	42.0
Alexander GS, G3	86793	G3	12.6	0.0	43.6	40.0
Manitou Falls GS, G3	86860	G3	14.9	0.0	53.2	48.0
Sir Adam Beck 1 GS, G4	86570	G4	53.1	2.0	109.4	96.7
Sir Adam Beck 1 GS, G6/G8	86372	G6	53.1	5.0	232.3	226.2
		G8	53.1	5.0		
Sir Adam Beck 2 GS, G20/G19	87768	G20	93.7	1.5	377.5	353.0
		G19	93.7	1.5		
Sir Adam Beck 2 GS, G18/G17	87356	G18	93.7	1.5	361.1	344.2
		G17	93.7	1.5		
Total			**718.0**	**22.5**	**1376.8**	**1279.1**

Note 1: Total project cost as per Ex. D1-1-2, Table 1.

Chart 2 – Tier 2 Projects (Allocated)

2027-2031 Hydroelectric Refurbishment Projects (Capital)	Project #	Unit	Capacity Sustained (MW)	Planned MW Capacity Added (MW)	Total Project Cost[2] ($M)	In-service 2027-2031 ($M)
Otto Holden GS, G1	87545	G1	28.1	1.9	13.3	12.0
Stewartville GS, G5	82351	G5	57.9	0.7	19.1	17.1
Total			**86**	**2.6**	**32.4**	**29.1**

Note 2: Total project cost as per Ex. D1-1-2, Table 2b.

Refer to Ex. L-D1-Staff-064 for further details on the use of unallocated portfolio funding.

Chart 3 – Unallocated Projects (Estimated Investment Cost >$10M)

2027-2031 Hydroelectric Refurbishment Projects (Capital)	Project #	Unit	Capacity Sustained (MW)	Planned MW Capacity Added (MW)	Estimated Investment Cost[3] ($M)	In-service 2027-2031 ($M)
Otter Rapids GS, G4	82545	G4	45.6	5.1	43.1	35.7
Otter Rapids GS, G3	82544	G3	45.6	5.1	43.3	35.8
Chenaux GS, 1st Unit	87529	G1	18.0	0.0	15.2	13.8
Chenaux GS, 2nd Unit	89134	G2	18.0	0.0	15.3	13.5
Chenaux GS, 3rd Unit	89135	G3	18.0	0.0	15.6	13.6
Otto Holden GS, G2	87546	G2	28.1	1.9	11.5	10.2
Otto Holden GS, G3	89154	G3	28.1	1.9	11.7	10.4
Otto Holden GS, G4	89155	G4	28.1	1.9	11.9	10.6
R.H. Saunders GS, G10	87548	G10	56.5	9.7	35.1	29.0
R.H. Saunders GS, G2	87549	G2	66.2	0.0	35.2	30.2

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2027-2031 Hydroelectric Refurbishment Projects (Capital)	Project #	Unit	Capacity Sustained (MW)	Planned MW Capacity Added (MW)	Estimated Investment Cost[3] ($M)	In-service 2027-2031 ($M)
Stewartville GS, 2nd Unit	87550	G4	57.9	0.7	18.6	17.1
Stewartville GS, 3rd Unit	87551	G1	22.1	0.0	19.0	17.5
Stewartville GS, 4th Unit	89168	G2	22.1	0.0	18.8	17.3
Stewartville GS, 5th Unit	89169	G3	22.1	0.0	19.3	17.6
Chat Falls[4] GS, G2-G9	87525	G3	24.0	0.0	32.5	27.6
		G7	24.0	0.0		
		G4	24.0	0.0		
		G8	24.0	0.0		
		G5	0.0	0.0		
		G6	0.0	0.0		
		G2	0.0	0.0		
		G9	0.0	0.0		
Manitou Falls GS, G1	89245	G1	14.9	0.0	40.5	37.0
Manitou Falls GS, G2	89246	G2	14.9	0.0	40.2	37.0
DeCew Falls 1 GS, G5, G6, G7, G8	89524	G5	5.7	0.0	126.0	126.0
		G6	5.7	0.0		
		G7	5.7	0.0		
		G8	5.7	0.0		
DeCew Falls 2 GS, G2	87963	G2	72.0	0.0	17.6	16.7
Total			**697**	**26.3**	**570.4**	**516.7**

Notes:
3. Estimated investment cost for unallocated projects greater than $10M as per Ex. L-D1-Staff-064, Attachment 1.
4. Total station installed capacity is 192 MW; OPG is entitled to 50% of the capacity (96 MW) – see Ex. A1-4-2, Section 2.1.

Chart 4 – Tier 3 Allocated Projects and Unallocated Projects (Estimated Total Project Cost <$10M)

2027-2031 Hydroelectric Refurbishment Projects (Capital)	Project #	Unit	Capacity Sustained (MW)	Planned MW Capacity Added (MW)	Estimated Investment Cost ($M)	In-service 2027-2031 ($M)
Hanna Chute GS, G1	87306	G1	1.4	0.0	2.9	2.8
Meyersburg GS, G2	86214	G2	1.7	0.0	9.3	8.5
Meyersburg GS, G3	87704	G3	1.7	0.0	6.7	6.3
Seymour GS, G5	89228	G5	1.1	0.0	0.7	0.6
Seymour GS, G4	89229	G4	1.1	0.0	0.7	0.7
South Falls GS, G1	83204	G1	2.2	0.0	7.9	7.5
South Falls GS, G3	83205	G3	2.2	0.0	8.4	8.0
Hagues Reach GS, G2/G3	86852	G2	1.2	0.0	5.7	5.4
		G3	1.2	0.0		
Total			**12.**	**0.0**	**42.3**	**39.8**

Chart 5 – Summary of Sustaining MW and Added Capacity

	Capacity Sustained MW	Planned Capacity Added MW
Chart 1	718.0	22.5
Chart 2	86.0	2.6
Chart 3	697.0	26.3
Chart 4	13.9	0.0
Total	**1,514.9**	**51.4**

AMPCO Interrogatory #092

Interrogatory

Reference:
F1-1-1 pp.5-6

Question(s):

With respect to the overhaul projects planned over the 2027-2031 period, please complete the following Table:

2027-2031 Hydroelectric Overhaul Projects (OM&A)	Project #	Capacity Sustained (MW)	Planned MW Capacity Added (MW)	LCOE $/MWh	OM&A $ 2027-2031
Total					

Response

In accordance with the Motions Resolutions letter filed on May 4, 2026, OPG has revised this interrogatory response.

Refer to Chart 1 and Chart 2 for the forecast allocated overhaul projects OM&A spending for the regulated hydroelectric facilities for 2027 and 2028-2031, respectively. Overhaul projects do not add capacity.

OPG does not perform Levelized Cost of Energy ("LCOE") analyses for overhaul projects.

Chart 1 – 2027 Allocated Regulated Hydroelectric Overhaul Projects OM&A Costs

Project #	2027 Hydroelectric Overhaul Projects (OM&A)		Capacity Sustained (MW)	OM&A 2027 ($M)
	Station	Unit		
82515	Otter Rapids GS	G1	45.6	0.0
87558	Otto Holden GS	G1	28.1	1.8
86945	R.H. Saunders GS	G16	61.7	3.1
82340	Stewartville GS	G5	57.9	5.8
86859	Manitou Falls GS	G3	14.9	0.6
82416	Sir Adam Beck 1 GS	G4	53.1	0.1
84293	Sir Adam Beck 2 GS	G20	93.7	1.3
		G19	93.7	
Total			**448.7**	**12.8**

Chart 2 – 2028-2031 Allocated Regulated Hydroelectric Overhaul Projects OM&A Costs

Project #	2028-2031 Hydroelectric Overhaul Projects (OM&A)		Capacity Sustained (MW)	OM&A 2028-2031 ($M)
	Station	Unit		
86945	R.H. Saunders GS	G16	61.7	0.6
82517	Alexander GS	G1	12.6	2.2
82021	Hanna Chute GS	G1	1.4	1.4
86859	Manitou Falls GS	G3	14.9	1.5
84293	Sir Adam Beck 2 GS	G20	93.7	0.5
		G19	93.7	
Total			**278.0**	**6.1**

Having provided this information in accordance with the Motions Resolutions letter filed on May 4, 2026, OPG maintains that the information for the outer years of the period

(i.e., 2028-2031) is not relevant under the proposed regulated hydroelectric rate-setting methodology (Ex. A1-3-2, Section 2.0). Outside of the C-factor which relies on a five-year forecast of capital related revenue requirement, OPG's proposed hydroelectric rate-setting methodology is based on a cost of service review of the 2027 test year (Ex. A1-3-2, Section 2.2). Beyond the 2027 test year, regulated hydroelectric revenue will be determined formulaically by the proposed annual adjustment mechanism outlined in Ex. A1-3-2, Section 2.3.

AMPCO Interrogatory #093

Interrogatory

Reference:
F1-1-1 p.8

Question(s):

With respect to the redevelopment projects planned over the 2027-2031 period, please complete the following Table:

2027-2031 Hydroelectric Redevelopment Projects (capital)	Project #	Capacity Sustained (MW)	Planned MW Capacity Added (MW)	LCOE $/MWh	Total Project Cost ($M)	In-service $ 2027-2031
Total						

Response

Refer to Chart 1 for the requested information.

Chart 1 – Redevelopment Projects (Allocated)

2027-2031 Hydroelectric Redevelopment Projects (capital)	Proj. #	Capacity Sustained (MW)	Planned MW Capacity Added (MW)	Estimated LCOE ($/MWh)	Total Proj. Cost[2] ($M)	In-Service[2] 2027-2031 ($M)
Bingham Chute GS Redevelopment[1]	86385	1.0	1.0	~83 ($2026)	24.0	0.5
Kakabeka Falls GS Redevelopment	86386	24.6	2.8	~90 ($2024)	519.0	487.1
Matabitchuan GS Redevelopment	86387	9.6	2.4	~125 ($2024)	190.0	183.4
Coniston/Stinson GS Redevelopment	82087	8.1	3.9	~110 ($2024)	178.0	45.9
Total		**43.3**	**10.1**		**911.0**	**716.9**

Notes:

[1] Project #86385 Bingham Chute GS Redevelopment has not yet progressed to the Execution Phase; levelized cost of energy ("LCOE"), total project cost, and in-service dates are based on a Class 4 estimate. A Class 3 estimate and refined estimate of added capacity will be completed for the project's transition into the Execution Phase.

[2] Total project cost and in-service amounts for Kakabeka Falls GS, Matabitchuan GS and Coniston/Stinson GS Redevelopment Projects are provided in Ex. D1-1-2, Table 1. Total project cost and in-service amounts for Bingham Chute GS Redevelopment are provided in Ex. D1-1-2, Table 2b.

AMPCO Interrogatory #094

Interrogatory

Reference:
F1-1-1 p.15

Question(s):

With respect to the expansion opportunities planned over the 2027-2031 period, please complete the following Table:

2027-2031 Expansion Projects (capital)	Project #	# New Units	Capacity Sustained (MW)	Planned MW Capacity Added (MW)	LCOE $/MWh	Total Project Cost ($M)	In-service $ 2027-2031
Total							

Response

Refer to Chart 1.

OPG is exploring adding generation to Chats Falls GS, an existing hydroelectric station, in the form of a new generating unit, in line with the Province's 2025 Integrated Energy Plan[1] and the 2023 Powering Ontario's Growth Report[2]. The project is a proposed investment (i.e., unallocated – refer to Ex. L-D1-Staff-064) and has not yet progressed to the Development Phase. The estimated investment cost is considered preliminary and will be refined if the investment transitions into the Development Phase (in accordance with the processes described in Ex. D2-1-1, p. 7). An estimated Levelized Cost of Energy will be determined once the project reaches such Gate 1, and the investment cost estimate and planning have further matured.

[1] "Energy for Generations: Ontario's Integrated Plan to Power the Strongest Economy in the G7", Ministry of Energy and Mines, p. 54
[2] Province of Ontario, Powering Ontario's Growth: Ontario's Plan for a Clean Energy Future, p. 53

Witness Panel: Hydroelectric Operations and Hydroelectric Projects, and Market Renewal Program

Chart 1 – Regulated Hydroelectric Proposed Expansion Investments

2027-2031 Expansion Projects (capital)	Project #	# New Units	Capacity Sustained (MW)	Planned MW Capacity Added (MW)[1]	LCOE $/MWh	Estimated Investment Cost ($M)[1]	In-service $ 2027-2031
Chats Falls GS Expansion	89553	1	0	16.5	n/a	124	0
Total	**-**	**1**	**0**	**16.5**	**-**	**124**	**0**

Note 1: As this facility is jointly owned with Hydro-Québec, 16.5 MW represents one-half of the capacity of the proposed new unit. Hydro-Québec is entitled to one-half of the energy, and the investment cost will be shared. The figure of $124M represents OPG's portion of the estimated investment cost.

AMPCO Interrogatory #095

Interrogatory

Reference:
F1-1-1 pp.17-29

Question(s):

For each of the measures under the Performance Metrics of Safety, Environment, Reliability, and Cost Effectiveness, please provide 2025 Actuals.

Response

Refer to Ex. L-F1-SEC-153.

AMPCO Interrogatory #096

Interrogatory

Reference:
F1-1-1 p.23

Question(s):

a) With respect to planned outages over the 2016-2024 period, please provide the forecast percentage allocated to the Eastern Region, Niagara Region and Western Region.

b) With respect to planned outages over the 2025-2031 period, please provide the forecast percentage allocated to the Eastern Region, Niagara Region and Western Region.

Response

In accordance with the Motions Resolutions letter filed on May 4, 2026, OPG has revised this interrogatory response.

a) Refer to Chart 1 for the actual and forecast regulated hydroelectric planned outage percentages (by region) for 2016-2024, where the forecast information for each year is from the respective year's budget.

Chart 1 - Allocated Planned Outage Percentage per Region (2016-2024)

	Forecast	Actual[1]
Eastern Region	61%	61%
Niagara Region	29%	28%
Western Region	10%	11%
Total Regulated Hydro	100%	100%

Note 1: as described in Ex. F1-1-1, p. 23.

Having provided this information in accordance with the Motions Resolutions letter filed on May 4, 2026, OPG maintains that the annual budgeted information from each year's respective budget is not relevant on the basis that the request goes beyond the scope of the OEB's current Filing Requirements, which were subject to extensive consultation in EB-2024-0136 with the "aim to address evolving regulatory landscape *and incorporate lessons learned from past proceedings.*" (emphasis added) OPG further notes that regulated hydroelectric payments in past

applications (EB-2016-0152 and EB-2020-0290) were determined mechanistically, rather than pursuant to cost-of-service rebasing reviews. As such, there are no OEB-approved amounts against which to compare the provided information.

b) Percentage allocation of planned outages for the regulated hydroelectric facilities by region for 2025 (actual), 2026-2027 (forecast) and 2028-2031 (forecast) are presented in Chart 2.

Chart 2 – 2025 (Actual), 2026-2027 (Forecast) and 2028-2031 (Forecast) Planned Outage Allocation by Region

Region	2025 (Actual)	2026-2027 (Forecast)	2028-2031 (Forecast)
Eastern Region	71%	60%	51%
Niagara Region	18%	29%	37%
Western Region	11%	11%	11%
Total	**100%**	**100%**	**100%**

Having provided this information in accordance with the Motions Resolutions letter filed on May 4, 2026, OPG maintains that the information for the outer years of the period (i.e., 2028-2031) is not relevant under the proposed regulated hydroelectric rate-setting methodology (Ex. A1-3-2, Section 2.0). Outside of the C-factor which relies on a five-year forecast of capital related revenue requirement, OPG's proposed hydroelectric rate-setting methodology is based on a cost of service review of the 2027 test year (Ex. A1-3-2, Section 2.2). Beyond the 2027 test year, regulated hydroelectric revenue will be determined formulaically by the proposed annual adjustment mechanism outlined in Ex. A1-3-2, Section 2.3.

AMPCO Interrogatory #097

Interrogatory

Reference:
F1-1-1 p.28

Question(s):

With respect to Chart 10 and Chart 11, please provide the data that underpins the Regulated Hydroelectric Unit Energy Cost Forecast ($/MWh) calculation for each of the years 2016 to 2027 including 2025 actuals and in the response provide 2014 and 2015 actuals.

Response

Refer to Attachment 1.

For clarity, annual submissions to the OEB for Regulated Hydroelectric Unit Energy Cost are completed at a point in time and are not restated to reflect any subsequent organizational changes.

As per the OEB's Decision and Order, EB-2016-0152, December 28, 2017, p. 149, there was no requirement to file targets prior to 2017.

Numbers may not add due to rounding.

Ex. L-F1-AMPCO-097 - Attachment 1
Regulated Hydroelectric Unit Energy Cost Forecast & Actual ($/MWh, 2025-2027)
Unit Energy Cost Target and Actual - 2014-2027[6]

UEC Calculation	2014 Actual[2]	2015 Actual[2]	2016 Actual[2]	2017 Target	2017 Actual	2018 Target	2018 Actual	2019 Target	2019 Actual	2020 Target	2020 Actual	2021 Target	2021 Actual
Base OM&A	171.0	192.9	194.1	205.1	200.7	176.6	201.2	189.2	199.1	198.8	198.3	190.4	200.2
Project OM&A[1]	45.1	52.4	39.0	61.0	42.3	70.8	53.6	52.9	53.8	65.7	51.9	84.1	81.0
Asset Service Fee[1]	5.6	6.3	5.2	5.3	5.7	5.9	5.6	6.1	6.9	9.4	7.9	9.2	9.9
Total Direct OM&A	221.7	251.6	238.3	271.4	248.7	253.2	260.4	248.2	259.8	273.9	258.1	283.7	291.0
Generation - net of SBG spill (TWh)[3,5]	31.4	30.4	29.5	31.2	30.7	30.5	29.8	29.6	30.5	31.3	30.3	32.2	29.0
Actual as submitted in F1-1-1 ($/MWh)[4]	7.1	8.3	8.1	N/A	8.1	N/A	8.7	N/A	8.5	N/A	8.5	N/A	10.0
Target as submitted in RRR ($/MWh)	N/A	N/A	N/A	8.7	N/A	8.3	N/A	8.4	N/A	8.8	N/A	8.8	N/A

UEC Calculation	2022 Target	2022 Actual	2023 Target	2023 Actual	2024 Target	2024 Actual	2025 Target	2025 Actual	2026 Target	2027 Target
Base OM&A	204.3	216.4	215.6	231.7	239.1	248.4	261.1	256.0	274.2	286.2
Project OM&A[1]	82.8	69.9	70.7	73.0	93.6	59.7	89.6	62.5	83.9	119.6
Asset Service Fee[1]	11.5	13.5	11.0	14.8	15.1	15.5	15.7	18.0	20.7	24.2
Direct OM&A ($M)	298.7	299.8	297.3	319.5	347.8	323.6	366.4	336.5	378.7	430.0
Generation - net of SBG spill (TWh)[3,5]	32.6	31.1	31.8	31.4	31.7	32.5	33.0	30.9	32.8	32.5
Actual as submitted in F1-1-1 ($/MWh)[4]	N/A	9.6	N/A	10.2	N/A	10.0	N/A	10.9	N/A	N/A
Target as submitted in RRR ($/MWh)[4]	9.2	N/A	9.3	N/A	11.0	N/A	11.1	N/A	11.5	13.2

Notes

1 Hydro redevelopment costs excluded, operating components of asset service fees excluded
2 No targets were submitted in RRR until 2017
3 2025-2027 production values are on a pre-spill basis, i.e. there are no deductions made for SBG as per Ex. E1-1-1, Section 3.1
4 RRR targets filed are subject to change upon finalization of assumptions and cost allocations
5 Actual generation is net of SBG spill
6 UEC is calculated at a point in time and not subsequently restated for organizational changes

AMPCO Interrogatory #098

Interrogatory

Reference:
F1-1-1 p.29

Question(s):

a) With respect to Chart 12, please provide the data that underpins the Regulated Hydroelectric Total Generation Cost Performance ($/MWh) calculation for each of the years 2016-2024 and in the response include 2014 and 2015 actuals.

b) With respect to Chart 12, please provide the calculation of the forecast Regulated Hydroelectric Total Generation Cost Performance ($/MWh) for each of the years 2025 to 2027 including 2025 actuals.

c) Please confirm why redevelopment projects are excluded from TGC calculation.

Response

a) Refer to Attachment 1 for 2014-2024 data that underpins the Regulated Hydroelectric Total Generation Cost Performance ("TGC") in Ex. F1-1-1, Chart 12, including 2014 and 2015 actuals.

In the course of responding to this interrogatory, OPG identified a minor discrepancy in the reconciliation of the 2024 TGC. The revision has been reflected in Attachment 1. The impact of the correction reduced the 2024 three-year average to $31.8/MWh from $32.0/MWh reported in the 2024 RRR submission.

b) Refer to Attachment 1 for 2025 actuals data that underpins the regulated hydroelectric TGC performance. As discussed in Ex. L-F1-Staff-168, OPG does not set Total Generating Cost targets for the regulated hydroelectric business.

c) Refer to Ex. L-F1-SEC-153.

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Numbers may not add due to rounding.

Ex. L-F1-AMPCO-098 - Attachment 1
Regulated Hydroelectric Total Generating Cost Actuals ($/MWh)

		Actual 2014 [1]	Actual 2015 [1]	Actual 2016	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Actual 2024	Actual 2025	
1	**Total Regulated Hydroelectric Generation - pre spill (MW)**	**34.7**	**33.3**	**33.7**	**35.9**	**33.0**	**33.8**	**34.6**	**30.9**	**32.7**	**32.4**	**32.9**	**31.6**	
2	Total OM&A for Value for Money Metrics ($M)	295.2	318.1	301.9	305.0	309.7	309.1	308.1	347.8	348.5	374.5	387.8	394.5	
3	Total Capital for Value for Money Metrics ($M)	80.0	83.3	125.5	118.4	131.8	170.9	220.6	285.7	229.1	342.4	379.2	497.7	
4	Total Fuel for Value for Money Metrics ($M)	352.6	353.3	362.0	388.5	360.7	366.6	379.6	341.9	352.3	350.4	355.6	343.0	
5	**Total Generating Costs for Value for Money Metrics ($M)**	**727.9**	**754.6**	**789.4**	**811.9**	**802.1**	**846.7**	**908.3**	**975.4**	**930.0**	**1067.3**	**1122.6**	**1235.2**	**Line 2 + Line 3 + Line 4**
6	Total Generating Costs per MWh ($/MWh) - 1 Year	21.0	22.7	23.4	22.6	24.3	25.0	26.3	31.6	28.5	32.9	34.1	39.0	**Line 5 divided by Line 1**
7	**Total Generating Costs per MWh ($/MWh) - 3 Year**	**N/A**	**N/A**	**22.4**	**22.9**	**23.4**	**24.0**	**25.2**	**27.6**	**28.8**	**31.0**	**31.9**	**35.4**	**Average of rolling 3 years**

Notes

1 2014 and 2015 data per RRR filing
2 RRR filings are subject to change upon finalization of assumptions and cost allocations
3 Numbers may differ slightly from pre-filed RRRs due to rounding.

AMPCO Interrogatory #099

Interrogatory

Reference:
F1-1-1 Table 1

Question(s):

Please add 2014 and 2015 OEB-approved and Actuals to Table 1 split between Previously Regulated Hydroelectric and Newly Regulated Hydroelectric.

Response

Consistent with the OEB's Letter regarding OPG's Updated Filing Requirements in EB-2024-0136 dated September 17, 2024, OPG has determined that it is unable to meaningfully provide the 2014 and 2015 information requested by this interrogatory. Organizational and cost structure changes over the past decade have made it impossible to present the 2014 and 2015 historical actual OM&A costs, compensation and benefits details, and staffing information for the regulated hydroelectric business in a manner that is comparable to the data provided in Ex. F1-1-1, Table 1.

AMPCO Interrogatory #100

Interrogatory

Reference:
F1-1-1 Table 2b

Question(s):

Please split Regulated Hydroelectric OM&A FTEs (Regular, Non-Regular, Temporary) between Base OM&A and Project OM&A.

Response

Refer to Attachment 1, filed in Microsoft Excel format.

AMPCO Interrogatory #101

Interrogatory

Reference:
F1-3-3 Table 1

Question(s):

With respect to Project #82328 Otto Holden GS Concrete Mitigation Phase 2, please provide the following:

a) Project Close Out Report.

b) Post Implementation Review (PIR) Report.

c) CPI and SPI results.

Response

a) Refer to Attachment 1.

b) Refer to part a). Consistent with OPG's governance, for Project #82328, the Project Closure Report is used as the PIR report.

c) The CPI for this project is 0.95; the SPI is 1.0.

ONTARIO POWER GENERATION

OPG Confidential
FIN-FORM-PA-004-R03
Project Closure Report

Part 1: Project Account Closure - Complete for all projects			
Is this PCR also used as a PIR report?	Yes	**Records Document Number (required only when the PCR is also used as a PIR report)**	NA6-REP-08700-1631650
Organization	RG - Renewable Projects	**Date**	04/10/2025
Project Number	82328	**Site / Location Name**	OTO - OTTO HOLDEN
Project Title	82328 OTO - CONCRETE MITIGATION PHASE 2		
Project and Asset (if any) Description	82328: Scope includes restoring the deteriorated concrete structure to its original functionality. Items to be completed east gravity dam restoration, tailrace training wall repairs, downstream powerhouse wall restoration, tailrace deck grating replacement, west gravity dam crack injection, powerhouse beam restoration, headworks deck restoration (U6-U8), headworks beam restoration (U7/U8), Pier #1 restoration.		
Super Asset Number	N/A	**Asset Class**	N/A
Company Code	N/A	**Business Area**	N/A

Part 2: Final In-service Transfer - Complete for CAPITAL projects	
Final In-service Transfer Credit Amount (Controller)	

Part 3: Project Cost and Schedule Variance - Complete for all projects

When the Cost variance is not within the acceptable range as per OPG Estimate Manual, OPG-MAN-00120-0012, cost variance root cause should be captured (e.g., inflation, scope, performance issues, etc.).

	(1) Original Approved Estimate	**(2) Current Approved Estimate**	**(3) Final / Actuals**	**(4) Variance (=3-2)**
Cost	23,600,000.00	31,820,000.00	30,995,895.78	(824,104.22)
Schedule (In-serivce date)	12/01/2020	03/31/2022	11/15/2022	32 weeks behind of schedule

Deliverables (Completed? Intended Functionality Achieved? Target vs. Actions?)

DELIVERABLES:
The following have been completed and restored:
- Restoration of the East and West gravity dams and the downstream powerhouse wall.
- Replacement of the tailrace deck grating.
- Completion of powerhouse beams.
- Restoring of the powerhouse floor to its original load-bearing capacity.
- Completion of the U7/U8 deck and beams, downstream training wall, and U6 deck.
- Completion of the U3/U4 in-water beams and the U1 to U6 downstream deck.
- Completion of the U4/U5 deck, U5/U6 in-water beams, and U7/U8 downstream deck.
- Completion of the U2/U3 deck, U1/U2 in-water beams, U1 pier, and U1 deck.

COST VARIANCE:

PREVIOUS BCS - According to the previous BCS estimate of $23,600,000 the project initially exceeded the budget by $8,220,000. This was due to unforeseen and as-found Alkali Aggregate Reaction (AAR) concrete conditions that were not apparent until removal, as well as changes in environmental regulation requirements.
Reference the previous BCS attached to this PCR, NA6-PLAN-26100-0002.

SUPERSEDING BCS - Based on the superseding BCS estimate of $31,820,000, the project was actually under budget by $824,104.22 due to a lower drawdown of contingency funds. Below is a summary of the variances between the previous BCS and the superseding BCS estimates:

OPG Project Management: To support schedule extension and unforeseen and as-found concrete conditions.
Previous BCS = $485,000
Superseding BCS = $729,000
Variance = $244,000

OPG Engineering including Design: To provide additional engineering and design support for schedule extension.
Previous BCS = $188,000
Superseding BCS = $233,000
Variance = $45,000

OPG Procured Materials: To procure additional miscellaneous materials and DFO/MNR testing not originally contemplated.
Previous BCS = $0
Superseding BCS = $141,000
Variance = $141,000

OPG Other (PWU): Underestimated production support requirements included unanticipated log operations and switching for diver safety and water management.
Previous BCS = $438,000
Superseding BCS = $1,026,000
Variance = $588,000

Construction Contract(s): To support schedule extension, unforeseen and as-found concrete conditions due to AAR.
Previous BCS = $19,950,000
Superseding BCS = $26,397,000
Variance = $6,447,000

Consultants: To support schedule extension, unforeseen and as-found concrete conditions due to AAR.
Previous BCS = $409,000
Superseding BCS = $814,000
Variance = $405,000

Contingency: To cover schedule extension, unforeseen and as-found concrete conditions due to AAR.
Previous BCS = $2,130,000
Superseding BCS = $2,480,000
Variance = $350,000

TOTAL:
Previous BCS = $23,600,000
Superseding BCS = $31,820,000
Variance = $8,220,000

Reference the superseding BCS attached to this PCR, NA6-BCS-08707-0007 R0, Appendix B, Project Variance Analysis, for a summary of the variances between the original BCS and the superseding BCS.

SCHEDULE VARIANCE:
A schedule variance of 32 weeks has arisen due to unexpected and as-found concrete conditions that became apparent only after concrete removal due to AAR, along with changes in environmental regulation requirements.

Associated REIS									
ID	**Project Number**	**Status**	**Approved Project Amount**	**Project Release Date**	**In Service Amount Prev Reported**	**Capital In Service Amount**	**Date Placed In Service**	**Date Ready For Service**	**LTD Actual Expenditure**

Lessons Learned				
Lessons Learned ID	**Title**	**Description**	**Category**	**Recommendation**

History of BCS						
Document Number	**Gate**	**Sub Gate**	**Release**	**Approval Date**	**Target Completion Date**	**Total Cost Estimate**

Finance SPOC Reviewer	
Reviewer	(202025) Rob Pretty
	Senior Financial Analyst Eastern Region Operations Controllership
Signature	Approved by: Rob Pretty
Date	4/25/2025 10:01:33 AM

Part 4: PCR Approval Signature - Complete for all projects			
Project Manager: The project is declared closed. I confirm that all remaining materials (if applicable) of the project are appropriately dispositioned as spare parts to accepting business areas or are declared surplus. No cost shall be charged to this project at this point forward.		**Controller for Project Organization (if applicable, i.e., the BU/Function has a Project Organization Controller):** I confirm the information documented in this PCR is correct.	
Project Manager	(202014) Jeff Hautanen	**Controller for Project Organization**	
	Senior Manager Projects Ottawa Projects Projects		
Signature	Approved by: Jeff Hautanen	**Signature**	
Date	4/25/2025 4:19:58 PM	**Date**	
Station/Plant Group/Function Controller: I confirm the information documented in this PCR is correct.		**Asset Owner:** I authorize the decision to declare project closure for this project.	
Controller for Sponsoring Organization	(212399) Martin Rupnik	**Asset Owner or Sponsoring Organization Authority**	(204230) Scott Gagnon
	Finance Controller Eastern Region Operations Controllership		Director Plant Operations Southeast Operations S: Production

Signature	Approved by: Martin Rupnik	**Signature**	Approved by: Scott Gagnon
Date	5/5/2025 1:24:30 PM	**Date**	5/8/2025 1:01:31 PM

Part 5: PIR Signature - Required only when the PCR is also used as a PIR report	
I have reviewed and accept the PIR results in this report.	
Project Sponser	(209693) Amanda Griener
	Director Asset & Project Mgmt Production Support Production Support
Signature	Approved by: Amanda Griener
Date	5/14/2025 1:35:50 PM

Part 6: Distribution - Required only when the PCR is also used as a PIR report	
Distribution: When this PCR is also used as a PIR report, the Project Sponsor shall ensure distribution (cc) to the following personnel if they have not already signed off above:	
Name **Title, Department, BU/Function**	
Finance Approver	
Line Approver	

Other Key Stakeholders

Part 7: PCR Checklist - Compele for all projects CSA or Project Manager		
Checklist Item	**Complete**	**Explanation**
Indicate if PCR related to a Project where Default Labour was posted via MyTime	Yes	Work events closed in EBX
Request sent to AS9 buyer to close PO/COs after closing related MRs/CRs	Yes	On 17-Apr/25, an email was sent to Katie P. to close 1 open MR; and another email was sent to Richard Marzec to close 1 open CN.
Request sent to Planner to close any AS9 Work Order Tasks	N/A	There is no open WOT.
Request sent to ONCORE to close all tasks and associated PO's	N/A	
All accruals have been cleared.	Yes	
Any purchases through purchasing cards (VISA) or Ariba Web Catalogue have been reconciled in Concur or shipped by Ariba Vendor	Yes	

All default Business Expense or VISA default accounts have been changed.	Yes	
All spare parts have been set up in AS9, including: Inventory by Cat ID with ROP/TMAX values	N/A	
Capital Spares are set up in the appropriate Asset Class and account	N/A	
All obsolete or surplus inventory or components have been identified and Surplus Declaratations routed to ensure that all retired assets have been properly removed from the fixed asset ledger and inventory accounts.	N/A	
The Super Asset Class, the Company Code, Super Asset Numbers agree with previous REIS.	N/A	
The Final Actual Costs and Current Approved Estimate agree with FRA and/or SAP.	Yes	
If this is combined PCR/PIR, it was defined in the approved BCS.	Yes	
If the Actuals are greater than the Approved amount, the overspend has been approved in accordance with the appropriate OAR Element specified in the BCS standard (OPG-STD-0076, Developing and Documenting Business Cases), with an approved OPG-FORM-0077, Project Over-Variance Approval or a Superseding BCS.	Yes	There is an approved superseding BCS for the overspend (NA6-BCS-08707-0007 R0).
A copy of the FRA and/or SAP Report is attached.	Yes	SAP is not applicable

Project CSA / Project Manager (Sign-Off): I confirm the completion of all the checklist items.	
Project CSA or Project Manager	(222289) Charles Shariff
	Project Control Officer SEO Projects RG & Corp
Signature	Confirmed by: Charles Shariff
Date	4/25/2025 9:32:33 AM

AMPCO Interrogatory #102

Interrogatory

Reference:
F1-3-3 Table 2

Question(s):

a) Please add the following column to Table 2:
   i. Total Project Cost at time of EB-2020-0290
   ii. Final Completion Date at time of EB-2020-0290.

b) Please confirm all OM&A projects with 2025 to March 2026 completion dates were completed as planned.

Response

a) OPG declines to provide the requested information on the basis of lack of clarity and relevance. Hydroelectric OM&A projects were not within scope in EB-2020-0290 and did not form the basis for setting payment amounts for the current 2022-2026 IR term. In addition, OPG notes that all but five projects in Ex. F1-3-3, Table 2 are identified as completed before 2027, and therefore do not form part of the 2027 test year revenue requirement that is within the scope of this proceeding.

b) Refer to Attachment 1. Note that for OM&A projects, Final Completion Date refers to the date at which the project is closed, which is subsequent to the date on which the work is substantially completed.

Ex. L-F1-AMPCO-102 - Attachment 1
Status of OM&A Projects With Completion Dates Jan 2025 - March 2026

Project Name	Project Number	EB-2025-0297 Final Completion Date	Actual / Forecast Completion Date	Completion Status	Variance Explanation
OTO - G7 Overhaul - Mechanical/Electrical Unit Overhauls	82326	Jan-25	Jan-25	Completed as planned	
R.H. Saunders GS - Concrete Growth Mitigation	80788	Feb-26	Mar-26	Late completion	No material difference.
Des Joachims GS - Headworks Piers Concrete Repairs	82588	Sep-25	Sep-25	Completed as planned	
BAR - NS G4 Mech/Elec Overhaul	84588	Feb-25	Feb-25	Completed as planned	
BAR - G1 Mech/Elec Overhaul	86078	Feb-26	Apr-26	Late completion	Project closed, delay to project closeout report completion.
BAR G2 Mech/Electrical Overhaul	86079	Dec-25	Apr-26	Late completion	Project closed, delay to project closeout report completion.
OTO - G8 Overhaul (NS)	86476	Jan-26	Aug-26	Pending	Project work complete. Administrative closeout in progress.
OTO - G5 Overhaul; NS	86481	Sep-25	Feb-26	Late completion	Project closed, delay to project closeout report completion.
SAU - Concrete Growth Mitigation	80788	Feb-26	Mar-26	Late completion	No material difference.
SAU - Unit Hatchcover Refurb	82334	Jun-25	Jun-25	Completed as planned	
DEJ - Auxiliary Dam Repair Deck & Handrails	84161	Dec-25	Jul-26	Pending	Project work complete. Administrative closeout in progress.
Otter G2 Non-Standard Overhaul	82521	Mar-26	May-26	Pending	Refer to Ex. L-D1-Staff-316.
Dredge Tunnel 1 and 2 Intakes	82413	Mar-25	Mar-25	Completed as planned	
Whitesand Erosion Repairs	80749	Dec-25	Dec-26	Pending	Work is substantially complete, ongoing monitoring in progress to ensure shoreline stability.

AMPCO Interrogatory #103

Interrogatory

Reference:
F1-3-3 Table 4b

Question(s):

For the two projects with a 2025 Potential Start Date, please indicate if the projects have started.

Response

The status of the two projects that displayed a Potential Start Date of 2025 in Ex. F1-3-3, Table 4b is shown in Chart 1.

Chart 1 – Status of Projects with 2025 Potential Start Date

Project	Status
SAU - Concrete Growth Mitigation-Phase 2	Not started. Further refinement of scope required. Estimated start 2026.
CHE - O/H Program 1st Unit Overhaul	Started

CCC Interrogatory #066

Interrogatory

Reference:
Exhibit F1, Tab 2, Schedule 1, pp. 3-4

Preamble:

2023 Actual versus 2022 Actual

Actual Base OM&A costs in 2023 were $236.5M, which was $21.0M or 10% higher than 2022 actual amount of $215.5M. All regulated hydroelectric organizations were impacted by higher labour cost escalation in 2023 reflecting collective bargaining process outcomes including as a result 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:

- Operations and Maintenance ($17.0M or 12% increase):

- Operations ($2.5M or 10% increase): no other reportable variance

- Maintenance ($14.4M or 12% increase): due to higher maintenance costs primarily at R.H. Saunders GS and Sir Adam Beck 1 GS and Sir Adam Beck 2 GS due to environmental remediation (e.g., lead paint and asbestos removal), storm response clean-up, and additional joint works expenditures (see Ex. A1-4-2).

- Integrated Fleet Management ($3.7M or 82% increase): due to increased staffing levels in security, and training to support increased work program and address training backlogs.

- Enterprise Projects ($1.0M or 51% increase): due to higher staffing levels to support the increased regulated hydroelectric project portfolio.

Question(s):

When were the environmental remediation, storm response clean-up, and additional joint works expenditures completed?

Response

OPG interprets this interrogatory to be referencing Ex. F1-2-2, pp. 3-4.

Environmental remediation, storm response clean-up, and joint works expenditures cited were completed in 2023.

CCC Interrogatory #067

Interrogatory

Reference:
Exhibit F1, Tab 2, Schedule 1, pp. 3-4

Preamble:

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.

Question(s):

a) Please provide the forecast hydroelectric Project OM&A budgets from 2028 to 2031.

b) How much, if any, of the proposed 2027 Project OM&A is eligible for the CRVA?

Response

In accordance with the Motions Resolutions letter filed on May 4, 2026, OPG has revised this interrogatory response.

a) Refer to Ex. L-A1-SEC-012, Attachment 1, Table 4, which has been provided pursuant to the Motions Resolutions letter filed on May 4, 2026.

   Having provided this information in accordance with the Motions Resolutions letter filed on May 4, 2026, OPG maintains that the information for the outer years of the period (i.e., 2028-2031) is not relevant under the proposed regulated hydroelectric rate-setting methodology (Ex. A1-3-2, Section 2.0). Outside of the C-factor, OPG's proposed hydroelectric rate-setting methodology is based on a detailed review of the 2027 test-year (Ex. A1-3-2, Section 2.2). Beyond the 2027 test year, regulated hydroelectric revenue will be determined formulaically by the proposed annual adjustment mechanism outlined in Ex. A1-3-2, Section 2.3.

b) The proposed 2027 Project OM&A costs include $25.3M of non-capital costs related to CRVA-eligible projects, as noted in Ex. F1-3-1, Table 1, Note 4. Refer to Ex. L-H1-CCC-100.

CCC Interrogatory #068

Interrogatory

Reference:
Exhibit F1, Tab 4, Schedule 2, p. 1

Preamble:

The GRC is directly dependant on energy production and year-over-year GRC variances result from production impacts (primarily unit outages, water conditions, and market conditions, see Ex. E1-1-1 and Ex. E1-1-2). For historical periods, GRC is based on the actual energy production. GRC forecasts are calculated based on the energy production forecast described in Ex. E-1-1-1. The differences between actual and forecast production that are attributable to changes in natural water conditions will be captured in the Hydroelectric Water Conditions Variance Account. The account applies to 27 regulated hydroelectric plants, located on nine river systems (see Ex. E1-1-1, Appendix 1 and Ex. H1-1-1). Changes in GRC associated with these energy variances are included in determining the account balance (see Ex. H1-1-1).

Question(s):

Please confirm that differences in GRC caused by differences in unit outages and market conditions are not captured in any variance account, and OPG is not proposing to capture such impacts in a new or existing variance account.

Response

Not confirmed. Differences between actual and forecast production can be attributable to market conditions that give rise to surplus baseload generation ("SBG"), the impact of which is recorded in the Hydroelectric Surplus Baseload Generation Variance Account. As discussed in Ex. H1-1-1, Section 5.4, the account captures such impacts net of associated GRC variances. These effects are fully captured in the account as OPG's hydroelectric payment amounts have been set using a hydroelectric production and GRC cost forecast that is not reduced by SBG. OPG proposes to continue with this approach in this Application, with SBG further discussed in Ex. E1-2-1, Section 4.0.

OPG confirms that differences in GRC costs attributable to unit outages or non-SBG market conditions are not captured in any variance account.

CCC Interrogatory #069

Interrogatory

Reference:
Exhibit F1, Tab 5, Schedule 1, p. 1, Chart 1

Preamble:

Total OM&A purchased services expenditures for all contactors for the historical period (2016-2024) was $57.1M in 2016, $53.2M in 2017, $57.1M in 2018, $56.5M in 2019, 49.9M in 2020, $64.7M in 2021, $78.3M in 2022, $80.2M in 2023, and $71.4M in 2024. For OM&A purchased services where costs are allocated to both the regulated and non-regulated facilities within Renewable Generation (such as work centers), only the amounts allocated to regulated hydroelectric facilities have been included (details on OPG's cost allocation methodology are described in Ex. F3-1-4 and Ex. F1-2-1). The average annual OM&A purchased services for the regulated hydroelectric facilities for all contractors over the period of 2016-2024 was $63.1M.

Question(s):

a) What are the budgeted OM&A purchased services expenditures for 2025, 2026 and 2027?

b) How can the contracts in chart 1 be sole sourced because they were less then $500,000, when the chart is supposed to be contracts in excess of $20M?

c) What was the average number of separate contracts/providers per year?

Response

a) Budgeted regulated hydroelectric OM&A purchased services expenditures for 2025, 2026 and 2027 are $93.6M, $95.6M and $120.7M, respectively.

b) As referenced in Ex. F1-5-1, p. 1, lines 26-28, the information presented in Chart 1 is contracts for OM&A purchased services with spend equal to or in excess of the $20M threshold, per supplier, for the years between 2016-2024. Since the information is presented as an aggregate for each supplier, an individual contract could be included in the aggregate that was issued by the supplier that is under the single-source threshold of $500,000.

c) OPG interprets this question as being the average number of distinct providers with spend, per year, between 2016-2024. The average number of separate providers per year was 305.

CCMBC Interrogatory #001

Interrogatory

Reference:
F1-1-1, Table 1, Operating Costs Summary - Regulated Hydroelectric

Question(s):

a) Please explain the reason for the large increase in Project OM&A from $90.5 million in 2026 Budget to $127.0 million in the 2027 Plan.

b) Why did the Allocation of Corporate Costs decrease from $50.1 million in 2016 to $38.4 million in 2020 and then increase each year to $55.3 million in 2027?

Response

a) The main driver of the increase in regulated hydroelectric Project OM&A costs between 2026 and 2027 is portfolio projects (Ex. F1-3-2, Section 2.1) and infrastructure projects for planned removal costs corresponding with increased refurbishment activity at regulated hydroelectric stations (Ex. F1-3-2, Section 2.2).

b) OPG notes that Allocation of Corporate Costs was $51.0M, not $50.1M, in 2016, per Ex. F1-1-1, Table 1, line 3, col. (a).

The decrease in costs from 2016-2020 was primarily due to a change in allocation methodology to use IT end users as the cost driver for Corporate & Technology Services ("CTS"), as identified in Ex. F3-1-2, p. 5. This methodology change was further discussed in EB-2020-0290, Ex. F3-1-4, Attachment 1, Section 4.1.4, where it was supported and found to be appropriately reflective of the principle of causality by Elenchus Research Associates Inc. in their review of OPG's cost allocation methodology.

As discussed throughout Ex. F3-1-2, pp. 2-5, the increase in the allocation of Corporate Support costs from 2020 to 2027 is largely related to:

- CTS: higher staffing levels to support increased IT requirements from the business and increased cost of digital tools across the enterprise resulting in higher software and hardware costs.
- Finance: 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).

Witness Panel: Hydroelectric Operations and Hydroelectric Projects, and Market Renewal Program

CCMBC Interrogatory #002

Interrogatory

Reference:
F1-1-1, Table 2b, Regulated Hydroelectric Staff Summary – Regular and Non-Regular (FTEs)1 – 2020-2031, and A1-3-2, page 11

Question(s):

a) Considering that OPG has not built or acquired any new hydroelectric stations, please explain the reasons for the increase of 430.1 FTEs or 39,4% in Regulated Hydroelectric Staff from 1091.4 FTEs in 2020 to 1521.5 FTEs in the 2027 Plan.

b) Please confirm that the increase in FTEs is one of the main reasons for the negative productivity of Regulated Hydroelectric of -0.40% and -1.01%.

Response

a) As shown in Ex. F1-1-1, Table 2b, the breakdown of the increase of 430.1 FTEs from 2020-2027 is as follows:

- Regulated Hydroelectric Capital, Regular: 188.6 FTEs
- Regulated Hydroelectric Capital, Temporary: 66.8 FTEs
- Regulated Hydroelectric OM&A, Regular: 173.3 FTEs
- Regulated Hydroelectric OM&A, Temporary: 1.5 FTEs

The increase in Capital Regular FTEs (188.6) and Temporary FTEs (66.8) reflects the addition of personnel required to support the increasing capital investment over the forecast period to address the condition of aging assets in the regulated hydroelectric fleet, as described in Ex. D1-1-1, Section 2.0. As further described in Ex. F1-1-1, Section 3.2, OPG's key business plan focus areas for the regulated hydroelectric facilities include the significant refurbishment program required to sustain approximately 1,500 MW of the existing regulated hydroelectric fleet capacity and add an estimated incremental capacity of approximately 50 MW. The increase in project resources supports the growth of the capital program and ensures capability to manage the increased complexity and volume of work, support schedule adherence, and compliance with enterprise governance requirements.

The increase in OM&A Regular FTEs (173.3) reflects the addition of personnel across project management, operations, maintenance, engineering, and training functions, as described in Ex. F1-2-1, Section 3.4. These additions support

improved fleet performance through key work programs, including enhanced governance, monitoring, and internal controls, as well as address the recommendations from the Auditor General's 2022 Value for Money audit of OPG's hydroelectric facilities to enhance OPG's maintenance planning and management systems (refer to Ex. F1-1-1, p. 4).

OM&A Temporary FTEs are not a significant contributor to the overall increase.

The response to part b) was prepared by London Economics International LLC:

b) Not confirmed. The FTE data referred to in the question is just for OPG, whereas the industry TFP results referred to in the question are for the industry as a whole, which is composed of 21 peers, including OPG. As noted in response to Ex. L-A1-Staff-279, part (h) above, OPG's regulated fleet accounts for only 15% of the industry capacity considered in the industry TFP study (based on data as of 2023). It is also worth noting that FTE data is not available for US peers; therefore, there are not long-term trends around FTEs available for the industry. To understand the key drivers of the industry TFP trends, please see Section 6 of LEI's TFP report.

SEC Interrogatory #146

Interrogatory

Reference:
F1-1-1, p. 4-5

Question(s):

With respect to refurbishment program/projects:

a) With respect to the turbine-generator refurbishment program, please provide a list of projects that constitute the $2,193.6M of capital expenditures on refurbishment projects in the 2027-2031 forecast period.

b) Please provide a list of the 53 regulated hydroelectric refurbishment projects that are expected to come into service during the 2027-2031 forecast period, including the total cost.

Response

a) Refer to Charts 1 and 2.

Chart 1- List of Allocated Regulated Hydroelectric Refurbishment Projects with Capital Expenditures 2027-2031

Project#	Generating Station and Unit(s)
83148	Abitibi Canyon GS, G1
87545	Otto Holden GS, G1
86937	R.H. Saunders GS, G16
82351	Stewartville GS, G5
86792	Alexander GS, G2
82391	Alexander GS, G1
86793	Alexander GS, G3
87306	Hanna Chute GS, G1
86860	Manitou Falls GS, G3
83204	South Falls GS, G1
86570	Sir Adam Beck 1 GS, G4
86372	Sir Adam Beck 1 GS, G6/G8

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87768	Sir Adam Beck 2 GS, G20/G19
87356	Sir Adam Beck 2 GS, G18/G17
82542	Otter Rapids GS, G1
83356	Otto Holden GS, Runner Only
83104	R.H. Saunders GS, Runner Only
86587	R.H. Saunders GS, G12
83257	Cameron Falls GS, G7
87357	Sir Adam Beck 2 GS, G14/G13

Chart 2- List of Unallocated Regulated Hydroelectric Refurbishment Projects with Capital Expenditures 2027-2031

Project#	Generating Station and Unit(s)
82545	Otter Rapids GS, G4
82544	Otter Rapids GS, G3
87529	Chenaux GS, G1
89134	Chenaux GS, G2
89135	Chenaux GS, G3
87546	Otto Holden GS, G2
89154	Otto Holden GS, G3
89155	Otto Holden GS, G4
87548	R.H. Saunders GS, G10
87549	R.H. Saunders GS, G2
87550	Stewartville GS, G4
87551	Stewartville GS, G1
89168	Stewartville GS, G2
89169	Stewartville GS, G3
87525	Chat Falls GS, G2-G9
86852	Hagues Reach GS, G2/G3
89245	Manitou Falls GS, G1
89246	Manitou Falls GS, G2
86214	Meyersburg GS, G2
87704	Meyersburg GS, G3
89228	Seymour GS, G5
89229	Seymour GS, G4
83205	South Falls GS, G3
89524	DeCew Falls 1 GS

87963	DeCew Falls 2 GS, G2
83157	Abitibi Canyon GS, G3
83159	Abitibi Canyon GS, G4
83161	Abitibi Canyon GS, G5
87516	Arnprior GS, Runners
89112	Arnprior GS, Refurb 1st Unit
89136	Chenaux GS, 4th Unit
89622	Des Joachims GS, G2, G4, G6, G7, G8
87574	R.H. Saunders GS, Field Poles Only
89164	R.H. Saunders GS, 6th Unit
89165	R.H. Saunders GS, 7th Unit
90200	Big Eddy GS, G1
90201	Big Eddy GS, G2
87233	Manitou Falls GS, G4
89247	Manitou Falls GS, G5
89227	Meyersburg GS, G1
80847	Pine Portage GS, G1
84469	Pine Portage GS, G2
87966	DeCew Falls 2 GS, G1
87956	Sir Adam Beck 2 GS, G26/G25
87955	Sir Adam Beck 2 GS, G16/G15
89876	Sir Adam Beck Pump GS 1st unit

b) Refer to Ex. L-F1-AMPCO-091.

SEC Interrogatory #147

Interrogatory

Reference:
F1-1-1, p. 6

Question(s):

Please provide further details on the Renewable Generation Programmatic Collaboration Agreement ("RG PCA"), including but not limited to commitments that OPG has made to the Original Equipment Manufacturers ("OEM") in terms of amount of work, any premiums or penalties, etc.

Response

Refer to Ex. L-D1-Staff-065.

SEC Interrogatory #148

Interrogatory

Reference:
F1-1-1, p. 6

Question(s):

For each of the RG PCA Agreements:

a) Please describe the process that was used to arrive at the agreement.

b) Please provide copies of the agreements.

Response

a) Beginning in 2022, OPG identified that increased demand on hydroelectric original equipment manufacturers ("OEMs") was expected to create a supply-capacity-constrained market, resulting in OEMs being selective and potentially declining to bid on work. OPG subsequently assessed its Renewable Generation hydroelectric refurbishment requirements over the coming years and confirmed that these market conditions posed a material risk to the execution of its future refurbishment program (refer to Ex. F1-1-1 and Ex. L-D1-Staff-065).

To address this risk and facilitate the execution of the hydroelectric refurbishment program, OPG explored a longer-term, collaboration-oriented contracting approach to secure supplier capacity. OPG requested submissions from the hydroelectric OEMs to validate market dynamics and to assess supplier interest and capability. OPG reviewed the submissions and considered the market dynamics in developing the procurement strategy.

OPG then conducted a competitive procurement with the hydroelectric OEMs, followed by extensive commercial negotiations to secure supplier capacity through long-term agreements, while maintaining value for money considerations. The agreements were awarded to two OEMs, while the remaining OEM was not advanced as part of the competitive outcome.

b) Refer to Ex. L-D1-Staff-065. Due to the size of the agreements, summaries have been provided, commensurate with OPG's summary of the DNNP Integrated Project Agreement provided in Ex. D2-4-3.

SEC Interrogatory #149

Interrogatory

Reference:
F1-1-1, p. 11-12

Question(s):

Please provide a breakdown, by year and by component, of the $5.7M of incremental costs necessary to comply with the 2019 amendments to the Fisheries Act.

Response

As stated in Ex. F1-1-1, Section 3.2.3.2, although the Fisheries and Oceans Canada ("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 (refer to Ex. D1-1-2, Table 5b).

Refer to Chart 1 for a breakdown of costs by year between labour and non-labour. Non-labour includes technical and consultative support required for the purpose of conducting assessments, compiling applications, and creating offset designs.

Chart 1
Annual Incremental Fisheries Act Authorization Costs 2026-2031 ($M)

Component	2026	2027	2028	2029	2030	2031	Subtotal
Labour	0.5	0.8	0.8	0.4	0.4	0.0	2.8
Non-labour	0.5	1.0	0.9	0.3	0.2	0.0	2.9

SEC Interrogatory #150

Interrogatory

Reference:
F1-1-1, p. 15

Question(s):

Please provide a copy of the OPG/Hydro-Québec O&M Agreement and the RG Excellence Plan.

Response

The OPG/Hydro-Québec Operation and Maintenance Agreement is provided in Attachment 1 (confidential).

The 2026-2028 RG Excellence Plan is provided in Attachment 2.

EXECUTION VERSION

OPERATION AND MAINTENANCE AGREEMENT

This operation and maintenance agreement (the "**Agreement**") is made as of the 30th day of May, 2019

between

HYDRO-QUÉBEC, a body politic and corporate, duly incorporated and regulated by the *Hydro-Québec Act* (R.S.Q. Chapter H-5) having its head office and principal place of business at 75 René-Lévesque Blvd. West, Montréal, Province of Québec H2Z 1A4 (hereinafter referred to as **"HQ"**)

and

ONTARIO POWER GENERATION INC., a corporation organized under the laws of the Province of Ontario and having its head office and principal place of business at 700 University Avenue, Toronto, Province of Ontario M5G 1X6 (hereinafter referred to as **"OPG"**)

and individually referred to as the "**Party**" and collectively as the "**Parties**".

WHEREAS:

A. HQ and OPG (or their respective predecessors in interest) have entered into various agreements (the "**Chats Falls Agreements**") relating to the Chats Falls GS (as defined below), including but not limited to:

1. the Joint Development Agreement between The Hydro-Electric Power Commission of Ontario and Chats Falls Power Company (now known as Ottawa Valley Power Company ("**OVPC**")) dated February 15, 1930 (the "**Joint Development Agreement**");

2. the Operating Services Agreement between Ontario Hydro and OVPC dated August 12, 1977 (the "**Operating Services Agreement**");

3. the Agreement between Ontario Hydro and La Compagnie D'Énergie De La Vallée de L'Outaouais (French name of the entity now known as "OVPC") dated May 1990 (the "**Maintenance Building Agreement**");

4. the Operation and Energy Accounting Agreement no. QO-S8 between HQ and Ontario Hydro replacing a March 17, 1980 agreement between the same parties and dated July 18, 1994 ("**QO-S8 Agreement**");

5. the Chats Falls Agreement between HQ and OPG dated April 8, 2003 which, *inter alia,* modified the procedures and methods of scheduling unit

operation and energy accounting at the Chats Falls GS (the "**2003 Chats Falls Agreement**");

6. the Enabling Agreement between HQ and OPG dated December 1, 2004 and effective December 23, 2004 which, *inter alia*, amends and supplements, as the case may be, the 2003 Chats Falls Agreement and the QO-S8 Agreement (the "**Enabling Agreement**"); and

7. the T30 Transformer Purchase and Sale Agreement between OPG and HQ (dated July 13, 2004) (the "**T30 Transformer Purchase and Sale Agreement**").

B. Pursuant to the *Power Commission Amendment Act, 1973*, The Hydro-Electric Power Commission of Ontario became Ontario Hydro in 1974.

C. Pursuant to Schedule A of the *Energy Competition Act, 1998* (entitled the *Electricity Act, 1998*) and in furtherance of the restructuring of the electricity marketplace in the Province of Ontario, the Government of the Province of Ontario transferred all of the right, title and interest of Ontario Hydro in generation stations located in the Province of Ontario, including the Chat Falls GS, to OPG on April 1, 1999.

D. Pursuant to an assignment agreement dated October 30, 2002, OVPC has assigned to HQ all its properties, right, title and interest in agreements relating to the Chats Falls GS.

E. Pursuant to an Emphyteutic Lease from the Government of the Province of Québec on the one hand and a lease from the Government of the Province of Ontario on the other hand, each of HQ and OPG are entitled to the use of one-half of the water available for power production at Chats Falls GS.

F. The Chats Falls GS comprises, *inter alia*, eight generating units, four of which (known as units 2 – 5) are owned by OPG and four of which (known as units 6 – 9) are owned by HQ; three transformer banks, two of which (known as T10 and T20) are owned by OPG and one of which (known as T30) is owned by HQ; and certain works that are jointly owned by OPG and HQ. Pursuant to the 2003 Chats Falls Agreement OPG operates the Chats Falls GS.

G. The Parties wish to terminate the Operating Services Agreement and the Maintenance Building Agreement and replace them with this Agreement.

H. In 2006 the Parties agreed that the annual cost of operating HQ's four generating units is [redacted] (the "**Base Amount**"), to be indexed for each year after 2006. Schedule E shows the annual amounts paid by HQ to OPG on account of the Base Amount for each of the years 2006 to and including 2018 and the associated unpaid indexation portion.

NOW THEREFORE in consideration of the mutual covenants and agreements contained herein and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

1. **Definitions**

In this Agreement:

(a) "**2003 Chats Falls Agreement**" has the meaning set forth in paragraph A(5) of the preamble.

(b) "**Activities**" means the HQ GU Operation, the Operation and Maintenance and the Projects.

(c) "**Agreement**" means this operation and maintenance agreement, including the schedules hereto.

(d) "**Base Amount**" has the meaning set forth in paragraph H of the preamble.

(e) "**Budgets**" means, collectively, the Operation and Maintenance Budgets and the Project Budgets and "**Budget**" means any one of them.

(f) "**Chats Falls Agreements**" has the meaning set forth in paragraph A of the preamble.

(g) "**Chats Falls GS**" means the Chats Falls generating station on the Ottawa River and installed facilities consisting of eight generating units fed by a common forebay and related works, all as shown in Schedule B hereto and as described in Section 1 (Introduction) of the **QO-S8 Agreement**.

(h) "**Chats Falls Operating Committee**" has the meaning set forth in Section 8.a.

(i) "**Common Works**" means Common Equipment and Joint Works as defined under the Joint Development Agreement, and for purposes of this Agreement includes, but is not limited to, works and equipment located at Chats Falls GS used to support the generating units of the Chat Falls GS, as described in Table 1 of Schedule A hereto and as shown in blue in Schedules B and C hereto.

(j) "**Contract Year**" means any calendar year during the Term.

(k) "**CPI**" means the consumer price index not seasonally adjusted for "All Items" published or established by Statistics Canada (or its successors) in relation to the Province of Ontario.

(l) "**Effective Date**" has the meaning set forth in Section 23.

(m) "**Enabling Agreement**" has the meaning set forth in paragraph A(6) of the preamble.

(n) "**Force Majeure Event**" means an event that is beyond the reasonable control of a Party, is not preventable by reasonable precautions, and cannot reasonably be circumvented by the Party through the use of commercially reasonable efforts; including by way of example but without limitation, an earthquake, tornado, fire, hurricane, flood, lightning or other act of God, explosion, insurrection, war (whether declared or not), revolution, invasion, riot, sabotage, terrorism, catastrophic computer failure caused by a computer virus, epidemic, disruption of transportation facilities caused by flood, major snow storm or other catastrophe, changes in law, strike, lock out and other industrial disputes.

(o) "**Guideline**" means a revision to a current Budget agreed by the Parties in accordance with Section 11.b.

(p) "**GU Operation Charge**" has the meaning set forth in Section 15.a.i.

(q) "**HQ GU Operation**" means all activities related to the operation of HQ's four generating units forming part of the Separate Works that are performed on a remote basis.

(r) "**HQ T30**" means the works at the Chats Falls GS that are referred to in Table 2 of Schedule A hereto and shown in green in Schedule D hereto, all of which are owned entirely by HQ. HQ T30 includes but is not limited to the following: T30 transformer bank including all attached instrumentation, current transformer bushings used for T30 revenue metering, the T30-Q4C motor operated disconnect switch and low voltage T30-X and T30-Y disconnects.

(s) "**Insurance Policies**" has the meaning set forth in Section 20.a.

(t) "**Interest Rate**" means, for any date, the reference lending interest rate per annum charged by Bank of Nova Scotia (or such other Canadian bank as OPG may give notice in writing to HQ from time to time) on Canadian dollar commercial loans made in Canada (known as the "prime rate"), plus two percent (2%).

(u) "**Joint Development Agreement**" has the meaning set forth in paragraph A(1) of the preamble.

(v) "**Maintenance Building**" means the maintenance building of the Chats Falls GS owned exclusively by OPG which is on the Ontario side of the provincial border and referred to in Table 5 of Schedule A.

(w) "**Maintenance Building Agreement**" has the meaning set forth in paragraph A(3) of the preamble.

(x) "**Operation and Maintenance**" means all ordinary or routine operation and maintenance activities to be performed on the Works, including repairs, and any other activity which is not otherwise a Project hereunder, and excluding the HQ GU Operation but including, for avoidance of doubt, all activities related to the operation of HQ's four generating units forming part of the Separate Works that are performed onsite at Chats Falls GS.

(y) "**Operation and Maintenance Budget**" means an annual budget for Operation and Maintenance to be carried out in any given calendar year.

(z) "**Operating Services Agreement**" has the meaning set forth in paragraph A(2) of the preamble.

(aa) "**OPG / HQ Operating Committee**" means the operating committee defined in Article 3 of the Enabling Agreement.

(bb) "**OPG T10 and T20**" means the works at the Chats Falls GS that are referred to in Table 3 of Schedule A hereto and shown in pink in Schedule D hereto, all of which are owned entirely by OPG. OPG T10 and T20 includes but is not limited to the following: T10 and T20 transformer banks including all attached instrumentation, associated motor operated disconnect switches and any installed low voltage T10 and/or T20 disconnects.

(cc) "**OVPC**" has the meaning set forth in paragraph A(1) of the preamble.

(dd) "**Projects**" means projects involving non-recurring costs and expenditures of a capital or non-standard investment nature to be carried out on any portion of the Works.

(ee) "**Project Budget**" means an itemized annual budget for one or more Projects to be carried out in any given calendar year.

(ff) "**QO-S8 Agreement**" has the meaning set forth in paragraph A(4) of the preamble.

(gg) "**Separate Works**" means the Separate Works as defined under the Joint Development Agreement, and for purposes of this Agreement includes, but is not limited to, generating units of the Chat Falls GS and associated equipment, all revenue metering equipment installed on T10, T20 and T30, and all associated equipment such as capacitive voltage transformers (CVTs), free standing current transformers (CTs), and supporting communication network (excluding HQ T30 CTs used for revenue metering and those items listed on Exhibit A of the T30 Transformer Purchase and Sale Agreement), all of which are owned by either of OPG or HQ, as described in Table 4 of Schedule A hereto and as shown in pink in Schedule C hereto. For the sake of clarity, the Separate Works assets include equipment up to but not including the low voltage bushing of the T10 transformer and the low voltage disconnect switches of the T20 and T30 transformers, provided

however that if low voltage disconnect switches were to be added to the T10 transformer, then the demarcation point would be similar to that of the T20 and T30 transformers.

(hh) "**T30 Transformer Purchase and Sale Agreement**" has the meaning set forth in paragraph A(7) of the preamble.

(ii) "**Term**" has the meaning set forth in Section 23.

(jj) "**Third Party Claim**" means a claim, demand, action, suit or legal proceeding made or brought by a third party against a Party.

(kk) "**Working Team**" has the meaning set forth in Section 9.

(ll) "**Works**" is used in this Agreement as a general short form term of convenience, and means any combination of the Common Works, Separate Works, HQ T30, OPG T10 and T20 and the Maintenance Building as required or permitted by the context of the section of the Agreement in which it is used. For the purposes of Sections 3 and 12, "Works" also refers to the Joint Works, Separate Works and Common Equipment, as defined in the Joint Development Agreement.

2. **Termination of Agreements**

The Operating Services Agreement and the Maintenance Building Agreement shall terminate as of the Effective Date. As soon as possible following the Effective Date, OPG shall issue a final invoice to HQ for all amounts owed by HQ to OPG pursuant to the aforesaid agreements and HQ shall pay such amounts in accordance with the provisions of Section 19. Subject to the payment of the amounts indicated in the aforementioned final invoice, each of OPG and HQ hereby give the other a full and final release and discharge from any and all claims, demands, obligations, liabilities, cause or causes of action, whensoever arising and occurring at any time up to and through the date hereof, whether known or unknown, suspected or unsuspected, liquidated or unliquidated, matured or unmatured, fixed or contingent, that arise out of or relate to the Operating Services Agreement and the Maintenance Building Agreement.

3. **Ownership of Works**

Nothing in this Agreement is intended to affect the rights of ownership and title of each of the Parties to the Works as set forth in the Joint Development Agreement.

4. **Operation and maintenance of the Chats Falls GS**

OPG shall perform the Activities so as to maintain the Chats Falls GS in service and in good repair.

5. **Activities Standards**

a. Subject to the terms of this Agreement and to the terms of any budget restrictions or other arrangements agreed to by the Parties from time to time, OPG shall carry out the Activities: (i) as a prudent and diligent generating station operator would do in the circumstances and in accordance with sound utility practice; (ii) in a manner reflecting the principles of the 2003 Chats Falls Agreement as amended or replaced from time to time, (iii) in compliance with all applicable laws and regulations of the Provinces of Quebec and Ontario and of Canada and all other principles or rules agreed to by the Parties from time to time including without limitation the rules established by the Independent Electricity System Operator (the "**IESO**") governing the IESO controlled grid.

b. Without limiting the generality of the foregoing, OPG agrees to perform the Activities (i) without discrimination based on ownership by either HQ or OPG of any portion of the Works and (ii) at the same level and upon the same standards used by OPG in maintaining and operating OPG's own equipment at the Chats Falls GS.

c. In addition to any other notification obligation hereunder, in the regular meetings of the Working Team OPG shall keep HQ apprised of the performance of the Activities and shall notify HQ of any event or matter which has occurred or is reasonably expected to occur affecting the Works in any material way, including without limitation any existing or potential dispute or Third Party Claim in respect of the Chats Falls GS.

6. **Sharing of Energy Output**

Since the Activities are carried out on the Works as a whole, regardless of ownership of the various components of the Works, the energy output of the Chat Falls GS, except as otherwise provided in Sections 11 and 12 hereof, will be shared equally by both Parties, in accordance with the terms of the 2003 Chats Falls Agreement as amended or replaced from time to time, regardless of the ownership of any portion of the Works that may be partly or fully out of service as a result of the performance of any Activities or for any other reason.

7. **OPG T10 and T20**

Notwithstanding any other provision in this Agreement, Sections 8, 9, 11, and 14, shall not apply to any Activities in respect of OPG T10 and T20.

8. **Chats Falls Operating Committee**

a. Duties

For the purposes of this Agreement, the Parties have established and will maintain an operating committee (the "**Chats Falls Operating Committee**") consisting of two members (one appointed by each Party) and two alternates (one appointed by each Party). While both the member and the alternate appointed by each of the Parties may participate at meetings of the Chats Falls Operating Committee, alternates may only vote in the absence of their respective member. A Party may change its member or its alternate at any time by notifying the other Party in writing.

The Chats Falls Operating Committee is authorized on behalf of the Parties to approve budgets and schedules for Operation and Maintenance and Projects (as further described in Section 11), to investigate the need for additional maintenance and investments, and to assess the need for changes in the method of operation of the Common Works, the Separate Works and HQ T30, relying on advice from engineers and other personnel within the respective Parties, as required.

The Chats Falls Operating Committee reports to the OPG/HQ Operating Committee regarding all matters pertaining to the Chats Falls GS, as provided for in Article III of the Enabling Agreement.

The Chats Falls Operating Committee will meet at least once each year.

The Chats Falls Operating Committee will record minutes of all of its meetings. Final minutes shall be approved by the members (or alternates, if applicable) of the Chats Falls Operating Committee and will be sent to the OPG/HQ Operating Committee.

When needed, the members may, by agreement, invite one or more non-members to attend the Chats Falls Operating Committee meetings.

b. Decisions

All decisions of the Chats Falls Operating Committee in respect of matters within its jurisdiction shall be unanimous. If the Chats Falls Operating Committee is unable to reach agreement, then the matter shall be referred to the OPG/HQ Operating Committee.

9. **Working Team**

A working team comprised of employees or resources of each Party (the "**Working Team**") shall meet regularly throughout the year to review programs, costs and

schedules and to follow up on the implementation of Operation and Maintenance and Projects. The Working Team's reviews shall include, without limitation, anticipated and actual variations of approved Budgets.

10. **Expenses**

Each Party shall pay the expenses of its member or alternate on the Chats Falls Operating Committee and of its employees or resources on the Working Team.

11. **Budget Approvals and Variances**

a. Establishing annual Budgets: Annually, the Chats Falls Operating Committee will prepare an Operation and Maintenance Budget and one or more Project Budgets for the following calendar year, based on information and recommendations of the Working Team (which recommendations shall incorporate all information as may be reasonably necessary to allow the Chats Falls Operating Committee to make appropriate determinations regarding expenditures). Each member of the Chats Falls Operating Committee will submit the proposed Operation and Maintenance Budget and proposed Project Budget(s) to the Party having appointed such member by July 1st of the calendar year preceding the year for which such Budgets are being proposed. A Party's approval regarding proposed Budgets shall not be unreasonably withheld. The proposed Budgets will be reviewed by the appropriate approval authorities of each Party and the approved Budgets will be returned to the Chats Falls Operating Committee, on a commercially reasonable efforts basis, by December 1st of the year preceding the year to which the Budgets relate.

b. Variations of approved Budgets: All duly budgeted Operation and Maintenance and Projects shall be completed by OPG without any additional approval being required from HQ.

Any additional non-budgeted Operation and Maintenance which individually, or in the aggregate, have an estimated net cost that does not exceed an amount equal to 10% of the Operation and Maintenance Budget shall also be completed by OPG without any additional approval being required from HQ. An Operation and Maintenance Budget Guideline shall be required for any new Operation and Maintenance which individually, or in the aggregate, have an estimated net cost exceeding an amount equal to 10% of the Operation and Maintenance Budget. The 10% limit set forth above may be revised by the Chats Falls Operating Committee in accordance with each Party's corporate governance policies and procedures.

A Project Budget Guideline shall be required in the event: (i) of any new Project requiring spending in the then current Budget year that is not listed

in the Budget, or (ii) that the estimated cost for a Budget year of a Project that is proceeding to execution is expected to exceed the approved Project Budget for the Budget year by an amount that is greater than 10% of the original approved Project Budget amount. OPG shall not commit any (further) resources to the subject Project prior to the approval of the Guideline. The 10% limit set forth above may be revised by the Chats Falls Operating Committee in accordance with each Party's corporate governance policies and procedures.

If a Guideline is required pursuant to this Section 11.b, OPG shall promptly submit a proposed Guideline to the Working Team. The Working Team members will seek approval of the Guideline in accordance with their Party's respective governance.

For the purposes of this Section 11.b, "**net cost**" means the share of the costs payable by HQ in respect of the applicable matter.

c. Working Team Budget Reviews: The Working Team will review and/or analyze year to date variations from approved Budgets on a "work package by work package" basis, to distinguish variations that must be implemented during a given current year from variations that could be corrected in a subsequent calendar year, allowing the Working Team to propose necessary funding adjustments to the business plan. As a general principle, every effort will be made to defer other recurring Operation and Maintenance when a permanent, unfavourable variation from an approved Budget is confirmed. In the event that the deferral of a proposed variation is not an option, the proposed variation will be approved (in accordance with each Party's corporate governance policies and procedures) on an exception basis with the expectation that the following year's expenditures will return to levels previously proposed by the Working Team.

The Working Team will also review year-end projections on a "work package by work package" basis to feed into both HQ's and OPG's overall forecast and to prioritize work. This process will also provide the opportunity to manage other current year costs so that the overall impact on the whole program is minimal and spending is as close to the Budgets as possible.

d. If a Party is silent regarding (i) the matters referred to in Section 11.a beyond December 31st of the relevant calendar year, or (ii) any of the matters referred to in Section 11.b for a period of three (3) months or more from the date OPG submits the Guideline to the Working Team, such Party shall be deemed to have elected not to approve the relevant Budget(s) or Budget variation(s) or to pay for its equal share of the relevant Operation and Maintenance Activity and/or Project. If a Party elects (or is deemed to elect) not to approve and/or pay its equal share of any Project or Operation and

Maintenance Activity, and in either case this affects the immediate generating capability of any of the Separate Works owned by such Party, then the relevant generating unit(s) belonging to such Party shall be deemed to be completely retired and the output of the Chats Falls GS shall be shared on the basis of the ratio of the number of generating units either Party has available for service to the total number available for service. If a Party elects (or is deemed to elect) not to approve and/or pay its equal share of any Project or Operation and Maintenance Activity on the other Party's Separate Works, the other Party may pay such costs and the energy output from such generating unit shall belong to the Party that has paid for such work.

e. If a Party is silent regarding (i) the matters referred to in Section 11.a beyond December 31st of the relevant calendar year or (ii) any of the matters referred to in Section 11.b for a period of three (3) months or more from the date OPG submits the Guideline to the Working Team, and its approval is required in relation to a proposed Project or Operation and Maintenance Activity on Common Works or Separate Works (other than as provided in Section 11.d), the issue shall be referred to the OPG/HQ Operating Committee.

12. **Force Majeure**

If either Party is prevented from performing any of its material obligations under this Agreement because of the occurrence of a Force Majeure Event, then, except for any payment obligation, such Party shall not be bound to perform its obligations under this Agreement to the extent that the fulfillment of its obligations is prevented by such event. Such Party shall be prompt and diligent in taking commercially reasonable measures to remove, overcome and/or mitigate any such cause or causes of interruption derived from the Force Majeure Event. Upon request, the Party that is not affected by the Force Majeure Event will render any commercially reasonable assistance it might be expected to render to the other Party. Without limiting the generality of the foregoing, in the event of a strike by OPG's employees and/or subcontractors, OPG:

a. will use commercially reasonable efforts to provide alternative resources to operate the Common Works, and

b. consents to HQ operating and maintaining the Separate Works owned by HQ and HQ T30 throughout the duration of such strike, if HQ so desires, provided that any such operation and maintenance shall be: (i) in compliance with any applicable laws and rules and the principles of this Agreement; (ii) at HQ’s sole cost and expense; and (iii) subject to HQ’s indemnification obligation set forth in Section 21.c, provided that using such commercially reasonable efforts or providing such consent is not in violation of any applicable laws or regulations, as determined by OPG

counsel. During any such time that HQ operates and maintains its Separate Works and HQ T30, HQ shall own 100% of the energy output from such Works.

Promptly upon obtaining knowledge thereof and in any event no later than 10 days therefrom, a Party shall notify the other Party in writing that a Force Majeure Event has occurred or is reasonably expected to occur.

13. **Access by HQ**

HQ shall at all times have free access to the Chats Falls GS and everything therein contained relating to this Agreement. HQ shall also have access at all reasonable times to all books, accounts and records of OPG concerning anything pertaining to this Agreement. Requests for access to books, accounts and records shall be made to OPG's member on the Chats Falls Operating Committee.

14. **Records**

a. OPG shall keep records, in accordance with OPG's record retention policies, covering all matters of essential importance hereunder and shall furnish such information to HQ in a format and at a time mutually agreed to by the members of the Chats Falls Operating Committee. In addition, OPG shall furnish, at HQ's sole expense, any special reports concerning any matters related to this Agreement and/or its implementation which may be requested by HQ during the Term of this Agreement.

b. OPG shall establish and maintain records, in accordance with OPG's record retention policies, in such form as will show in detail all receipts and expenditures and the costs of all Activities performed pursuant to this Agreement so that the same may be reviewed by HQ.

15. **Cost allocation of Activities**

a. **HQ GU Operation**

i. HQ shall pay an annual fee to OPG for performing the HQ GU Operation (the "**GU Operation Charge**"). The GU Operation Charge for any given Contract Year shall be calculated as follows:

[redacted]

where:

[redacted] (rounded to the nearest cent);

[redacted] (rounded to the nearest cent);

[redacted]

[redacted]

ii. The GU Operation Charge for the first Contract Year of this Agreement, being from January 1, 2019 to December 31, 2019, is [redacted]. The GU Operation Charge for the first Contract Year of this Agreement was calculated in accordance with the provisions of Section 15.a.i. Schedule E shows annual GU Operation Charges from 2007 to 2018.

iii. The Parties further acknowledge that HQ shall pay, upon execution of this Agreement, an amount of [redacted] representing full and final payment of the unpaid indexation portion of the GU Operation Charge payable to OPG for calendar years 2007 to 2018, as further detailed in Schedule E.

iv. HQ agrees to pay the GU Operation Charge in the manner set forth in Section 19.

b. **Operation and Maintenance**

All costs of Operation and Maintenance shall be calculated and payable according to the principles and in the manner set forth in Sections 18 and 19 hereof and shall be shared between OPG and HQ as follows:

i. <u>On the Common Works and Separate Works</u>

The costs of Operation and Maintenance relating to the Common Works and Separate Works shall be shared equally between OPG (50%) and HQ (50%).

ii. <u>On the Maintenance Building</u>

All costs of Operation and Maintenance relating to the Maintenance Building and land associated therewith shall be borne by OPG (63%) and by HQ (37%).

iii. On the HQ T30

The costs of Operation and Maintenance relating to the HQ T30 and all items listed in Exhibit A of the T30 Transformer Purchase and Sale Agreement shall be paid by HQ.

iv. On the OPG T10 and T20

OPG shall be responsible for the costs of Operation and Maintenance relating to the OPG T10 and T20.

c. **Cost allocation of Projects**

All costs of Projects shall be calculated and payable according to the principles and in the manner set forth in Sections 18 and 19 hereof and shall be shared between OPG and HQ as follows:

i. The cost of Projects pertaining to Common Works or Separate Works shall be borne by OPG (50%) and HQ (50%), regardless of which Party owns the subject Works.

ii. The cost of Projects pertaining to HQ T30 shall be borne entirely by HQ.

iii. The cost of Projects pertaining to OPG T10 and T20 shall be borne entirely by OPG.

iv. The cost of Projects pertaining to the Maintenance Building and land associated therewith shall be borne by OPG (63%) and HQ (37%).

16. **Maintenance Building**

In the event this Agreement, the Joint Development Agreement and the 2003 Chats Falls Agreement are terminated without being replaced by an agreement or agreements covering substantially the same subject matters, then OPG agrees to refund to HQ within ninety (90) days of the termination of the above referenced agreements the unamortized portion of HQ's capital cost contribution with respect to the Maintenance Building provided the Maintenance Building will continue to be used after the termination of the above mentioned agreements. The Parties agree that for the purposes of this Agreement, the Maintenance Building is being fully depreciated over a period of thirty (30) years on a straight line depreciation basis, commencing June 1, 1991. HQ’s share of the undepreciated capital cost of the Maintenance Building as of June 1, 1991 was $1,492,686.00.

17. **Administration of joint lands**

All costs of administration and maintenance of the "joint lands" will continue to be shared as provided in the Joint Development Agreement. All revenues received from leases and rentals of the "joint lands" shall be shared equally between OPG and HQ.

18. **Costs Allocated to HQ**

a. **On Operation and Maintenance**

HQ's share of Operation and Maintenance expenditures shall be based on the actual Operation and Maintenance costs as determined by OPG, and shall, without limiting the generality of the foregoing, include the items described below, without duplication.

i. All actual costs of materials, supplies, sundries, external contracts, tools, stores, apparatus, machinery and equipment in connection with the Operation and Maintenance.

ii. All salaries, wages and other remuneration including prevailing payroll burdens of all persons employed in connection with the Operation and Maintenance, to which shall be added an overhead rate of 100% to burdened operating and maintenance trade labour rates (collectively, "**Labour Costs**") which are established annually for recovery of administration costs. These costs include the following:

I. The overhead rate which is intended to recover a portion of the cost of OPG's functional support staff employed in connection with the Operation and Maintenance, such as Eastern Operations and OPG corporate functions. Eastern Operations is an operational division of OPG with responsibility for Chats Falls GS and other stations. Existing (as at the date of this Agreement) functional support departments include: Eastern Operations management and production support such as programming and project management, and OPG corporate functions such as controllership, engineering, environment, real estate, information technology and law divisions.

II. Administration costs which include the recovery of supervisory and administrative support functions of the Chats Falls GS Production group (a subset of the Eastern Operations that is responsible for Chats Falls GS), indirect activities (e.g. training, meetings, and travel), transport and work equipment.

III. Administration costs which include the recovery of insurance premiums and certain infrastructure and communications costs related to the operation of Chats Falls GS including, but not limited to: telephone systems and information networks and equipment which are not included in the Eastern Operations budget or costs.

iii. The Labour Costs for all special engineering, legal, accounting and other special services approved by HQ and rendered by employees and officers of OPG who are not regularly employed in Eastern Operations, as agreed to by the Chats Falls Operating Committee.

b. **On Projects**

HQ's share of Project expenditures (the "**HQ Project Cost**") shall be based on the actual cost of the Project as determined by OPG. In addition to HQ Project Cost, HQ shall pay to OPG an amount representing a portion of OPG's support costs associated with the administration and execution of the Project (the "**HQ Overhead Amount**") that shall be equal to 10% of the HQ Project Cost (the "**Overhead Rate**"), provided that the Chat Falls Operating Committee may revise the Overhead Rate in accordance with each Party's corporate governance policies and procedures.

19. **Invoicing**

All invoices to be sent by OPG pursuant to this Agreement shall incorporate all information as may be reasonably necessary to determine amounts due.

As a general principle, only charges, costs and expenditures which form part of an approved Budget (or any permitted variation thereto) will be invoiced by OPG to HQ.

Unless otherwise provided in this Agreement, HQ shall pay to OPG the costs allocated to HQ under Section 15 in Canadian dollars on a monthly basis. Monthly invoices shall be issued by OPG to HQ and shall be paid by HQ within thirty (30) days from the date of receipt by HQ of any given invoice. Any amounts not paid by the due date shall be deemed delinquent and shall accrue interest at the Interest Rate, calculated from and including the due date up to but excluding the date the delinquent amount(s) and accrued interest is/are paid in full.

In the event HQ reasonably disputes the amount of any invoice, whether in whole or in part, it shall notify OPG of such dispute no later than thirty (30) days from receipt of the invoice, indicating to OPG the amount of such invoice subject to dispute and providing reasonable particulars of such dispute. In such event, the Parties shall use their reasonable commercial efforts to resolve such dispute within a reasonable period of time, not exceeding sixty (60) days from the date of such

notice. HQ shall nonetheless be obligated to make timely payment of any non-disputed amount. If it is ultimately determined that the disputed amount, in whole or in part, was properly payable to OPG, then HQ shall promptly pay OPG such amount with interest accruing at the Interest Rate from the payment due date of the invoice in accordance with this Section 19.

20. **Insurance**

a. During the Term of this Agreement, OPG shall secure and maintain in force the following insurance coverage, with deductibles as would be maintained by a prudent operator of a facility of similar size, function and location, with respect to the Chats Falls GS:

i. All risks insurance for the full replacement cost value of the Chats Falls GS (including earthquake, flood and sewer back-up coverage or endorsements);

ii. Loss of revenue (business interruption) insurance on the income derived from Chats Falls GS with a period of indemnity of 18 months;

iii. Boiler and machinery insurance on a comprehensive basis; and

iv. Commercial general liability insurance with a limit of liability of not less than ten million dollars ($10,000,000.00) per accident or occurrence in or for the Chats Falls GS and the lands related or adjacent thereto, including but not limited to bodily injury and personal injury liability, property damage, products liability, completed operations liability, owners and contractors protective liability, blanket contractual liability, premises liability, broad form property damage, employers liability, including coverage for injury, pollution liability on at least a sudden and accidental basis, and loss or damage due to pollution arising from "hostile fires",

(the insurance policies listed in (i) through (iv) being, collectively, the "**Insurance Policies**").

b. The Insurance Policies shall cover both OPG and HQ as co-insureds and OPG shall deliver to HQ copies of any endorsements evidencing such co-insured status following OPG's receipt of same. OPG shall use commercially reasonable efforts to ensure that the Insurance Policies are secured with one or more insurers licensed to sell commercial insurance under the laws of Ontario and Quebec and that, as of the policy renewal date, each insurer has an "A-" rating or better by A.M. Best or an equivalent rating agency.

c. OPG shall, from time to time, instruct a licensed appraiser to perform an appraisal of Chats Falls GS for the purposes of determining its replacement cost value, and the period between each such appraisal shall not exceed 10 years, unless otherwise agreed to by OPG and HQ. OPG shall provide a copy of each appraisal report to HQ promptly following OPG's receipt of same. The all risks insurance coverage secured by OPG pursuant to Section 20.a.i hereof shall cover the full replacement cost value as indicated in the most recent appraisal report plus annual indexation.

d. On the Effective Date and on an "as soon as practicable" basis for each Contract Year thereafter, OPG shall provide to HQ an insurance certificate evidencing compliance with Section 20.a hereof as well as a summary of HQ's share of the insurance premiums payable (including the applicable premium rate) under the Insurance Policies for such Contract Year.

e. For the avoidance of doubt, it is understood that the cost of securing and maintaining insurance coverage, including the payment of any associated deductible, for Chats Falls GS in accordance with this Section 20 shall be included in the Operation and Maintenance Budget and shared between OPG and HQ in accordance with Section 15.b.i hereof.

f. HQ hereby acknowledges receipt of a summary of the deductibles that are applicable under the Insurance Policies in effect as of the date hereof (the "**Deductibles**") and that the Deductibles comply with the standard set out in Section 20.a. OPG shall advise HQ through the Working Team of any material changes to the Deductibles during the Term.

21. **Claims and Indemnification**

a. In case any Third Party Claim shall be made against OPG or HQ in connection with the performance of a Party's obligations hereunder, OPG or HQ, as the case may be, shall promptly notify the other Party thereof. Each Party shall render to the other all reasonable assistance for such purposes of defending such claim. Subject to this Section 21, all costs, expenses and damages in connection with such claims shall be shared equally between the Parties.

b. Subject to the provisions of the Chats Falls Agreements OPG shall indemnify, defend and hold harmless HQ and its affiliates, directors, officers, employees, agents and representatives (collectively, the "**HQ Indemnified Persons**") from and against any loss, liability, obligation, claim and damages (including reasonable legal fees) (collectively, the "**Damages**") suffered by, imposed upon or asserted against any HQ Indemnified Person, as a result of, in respect of, connected with or arising out of Third Party Claims for personal injury (including death) and property

damage to the extent caused solely by the gross negligence or wilful misconduct of OPG.

c. HQ shall indemnify, defend and hold harmless OPG and its affiliates, directors, officers, employees, agents and representatives (collectively, the "**OPG Indemnified Persons**") from and against any Damages suffered by, imposed upon or asserted against any OPG Indemnified Person as a result of, in respect of, connected with or arising out of any operation or maintenance of any Works by or on behalf of HQ during any strike by OPG's employees or subcontractors.

d. Promptly upon obtaining knowledge thereof, and in any event no later than one (1) month therefrom, a Party shall notify the other Party of any cause which has given or could reasonably be expected to give rise to indemnification under this Section 21.

e. If any Third Party Claim shall be asserted against a Party in respect of which the Party proposes to demand indemnification hereunder, then the other Party shall have the right, upon reasonable prior written notice, to defend (and to control the defense of) the Third Party Claim at its own cost and expense with counsel of its choice, provided that the indemnified Party shall at all times have the right to fully participate in the defence at its own expense and with counsel of its choice.

f. The indemnifying Party shall not be permitted to compromise and settle or to cause a compromise and settlement of any Third Party Claim without the prior written consent of the indemnified Party, such consent not to be unreasonably withheld.

g. If the indemnifying Party fails, within thirty (30) days after having been apprised of the Third Party Claim, to give notice of its intention to defend the Third Party Claim in accordance with this Section 21, then the indemnifying Party shall be deemed to have waived its right to defend the Third Party Claim and the indemnified Party shall have the right (but not the obligation) to undertake the defence of the Third Party Claim and compromise and settle the Third Party Claim for the account and at the risk and expense of the indemnifying Party. In such event, the indemnifying Party shall at all times have the right to fully participate in the defence of such Third Party Claim at its own expense and with counsel of its choice.

22. **Inconsistency with Joint Development Agreement or 2003 Chats Falls Agreement**

Nothing in this Agreement shall relieve OPG or HQ from any obligation under the Joint Development Agreement or the 2003 Chats Falls Agreement, provided that in the event of an inconsistency between this Agreement and the Joint Development

Agreement or the 2003 Chats Falls Agreement and unless otherwise specified herein, this Agreement shall prevail.

23. **Term**

This Agreement shall be deemed to come into effect as of January 1, 2019 (the "**Effective Date**") without regard to the date of its signature by the Parties and shall remain in effect indefinitely (the "**Term**"). Either Party may terminate this Agreement at any time upon three (3) years' written notice to the other Party without any penalty or liability whatsoever. For avoidance of doubt, termination of this Agreement does not, unless expressly stated otherwise, result in the termination of any of the Chats Falls Agreements.

24. **Review of this Agreement**

Either Party may request a review of this Agreement at any time. If, as a result of such a review it is agreed that any of the provisions of this Agreement, or the practices or conduct of either Party impose a hardship or undue burden upon the other, the Chats Falls Operating Committee shall endeavour to negotiate an amendment to this Agreement which will remove such hardship or undue burden. Any proposed amendment(s) to the Agreement shall, once formulated by the Chat Falls Operating Committee, be submitted by each member of the Chats Falls Operating Committee to the Party which has appointed it, for approval by such Party's approval authorities.

25. **Notice**

Any notice, consent or other communication required herein shall be in writing and delivered by hand or by registered mail (return receipt requested), overnight courier service (receipt effective upon scheduled weekday delivery day) or given by email (receipt effective upon receipt of evidence, including email evidence that email was received before 3:00 p.m. on a business day in the Province where the recipient's office address below is located) and addressed or directed as follows:

<u>If to OPG</u>:

Lennox Generating Station
7263 Highway 33 W
PO Box 1000
Bath, Ontario
K0H 1G0
Attention: John Hefford, Vice President Regional Operations – Eastern Operations
Email: john.hefford@opg.com

If to HQ:

75 boul. René-Lévesque O.
Montréal, Qc
H2Z 1A4
Attention: Érik Bellavance, Chef Développements commerciaux
Email: Bellavance.Erik@hydro.qc.ca

Any change in the identity and/or contact details of a Chats Falls Operating Committee member and any change in the address of a Party shall be promptly communicated to the other Party in writing and any subsequent notice or communications shall be sent to such member or Party's changed address.

26. **Governing Law**

This Agreement and the rights and duties hereunder shall be governed by and construed, enforced and performed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein, without regard to the principles of conflicts of law. All actions and proceedings arising out of or relating to this Agreement shall be heard and determined exclusively in a court located in the Province of Ontario.

27. **Confidentiality**

Each Party shall preserve the strict confidentiality of this Agreement and shall not disclose its terms and conditions nor any information obtained in connection therewith (collectively the "**Confidential Information**"), whether before or after the Effective Date, without obtaining the prior written approval of the other Party.

If a Party is required by law, order or judgment or by request of a regulatory agency or other governmental entity to disclose any of the Confidential Information, the legally compelled Party shall provide the other Party with prompt written notice of such request or requirement and shall cooperate with such other Party so it may seek, at its expense, an appropriate protective order or other appropriate remedy.

28. **Execution in several counterparts**

This Agreement may be executed in any number of counterparts (including by means of PDF), each of which when executed, shall be deemed to be an original and all of which together will be deemed to be one and the same instrument binding upon the Parties notwithstanding the fact that both Parties are not signatory to the original or the same counterpart. Delivery of an executed counterpart of a signature page to this Agreement electronically shall be effective as delivery of a manually executed counterpart of this Agreement.

29. **Language and prevailing version**

The Parties have elected to negotiate this Agreement in the English language. The English version of this Agreement shall prevail in the event of any discrepancy between the English version and any French version.

30. **Headings**

All headings used in the Agreement are for convenience only and do not form part of this Agreement.

31. **No assignment**

Neither Party may assign this Agreement, in whole or in part, without the prior written consent of the other Party. This Agreement enures to the benefit of and binds each of the Parties and their respective successors and permitted assigns.

[Signature page follows]

EXECUTION VERSION

IN WITNESS WHEREOF the Parties hereto have caused this Agreement to be executed attested by the signatures of their proper officers duly authorized thereto.

ONTARIO POWER GENERATION INC.

By: May 30th 2019

Name: Mike Martelli
Title: President, Renewable Generation

HYDRO-QUÉBEC

By: Signature numérique de CG3749
Date : 2019.05.24 15:02:21 -04'00'

Name: Simon Bergevin
Title: Directeur, Parquet de transactions énergétiques

SCHEDULE A
Types of Works

Table 1

Item	Designation	Ownership (refer to Schedule B)	Accounting Practice (refer to Schedule D)
Common Works - including but not limited to: • station service • sluice gates • bridges • roads • dam including powerhouse intake structure • log sluice • backup diesel generator • compressed air system	Common Works	OPG, HQ, or OPG and HQ	50%/50%

Table 2

Item	Designation	Ownership (refer to Schedule B)	Accounting Practice (refer to Schedule D)
T30 etc	HQ T30	HQ	100% HQ

Table 3

Item	Designation	Ownership (refer to Schedule B)	Accounting Practice (refer to Schedule D)
T10 etc	OPG T10, T20	OPG	100% OPG
T20 etc	OPG T10, T20	OPG	100% OPG
T20-T	OPG T10, T20	OPG	100% OPG
T20-B2	OPG T10, T20	OPG	100% OPG

Table 4

Item	Designation	Ownership (refer to Schedule B)	Accounting Practice (refer to Schedule D)
Revenue Metering including: • Revenue meters both primary and back up	Separate Works	OPG	50%/50%

• associated CVTs • associated free standing CTs • associated telecommunication devices			
G2	Separate Works	OPG	50%/50%
G3	Separate Works	OPG	50%/50%
G4	Separate Works	OPG	50%/50%
G5	Separate Works	OPG	50%/50%
G6	Separate Works	HQ	50%/50%
G7	Separate Works	HQ	50%/50%
G8	Separate Works	HQ	50%/50%
G9	Separate Works	HQ	50%/50%

Table 5

Item	**Designation**	**Ownership (refer to Schedule B)**	**Accounting Practice (refer to Schedule D)**
Maintenance Building	Maintenance Building	OPG	63% OPG/37% HQ

SCHEDULE B

Station Operating Diagram - Ownership

See attached.

[redacted]

SCHEDULE C

Station Operating Diagram – Common Works and Separate Works

See attached.

SCHEDULE D

Station Operating Diagram - Accounting

See attached.

SCHEDULE E

Application of Section 15.a from 2006 to 2018

Year	[redacted]	*Annual GU Operation Charge*	*GU Operation Charge invoiced and paid*	*Cumulative unpaid indexation portion*
2005	[redacted]			
2006	[redacted]	[redacted]	[redacted]	
2007	[redacted]	[redacted]	[redacted]	[redacted]
2008	[redacted]	[redacted]	[redacted]	[redacted]
2009	[redacted]	[redacted]	[redacted]	[redacted]
2010	[redacted]	[redacted]	[redacted]	[redacted]
2011	[redacted]	[redacted]	[redacted]	[redacted]
2012	[redacted]	[redacted]	[redacted]	[redacted]
2013	[redacted]	[redacted]	[redacted]	[redacted]
2014	[redacted]	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]	[redacted]

MyBusiness | ONTARIO POWER GENERATION

Strategy & Excellence Plan | Renewable Generation 2026-2028

Our People | **Our Plant** | **Our Future**

Filters

Portfolio / Excellence Plan: Renewable Generation

Strategic Objectives | Pillars

OUR PEOPLE Drive a strong safety culture	OUR PEOPLE Foster a positive work environment	OUR PLANT Maximize equipment performance	OUR PLANT Strengthen work planning and execution	OUR FUTURE Earn the right to generate the future
Goal				
Foster a strong culture to achieve higher safety standards	Build an engaged team that embodies OPG's values	Execute the right work to optimize unit reliability	Excellence in maintenance, outage, and project execution	Be the generator of choice
Key Focus Areas				
• Promote simple and clear safety messages that resonate with our workforce and vendor partners • Champion continuous improvement of Work Protection performance and culture of corrective actions • Strengthen Safe Work Planning, Pre-Job Briefs, and Tailboard best practices	• Build up agility to lead change to focus on modernization • Advance trust, respect, and inclusion through RG Culture Plans • Actively guide and support employees to achieve performance expectations	• Enhance Asset Management processes to drive consistency in asset planning and evaluation • Focus efforts to advance key areas of Equipment Reliability • Align on fleet-wide strategies for governors, bearings, and runners	• Optimize maintenance strategies and work management processes across the fleet to start data-centric decision making • Improve unit-over-unit performance through predictability and reliability in project planning and execution • Augment process for generation planning and outage planning	• Modernize work processes; integrating data, transitioning to data-centric operations, and standardizing plant configuration across the fleet • Expand training programs to meet tomorrow's needs • Future-proof our workforce through knowledge management and succession planning
Measure(s) of Success				
Vendor safety performance Work Protection Performance Index SIIR & TRIF	Modernization Change Management Plan Engagement Results Absenteeism data, 9-Box	Optimized Project Portfolio Reliability metrics Availability metric	Work Management Performance Index Project Milestone & Capital Spend / In-service & Gate 3 Release Schedule Outage Factor	Modernization Change Management Plan Training metrics MyPower metrics

***Right-click** on the table and select **Drill through** to view GDARs associated with a specific Objective*

SEC Interrogatory #151

Interrogatory

Reference:
F1-1-1, p. 16-17

Question(s):

For each continuous improvement initiative for the hydroelectric business, please provide for each year between 2025 and 2031, a) the annual costs, and b) any quantified benefit (in cost savings or increased output). Please provide all calculations including any details regarding methodology and assumptions made.

Response

As discussed in Ex. F1-1-1, Section 5.3, OPG's regulated hydroelectric business demonstrates strong cost performance, ranking in the first quintile for OM&A costs relative to a benchmark group of peer utilities. While this performance compares favourably, OPG's Renewable Generation business unit ("RG") plans to pursue a series of initiatives over the business plan period to maintain and further improve performance.

The goal of this continuous improvement is to enhance or optimize established work processes. Since 2023, these initiatives have been guided by the Excellence Plan framework, which supports continuous improvement in People, Plant, and Future pillars (refer to Ex. L-F1-SEC-150, Attachment 2).

To support continuous improvement in cost and production performance and to sustain benchmark outcomes, RG actively shares and adopts best practices through structured peer-learning forums, including the Center for Energy Advancement through Technological Innovation ("CEATI"), as well as through targeted engagements with peer utilities such as Hydro-Québec and the New York Power Authority across project interfaces. These peer-learning activities are embedded across multiple focus areas within the business's continuous improvement planning and are reinforced through benchmarking to drive ongoing reflection and performance improvement.

OPG is unable to attribute discrete cost savings or isolate incremental production increases to individual initiatives, as overall performance reflects the combined and interacting effects of multiple initiatives, external conditions, and other operational factors that together drive the aggregate outcome.

Our People

A core focus of the People pillar is safe work execution. There is a direct link between safety and efficient execution, as safety events or near misses can have an impact on the individual worker and the team. The subsequent event response also has an operational impact. The initiatives in this area aim to make safety easier by reducing administrative burden, bringing safety to the forefront, and identifying early warning signs to prevent events, in order to support reliable and predictable execution.

Safety

The safety initiative focuses on further strengthening supervisors' capability to lead workers to improve hazard recognition and make consistent, safer choices. A balanced approach is required to address low energy events, typically responsible for Total Recordable Injury Frequency injuries (refer to Ex. F1-1-1, Section 4.1), and high-energy work that has the potential for serious consequences.

Building on the work discussed in Ex. L-F1-SEC-152, hand safety remains a priority to continue improvements in this area; RG also continues to review best practices in the construction industry and through the years of 2025-2031 will implement further Personal Protective Equipment improvements. The safety initiative ties in with leadership development to build coaching skills. The observation and coaching initiative will include a greater focus on high-energy work and the associated controls in order to achieve stronger performance.

Work Protection

As discussed in Ex. L-F1-SEC-152, RG upgraded to a re-platformed Equipment Status Monitoring ("ESM3R") application, which incorporated fully electronic Work Protection Packages, increasing safety measures and reducing administrative errors. Since the adoption of this application, RG saw significantly reduced Level 1 Work Protection Events.[1] For the 2025-2031 period, the Work Protection initiative continues this progress by standardizing and digitizing the data required to realize the full benefits of the system. Key efforts include:

- Plant Configuration Management to align Work Management equipment identification with Work Protection equipment identification, and
- Digitizing Operating Prints to enhance ESM3R capabilities by incorporating live electronic operating diagrams that display equipment status in real time.

Building on the work discussed in Ex. L-F1-SEC-152, the Work Protection initiatives are expanding to include a stronger focus on low-level reporting. This enables RG to shift from reactive event response to proactive monitoring for early warning signs. Increased low-level reporting helps surface potential near misses early, where they can be identified and addressed through programmatic barriers.

[1] Level 1 Work Protection Events are events in which no programmatic barriers remain between the individual worker and the hazardous energy.

Our Plant

The focus of the Plant pillar is on continuous improvement and integration of standardized processes and programs across the fleet. There is a direct link between equipment reliability, maintenance initiatives, and the digital tools that make data more readily available.

Equipment Reliability

The Equipment Reliability program will continue to strengthen equipment health monitoring (described in Ex. L-D1-SEC-041) by expanding to generating units across the fleet. The equipment health monitoring process evaluates asset condition, as described in Ex. L-D1-SEC-041. This process continues to improve through software enhancements and stronger system health groups, further enhancing the condition assessments.

Focus on forced outages remain a priority through the Equipment Failure Review ("EFR") process. EFR evaluates forced outage cause and informs actions to reduce the likelihood of recurrence (refer to Ex. L-F1-SEC-152). This may also inform future project scope and internal evaluation of forced outage target-setting and benchmarking with industry, as described in Ex. L-F1-Staff-321.

Maintenance

As discussed in Ex. L-F1-SEC-152, the Work Management Performance Index and digital tools have driven improvements in regional focus and action to improve maintenance execution, including reduction in administrative burden. The maintenance focus is to further enhance the utilization of digital tools and standardization of maintenance programs. To support standardization, a Preventative Maintenance ("PM") Review Board was introduced in 2025 as a cross-functional review of PM tasks across regions by Maintenance and Engineering. This integrates technical basis and operational experience to optimize similar PM tasks across the regions.

Our Future

A key focus of the Future pillar is building on the foundation to enable continued progress for improvement initiatives across the business. RG's work in this area is centered on shifting from analogue to digital data and moving from regionally stored documentation to more standardized processes. These are core prerequisites for delivering future efficiencies.

Environment

As discussed in Ex. F1-1-1, Section 4.2, Total Recordable Environmental Events ("TREE") metric is newly established in 2026 and combines total reportable spills and environmental infractions for OPG. For RG, the 2026 through 2031 target is 10, which improves upon the previous Environmental Performance Index ("EPI") target of 11.

In addition, RG continues to achieve environmental sustainability recognized through the Wildlife Habitat Council ("WHC") certification. R.H. Saunders GS has received a Gold certification in 2026, and Niagara and southeastern stations will seek re-certification of Gold status in 2026 and 2027.

Modernization

As discussed in Ex. D3-1-1, Section 3.1.3, RG will be transitioning to a new Enterprise Asset Management ("EAM") system. RG has started prerequisite work to lay the foundational data and technology infrastructure required to realize the intended outcome of OPG's Digital Roadmap, as discussed in Ex. D3-1-1, Section 3.1 and Ex. D3-1-1, Attachment 1.

The Excellence Plan captures modernization across the three categories with focus on training and skills development in the People category, work management process improvements in the Plant category, and digitization of data and standardizing best practices in the Future category.

SEC Interrogatory #152

Interrogatory

Reference:
F1-1-1, p. 16-17

Question(s):

For each historic or current continuous improvement or productivity initiative for the hydroelectric business, please provide for each year between 2016 and 2024, a) the annual costs, and b) any quantified benefit (in cost savings or increased output). Please provide all calculations including any details regarding methodology and assumptions made.

Response

The Renewable Generation ("RG") business unit is focused on demonstrating a commitment to operational and project excellence while managing the impact on safety, reliability, and environmental sustainability of operations. These priorities are reflected in the annual business planning process. As discussed in Ex. F1-1-1, Section 5.3, when benchmarked against other utilities, OPG's regulated hydroelectric business ranks first quintile for OM&A costs relative to a benchmark group of peer utilities. To support achieving these results, RG has undergone several initiatives between 2016-2024 to enhance or optimize established work processes. Presented in this response is a summary of the key focus areas.

OPG is unable to attribute discrete cost savings or isolate incremental production increases to individual initiatives, as overall performance reflects the interacting effects of multiple initiatives, external conditions, and other operational factors that together drive the aggregate outcome.

Organizational Realignment

In 2016, RG was operated by five regions (Niagara, Northeast, Southeast, Northwest, and Central Operations) with six control centres providing remote control and monitoring for OPG's hydroelectric generating facilities. The business has since undergone a series of amalgamations and realigned its structure to the current status of three operating regions (Niagara, Eastern, and Western) and four control centres, as described in Ex. A1-4-2, Section 2.0. These realignments were optimized to ensure effective regional oversight and increased cross-functional collaboration.

Safety

RG maintains a steadfast focus on safety initiatives to protect workers and minimize disruption to operations. The business has continuously improved safety performance and continues to focus in this area (refer to Ex. L-F1-SEC-151). As discussed in Ex. F1-1-1, Section 5.1, the 2023 benchmarking ranked RG's Total Recordable Injury Frequency ("TRIF") performance as first quartile for Electricity Canada (formerly Canadian Electrical Association) and second quartile of Edison Electric Institute and Electric Utility Cost Group.

In 2016, OPG launched an enterprise-wide focus on hand-related injuries and glove usage for employees in industrial and construction settings to reduce hand and finger injuries. Through this initiative, RG implemented a minimum glove protection requirement of ANSI 3-3-3 (Level 3 performance for cut, abrasion, and puncture resistance). This contributed to a reduction in hand and finger injuries in 2018. To drive further improvement in low energy tasks that contribute to the TRIF metric, additional focus was directed to hand safety in 2024 and 2025.

In 2022, RG introduced an Observation & Coaching program in response to first quarter safety performance. This initiative focused on supervisor oversight, enhanced safe work planning discussions, and worksite hazard recognition. Along with other factors, this contributed to an 18% reduction in year-over-year recordable events and a 9% reduction in year-over-year hand injuries reflected in the TRIF numbers from 2023-2025 (refer to Ex. F1-1-1, Chart 1).

In 2023, RG implemented an electronic Safe Work Plan ("SWP") database and electronic SWP methodology. This ensures the business has a record of appropriate instructions before beginning less-frequent tasks. A focus on written SWPs puts emphasis on safe job planning, ensuring every worker involved in high energy work has the opportunity to participate in establishing a safe work plan.

In 2024, OPG adopted the Safety Classification Learning model which is an industry-accepted method for rating incidents. Adoption of the expanded criteria for investigation provided additional insights to share across the business.

Work Protection

In 2022, Equipment Status Monitoring ("ESM") was upgraded to a re-platformed ESM application (ESM3R) which incorporated fully electronic Work Protection Packages. This initiative introduced system controls that prevent work from proceeding when required conditions are not met, in order to improve worker safety. Along with other factors, this contributed to a reduction in Level 1 Work Protection[1] events between

[1] Level 1 Work Protection Events are events in which no programmatic barriers remain between the individual worker and the hazardous energy.

2016 to 2024. As discussed in Ex. L-F1-SEC-151, a reduction in events is a reduction in an event response, allowing workers to execute work more predictably and safely.

Equipment Reliability

In 2018, RG adopted an industry standard toolset through the Engage platform to improve the equipment health monitoring and engineering risk assessment processes, as described in Ex. L-D1-SEC-041. The platform provides a centralized repository of data, which enables the business to more effectively trend and analyze equipment health to strengthen the management of fleet equipment risks.

To strengthen cross-functional oversight, Equipment Failure Reviews were implemented in 2020 and had a focus on forced outage causes, to inform business and operational decisions. In addition, to strengthen cross-functional ownership of equipment reliability, annual Plant Health Committee meetings were established in 2022 for each work center to facilitate a comprehensive review, tying together equipment condition, risk mitigation plans, failure reviews, and metrics.

In 2021, RG adopted industry guidelines published by the Electric Power Research Institute and established an Equipment Reliability Index ("ERI"). The implementation of the Equipment Reliability program and metrics have supported performance improvement. Preventative Maintenance ("PM") cancellations, which can occur for several reasons (such as scope satisfied by another work order, or pre-inspection results indicate satisfactory condition) are a focus. A lower cancellation rate is an indication that identified PM work on critical equipment has been executed. This helps moderate equipment reliability reductions over time and the "time to failure" risk increase, as equipment condition deteriorates. As part of ERI, the PM Work Order Task Cancellation metric tracks the rate of tasks cancelled on critical equipment and has improved from 0.87 in 2022 to less than 0.30 by the end of 2025.

Maintenance

In 2020, RG introduced electronic work packages and tablets for maintenance personnel to reduce administration burden and progress towards digital work processes.

As discussed in Ex. F1-1-1, Section 3.1.2, in its 2022 Value for Money audit, the Auditor General outlined recommendations to further strengthen maintenance planning. In response to the recommendations, RG introduced the Work Management Performance Index monitoring and tracking which focused attention on critical equipment and backlog reduction backlog of work order tasks has steadily declined.

Environment

RG demonstrates its commitment to environmental sustainability through a number of initiatives, as described in Ex. F1-1-1, Section 4.2.

In 2019, RG compiled and maintained a comprehensive tracking list of equipment requiring removal to be in compliance with Federal Polychlorinated Biphenyls ("PCB") Reg. SOR/2008-273. In total, 741 items were identified for removal. In 2025, after sustained efforts, the business successfully completed removal of all identified electrical equipment containing or suspected to contain PCBs in a concentration ≥ 50 ppm prior to the regulatory deadline of December 31, 2025.

RG has also received Gold certification from the Wildlife Habitat Council ("WHC") in several areas.

In 2020, a goat grazing program was implemented to manage overgrown vegetation and invasive plant species at Sir Adam Beck Pump Generating Station and DeCew Falls generating stations, as such vegetation can interfere with monitoring water level readings, water quality, and rate of flow. The program eliminates the use of herbicides and minimizes potential environmental contamination, in addition to helping with erosion control. In 2022, Niagara received Gold certification from WHC in recognition of this goat grazing program and several other initiatives.

In 2023, R.H. Saunders GS and a group of OPG's southeastern Ontario stations also received Gold certification from WHC. At R.H. Saunders GS, the certification recognized the station's biodiversity program and its habitat management of meadows, grasslands, and gardens. In the southeastern region, the certification recognizes work to protect and enhance wetland, grassland, and forest habitat, as well as the construction of nesting structures for migratory songbirds, birds of prey, and species at risk.

SEC Interrogatory #153

Interrogatory

Reference:
F1-1-1, p. 17-36

Question(s):

With respect to hydroelectric key performance metrics:

a) Please update Charts 1,3,4,6,8,10 and 12 with actuals for 2025.

b) [p.25, Chart 8] Please explain the high Equivalent Forced Outage Rate of 14% for Pine Portage GS as shown in 2024.

c) [p.29] Please provide the targets for Regulated Hydroelectric Total Generation Cost ("TGC") Performance for 2025-2031. If targets are not developed, please explain why.

d) [p.29] Please explain why redevelopment projects are excluded from TGC.

Response

a) Refer to Chart 1.

Chart 1 – Key Performance Metrics (2025 Actuals)

Performance Metric	2025 Actuals
Total Recordable Injury Frequency	0.33
Environmental Performance Index (%)	100%
Total Recordable Environmental Events	4
Availability (%)	85.5%[1]
Equivalent Forced Outage Rate (%)	6.6%[2]
Unit Energy Cost ($/MWh)	$10.9/MWh[3]
Total Generating Cost ($/MWh)	$35.4/MWh[4]

b) The 14% Equivalent Forced Outage Rate shown in Ex. F1-1-1, Chart 8, for the year 2024, is attributable to a turbine bearing failure on Pine Portage GS G3.

c) Refer to Ex. L-F1-Staff-168.

d) Total Generating Cost ("TGC") is calculated in alignment with Electric Utility Cost Group methodology to facilitate peer-utility comparisons. Given the nature of redevelopment projects, including that they are not completed in the normal course of operations, tend to be larger and are infrequent, and due to the variability in timing of such work across utilities, redevelopment project costs are excluded from the TGC calculation to help ensure a more comparable analysis.

[1] Refer to Ex. L-F1-Staff-170, Attachment 1 for details related to Availability 2025 actuals.
[2] Refer to Ex. L-F1-Staff-170, Attachment 2 for details related to Equivalent Forced Outage Rate 2025 actuals.
[3] Refer to Ex. L-F1-AMPCO-097 for details related to Unit Energy Cost 2025 actuals.
[4] Refer to Ex. L-F1-AMPCO-098 for details related to Total Generating Cost 2025 actuals.

Witness Panel: Hydroelectric Operations and Hydroelectric Projects, and Market Renewal Program

SEC Interrogatory #154

Interrogatory

Reference:
F1-2-1, Tables 1 and 2

Question(s):

With respect to Hydroelectric Base OM&A:

a) Please provide a breakout of the total FTEs (shown in F1-1-1 Table 2b) by the categories listed in F1-2-1 Table 1.

b) Please provide details on how overtime costs shown in F1-2-1 Table 2 are forecasted.

c) Please provide a further breakdown of Other Purchased Services costs shown in F1-2-1 Table 2.

Response

a) Refer to Attachment 1.

b) Refer to Ex. L-F4-CCC-085 for details on how overtime is forecasted in Ex. F1-2-1, Table 2. Overtime has remained relatively stable as a percentage of total labour costs over the 2016-2027 period.

c) As described in Ex. F1-2-1, p. 5, lines 4-7, purchased services include the costs of specialized external services, primarily for construction and maintenance services supporting work programs, such as shoreline erosion services, environmental assessments, programs such as eel and fishery monitoring, and elevator and HVAC inspections.

OPG interprets this question to be in reference to the actual Base OM&A costs from 2016-2025 and the budgeted and planned Base OM&A costs for 2026-2027. Refer to Attachment 2 for further breakdown of Other Purchased Services costs shown in Ex. F1-2-1, Table 2 and the nature of these purchased services. Given the large volume and diverse nature of services and vendors used, OPG does not maintain a more detailed category-level breakdown for Base OM&A costs purchased services.

Numbers may not add due to rounding.

L-F1-SEC-154 - Attachment 1
Chart 1 - Regulated Hydroelectric Base OM&A Regular and Non-Regular (FTEs) - 2020-2031

Group	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Actual	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
Regulated Hydroelectric Base OM&A:												
Operating Region:												
Niagara Region	199.0	194.0	195.9	191.8	214.2	225.5	229.8	229.1	229.1	229.1	229.1	229.1
Eastern Region	313.4	319.5	326.3	338.6	335.9	366.6	377.4	375.0	372.5	374.5	376.5	376.4
Western Region	134.1	124.3	119.1	120.6	133.3	129.1	135.2	133.5	133.4	134.4	136.0	136.0
Total Operating Regions FTEs	**646.5**	**637.8**	**641.3**	**651.0**	**683.4**	**721.2**	**742.4**	**737.5**	**735.0**	**738.0**	**741.6**	**741.5**
Operations and Project Support												
Enterprise Engineering	104.8	101.7	119.8	108.5	126.1	119.3	137.2	138.8	136.2	138.1	142.4	140.9
Integrated Fleet Management	37.2	20.4	19.7	34.2	33.9	40.0	37.2	37.0	36.6	35.9	36.8	36.4
Environment, Health & Safety	17.1	17.5	18.5	18.2	21.2	20.7	20.3	21.9	21.6	18.8	19.6	18.8
Enterprise Projects	13.7	9.7	8.3	13.4	13.0	10.5	8.1	7.1	6.9	6.8	6.8	7.4
Other Support	41.7	38.7	41.1	43.8	53.9	53.8	58.2	62.6	61.8	62.4	67.2	67.7
Total Operations and Project Support FTEs	**214.5**	**188.1**	**207.4**	**218.1**	**248.1**	**244.3**	**261.1**	**267.5**	**263.1**	**262.0**	**272.9**	**271.3**
Total Regulated Hydroelectric Base OM&A FTEs:	**861.0**	**825.9**	**848.7**	**869.1**	**931.5**	**965.5**	**1003.5**	**1004.9**	**998.1**	**999.9**	**1014.5**	**1012.8**

Numbers may not add due to rounding.

L-F1-SEC-154 - Attachment 2
Chart 1 - Regulated Hydroelectric Base OM&A Other Purchase Services ($M)

Line No.	Item	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Actual	2026 Budget	2027 Plan
	Operating Region:												
1	Species at Risk Mitigation Plan[1]	2.1	1.3	1.4	1.0	1.8	1.2	1.9	1.8	1.7	1.8	1.6	1.8
2	New York Power Authority Joint Works[2]	1.9	3.1	2.2	3.3	2.0	1.5	1.5	2.5	1.1	2.7	1.7	1.7
3	Ongoing Maintenance & Repairs[3]	14.9	16.4	12.8	13.6	12.7	14.3	16.2	20.9	22.7	21.1	20.3	21.6
	Total Operating Regions	18.8	20.8	16.4	17.9	16.5	17.0	19.5	25.2	25.5	25.5	23.6	25.1
	Operations and Project Support[4]	4.3	3.6	3.6	3.7	4.4	7.3	6.7	5.8	6.4	7.0	4.2	6.0
	Total Base OM&A	23.1	24.4	19.9	21.6	20.9	24.3	26.2	31.1	32.0	32.5	27.8	31.1

Notes:

1 Services for environmental assessments and monitoring on the Ottawa River and St Lawrence River. This includes programs such as the American Eel Action Plan and Lake Sturgeon species at risk mitigation plan (Ex. F1-1-1, p. 12)

2 OPG portion of the cost of operation and maintenance for assets operated by New York Power Authority in accordance with the Joint Works agreement (Ex. F1-2-1, Attachment 1 pp. 2-3)

3 Services performed for OPG to support ongoing maintenance and repairs including:
- Minor work that does not meet project governance thresholds in accordance with OPG's capitalization policy (Ex. D4-1-1, Section 2.0)
- General repairs and maintenance of assets
- Inspections (HVAC, fire safety, Elevator, asset inspection etc.)
- Equipment rentals
- Property maintenance

4 Includes external engineering assessments in support of asset management and front-end planning activities, dam safety, and operations and maintenance to sustain reliability of the regulated hydroelectric assets (Ex. F1-2-1, Attachment 1, pp.3-4) and other operations and support costs including security and environment health and safety services (Ex. F1-2-1, Attachment 1, p. 5)

SEC Interrogatory #155

Interrogatory

Reference:
F1-2-2, p. 1

Question(s):

Please explain the derivation of the materiality threshold used to explain variances for the Hydroelectric OM&A (i.e. "10% or greater at the function level, subject to a minimum materiality limit of $1M").

Response

The threshold of 10% or greater used to explain variances in the Hydroelectric OM&A costs reflects OPG's filing requirements, with the $1M minimum limit applied to exclude small variances in dollar terms in the context of the Application. This approach is consistent with past OPG payment amounts proceedings and helps to manage the volume of already extensive pre-filed evidence.[1]

[1] For example, EB-2020-0290, Ex. F2-2-2, p. 1, lines 21-22.

SEC Interrogatory #156

Interrogatory

Reference:
F1-3-1, p. 3

Question(s):

With respect to hydroelectric portfolio projects:

a) Please provide a listing, by year, of turbine-generator overhaul projects by station completed or forecasted to be completed between 2022 and 2026 and associated costs.

b) Please provide a listing, by year, of concrete restoration initiatives by station completed or forecasted to be completed between 2022 and 2027 and associated costs.

Response

a) Refer to Attachment 1.

b) Refer to Attachment 2.

Numbers may not add due to rounding.

L-F1-SEC-156 - Attachment 1
OM&A Project Listing - Regulated Hydroelectric
Turbine Generator Overhaul Projects Completed or Forecast Completed 2022-2026 ($M)

Line No.	Generating Station	Project Number	Project Description	2022 Actual	2023 Actual	2024 Actual	2025 Actual	2026 Budget
				(a)	(b)	(c)	(d)	(e)
1	Aguasabon GS	82499	AGU G1 OVERHAUL	0.0	0.0	0.0	0.0	0.0
2	Arnprior GS	84831	ARN - G2 RIM RESHRINK	0.0	0.0	0.0	0.0	0.0
3	Auburn GS	89518	AUBURN GS OM&A	0.0	0.0	0.0	0.5	0.0
4	Barrett Chute GS	82319	BAR - MECH/ELEC UNIT OVERHAULS G1 - G4	3.0	0.0	0.0	0.0	0.0
5	Barrett Chute GS	84588	BAR-NS G4 MECH/ELEC OVERHAUL	6.1	2.2	0.1	0.0	0.0
6	Barrett Chute GS	86078	BAR-G1 MECH/ELEC OVERHAUL	0.8	6.1	1.6	0.0	0.0
7	Barrett Chute GS	86079	BAR G2 MECH/ELECTRICAL OVERHAUL	0.0	0.1	5.2	1.4	0.0
8	Sir Adam Beck 1 GS	82199	G5 MAJOR OVERHAUL	0.0	0.0	0.0	0.0	0.0
9	Sir Adam Beck 1 GS	84526	G9 RUNNER AND HEADCOVER REPAIRS	0.0	0.0	0.0	0.0	0.0
10	Sir Adam Beck 2 GS	86627	BK2 G19 OVERHAUL	0.3	0.0	0.0	0.0	0.0
11	Sir Adam Beck PGS GS	82421	PG6 OVERHAUL	0.0	0.0	0.0	0.0	0.0
12	Sir Adam Beck PGS GS	84651	PG5 RUNNER GENERATOR REHAB (OMA)	0.1	0.0	0.0	0.0	0.0
13	Sir Adam Beck PGS GS	84731	PG3 RUNNER GENERATOR REPAIRS	0.4	1.0	0.4	0.4	0.0
14	Sir Adam Beck PGS GS	87852	BKP PG4 GOVERNOR AND EXCITER SYSTEM FEAS	0.0	0.0	0.0	0.3	0.0
15	Cameron Falls GS	82531	CAM G7 OVERHAUL	0.0	0.1	0.1	0.0	2.9
16	Abitibi Canyon GS	83156	ABITIBI - G2 OVERHAUL - NS	1.8	(0.1)	0.0	0.0	0.0
17	Abitibi Canyon GS	87054	ABI - G1 RUNNER REPAIRS	0.2	2.5	0.1	0.0	0.0
18	Big Chute GS	84862	CHU G1 TURBINE BEARING FAILURE	0.0	0.0	0.0	0.0	0.0
19	Crystal Falls GS	82471	CRYSTAL FALLS G3 OVERHAUL	1.9	0.0	0.0	0.0	0.0
20	Crystal Falls GS	82481	CRYSTAL FALLS G4 OVERHAUL	0.0	0.0	0.0	0.0	0.0
21	Des Joachims GS	80605	DEJ - RE-INSULATE ROTOR FIELD POLES	1.2	0.3	0.0	0.0	0.0
22	Eugenia GS	82271	EUG G3 TURBINE OVERHAUL - OMA	0.3	0.1	0.1	0.3	0.0
23	Frankford GS	89519	FRANKFORD GS OM&A	0.0	0.0	0.0	0.5	0.0
24	Hanna Chute GS	82021	HAN G1 OVERHAUL OMA	0.0	0.0	0.0	0.0	0.0
25	Meyersburg GS	82272	MEY TURBINE OVERHAUL (NON-STD)	0.0	0.0	0.1	0.7	0.0
26	Otto Holden GS	82326	OTO - MECH/ELECT UNIT OVERHAULS	5.3	0.0	0.0	0.0	0.0
27	Otto Holden GS	86476	OTO - G8 OVERHAUL (NS)	0.0	0.5	5.9	3.3	0.0
28	Otto Holden GS	86479	OTO - G6 OVERHAUL; NS	0.0	0.0	1.0	4.4	3.9
29	Otto Holden GS	86481	OTO - G5 OVERHAUL; NS	3.0	5.6	1.0	(0.8)	0.0
30	Otter Rapids GS	82521	OTTER G2 OVERHAUL	0.1	0.2	6.3	7.3	0.0
31	R.H. Saunders GS	83371	SAU - MECH/ELEC UNIT OVERHAULS	1.6	9.7	3.1	0.2	0.0
32	R.H. Saunders GS	86593	SAU - G12 OVERHAUL	0.1	0.3	2.2	6.9	0.2
33	R.H. Saunders GS	87856	SAUNDERS G3 THRUST BEARING REPLACEMENT	0.0	0.9	0.0	0.0	0.0
34	Silver Falls GS	82381	OVERHAUL	2.1	0.1	0.0	0.0	0.0
			Total	28.5	29.8	27.2	25.5	6.9

Numbers may not add due to rounding.

L-F1-SEC-156 - Attachment 2
OM&A Project Listing - Regulated Hydroelectric
Concrete Initiatives Completed or Forecast Completed 2022-2027 ($M)

Line No.	Generating Station	Project Number	Project Description	2022 Actual	2023 Actual	2024 Actual	2025 Actual	2026 Budget	2027 Plan
				(a)	(b)	(c)	(d)	(e)	(f)
1	Arnprior GS	86940	ARN-CNR BRIDGE EXPANSION JOINT REPAIRS	0.0	0.0	0.0	0.0	0.3	0.0
2	Auburn GS	82433	AUB FOREBAY CONCRETE REPAIRS	0.0	0.0	0.0	0.0	0.1	2.4
3	Sir Adam Beck 2 GS	82426	SAB2 ROCK CLIFF CONCRETE REHAB	0.2	1.6	2.7	0.4	0.0	0.0
4	Sir Adam Beck PGS GS	83636	PGS TAILRACE DECK, TX RUNWAY REPAIRS	0.6	0.1	0.0	0.0	0.0	0.0
5	Cameron Falls GS	86536	CAM G7 ROCK FACE REMEDIATION	0.1	1.3	0.0	0.0	0.0	0.0
6	Abitibi Canyon GS	82536	CANYON MAIN DAM CONCRETE REPAIR	0.3	0.1	0.4	0.1	(0.0)	0.0
7	Abitibi Canyon GS	83154	ABI REP. TUNNELS AND HEADWORK EAST STAIR	0.1	0.7	1.4	3.3	0.0	0.0
8	Abitibi Canyon GS	84584	ABITIBI G5 PENSTOCK DRAFT TUBE GROUTING	0.0	0.5	0.0	1.4	0.0	0.0
9	Abitibi Canyon GS	86405	ABITIBI-G3 PENSTOCK DRAFT. TUBE GROUTING	0.0	0.5	1.2	0.0	0.0	0.0
10	Abitibi Canyon GS	86406	ABITIBI-G4 PENSTOCK DRAFT. TUBE GROUTING	0.0	0.6	0.1	1.8	0.0	0.0
11	Chenaux GS	86590	CHE-LIMERICK ISLAND DAM-REHAB CONCRETE	0.0	0.0	0.0	0.0	0.2	1.4
12	Chats Falls GS	89192	CHF - TRANSFORMER TUNNEL CONCRETE REPAIR	0.0	0.0	0.0	0.0	0.8	0.0
13	Des Joachims GS	80947	DEJ - REPAIRS TO TAILRACE DECK	0.1	0.0	0.0	0.0	0.0	0.0
14	Des Joachims GS	82588	DEJ - REP HDWKS PIERS, GAINS, BULKHEADS	4.1	2.4	1.5	0.1	0.0	0.0
15	Des Joachims GS	84161	DEJ-AUXILIARY DAM REPAIR DECK &HANDRAILS	1.4	3.5	2.7	2.2	0.0	0.0
16	Elliot Chute GS	82762	ELL82762 ELLIOT CHUTE CONCRETE REPAIRS TO SLUICEWAY # 1	4.5	0.1	0.0	0.0	0.0	0.0
17	Kakabeka Falls GS	84462	INTAKE RETAINING WALL	0.0	0.0	0.0	0.0	0.8	0.0
18	Kakabeka Falls GS	87914	KAK G3/G4 PENSTOCK REPAIR	0.0	0.0	0.5	0.0	0.0	0.0
19	Lower Notch GS	87080	LOWER NOTCH SPILLWAY CONCRETE REPAIRS	0.0	0.0	0.0	0.1	0.6	2.7
20	Mountain Chute GS	84166	MTN-REPAIR LEAKAGE IN HDWORKS STAIRWAY	0.0	0.0	0.0	0.0	0.2	1.1
21	Mountain Chute GS	87557	87557 - MTN-RHAB CNCRTE SPILWAY PIERS,DECK&CHANL	0.0	0.0	0.0	0.0	0.1	0.5
22	Niagara Region	82411	INTAKE 2 APRON REPAIR	0.0	0.0	0.0	0.0	0.1	0.8
23	Otto Holden GS	82327	OTO - REPAIR LOG SLUICE PIER NOSINGS	0.0	0.3	(0.0)	0.0	0.0	0.0
24	Otto Holden GS	82328	OTO - CONCRETE MITIGATION PHASE 2	3.4	0.0	0.1	0.0	0.0	0.0
25	Otter Rapids GS	82547	OTR82547 OTTER PENSTOCK CONCRETE TRANSITION GROUTING	0.0	0.0	0.0	0.0	0.0	0.0
26	Pine Portage GS	86879	G1&G2 PENSTOCK/SCROLL CASE GROUT REPAIR	0.9	0.0	0.0	0.0	0.0	0.0
27	R.H. Saunders GS	80788	SAU - CONCRETE GROWTH MITIGATION	3.4	3.8	2.1	0.4	1.2	0.0
28	R.H. Saunders GS	83007	SAU - AIR VENT SHAFT CONCRETE REPAIRS	0.1	0.2	0.0	0.0	0.0	0.0
29	R.H. Saunders GS	83370	SAU - REP TAILRACE DECK CNCRT & GANTRY	0.0	0.0	0.0	0.0	0.0	0.0
30	R.H. Saunders GS	87263	SAU - SLOT CUTTING	0.0	0.0	0.0	0.0	0.1	0.0
31	Seymour GS	87707	SEY CANAL ROCK REMOVAL	0.0	0.0	0.0	0.0	0.0	0.8
32	Stinson GS	89093	STI - INTAKE DECK CONCRETE REPAIR	0.0	0.0	0.6	2.9	0.0	0.0
33	Stewartville GS	84960	STW - OIL CONTAINMENT LINER NS	0.1	0.4	0.8	0.6	0.0	0.0
34	Trethewey Falls GS	82447	Civil Repair-N and S Gravity Wall	0.0	0.0	0.0	0.0	0.1	1.9
			Total	**19.3**	**16.0**	**13.9**	**13.4**	**4.5**	**11.6**

Board Staff Interrogatory #160

Interrogatory

Reference:
Ref 1: Exhibit F1 / Tab 1 / Schedule 1 p. 25 Chart 8
Ref 2: Exhibit F1 / Tab 1 / Schedule 1 p. 29
Ref 3: EB-2020-0290 Exhibit A1 / Tab 3 / Schedule 2 Attachment 1 p. 1
Ref 4: Exhibit A1 / Tab 3 / Schedule 2 Attachment 4
Ref 5: Exhibit A2 / Tab 1 / Schedule 1 Attachment 4

Preamble:

At Reference 1, OPG states that the Equivalent Forced Outage Rate is 6.7% in 2019.

At Reference 3, OPG states that the Equivalent Forced Outage Rate is 6.4% in 2019 in the Performance Scorecard.

At Reference 2, OPG states that the Total Generation Cost is $23.6/MWh in 2018.

At Reference 3, OPG states that the Total Generating Cost is $23.4/MWh in 2018 in the Performance Scorecard.

At Reference 4, OPG states that the Availability Factor for Hydroelectric is 85.2% in 2024 in the Performance Scorecard.

At Reference 5, OPG states that the Hydroelectric Availability is 85.8% in 2024 in the Financial Summary.

Question(s):

a) Please confirm the numbers of the reported hydroelectric performance metrics in the current application for the years 2018 and 2019. If confirmed, please explain the change in amounts between the EB-2020-0290 reporting and the EB-2025-0297 reporting for the metrics. If not confirmed, please revise the numbers reported in the current application.

b) Please confirm that the Hydroelectric Availability referenced in the Financial Summary at Reference 5 is the same metric as the Hydroelectric Availability referenced at Reference 4. If confirmed, please revise the values in Exhibit A2-1-1 and Exhibit A1-3-2. If not confirmed, please explain the difference in calculating the two metrics. If providing this explanation, please provide the formula for each metric.

Witness Panel: Hydroelectric Operations and Hydroelectric Projects, and Market Renewal Program

Response

a) OPG acknowledges the discrepancy identified in Reference 2 (Ex. F1-1-1, Chart 12) with respect to Total Generating Cost. In the course of responding to this interrogatory, OPG identified that the 2018 value was reported erroneously and should have been stated as $23.40, which is consistent with the value presented in Reference 3 (EB-2020-0290, Ex. A1-3-2, Attachment 1).

OPG confirms Equivalent Forced Outage Rate ("EFOR") in 2019 for the regulated hydroelectric fleet, as reported in Reference 1 (Ex. F1-1-1, Chart 8) is 6.7%. OPG also confirms that Reference 3 (EB-2020-0290, Ex. A1-3-2, Attachment 1) reported the 2019 EFOR for the regulated hydroelectric fleet as 6.4%.

The difference between the 2019 EFOR value reported in Reference 1 (6.7%) and Reference 3 (6.4%) is attributable to the reclassification of an outage at Sir Adam Beck Pump Generating Station over the period of September 23, 2019 to January 25, 2020. Applying the impact of the reclassification to the Reference 3 calculation basis increases the reported EFOR from 6.4% to 6.7%, thereby reconciling with the value reported in Reference 1. The outage-type change arose from an entry error in the outage reporting source system that was subsequently corrected in January 2020; all reporting from that point reflected the corrected EFOR value.

b) Confirmed. The regulated hydroelectric Availability referenced in the Financial Summary at Reference 5 (Ex. A2-1-1, Attachment 4) is the same metric as the regulated hydroelectric Availability in Reference 4 (Ex. A1-3-2, Attachment 4). Availability for the regulated hydroelectric fleet in 2024 was 85.2%, not 85.8% as reported in Reference 5. As the 2024 and 2025 Annual Consolidated Financial Statements and Management's Discussion and Analysis have already been published, OPG is unable to correct the error.

Board Staff Interrogatory #161

Interrogatory

Reference:
Ref 1: Exhibit F1 / Tab 1 / Schedule 1 p. 28 Chart 10
Ref 2: Exhibit F1 / Tab 1 / Schedule 1 p. 30 Chart 12

At Reference 1, OPG shows its OM&A Unit Energy Cost did not meet the target values as per Business Plan in the years of 2018, 2019, 2021, 2022 & 2023.

At Reference 2, OPG shows an approximate 43% increase in the three-year rolling average of the Total Generating Cost between 2016 and 2024.

Question(s):

a) Please explain the relationship between Unit Energy Cost and Total Generating Cost. Please confirm that Unit Energy Cost is a key driver to Total Generation Cost. If not confirmed, please explain.

b) Please outline the strategies OPG intends to implement to better align its cost effectiveness performance with Business Plan targets.

Response

a) Unit Energy Cost ("UEC") and Total Generating Cost ("TGC") are distinct financial metrics used to assess cost effectiveness and financial productivity.[1] While the two metrics share common drivers, including operations, maintenance, and administration ("OM&A") costs and generation, they are calculated differently. The UEC is not a key driver of TGC.

   UEC measures direct OM&A costs per unit of energy produced (MWh). The UEC calculation excludes capital costs, gross revenue charge, and any other OM&A costs. In calculating UEC, generation is based on actual net energy production, net of surplus baseload generation ("SBG") spill and is measured on an annual basis.

   For clarity, the generation denominator of the UEC is sensitive to drivers such as waterflow conditions and electricity demand, causing variances in performance relative to targets. An example of this occurred in 2021 when low water flows had a considerable impact on generation (refer to Ex. E1-1-1, Figure 1, and Ex. E1-1-2), and resulted in a higher reported UEC (refer to Ex. F1-1-1, Chart 10).

[1] UEC and TGC are defined in Ex. F1-1-1, Section 4.4.1 and 4.4.2, respectively.

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TGC measures the total cost of operating the regulated hydroelectric facilities per unit of energy produced (MWh). The TGC calculation includes most OM&A costs, gross revenue charge, and sustaining capital. For the purposes of calculating TGC, generation adds back amounts spilled due to SBG. TGC is measured as a three-year rolling average, which helps to normalize fluctuations in generation and capital spend over time.

b) While the regulated hydroelectric business demonstrates strong cost performance – ranking in the first quintile for OM&A costs relative to a benchmark group of peer utilities (refer to Ex. F1-1-1, Section 5.3) – the Renewable Generation business unit ("RG") is planning a series of initiatives over the IR term to maintain performance and further improve results in line with business plan targets.

RG's continuous improvement goal is to enhance and optimize established work processes. Since 2023, these initiatives have been guided by the Excellence Plan framework, which supports sustained improvement across the People, Plant, and Future pillars. The Excellence Plan framework, described in Ex. L-F1-SEC-151, identifies RG's leadership and process improvements addressing safety, work management, preventive maintenance, equipment reliability, KPI focus, and discrete initiatives related to the environment and modernization.

Board Staff Interrogatory #162

Interrogatory

Reference:
Ref 1: Exhibit F1 / Tab 1 / Schedule 1 p. 22 Chart 6
Ref 2: Exhibit F1 / Tab 1 / Schedule 1 p. 30 Chart 8

Preamble:

At Reference 1, OPG shows its Hydroelectric Availability factors in 2023 & 2024 are below business targets.

At Reference 2, OPG shows its Equivalent Forced Outage Rates (EFOR) has never met its business targets since 2016.

Question(s):

1. Given the underperformance against the business targets in EFOR, as well as the emerging unfavorable trend in Hydroelectric Availability, please outline the strategies OPG intends to implement to better align its system reliability performance with Business Plan targets.

Response

OPG interprets “system reliability” to mean “unit reliability”, as hydroelectric Availability and EFOR are not measures of system reliability, which is assessed at the IESO-controlled grid level.

As described in Ex. F1-1-1, Section 5.2, OPG’s regulated hydroelectric fleet demonstrates strong operational performance, ranking very closely to the first quartile for Availability, and at industry median for Forced Outage Rate (FOR). Overall, the fleet’s performance reflects a high standard of reliability and operational excellence, particularly among the largest stations.

The reduction in availability observed in 2023-2024 generally reflects the asset condition of OPG’s aging regulated hydroelectric fleet, as outlined in Ex. F1-1-1, Sections 2.0 and 3.0.

While the turbine-generator overhaul and refurbishment projects are in progress, planned outages will increase, which will reduce Availability. These planned outages

are included in the forecast. Station Availability is expected to improve once all the planned unit overhaul and refurbishment activities at the station are complete.

At times, OPG may make risk-informed decisions to extend a forced outage when the outage has no adverse impact on generation (e.g., there is insufficient water to run all units of a generating station). This allows resources to be focused on higher priority work. While these operational decisions can negatively affect EFOR, making it higher than it would otherwise be, this approach reflects the integration of risk and cost-informed decision-making in the management of the hydroelectric business.

Over the IR term, OPG is focused on driving fleet performance in the following areas:

- Capital investment: As described in Ex. F1-1-1, Section 3, OPG is undertaking a significant capital investment program to manage the asset condition and maintain the reliable operation of an aging fleet over the longer term. Key investments include turbine generator overhaul and refurbishment projects.

- Planned outages: the RG Excellence Plan (provided at Ex. L-F1-SEC-150, Attachment 2) aims to sustain and enhance outage planning processes and improve unit-over-unit refurbishment outage performance, where appropriate.

- Forced outages:
  - The turbine-generator overhaul and refurbishment projects are expected to reduce forced outages and improve the health ratings of replaced equipment (refer to Ex. L-D1-SEC-041). This is expected to reduce the likelihood of longer duration forced outages caused by the system components within scope of these projects.
  - As described in Ex. L-F1-SEC-152, the Renewable Generation business unit has implemented an equipment failure review process that places a focus on forced outage reviews to determine the cause of failure and develop corrective actions to reduce reoccurrence, where economically prudent.
  - As overhaul and refurbishment projects progress over the IR term, OPG will continue to internally evaluate as well as benchmark forced outage rate performance with industry peers and user groups to identify opportunities for improvement. This is expected to include a review of the use of historical averages to forecast reliability targets, as described in Ex. F1-1-1, Section 4.1, as well as how water and unit availability jointly impact production.

Board Staff Interrogatory #163

Interrogatory

Reference:
Ref 1: Exhibit F1 / Tab 1 / Schedule 1 p. 20

Preamble:

At Reference 1, OPG states that Total Recordable Environmental Events will replace the Environmental Performance Index in 2026. This change removes the Polychlorinated Biphenyl equipment removal program due to the program finishing.

Question(s):

a) Please confirm that the current Environmental Performance index is the sum of Polychlorinated Biphenyl equipment removal incidents, spills, and regulatory infractions, while its replacement Total Recordable Environmental Events includes only spills and regulatory infractions.

Response

a) Not confirmed. As discussed in Ex. F1-1-1, Section 4.2, Environmental Performance Index ("EPI") is a composite, weighted index as opposed to a sum. It includes the number of environmental spills, the number of regulatory infractions, and the implementation of other environmental initiatives. The Polychlorinated Biphenyl equipment removal program was the final environmental initiative being tracked through EPI; there were no other initiatives remaining in the composite metric.

   EPI's replacement in 2026 is Total Recordable Environmental Events ("TREE"). This metric provides a clearer view as to the exact number of regulatory and reportable impact of environmental infractions and spills (as opposed to being a composite metric).

Board Staff Interrogatory #164

Interrogatory

Reference:
Ref 1: Exhibit F1 / Tab 1 / Schedule 1 / p. 5

Preamble:

At Reference 1, OPG states that hydroelectric overhaul projects are typically required every 25-30 years and involve significant OM&A maintenance activities. Refurbishment projects are capital investments aimed at extending useful life of the equipment.

Question(s):

a) Please explain whether all overhaul project costs are expensed as OM&A (i.e. no capitalized costs), and whether the costs are included as base OM&A, project OM&A, or a combination both.

b) Please clarify whether refurbishment projects incur OM&A. If yes, please clarify whether the refurbishment-related OM&A is included as base OM&A, project OM&A, or both.

c) Please provide 2016-2027 actual and budgeted and/or planned overhaul project OM&A by year.

d) If applicable, please provide 2016-2027 actual and budgeted planned refurbishment project OM&A by year.

Response

a) All overhaul project costs are expensed as OM&A costs (i.e., not capitalized), in accordance with OPG's capitalization policy as described in Ex. D4-1-1. All such costs are expensed as Project OM&A costs.

b) As described in Ex. F1-1-1, Section 3.3, refurbishment projects may incur OM&A costs to remove existing assets. Removal costs include costs associated with dismantling, crating, tearing down, or disassembling equipment formerly in service. These costs are expensed to Project OM&A costs, in accordance with US GAAP (see Ex. D4-1-1, Section 2.0); there are no Base OM&A costs associated with this work.

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c) The 2016-2027 actual and budgeted and/or planned overhaul Project OM&A costs by year (included in Ex. F1-3-1, Table 1, Line 4 and Line 9) are provided in Chart 1 below.

Chart 1 – 2016-2027 Actual and Budgeted and/or Planned Overhaul Project OM&A

Year	Overhaul Project OM&A ($M)
2016 Actual	14.4
2017 Actual	14.4
2018 Actual	12.5
2019 Actual	9.8
2020 Actual	17.0
2021 Actual	25.8
2022 Actual	28.3
2023 Actual	29.8
2024 Actual	27.3
2025 Actual	29.9
2026 Budget	36.0
2027 Plan	39.7

d) The 2016-2027 actual and budgeted and/or planned refurbishment Project OM&A costs by year (included in Ex. F1-3-1, Table 1, Line 5) are provided in Chart 2 below.

Chart 2 – 2016-2027 Actual and Budgeted and/or Planned Refurbishment Project OM&A

Year	Refurbishment Project OM&A ($M)
2016 Actual	0.1
2017 Actual	1.1
2018 Actual	0.0
2019 Actual	0.0
2020 Actual	2.9
2021 Actual	0.5
2022 Actual	1.1
2023 Actual	0.6

Year	Refurbishment Project OM&A ($M)
2024 Actual	2.6
2025 Actual	0.8
2026 Budget	9.9
2027 Plan	17.0

1

Board Staff Interrogatory #165

Interrogatory

Reference:
Ref 1: Exhibit F1 / Tab 1 / Schedule 1 / p. 7

Preamble:

At Reference 1, OPG states that one of the cornerstones of the Renewable Generation Programmatic Collaboration Agreement (RG PCA) initiative is to facilitate early Original Equipment Manufacturers (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.

Question(s):

a) For the RG PCA initiative, please explain how OPG allocates common costs to regulated and unregulated hydroelectric businesses.

Response

a) An Original Equipment Manufacturer ("OEM") performing work under a Renewable Generation Programmatic Collaboration Agreement assigns costs directly to the specific refurbishment project to which the work relates, whether the project is regulated or unregulated. The OEM does not incur common costs that need to be allocated across multiple refurbishment projects.

Board Staff Interrogatory #166

Interrogatory

Reference:
Ref 1: Exhibit F1 / Tab 1 / Schedule 1 / p. 24

Preamble:

At Reference 1, Chart 7 – Regulated Hydroelectric Availability (%, 2025-2031 Targets) sets out all 54 regulated hydroelectric stations' Availability forecast in 2025-2031.

Question(s):

a) OEB staff notes the Availability forecast is trending lower in 2027 throughout 2031 (i.e. 83.7% - 84.9%), compared to historical years and the 2025-2026 forecast values (i.e., 87.4% - 89.2%). To what extent is the lower forecast due to an expected increase in station project work in 2027-2031?

Response

a) The lower forecasted availability is driven by the expected increase in planned station work in 2027-2031. Between 2027-2031, 65% of the forecast outage hours are associated with station project work (i.e., non-maintenance outages).

   For comparison, forecast outage hours associated with planned station project work were 57% in 2026 and 53% in 2025.

Board Staff Interrogatory #167

Interrogatory

Reference:
Ref 1: Exhibit F1 / Tab 1 / Schedule 1 / Chart 8 / p. 25
Ref 2: Exhibit F1 / Tab 1 / Schedule 1 / p. 26

Preamble:

Reference 1 shows that OPG has missed its Equivalent Forced Outage Rate (EFOR) target in all years from 2016 to 2024 (i.e. EFOR was higher than target).

At Reference 2, OPG states that the forecasted outage plan for each station accounts 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.

Question(s):

a) Please explain whether the 2016-2024 missed targets are due to actual planned outage work being ahead of schedule, changes to the scope of planned outage work, or nether.

b) Please explain why there were higher than planned outage activities in 2016-2024.

Response

a) and b)

OPG interprets these questions to be in relation to the historical Equivalent Forced Outage Rate ("EFOR") discussed in References 1 and 2, and not the forecast period.

The missed EFOR targets for 2016-2024 were neither due to actual planned outage work being ahead of schedule nor changes to the scope of planned outage work. The targets were missed due to forced outages (Ex. F1-1-1, p. 26, lines 1-15).

The primary contributors to higher EFOR during this period were bearing failures, most notably at R.H. Saunders GS, and turbine reliability issues at the Sir Adam Beck complex and Lower Notch GS.

Board Staff Interrogatory #168

Interrogatory

Reference:
Ref 1: Exhibit F1 / Tab 1 / Schedule 1 / Chart 12 / p. 29

Preamble:

At Reference 1, the chart illustrates the Total Generating Cost metric performance in 2016-2024.

Question(s):

a) Please provide the Total Generating Cost forecasts and targets for 2016-2024, if they exist. If they do not exist, please explain why not.

b) Please provide the Total Generating Cost forecasts and targets for 2025-2027. If they do not exist, please explain why not.

Response

a) and b)

Consistent with historical practice, as explained in EB-2016-0152,[1] OPG does not set Total Generating Cost targets for the regulated hydroelectric business.

[1] OPG Reply Argument, EB-2016-0152, June 19, 2017, p. 220; Decision and Order, EB-2016-0152, December 28, 2017, pp. 148-149.

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Board Staff Interrogatory #169

Interrogatory

Reference:
Ref 1: Exhibit F1 / Tab 1 / Schedule 1 / Table 1
Ref 2: Exhibit F1 / Tab 1 / Schedule 1 / Table 2a
Ref 3: Exhibit F1 / Tab 1 / Schedule 1 / Table 2b

At Reference 1, the Operating Costs Summary - Regulated Hydroelectric ($M) table provides Base and Project OM&A in 2016-2027.

At Reference 2, the Regulated Hydroelectric Staff Summary - Regular and Non-Regular (FTEs) table provides FTEs in 2016-2019.

At Reference 3, the Regulated Hydroelectric Staff Summary - Regular and Non-Regular (FTEs) table provides FTEs in 2020-2031.

OEB staff created the following table based on the information in the references:

Table 1 – OM&A and FTE increase comparison

	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Base OM&A ($ millions) - Ref 1 table Line No. 1	204.52	205.42	215.47	236.47	251.16	264.26	274.16	286.22
Project OM&A ($ millions) - Ref 1 table Line No. 2	53.55	81.11	74.10	75.26	68.32	92.63	90.48	126.97
Subtotal	258.08	286.53	289.57	311.73	319.48	356.89	364.64	413.19
Year-Over-Year increase in OM&A		**11.02%**	1.06%	**7.65%**	2.49%	**11.71%**	2.17%	**13.31%**
Regulated Hydroelectric OM&A FTEs - Ref 3 table Line No. 6	899.2	882.4	905.5	931.8	978.6	1051.6	1075.0	1074.0
Year-Over-Year increase in OM&A FTEs	N/A	**-1.87%**	2.62%	**2.91%**	5.02%	**7.46%**	2.23%	**-0.09%**

Question(s):

a) Please provide FTE breakdowns into OM&A and Capital in 2016-2019 as shown in the table in Reference 2 above.

b) OEB staff notes the year-over-year increase in OM&A is much higher than the year-over-year increase in OM&A FTEs in 2021, 2023, 2025 and 2027 (i.e. % bolded in Table 1). Please provide any non-compensation cost drivers that result in Base and Project OM&A increases in 2021, 2023, 2025 and 2027

Response

a) Refer to Chart 1 below.

Chart 1 – Regulated Hydroelectric FTEs Breakdown 2016-2019

	2016 Actual	2017 Actual	2018 Actual	2019 Actual
Regulated Hydroelectric Capital:				
Regular Staff	43.3	59.9	78.5	109.4
Non-Regular Staff:				
Temporary	0.8	2.1	3.8	5.1
Total Regulated Hydroelectric Capital	**44.1**	**62.0**	**82.4**	**114.4**
Regulated Hydroelectric OM&A:				
Regular Staff	936.9	903.8	947.6	915.2
Non-Regular Staff:				
Temporary	34.4	42.1	48.6	43.5
Total Regulated Hydroelectric OM&A	**971.3**	**945.9**	**996.3**	**958.7**
Total Regulated Hydroelectric	**1,015.4**	**1,008.0**	**1,078.6**	**1,073.1**

b) The main drivers of the referenced non-compensation increases in Base and Project OM&A costs in 2021, 2023, 2025, and 2027 are identified below. Additionally, OPG notes that compensation OM&A costs, while not the primary driver of these variances, are impacted year over year by wage escalation, in addition to the number of FTEs.

2021 (Actual)

The main driver of higher non-compensation costs in 2021, compared to 2020, is Project OM&A in Western and Eastern Region portfolios:

- Western Region: 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 (refer to Ex. F1-3-2, p.4, lines 6-12 and Ex. F1-3-1, Table 1, Note 2).
- Eastern Region: Purchased services in the OM&A Project portfolio increased primarily due to turbine-generator overhaul work ($10M).

2023 (Actual)

The main driver of non-compensation costs in 2023, compared to 2022, is an increase in Base OM&A purchased services related to maintenance costs, primarily at R.H. Saunders GS, Sir Adam Beck 1 GS and Sir Adam Beck 2 GS due to environmental remediation (e.g., lead paint and asbestos removal), storm response clean-up, and additional joint works expenditures (refer to Ex. F1-2-2, p.4, lines 1-4).

2025 (Budget)

The main driver of higher non-compensation costs in 2025, compared to 2024, is an increase in Project OM&A costs for Infrastructure expenditures consisting of removal costs associated with capital work (Ex. F1-3-1, p. 4, Section 3.3 and Table 1).

2027 (Plan)

The main driver of higher non-compensation costs in 2027, compared to 2026, is Project OM&A purchased services in Eastern and Niagara Regions, and removal costs (refer to Ex. F1-3-2, Section 2.1):

- Eastern Region: Increased expenditures related to concrete repair and restoration projects, primarily pertaining to concrete structures at Des Joachims GS and R.H. Saunders GS.
- Niagara Region: Increased expenditures for Niagara station overhaul projects, such as DeCew Falls 1 GS. Additional contributors include building rehabilitation programs.
- Infrastructure costs: Increase in planned removal costs associated with capital work (Ex. F1-3-1, p. 4, Section 3.3 and Table 1).

The percentage increase in the labour costs is higher than the percentage increase in FTEs, primarily due to cumulative wage escalation assumptions between 2027 and 2031 (refer to Ex. L-F4-Staff-227).

On average, labour costs account for an average of 78% of total Base OM&A over the 2016-2027 period. While labour rates have escalated annually (as described in Ex. L-F4-Staff-227), the primary driver for the discrepancy between the year-over-year increase in OM&A versus the year-over-year increase in OM&A FTEs is non-compensation costs.

Board Staff Interrogatory #170

Interrogatory

Reference:
Ref 1: Exhibit F1 / Tab 1 / Schedule 1 / Chart 6
Ref 2: Exhibit F1 / Tab 1 / Schedule 1 / Chart 8
Ref 3: Exhibit E1 / Tab 1 / Schedule 1 / Table 1

Preamble:

Reference 1 presents historical hydroelectric availability for the 12 hydroelectric generating stations that OPG states have a substantial influence on fleet-wide results. Reference 2 presents the historical equivalent forced outage rate for the same 12 generating stations.

Question(s):

a) For each of Reference 1 and Reference 2, please confirm whether there are any stations other than those identified in the Charts that have a substantial influence on each of the Regional results of historical hydroelectric availability or the results of historical equivalent forced outage rate. If yes, please identify them.
   i. For any stations identified in part a) please include them in the responses to parts d) and e)

b) Please provide a mathematical example of how hydroelectric availability is calculated.

c) Please provide a mathematical example of how equivalent forced outage rate is calculated

d) Please update Reference 1 for 2025 actual results, and the hydroelectric availability from the 2026 and 2027 forecasts presented in Reference 3. Please provide the table in excel format.

e) Please update Reference 2 for 2025 actual results, and the equivalent forced outage rate from the 2026 and 2027 forecasts presented in Reference 3. Please provide the table in excel format.

Response

a) OPG has provided the list of regulated hydroelectric stations with the most substantial influence on historical Availability and historical Equivalent Forced Outage Rate ("EFOR") in Ex. F1-1-1, Chart 6 and Chart 8.

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b) Availability, as described in Ex. F1-1-1, Section 4.3.1, is calculated using the formula below. This calculation method aligns with the Availability Factor definition established by Electricity Canada, which is an industry-standard metric used for Canadian performance reporting for hydroelectric generating facilities.

The following examples are simplified for ease of illustration and therefore do not include Maximum Continuous Rating ("MCR") weighting. In practice, each unit event duration is weighted by the applicable MCR during that event. This weighting is used where units or stations have different MCR values so that higher-capacity units are proportionately reflected in the overall performance metrics. For reference, MCR is defined in Ex. F1-1-1, Section 4.3.

Note: hours are represented as hrs.

$$\text{Availability} = (1 - \text{Incapability Factor}) * 100\%$$

$$\text{Incapability Factor} = \frac{\text{Planned outage hrs} + \text{Equivalent Planned derate hrs} + \text{Forced outage hrs} + \text{Equivalent Forced derate hrs}}{\text{Period hrs (typically 8760 hrs)}}$$

Example 1 – Planned and Forced Outages Only (No Derates)

Planned outages: 30 days (720 hrs)
Forced outages: 2 days (48 hrs)
Planned derates: 0 days (0 hrs)
Forced derates: 0 days (0 hrs)
Period: 365 days (8760 hrs)

Step 1: Calculate Incapability Factor:

$$\text{Incapability Factor} = \frac{(720+48)}{8760} = 0.088$$

Step 2: Calculate Availability:

$$\text{Availability} = (1 - 0.088) * 100\%$$
$$\text{Availability} = 0.9123 * 100\%$$
$$\text{Availability} = 91.2\%$$

Example 2 – Planned and Forced Outages with Derate

Planned outages: 30 days (720 hrs)
Forced outages: 2 days (48 hrs)
Planned derates: 0 days (0 hrs)
Forced derates: unit ran for 5 days (120 hrs) at 25% derate from total MCR
Period: 365 days (8760 hrs)

Step 1: Calculate the impact of forced derate on Incapability Factor if the unit was running for 120 hours at 25% derate from total MCR. The equivalent forced outage hours ("EFOH") would be calculated as:

$$\text{EFOH} = \%\text{ of derate from total MCR} * \text{number of hrs unit was derated}$$
$$\text{EFOH} = 0.25 * 120$$
$$\text{EFOH} = 30\text{ hrs}$$

Step 2: Calculate Incapability Factor:

$$\text{Incapability Factor} = \frac{(720 + 48 + 30)}{8760} = 0.091$$

Step 3: Calculate Availability:

$$\text{Availability} = (1 - 0.091) * 100\%$$
$$\text{Availability} = 0.909 * 100\%$$
$$\text{Availability} = 90.9\%$$

c) The EFOR, as described in Ex. F1-1-1, Section 4.3.2, is calculated using the formula below. This calculation method aligns with the Derated Adjusted Forced Outage Rate definition established by Electricity Canada, which is an industry-standard metric used for Canadian performance reporting for hydroelectric generating facilities. As per the response to part b), the following examples are simplified for ease of illustration and therefore do not include MCR weighting.

$$\text{EFOR} = \frac{\text{Forced outage hrs} + \text{Equivalent Forced derate hrs}}{\text{Operating hrs} + \text{Forced outage hrs} + \text{Equivalent Forced derate hrs}} * 100\%$$

Example 1 – Planned and Forced Outages Only (No Derates)

Forced outages: 2 days (48 hrs)
Planned derates: 0 days (0 hrs)
Forced derates: 0 days (0 hrs)
Operating hours: (5,000)
Period: 365 days (8760 hrs)

Step 1: Calculate EFOR:

$$\text{EFOR} = \frac{48}{(5000+48)} * 100\%$$
$$\text{EFOR} = 0.0095 * 100\%$$
$$\text{EFOR} = 0.95\%$$

Example 4 – Planned and Forced Outages with Derate

Forced outages: 2 days (48 hrs)
Planned derates: 0 days (0 hrs)
Forced derates: unit ran for 5 days (120 hrs) at 25% derate from total MCR
Operating hours: (5,000)
Period: 365 days (8760 hrs)

Step 1: Calculate the impact of forced derate on Incapability Factor if the unit was running for 120 hours at 25% derate from total MCR. The equivalent forced outage hours ("EFOH") would be calculated as:

$$\text{EFOH} = \%\text{ of derate from total MCR} * \text{number of hrs unit was derated}$$
$$\text{EFOH} = 0.25 * 120$$
$$\text{EFOH} = 30\text{ hrs}$$

Step 2: Calculate EFOR:

$$\text{EFOR} = \frac{48+30}{(5000+48+30)} * 100\%$$
$$\text{EFOR} = 0.015 * 100\%$$
$$\text{EFOR} = 1.5\%$$

d) OPG interprets the question to provide the following data in Excel format:
- For the period 2016-2024 and 2025, historical regulated hydroelectric Availability for the 12 hydroelectric generating stations detailed in Chart 6 (refer to Attachment 1).
- For the years 2026 and 2027, regulated hydroelectric Availability targets as detailed in Chart 7 of Ex. F1-1-1 (refer to Attachment 2).

The information discussed in Reference 3 is not used in the calculation of Availability.

e) OPG interprets the question to provide the following in Excel format:
- For the period 2016-2024 and 2025, historical regulated hydroelectric EFOR for the 12 hydroelectric generating stations detailed in Chart 8 (refer to Attachment 3).
- For the years 2026 and 2027, regulated hydroelectric EFOR targets as detailed in Chart 9 of Ex. F1-1-1 (refer to Attachment 4).

The information discussed in Reference 3 is not used in the calculation of EFOR.

L-F1-Staff-170 - Attachment 1
Regulated Hydroelectric Historic Availability (2016-2025)

Station		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
DeCew Falls 2 GS	Actual	88.9%	45.5%	47.6%	61.0%	93.4%	93.7%	96.1%	78.2%	54.5%	89.9%
	Target	85.3%	45.2%	84.6%	94.2%	93.8%	96.2%	96.9%	82.6%	67.1%	94.1%
Sir Adam Beck 1 GS	Actual	73.2%	78.0%	91.1%	81.6%	92.7%	88.1%	94.1%	92.8%	93.2%	89.0%
	Target	82.3%	81.1%	88.1%	84.4%	86.0%	75.0%	81.7%	86.6%	92.2%	86.5%
Sir Adam Beck 2 GS	Actual	95.2%	96.3%	95.6%	93.5%	96.0%	96.4%	94.7%	94.6%	95.8%	96.0%
	Target	93.8%	92.2%	95.2%	97.0%	96.6%	95.8%	92.1%	89.7%	95.4%	94.8%
Niagara Region (5 Stations)	Actual	84.7%	85.8%	88.4%	86.2%	91.7%	91.2%	91.8%	90.0%	89.6%	88.4%
	Target	85.4%	84.4%	91.4%	91.4%	92.7%	90.3%	88.5%	87.2%	91.9%	89.9%
Cameron Falls GS	Actual	96.2%	97.0%	98.9%	79.9%	99.4%	89.0%	97.7%	96.3%	78.8%	85.3%
	Target	97.1%	92.4%	89.4%	90.3%	94.8%	90.0%	97.5%	91.2%	82.6%	84.3%
Pine Portage GS	Actual	94.9%	96.4%	96.0%	99.0%	86.0%	94.3%	95.9%	91.4%	88.0%	88.8%
	Target	95.1%	95.2%	91.7%	97.8%	88.2%	92.9%	98.3%	91.4%	97.2%	92.3%
Western Region (27 Stations)	Actual	92.3%	87.6%	87.6%	90.1%	88.0%	80.3%	88.3%	84.3%	85.3%	84.3%
	Target	92.2%	90.2%	89.0%	90.7%	83.5%	84.6%	92.2%	87.2%	91.7%	87.9%
Abitibi Canyon GS	Actual	92.4%	96.4%	86.5%	91.9%	71.5%	94.2%	71.0%	62.1%	71.4%	85.4%
	Target	90.5%	93.4%	90.2%	85.2%	78.1%	75.3%	74.6%	68.4%	64.1%	80.5%
Chats Falls GS	Actual	88.0%	87.8%	89.7%	95.3%	92.9%	90.5%	79.7%	87.4%	86.7%	87.8%
	Target	90.4%	87.3%	87.4%	91.4%	88.9%	89.1%	95.2%	93.6%	89.4%	90.3%
Chenaux GS	Actual	93.2%	90.6%	81.6%	80.0%	97.9%	73.1%	81.5%	80.5%	82.4%	91.7%
	Target	90.2%	91.4%	86.3%	88.2%	89.7%	87.3%	93.6%	89.1%	84.4%	83.5%
Des Joachims GS	Actual	90.6%	90.1%	78.3%	78.5%	79.4%	78.1%	81.7%	82.3%	90.0%	96.3%
	Target	91.8%	90.8%	86.9%	80.9%	77.2%	77.6%	68.7%	83.8%	81.7%	94.7%
Otter Rapids GS	Actual	97.3%	95.5%	90.2%	94.2%	91.8%	90.7%	93.7%	88.9%	80.8%	64.5%
	Target	93.0%	93.0%	88.7%	85.9%	92.8%	91.5%	93.1%	83.5%	72.9%	71.2%
Otto Holden GS	Actual	88.8%	90.1%	76.5%	77.4%	76.9%	80.8%	76.8%	80.0%	87.1%	81.5%
	Target	89.6%	88.3%	95.1%	73.5%	70.5%	66.6%	59.9%	80.5%	81.2%	83.8%
R.H. Saunders GS	Actual	90.8%	92.8%	94.5%	89.0%	95.5%	92.4%	89.4%	85.6%	82.7%	84.5%
	Target	91.0%	90.2%	91.3%	85.0%	90.5%	92.5%	89.2%	91.3%	85.5%	84.1%
Eastern Region (22 Stations)	Actual	91.1%	89.6%	84.0%	86.1%	87.2%	88.3%	85.0%	82.4%	82.1%	83.7%
	Target	89.1%	88.5%	87.7%	85.1%	84.3%	83.9%	82.6%	85.9%	82.8%	85.7%
All 54 Regulated Hydroelectric Stations	Actual	89.0%	88.0%	86.0%	86.6%	88.8%	88.4%	87.8%	85.4%	85.2%	85.5%
	Target	88.1%	87.3%	89.2%	88.0%	87.3%	86.2%	85.8%	86.6%	87.1%	87.5%

L-F1-Staff-170 - Attachment 2
Regulated Hydroelectric Availability (2026-2031 Targets)

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

L-F1-Staff-170 - Attachment 3
Regulated Hydroelectric Historical EFOR (2016-2025)

Station		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
DeCew Falls 2 GS	Actual	0.3%	0.5%	0.5%	11.3%	3.6%	5.3%	1.7%	2.0%	1.0%	5.1%
	Target	2.5%	2.1%	1.7%	1.8%	1.6%	1.6%	1.9%	2.2%	1.8%	3.2%
Sir Adam Beck 1 GS	Actual	8.6%	6.4%	0.4%	15.7%	4.7%	2.6%	0.8%	0.7%	1.6%	2.3%
	Target	3.5%	3.2%	3.6%	4.1%	3.7%	3.9%	4.0%	3.3%	3.3%	3.7%
Sir Adam Beck 2 GS	Actual	0.6%	0.2%	2.0%	2.9%	2.2%	1.0%	2.4%	0.4%	1.3%	0.8%
	Target	0.4%	0.4%	0.4%	0.4%	0.4%	0.6%	0.8%	0.9%	0.9%	1.4%
Niagara Region (5 Stations)	Actual	2.1%	2.5%	2.9%	8.4%	5.1%	4.6%	4.6%	3.5%	4.2%	7.3%
	Target	1.3%	1.2%	1.3%	1.4%	1.4%	1.9%	2.3%	2.5%	2.5%	3.1%
Cameron Falls GS	Actual	0.2%	0.3%	0.5%	1.0%	0.4%	3.5%	0.1%	0.5%	3.0%	0.8%
	Target	0.9%	0.7%	0.6%	0.8%	0.9%	0.9%	0.5%	0.5%	0.5%	0.4%
Pine Portage GS	Actual	1.3%	2.6%	0.8%	0.4%	0.2%	0.5%	0.5%	0.4%	14.0%	14.5%
	Target	0.8%	0.6%	0.7%	1.2%	1.4%	1.3%	0.7%	0.6%	0.6%	0.5%
Western Region (27 Stations)	Actual	2.1%	6.5%	4.0%	2.7%	4.2%	7.1%	4.9%	2.3%	10.0%	10.1%
	Target	1.8%	1.8%	2.0%	2.5%	2.5%	2.9%	2.0%	2.4%	2.4%	2.4%
Abitibi Canyon GS	Actual	1.4%	0.4%	8.6%	1.1%	7.3%	3.1%	2.7%	1.1%	2.1%	2.5%
	Target	3.1%	3.0%	2.8%	2.4%	2.4%	1.8%	2.4%	2.4%	2.4%	2.7%
Chats Falls GS	Actual	4.1%	3.3%	1.8%	0.9%	1.2%	1.4%	1.5%	0.4%	0.5%	2.8%
	Target	1.1%	1.1%	1.6%	1.6%	1.7%	1.6%	1.6%	1.6%	1.6%	1.8%
Chenaux GS	Actual	3.2%	0.5%	3.0%	2.8%	0.7%	0.6%	2.2%	2.1%	0.6%	0.8%
	Target	0.4%	0.7%	1.1%	0.9%	1.0%	1.7%	1.7%	1.6%	1.6%	2.4%
Des Joachims GS	Actual	1.9%	1.3%	0.2%	0.5%	5.1%	0.8%	0.6%	1.7%	0.2%	0.4%
	Target	0.7%	0.8%	1.0%	0.9%	1.0%	1.2%	1.7%	1.5%	1.4%	1.8%
Otter Rapids GS	Actual	0.5%	0.3%	0.4%	2.1%	2.7%	6.1%	2.9%	3.1%	2.9%	4.5%
	Target	3.9%	3.7%	3.2%	2.8%	2.8%	1.7%	1.7%	2.1%	2.0%	2.0%
Otto Holden GS	Actual	1.9%	2.9%	3.3%	3.5%	10.0%	2.8%	1.0%	1.0%	0.8%	2.9%
	Target	0.4%	0.5%	0.7%	0.7%	0.7%	1.7%	2.0%	2.1%	2.1%	2.8%
R.H. Saunders GS	Actual	4.4%	4.6%	1.2%	9.8%	2.0%	0.4%	5.1%	3.5%	3.2%	3.1%
	Target	0.4%	0.4%	0.6%	0.9%	1.0%	1.9%	2.1%	2.2%	2.2%	3.4%
Eastern Region (22 Stations)	Actual	2.7%	3.2%	5.2%	6.1%	6.5%	1.8%	3.6%	2.6%	5.6%	5.1%
	Target	1.9%	2.0%	2.0%	2.1%	2.1%	2.6%	3.1%	3.0%	3.0%	3.5%
All 54 Regulated Hydroelectric Stations	Actual	2.4%	3.3%	4.2%	6.7%	5.7%	3.5%	4.1%	2.9%	5.5%	6.6%
	Target	1.6%	1.7%	1.7%	1.8%	1.8%	2.3%	2.7%	2.6%	2.7%	3.2%

L-F1-Staff-170 - Attachment 4
Regulated Hydroelectric EFOR (2026-2031 Targets)

Station	2026	2027	2028	2029	2030	2031
DeCew Falls 2 GS	2.0%	1.9%	2.0%	2.0%	2.2%	1.8%
Sir Adam Beck 1 GS	3.5%	3.3%	3.4%	3.4%	3.4%	3.4%
Sir Adam Beck 2 GS	1.4%	1.3%	1.4%	1.4%	1.4%	1.4%
Niagara Region (5 Stations)	**3.5%**	**3.5%**	**3.4%**	**3.4%**	**3.5%**	**3.3%**
Cameron Falls GS	0.7%	0.8%	0.8%	0.8%	0.8%	0.8%
Pine Portage GS	0.8%	0.8%	0.8%	0.9%	0.9%	0.9%
Western Region (27 Stations)	**3.0%**	**3.0%**	**3.0%**	**3.0%**	**3.0%**	**3.0%**
Abitibi Canyon GS	2.9%	2.7%	2.7%	2.7%	2.7%	2.7%
Chats Falls GS	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%
Chenaux GS	2.5%	2.5%	2.4%	2.5%	2.5%	2.5%
Des Joachims GS	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%
Otter Rapids GS	2.3%	2.2%	2.0%	2.1%	2.1%	2.1%
Otto Holden GS	2.9%	2.9%	2.8%	2.8%	2.7%	2.8%
R.H. Saunders GS	4.0%	4.0%	3.9%	3.9%	3.9%	3.9%
Eastern Region (22 Stations)	**3.9%**	**3.9%**	**3.9%**	**3.9%**	**3.9%**	**3.9%**
All 54 Regulated Hydroelectric Stations	**3.6%**	**3.6%**	**3.6%**	**3.6%**	**3.6%**	**3.6%**

Board Staff Interrogatory #171

Interrogatory

Reference:
Ref 1: Exhibit F1 / Tab 1 / Schedule 1 tables
Ref 2: Exhibit F1 / Tab 2 / Schedule 1 tables
Ref 3: Exhibit F2 / Tab 1 / Schedule 1 tables
Ref 4: Exhibit F2 / Tab 2 / Schedule 1 tables
Ref 5: Exhibit F2 / Tab 2 / Schedule 2 tables
Ref 6: Exhibit F2 / Tab 3 / Schedule 1 tables
Ref 7: Exhibit F2 / Tab 3 / Schedule 2 tables
Ref 8: Exhibit F2 / Tab 4 / Schedule 1 tables
Ref 9: Exhibit F2 / Tab 4 / Schedule 2 tables
Ref 10: Exhibit F2 / Tab 5 / Schedule 1 tables
Ref 11: Exhibit F2 / Tab 5 / Schedule 2 tables
Ref 12: Exhibit F2 / Tab 7 / Schedule 1 tables

Preamble:

The tables referenced above provide 2025 budget numbers.

Question(s):

a) Please update the references above to include 2025 year-end actual numbers.

Response

a) Refer to Attachment 1 and Ex. L-A1-CCC-001, Attachment 1, per the chart below.

Chart 1 – Location of Requested Tables

Regulated Hydroelectric			
Pre-filed Reference			**Interrogatory Response Reference**
F1-1-1	Table	1	L-A1-CCC-001 – Attachment 1 – Table 32
F1-1-1	Table	2b	L-A1-CCC-001 – Attachment 1 – Table 33
F1-2-1	Table	1	L-A1-CCC-001 – Attachment 1 – Table 34
F1-2-1	Table	2	L-A1-CCC-001 – Attachment 1 – Table 35
F1-2-1	Table	9	L-F1-Staff-171 – Attachment 1 - Table 1
Nuclear			
Pre-filed Reference			**Interrogatory Response Reference**
F2-1-1	Table	1a	L-A1-CCC-001 – Attachment 1 – Table 38
F2-1-1	Table	2a	L-A1-CCC-001 – Attachment 1 – Table 39
F2-2-1	Table	1a	L-A1-CCC-001 – Attachment 1 – Table 40
F2-2-1	Table	2a	L-A1-CCC-001 – Attachment 1 – Table 41
F2-2-1	Table	8	L-F1-Staff-171 – Attachment 1 – Table 2
F2-2-2	Table	1a	L-F1-Staff-171 – Attachment 1 – Table 3a
F2-2-2	Table	1b	L-F1-Staff-171 – Attachment 1 – Table 3b
F2-3-1	Table	1	L-A1-CCC-001 – Attachment 1 – Table 42
F2-3-1	Table	2	L-F1-Staff-171 – Attachment 1 – Table 4
F2-3-2	Table	1	L-F1-Staff-171 – Attachment 1 – Table 5
F2-4-1	Table	1	L-A1-CCC-001 – Attachment 1 – Table 43
F2-4-1	Table	2	L-F1-Staff-171 – Attachment 1 – Table 6
F2-4-2	Table	1a	L-F1-Staff-171 – Attachment 1 – Table 7a
F2-4-2	Table	1b	L-F1-Staff-171 – Attachment 1 – Table 7b
F2-5-1	Table	1a	L-A1-CCC-001 – Attachment 1 – Table 44
F2-5-2	Table	1a	L-F1-Staff-171 – Attachment 1 – Table 8a
F2-5-2	Table	1b	L-F1-Staff-171 – Attachment 1 – Table 8b
F2-5-2	Table	1c	L-F1-Staff-171 – Attachment 1 – Table 9
F2-7-1	Table	1	L-A1-CCC-001 – Attachment 1 – Table 45
F2-7-1	Table	2	L-F1-Staff-171 – Attachment 1 – Table 10

Numbers may not add due to rounding.

Table 1
Regulated Hydroelectric Base OM&A by Function ($M)
Actual - Calendar Year Ending December 31, 2025

Line No.	Function	Actual Niagara Region	Actual Eastern Region	Actual Western Region	Actual Total
		(a)	(b)	(c)	(d)
	Operating Regions				
1	Operations & Maintenance	50.2	91.1	32.4	173.7
2	- Operations	13.1	12.3	5.2	30.5
3	- Maintenance	37.1	78.8	27.3	143.2
4	Site and Support Services	6.6	8.1	2.2	16.9
5	**Total Operating Regions**	56.8	99.2	34.6	190.6
	Operations and Project Support [1,2]				
6	**Operations and Project Support**	21.0	33.5	11.0	65.4
7	**Total Base OM&A**	77.8	132.7	45.6	256.0

Numbers may not add due to rounding.

Table 2
Combined Nuclear Base OM&A by Function ($M)
Actual - 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	291.3	295.1	586.3	0.0
2	- Operations	100.5	77.5	178.0	
3	- Maintenance	190.8	217.6	408.3	
4	Work Management	20.1	16.1	36.3	
5	Site and Support Services	36.4	50.0	86.4	
6	Tritium Removal Facility	12.7		12.7	
7	**Total Nuclear Stations**	360.5	361.2	721.6	0.0
	Operations and Project Support[1]				
8	**Operations and Project Support**	271.1	257.2	528.2	0.0
	CRVA Eligible Costs				
9	Fuel Channel Life Extension Project	0.4	(0.2)	0.3	
10	Pickering Extended Operations		0.0	0.0	
11	Optimization of Pickering Shutdown		0.2	0.2	
12	**Total CRVA Eligible Costs**	0.4	0.1	0.5	0.0
13	**Total Base OM&A**	631.9	618.4	1,250.3	0.0

Numbers may not add due to rounding.

Table 3a

Comparison of OPG Nuclear Facilities Base OM&A by Function ($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)
	Nuclear Stations											
1	Operations & Maintenance	667.8	(22.3)	645.5	(5.2)	670.1	(29.8)	640.2	(8.2)	645.8	(13.8)	632.1
2	- Operations	226.8	(12.0)	214.8	(5.8)	222.5	(13.5)	208.9	(6.8)	206.5	(4.4)	202.1
3	- Maintenance	441.0	(10.3)	430.7	0.6	447.6	(16.3)	431.3	(1.4)	439.3	(9.3)	430.0
4	Work Management	40.0	***(5.9)***	34.1	1.0	37.8	(2.8)	35.0	***5.7***	33.7	***7.0***	40.8
5	Site and Support Services	104.5	***(11.6)***	93.0	***12.6***	107.6	(2.0)	105.6	(2.2)	100.2	3.2	103.4
6	Tritium Removal Facility	12.2	(0.8)	11.4	***3.0***	12.5	***1.9***	14.4	***(3.0)***	14.5	***(3.1)***	11.4
7	**Total Nuclear Stations**	824.5	(40.7)	783.9	11.4	828.0	(32.8)	795.2	(7.6)	794.2	(6.6)	787.7
	Operations and Project Support											
8	Enterprise Engineering	236.8	(19.6)	217.2	(7.9)	244.5	***(35.3)***	209.3	6.4	231.1	(15.4)	215.7
9	Integrated Fleet Management	185.0	3.2	188.2	(9.2)	188.5	(9.5)	178.9	(5.4)	190.3	(16.8)	173.6
10	Environment, Health & Safety	15.3	***2.7***	18.0	***3.9***	15.9	***5.9***	21.9	***(5.9)***	13.4	***2.6***	16.0
11	Enterprise Projects	14.9	0.6	15.5	1.4	13.1	***3.8***	16.9	0.8	14.9	***2.9***	17.7
12	Other Support	68.7	(0.0)	68.7	3.4	67.6	4.5	72.1	(4.7)	73.6	(6.2)	67.4
13	Low and Intermediate Level Waste	5.6	***1.3***	6.9	(0.2)	5.8	0.9	6.7	***9.5***	4.8	***11.5***	16.3
14	**Total Operations and Project Support**	526.3	(11.9)	514.4	(8.7)	535.4	(29.7)	505.8	0.9	528.0	(21.4)	506.6
	CRVA Eligible Costs											
15	Fuel Channel Life Extension Project	6.0	***1.8***	7.8	0.9	6.0	***2.7***	8.7	***1.0***	5.9	***3.8***	9.7
16	Pickering Extended Operations	0.0	***7.2***	7.2	***(1.8)***	0.0	***5.4***	5.4	***(5.4)***	0.0	0.0	0.0
17	Pickering Optimization of Shutdown	0.0	0.5	0.5	0.3	0.0	0.9	0.9	0.8	5.8	***(4.2)***	1.7
18	**Total CRVA Eligible Costs**	6.0	***9.6***	15.6	(0.6)	6.0	***9.0***	15.0	***(3.6)***	11.7	(0.3)	11.4
19	**Total Base OM&A Before Adjustments**	1,356.8	(43.0)	1,313.9	2.1	1,369.5	(53.5)	1,316.0	(10.3)	1,334.0	(28.3)	1,305.7
20	**OEB/Settlement Adjustments**[3,4]	(56.1)	***56.1***	0.0	0.0	(56.2)	***56.2***		0.0	(40.0)	***40.0***	
21	**Total Base OM&A Including Adjustments**	1,300.7	13.2	1,313.9	2.1	1,313.2	2.8	1,316.0	(10.3)	1,294.0	11.7	1,305.7

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 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Nuclear Stations											
22	Operations & Maintenance	632.1	60.5	638.9	53.7	692.5	(5.4)	630.0	57.2	687.2	***(100.9)***	586.3
23	- Operations	202.1	11.7	195.0	18.7	213.8	11.1	194.3	***30.5***	224.8	***(46.8)***	178.0
24	- Maintenance	430.0	***48.8***	443.8	34.9	478.8	(16.4)	435.7	26.7	462.4	***(54.0)***	408.3
25	Work Management	40.8	***(9.6)***	34.0	(2.8)	31.2	***5.2***	29.9	***6.5***	36.4	(0.1)	36.3
26	Site and Support Services	103.4	***22.6***	100.7	***25.3***	126.0	***(31.0)***	96.3	(1.4)	94.9	(8.6)	86.4
27	Tritium Removal Facility	11.4	0.5	14.7	***(2.8)***	11.9	(0.2)	15.1	***(3.4)***	11.7	1.0	12.7
28	**Total Nuclear Stations**	787.7	73.9	788.2	73.3	861.6	(31.4)	771.3	58.9	830.2	***(108.6)***	721.6
	Operations and Project Support											
29	Enterprise Engineering	215.7	***26.7***	229.8	12.7	242.5	10.5	236.0	16.9	253.0	***(28.0)***	224.9
30	Integrated Fleet Management	173.6	15.0	192.2	(3.6)	188.5	***33.3***	189.5	***32.4***	221.9	***(26.8)***	195.1
31	Environment, Health & Safety	16.0	***(2.1)***	13.4	0.5	13.9	(0.4)	13.2	0.3	13.5	***(1.5)***	12.1
32	Enterprise Projects	17.7	(1.6)	14.1	***2.1***	16.1	0.3	13.5	***2.9***	16.4	***(8.8)***	7.6
33	Other Support	67.4	***14.1***	74.8	6.6	81.5	2.6	76.5	7.6	84.1	(4.8)	79.3
34	Low and Intermediate Level Waste	16.3	***(4.0)***	5.1	***7.2***	12.3	(0.8)	5.5	***6.0***	11.5	***(2.4)***	9.2
35	**Total Operations and Project Support**	506.6	48.2	529.4	25.4	554.8	45.6	534.2	***66.2***	600.4	***(72.2)***	528.2
	CRVA Eligible Costs											
36	Fuel Channel Life Extension Project	9.7	***(8.6)***	4.3	***(3.1)***	1.1	***(1.3)***	0.8	(0.9)	(0.1)	0.4	0.3
37	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
38	Optimization of Pickering Shutdown	1.7	(0.3)	2.7	***(1.3)***	1.4	***1.6***	4.8	***(1.8)***	3.0	***(2.7)***	0.2
39	**Total CRVA Eligible Costs**	11.4	***(8.9)***	7.0	***(4.4)***	2.5	0.3	5.6	***(2.8)***	2.8	***(2.4)***	0.5
40	**Total Base OM&A Before Adjustments**	1,305.7	113.2	1,324.6	94.3	1,418.9	14.6	1,311.2	122.3	1,433.5	***(183.2)***	1,250.3
41	**OEB/Settlement Adjustments**[3,4]		0.0	(39.7)	***39.7***		0.0	(39.3)	***39.3***		0.0	
42	**Total Base OM&A Including Adjustments**	1,305.7	113.2	1,284.8	***134.0***	1,418.9	14.6	1,271.8	***161.6***	1,433.5	***(183.2)***	1,250.3

Notes:

1 Bold italic font indicates variance of 10% or greater.

2 All 2020-2026 amounts (within the Actual, Budget, and OEB Approved columns) 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).

3 OEB Adjustments to approved values in 2020-2021 include the annual disallowance of $25M for nuclear base OM&A (EB-2016-0152 Decision and Order, p. 55) and the annual $30M disallowed in compensation (EB-2016-0152 Decision and Order, p. 84). OEB adjusted values also include adjustments to low and intermediate level waste management variable expenses (EB-2016-0152 Payment Amounts Order, App. A Table 1a/2a/3a/4a/5a, note 5b and per Ex. N1).

4 Per EB-2020-0290 OEB Decision and Order, Schedule A, p. 25, nuclear base OM&A costs are reduced by 3% per year over the 2022-2026 period.

Numbers may not add due to rounding.

Table 3b
Comparison of OPG Nuclear Facilities Base OM&A by Function ($M)[1, 2]

Line No.	Business Unit	2025 OEB Approved	(c)-(a) Change	2025 Actual	(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)
	Nuclear Stations											
43	Operations & Maintenance	527.8	***58.5***	586.3	(29.3)	290.0	***267.0***	557.0	***(229.1)***	327.8	16.0	343.9
44	- Operations	150.2	***27.8***	178.0	0.4	91.1	***87.2***	178.4	***(61.1)***	117.2	6.0	123.2
45	- Maintenance	377.6	30.7	408.3	(29.7)	198.8	***179.8***	378.6	***(168.0)***	210.6	10.0	220.6
46	Work Management	27.4	***8.9***	36.3	***(7.4)***	16.3	***12.6***	28.9	***3.8***	32.7	***(13.7)***	18.9
47	Site and Support Services	94.0	(7.6)	86.4	(7.0)	37.0	***42.4***	79.4	***(37.2)***	42.2	1.7	43.8
48	Tritium Removal Facility	14.2	***(1.5)***	12.7	1.2	14.5	(0.6)	13.8	0.6	14.4	0.4	14.8
49	**Total Nuclear Stations**	663.4	58.2	721.6	(42.6)	357.7	***321.3***	679.0	***(261.9)***	417.1	4.4	421.4
	Operations and Project Support											
50	Enterprise Engineering	187.9	***37.1***	224.9	(7.1)	112.1	***105.7***	217.8	***(53.9)***	164.0	0.8	164.8
51	Integrated Fleet Management	130.2	***64.8***	195.1	5.2	82.0	***118.2***	200.3	***(34.5)***	165.8	3.7	169.5
52	Environment, Health & Safety	12.9	(0.8)	12.1	***2.2***	8.0	***6.3***	14.3	(0.2)	14.0	0.3	14.3
53	Enterprise Projects	11.3	***(3.6)***	7.6	***1.8***	9.9	(0.5)	9.5	***(3.1)***	6.4	0.5	6.9
54	Other Support	69.2	***10.1***	79.3	0.3	48.4	***31.2***	79.6	***(10.1)***	69.5	0.8	70.3
55	Low and Intermediate Level Waste	4.8	***4.3***	9.2	0.6	3.5	***6.2***	9.7	***(6.1)***	3.6	(0.2)	3.4
56	**Total Operations and Project Support**	416.2	***112.0***	528.2	3.0	264.0	***267.2***	531.2	***(107.9)***	423.3	5.9	429.2
	CRVA Eligible Costs											
57	Fuel Channel Life Extension Project	0.4	(0.2)	0.3	(0.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
58	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
59	Optimization of Pickering Shutdown	0.0	0.2	0.2	(0.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
60	**Total CRVA Eligible Costs**	0.4	0.1	0.5	(0.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
61	**Total Base OM&A Before Adjustments**	1,080.0	***170.3***	1,250.3	(40.1)	621.7	***588.5***	1,210.2	***(369.8)***	840.4	10.3	850.7
62	**OEB/Settlement Adjustments[3]**	(32.4)	***32.4***		0.0	(18.6)	***18.6***		0.0		0.0	
63	**Total Base OM&A Including Adjustments**	1,047.6	***202.7***	1,250.3	(40.1)	603.0	***607.2***	1,210.2	***(369.8)***	840.4	10.3	850.7

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)
	Nuclear Stations							
64	Operations & Maintenance	343.9	22.3	366.1	4.2	370.3	***183.4***	553.7
65	- Operations	123.2	***12.8***	136.0	2.7	138.7	***57.0***	195.7
66	- Maintenance	220.6	9.5	230.1	1.5	231.6	***126.3***	358.0
67	Work Management	18.9	***6.2***	25.2	***(2.7)***	22.5	***7.7***	30.2
68	Site and Support Services	43.8	3.8	47.6	***5.9***	53.5	***49.4***	102.9
69	Tritium Removal Facility	14.8	0.9	15.7	0.2	15.8	0.7	16.5
70	**Total Nuclear Stations**	421.4	33.1	454.5	7.5	462.1	***241.2***	703.3
	Operations and Project Support							
71	Enterprise Engineering	164.8	9.1	173.9	3.2	177.0	***40.6***	217.6
72	Integrated Fleet Management	169.5	6.6	176.1	7.1	183.1	***22.1***	205.2
73	Environment, Health & Safety	14.3	(0.6)	13.7	0.9	14.6	1.0	15.6
74	Enterprise Projects	6.9	(0.4)	6.5	(0.1)	6.4	0.6	7.0
75	Other Support	70.3	0.9	71.2	(0.3)	70.9	1.8	72.7
76	Low and Intermediate Level Waste	3.4	(0.8)	2.6	0.1	2.7	***1.4***	4.1
77	**Total Operations and Project Support**	429.2	14.7	443.9	10.8	454.7	***67.4***	522.2
	CRVA Eligible Costs							
78	Fuel Channel Life Extension Project	0.0	0.0	0.0	0.0	0.0	0.0	0.0
79	Pickering Extended Operations	0.0	0.0	0.0	0.0	0.0	0.0	0.0
80	Optimization of Pickering Shutdown	0.0	0.0	0.0	0.0	0.0	0.0	0.0
81	**Total CRVA Eligible Costs**	0.0	0.0	0.0	0.0	0.0	0.0	0.0
82	**Total Base OM&A**	850.7	47.8	898.4	18.4	916.8	***308.6***	1,225.4

Notes:

1 Bold italic font indicates variance of 10% or greater.

2 All 2020-2026 amounts (within the Actual, Budget, and OEB Approved columns) 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).

3 Per EB-2020-0290 OEB Decision and Order, Schedule A, p. 25, nuclear base OM&A costs are reduced by 3% per year over the 2022-2026 period.

Numbers may not add due to rounding.

Table 4
Project OM&A Summary - OPG Nuclear Facilities Projects (Allocated) ($M)
By Project Category

Line No.	OM&A Project Category	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Actual	2026 Plan	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	**Regulatory**	5.1	7.5	7.1	8.3	6.8	4.6	0.5	0.0	0.0	0.0	0.0	0.0
2	**Sustaining**	20.6	27.9	32.8	37.2	49.6	18.5	13.6	7.7	1.5	0.8	1.1	1.8
3	**Value Enhancing**	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0
	Total	25.7	35.4	39.8	45.4	56.4	23.3	14.0	7.7	1.5	0.8	1.1	1.8

Numbers may not add due to rounding.

Table 5

Comparison of Project OM&A - OPG Nuclear Facilities ($M)[2]

Line No.	Business Unit	2020 OEB Approved[1]	(c)-(a) Change	2020 Actual	2021 OEB Approved[1]	(f)-(d) Change	2021 Actual	2022 OEB Approved	(i)-(g) Change	2022 Actual	2023 OEB Approved	(l)-(j) Change	2023 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Portfolio Projects (Allocated)												
1	**Darlington NGS**	0.8	***13.1***	13.9	0.0	***30.4***	30.4	19.0	***10.1***	29.1	14.2	***5.0***	19.2
2	**Pickering NGS**	0.0	***1.8***	1.8	0.0	***1.0***	1.0	0.6	***0.9***	1.5	0.0	***21.4***	21.4
3	**Operations and Project Support**	0.0	***7.0***	7.0	0.0	***5.1***	5.1	1.8	***7.1***	8.9	0.0	***4.3***	4.3
4	**Subtotal Portfolio Projects (Allocated)**	0.8	***21.9***	22.7	0.0	***36.5***	36.5	21.4	***18.1***	39.5	14.2	***30.8***	45.0
5	**Infrastructure**	33.0	***8.0***	41.0	29.0	***18.8***	47.7	41.5	***(3.9)***	37.6	49.0	***9.5***	58.5
6	**Portfolio Projects (Unallocated)**	47.8	***(47.8)***	0.0	57.9	***(57.9)***	0.0	18.0	***(18.0)***	0.0	21.8	***(21.8)***	0.0
7	**Subtotal Project OM&A (Portfolio)**	81.5	***(17.9)***	63.6	86.9	***(2.7)***	84.2	80.8	***(3.7)***	77.1	85.0	***18.4***	103.4
	Non Portfolio Projects												
8	**Pickering Extended Operations**	18.7	***11.3***	30.0	0.0	***19.6***	19.6	0.0	***0.9***	0.9	0.0	***0.4***	0.4
9	**Optimization of Pickering Shutdown**	0.0	***0.3***	0.3	0.0	***1.7***	1.7	7.8	***(2.9)***	4.9	0.0	***3.0***	3.0
10	**Darlington Spacer Life Management[3]**	0.0	***3.0***	3.0	0.0	***(1.2)***	(1.2)	0.0	***0.3***	0.3	0.0	***0.4***	0.4
11	**Darlington Unit 3 F/C Comp Retrieval[4]**	0.0	***1.9***	1.9	0.0	***2.2***	2.2	0.0	***(0.2)***	(0.2)	0.0	***0.1***	0.1
12	**Fuel Channel Life Extension Project**	0.0	***0.7***	0.7	0.0	***5.0***	5.0	0.4	***2.7***	3.2	0.0	***1.9***	1.9
13	**Fuel Channel Life Management Phase V Project**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	***1.1***	1.1
14	**FCLE Related Ongoing Costs[5]**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	***26.2***	26.2
15	**Darlington Steam Generator Primary Moisture Separators Projects[6]**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	***3.3***	3.3	0.0	***4.5***	4.5
16	**Total Project OM&A Before Adjustments**	100.2	(0.7)	99.5	86.9	***24.7***	111.6	89.1	0.4	89.5	85.0	***56.1***	141.1
17	**OEB/Settlement Adjustments**	0.0	0.0	0.0	0.0	0.0	0.0	(2.7)	***2.7***	0.0	(2.6)	***2.6***	0.0
18	**Total Project OM&A Including Adjustments**	100.2	(0.7)	99.5	86.9	***24.7***	111.6	86.4	***3.1***	89.5	82.5	***58.7***	141.1

Line No.	Business Unit	2024 OEB Approved	(c)-(a) Change	2024 Actual	2025 OEB Approved	(f)-(d) Change	2025 Actual	2026 OEB Approved	(i)-(g) Change	2026 Budget	2022-2026 Actuals & Budget	(l)-(j) Change	2027-2031 Plan[4] EB-2025-0297
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Portfolio Projects (Allocated)												
19	**Darlington NGS**	5.5	***25.4***	30.9	3.0	***5.3***	8.3	0.8	***6.5***	7.4	95.0	***(88.7)***	6.3
20	**Pickering NGS**	0.0	***22.4***	22.4	0.0	***14.8***	14.8	0.0	***2.4***	2.4	62.5	***(56.2)***	6.4
21	**Operations and Project Support**	0.0	***3.2***	3.2	0.0	0.3	0.3	0.0	***4.2***	4.2	20.9	***(20.7)***	0.2
22	**Subtotal Portfolio Projects (Allocated)**	5.5	***51.0***	56.5	3.0	***20.4***	23.4	0.8	***13.2***	14.0	178.4	***(165.6)***	12.8
23	**Infrastructure**	49.0	***(7.6)***	41.4	46.5	***(15.4)***	31.1	42.5	***(2.4)***	40.1	208.7	***31.5***	240.2
24	**Portfolio Projects (Unallocated)**	24.5	***(24.5)***	0.0	25.6	***(23.3)***	2.3	18.7	***(5.0)***	13.7	16.0	***136.6***	152.6
25	**Subtotal Project OM&A (Portfolio)**	79.0	***18.9***	97.9	75.1	***(18.3)***	56.8	62.0	***5.8***	67.8	403.1	***2.6***	405.7
	Non Portfolio Projects												
26	**Pickering Extended Operations**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.3	***(1.3)***	0.0
27	**Optimization of Pickering Shutdown**	0.0	***0.2***	0.2	0.0	***0.0***	0.0	0.0	0.0	0.0	8.1	***(8.1)***	0.0
28	**Darlington Spacer Life Management[3]**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	***(0.8)***	0.0
29	**Darlington Unit 3 F/C Comp Retrieval[4]**	0.0	***0.1***	0.1	0.0	0.1	0.1	0.0	0.0	0.0	0.1	***(0.1)***	0.0
30	**Fuel Channel Life Extension Project**	0.0	***0.1***	0.1	0.0	0.0	0.0	0.0	0.0	0.0	5.1	***(5.1)***	0.0
31	**Fuel Channel Life Management Phase V Project**	0.0	***5.3***	5.3	0.0	***6.3***	6.3	0.0	***2.3***	2.3	15.0	***(14.9)***	0.2
32	**FCLE Related Ongoing Costs[5]**	0.0	***0.6***	0.6	0.0	0.0	0.0	0.0	0.0	0.0	26.8	***(26.8)***	0.0
33	**Darlington Steam Generator Primary Moisture Separators Replacement Projects[6]**	0.0	***3.8***	3.8	0.0	0.0	0.0	0.0	***3.1***	3.1	14.7	***(10.0)***	4.7
34	**Total Project OM&A Before Adjustments**	79.0	***28.9***	107.9	75.1	***(12.0)***	63.1	62.0	***11.3***	73.3	474.9	***(64.4)***	410.6
35	**OEB/Settlement Adjustments**	(2.4)	***2.4***	0.0	(2.3)	***2.3***	0.0	(1.9)	***1.9***	0.0	0.0	0.0	
36	**Total Project OM&A Including Adjustments**	76.6	***31.4***	107.9	72.8	***(9.7)***	63.1	60.1	***13.1***	73.3	474.9	***(64.4)***	410.6

Notes:

1 As OEB Approved adjustments are applied to Base OM&A in Ex. F2-2-2 Table 1a and Table 1b, the figures presented here are 2017 Plan - 2021 Plan (from EB-2016-0152, Ex. F2-3-2, Table 1).

2 Bold italic font indicates variance of 10% or greater.

3 Project #83280 - DN Annulus Spacer Life Mgmt.

4 Project #83926 - IRI DNRU3 FC Component Retrieval.

5 Represents the Pickering Unit 8 Boiler Secondary Side Advancement Scale Conditioning.

6 Project #86873 Darlington Steam Generator Primary Moisture Separators Replacement (Removal).

Numbers may not add due to rounding.

Table 6
Outage OM&A - OPG Nuclear Facilities ($M)[1]

Line No.	Resource Type	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Actual	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**	17.9	19.8	16.2	21.5	26.2	12.0	14.2	11.8	10.8	14.0	12.0	11.3	7.3%
2	**Non-Regular Labour[3]**	40.1	53.2	32.6	35.1	35.9	10.6	20.7	9.7	7.9	16.5	8.3	8.5	6.2%
3	**Overtime**	38.7	57.2	35.4	40.9	52.6	15.9	25.0	29.6	15.4	28.6	17.9	17.0	13.2%
4	**Augmented Staff**	1.9	2.0	1.6	2.2	5.1	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
5	**Materials**	57.4	59.2	49.0	58.7	65.7	31.7	33.2	41.5	21.2	38.4	19.4	26.1	17.9%
6	**Other Purchased Services**	135.2	188.1	128.0	157.3	169.6	69.5	113.7	128.6	56.6	119.8	63.1	77.4	54.4%
7	**Other**	2.6	3.3	2.1	2.4	3.0	0.4	2.6	2.6	0.9	1.8	0.9	1.9	1.0%
8	**Total OPG Nuclear Facilities Outage OM&A**	293.9	382.8	265.0	318.1	358.1	141.1	209.4	223.7	112.7	219.1	121.6	142.2	100.0%

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 IR Term Percentage = Sum of IR Term Resource Costs divided by Sum of IR Term Outage OM&A.
3 Non-Regular labour includes costs for term and temporary staff.

Numbers may not add due to rounding.

Table 7a

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 Actual
		(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	***(82.9)***	76.4
21	Operations and Project Support	14.0	(0.3)	28.1	***(14.3)***	13.8	***31.6***	12.7	***32.6***	45.4	***(30.5)***	14.9
22	**Total Darlington Outages**	89.6	***16.2***	187.2	***(81.4)***	105.8	***98.9***	94.7	***110.0***	204.6	***(113.4)***	91.3
	Pickering Outages											
23	Pickering NGS	110.5	***11.2***	105.8	***15.9***	121.7	***(30.0)***	77.0	***14.6***	91.6	***(62.6)***	29.0
24	Operations and Project Support	37.8	***25.0***	51.6	***11.3***	62.9	***(14.1)***	27.0	***21.8***	48.7	***(29.0)***	19.7
25	**Total Pickering Outages**	148.3	***36.2***	157.4	***27.2***	184.5	***(44.2)***	104.0	***36.4***	140.4	***(91.7)***	48.7
	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	***(10.7)***	1.1
29	**Total CRVA Eligible Costs**	27.0	0.7	16.7	***11.1***	27.8	***(14.7)***	13.8	(0.6)	13.1	***(12.0)***	1.1
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	***(217.1)***	141.1
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	***(217.1)***	141.1
	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 7b
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 Actual	(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	***(80.5)***	76.4	***47.3***	57.8	***65.9***	123.7	***62.7***	186.4	***(104.6)***	81.8
2	Operations and Project Support	35.7	***(20.8)***	14.9	***17.4***	3.5	***28.7***	32.3	***5.1***	37.4	***(6.4)***	30.9
3	**Total Darlington Outages**	192.6	***(101.3)***	91.3	***64.7***	61.3	***94.6***	155.9	***67.8***	223.7	***(111.0)***	112.7
	Pickering Outages											
4	Pickering NGS	0.0	***29.0***	29.0	***10.9***	0.0	***39.9***	39.9	***(39.9)***	0.0	0.0	0.0
5	Operations and Project Support	0.0	***19.7***	19.7	***(6.2)***	0.0	***13.5***	13.5	***(13.5)***	0.0	0.0	0.0
6	**Total Pickering Outages**	0.0	***48.7***	48.7	4.8	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	***1.1***	1.1	***(1.1)***	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	**Total CRVA Eligible Costs**	0.0	***1.1***	1.1	***(1.1)***	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	***(51.5)***	141.1	***68.3***	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 Adjustment**	186.8	***(45.7)***	141.1	***68.3***	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.

Table 8a
Comparison of OPG Nuclear Facilities Fuel Costs ($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)
	CANDU:											
1	**Darlington NGS[1]**	83.8	14.5	98.2	(24.2)	70.4	3.6	74.0	(21.0)	53.5	(0.5)	53.0
2	**Pickering NGS[1]**	80.1	(0.2)	79.9	(1.5)	78.0	0.4	78.4	1.9	73.8	6.5	80.3
3	**Total CANDU Fuel Bundle Cost**	163.9	14.2	178.1	(25.7)	148.4	4.0	152.4	(19.1)	127.3	6.0	133.3
4	**Nuclear Fuel Settlement Adjustment[5]**									(1.1)		
	Total CANDU Fuel Bundle Cost	163.9	14.2	178.1	(25.7)	148.4	4.0	152.4	(19.1)	126.2	7.1	133.3
5	**Total CANDU Fuel Bundle Cost[2] ($/MWh)**	4.39	(0.3)	4.05	(0.2)	4.19	(0.3)	3.85	(0.1)	3.83	(0.1)	3.78
6	**CANDU Used Fuel Storage & Disposal[3,4]**	43.3	12.0	55.2	21.5	43.9	32.9	76.7	5.9	46.2	36.5	82.7
7	**CANDU Fuel Oil**	4.6	(3.1)	1.5	1.4	4.7	(1.8)	2.9	3.6	4.8	1.7	6.6
8	**Total OPG Nuclear Facilities CANDU Fuel Costs**	211.8	23.1	234.9	(2.8)	197.0	35.1	232.0	(9.5)	177.3	45.3	222.5

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 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	CANDU:											
9	**Darlington NGS[1]**	53.0	10.3	40.3	23.1	63.4	(1.6)	60.1	1.7	61.8	51.3	113.1
10	**Pickering NGS[1]**	80.3	3.5	81.7	2.2	83.9	7.6	85.7	5.8	91.4	(7.1)	84.3
11	**Total CANDU Fuel Bundle Cost**	133.3	13.9	122.0	25.2	147.2	6.0	145.8	7.4	153.2	44.2	197.4
12	**Nuclear Fuel Settlement Adjustment[5]**			(0.8)				0.1				
13	**Total CANDU Fuel Bundle Cost**	133.3	13.9	121.1	26.1	147.2	6.0	145.9	7.3	153.2	44.2	197.4
13	**Total CANDU Fuel Bundle Cost[2] ($/MWh)**	3.78	0.3	3.91	0.2	4.08	0.6	4.28	0.4	4.65	0.5	5.18
14	**CANDU Used Fuel Storage & Disposal[3,4]**	82.7	(16.1)	55.2	11.3	66.5	(13.8)	58.6	(5.9)	52.7	7.5	60.2
15	**CANDU Fuel Oil**	6.6	(1.9)	5.0	(0.3)	4.7	1.2	5.1	0.8	5.9	(4.9)	1.0
16	**Total OPG Nuclear Facilities CANDU Fuel Costs**	222.5	(4.1)	181.3	37.1	218.4	(6.6)	209.5	2.3	211.8	46.8	258.6

Notes:

1 Includes fuel expense of 50% total refueling cost for each refurbished Darlington and Pickering unit applied during the first three months after return to service.

2 Nuclear fuel bundle costs (2020-2021 OEB approved) reflects 2% downward adjustment per partial settlement as described in EB-2016-0152 Decision and Order, p. 52.

3 From Ex. C2-1-1 Table 2, line 2. Used Fuel Storage & Disposal is discussed in Ex. C2-1-1.

4 For 2020-2021 OEB approved, adjustments to used fuel storage and disposal variable expenses to reflect actual year-end 2016 asset retirement obligation adjustment and discount rate as reflected in Ex. J21.2 (OEB Decision and Order p. 98).

5 Per EB-2020-0290 OEB Decision and Order, Schedule A, p. 26, nuclear fuel bundle costs are reduced by 2% per year and include the flow through impacts of the production forecast adjustments, for 2022-2026 OEB approved.

Table 8b
Comparison of OPG Nuclear Facilities Fuel Costs ($M)

Line No.	Business Unit	2025 OEB Approved	(c)-(a) Change	2025 Actual	(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)
	CANDU:											
1	**Darlington NGS[1]**	67.6	45.5	113.1	14.5	103.7	23.9	127.6	(6.3)	121.2	60.3	181.6
2	**Pickering NGS[1]**	71.6	12.7	84.3	(18.9)	0.0	65.4	65.4	(65.4)	0.0	0.0	0.0
3	**Total CANDU Fuel Bundle Cost**	139.2	58.2	197.4	(4.4)	103.7	89.4	193.0	(71.8)	121.2	60.3	181.6
4	**Nuclear Fuel Settlement Adjustment[3]**	1.3				(0.2)						
	Total CANDU Fuel Bundle Cost	140.5	56.9	197.4	(4.4)	103.5	89.5	193.0	(71.8)	121.2	60.3	181.6
5	**Total CANDU Fuel Bundle Cost ($/MWh)**	4.61	0.6	5.18	0.8	4.82	1.1	5.95	0.5	6.49	0.3	6.80
6	**CANDU Used Fuel Storage & Disposal[2]**	44.1	16.1	60.2	(18.4)	42.9	(1.1)	41.8	(15.0)	26.8	11.7	38.5
7	**CANDU Fuel Oil**	5.2	(4.2)	1.0	3.4	1.6	2.8	4.4	(1.5)	2.9	(1.2)	1.7
8	**Total OPG Nuclear Facilities CANDU Fuel Costs**	189.9	68.7	258.6	(19.4)	148.0	91.2	239.2	(88.3)	150.9	70.8	221.7

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)
	CANDU:							
9	**Darlington NGS[1]**	181.6	2.3	183.9	25.4	209.3	12.6	221.9
10	**Pickering NGS[1]**	0.0	0.0	0.0	0.0	0.0	28.2	28.2
11	**Total CANDU Fuel Bundle Cost**	181.6	2.3	183.9	25.4	209.3	40.9	250.2
12	**Total CANDU Fuel Bundle Cost ($/MWh)**	6.80	0.5	7.33	0.5	7.80	0.8	8.64
13	**CANDU Used Fuel Storage & Disposal[2]**	38.5	(0.5)	38.0	12.2	50.2	4.0	54.2
14	**CANDU Fuel Oil**	1.7	0.0	1.7	0.0	1.7	0.0	1.8
15	**Total OPG Nuclear Facilities CANDU Fuel Costs**	221.7	1.8	223.6	37.7	261.2	44.9	306.1

Notes:

1 Includes fuel expense of 50% total refueling cost for each refurbished Darlington and Pickering unit applied during the first three months after return to service.

2 From Ex. C2-1-1 Table 2, line 2. Used Fuel Storage & Disposal is discussed in Ex. C2-1-1.

3 Per EB-2020-0290 OEB Decision and Order, Schedule A, p. 26, nuclear fuel bundle costs are reduced by 2% per year and include the flow through impacts of the production forecast adjustments, for 2022-2026 OEB approved.

Table 9
Comparison of Darlington New Nuclear Program (DNNP) Facilities Fuel Costs ($M)

Line No.	Business Unit	2025 OEB Approved	(c)-(a) Change	2025 Actual	(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)
	SMR:											
11	**Total SMR Fuel Assembly Cost**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	**Total SMR Fuel Assembly Cost ($/MWh)**	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00
13	**SMR Fuel Oil**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	**Total DNNP Facilities SMR Fuel Costs**	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)
	SMR:							
15	**Total SMR Fuel Assembly Cost**	0.0	0.0	0.0	7.2	7.2	20.6	27.8
16	**Total SMR Fuel Assembly Cost ($/MWh)**	0.00	0.0	0.00	14.4	14.4	(0.0)	14.4
17	**SMR Fuel Oil**	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	**Total DNNP Facilities SMR Fuel Costs**	0.0	0.0	0.0	7.2	7.2	20.6	27.8

Notes:

1 The energy portion of the fuel acquisition cost for the initial core load in 2030 is projected to be 31% which is prorated over the planned energy production period. The energy portion of the fuel acquisition cost for the first fuel reload outage in 2031 is projected to be 74% which is prorated over the planned energy production period. Refer to Ex. F2-5-1, Section 5.0 for further details.

Numbers may not add due to rounding.

Table 10
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 Actual
		(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	(48.8)	10.9
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	(48.8)	10.9

Line No.	Business Unit	2025 OEB Approved	(c)-(a) Change	2025 Actual	(g)-(c) Change	2026 OEB Approved	(g)-(e) Change	2026 Budget
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
9	**Darlington Refurbishment Program - Unit Refurbishment[1]**	25.0	(14.1)	10.9	(9.4)	8.4	(7.0)	1.5
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	(14.1)	10.9	(9.4)	8.4	(7.0)	1.5

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.

Board Staff Interrogatory #172

Interrogatory

Reference:
Ref 1: Exhibit F1 / Tab 1 / Schedule 1 / Table 2b

Preamble:

At Reference 1, OPG states that the budgeted 2025 regulated hydroelectric regular and non-regular FTEs are 1,428.3, an increase from the 2024 actual of 1,236.6.

Question(s):

a) Please provide the actual regulated hydroelectric FTE number at December 31, 2025.

Response

a) The actual 2025 regulated hydroelectric regular and non-regular FTEs are 1329.9. This represents a variance of -98.4 to the 2025 budget of 1428.3 FTEs.

   Although actual FTEs were under budget in 2025, increased hiring occurred in the last four months of the year in Renewable Generation Operations and Support functions, such as Engineering. If such headcount increases were annualized and normalized to a full-year basis, the 2025 FTE variance would be reduced by approximately 45 regular FTEs. Additional hiring has continued into 2026 to ensure Renewable Generation is appropriately positioned to execute the planned project portfolio.

Board Staff Interrogatory #173

Interrogatory

Reference:
Ref 1: Exhibit F1 / Tab 2 / Schedule 1 / p. 2

Preamble:

At Reference 1, OPG states that the total Base OM&A expenses increased in 2022 to 2024 reflecting labour cost escalation as a result of collective bargaining

Question(s):

a) Please provide the contribution of compensation costs to each of 2022-2027's Base OM&A increase, breaking down the amounts attributable to wage escalation as a result of collective bargaining, to the hiring of new FTEs, and to any other sources.

Response

a) Chart 1 provides the requested breakdown of the compensation-related year-over-year change in Regulated Hydroelectric Base OM&A costs over the 2022-2027 period.

Chart 1: Compensation Related Hydroelectric Base OM&A Year-over-Year Changes

($millions)	**2023**	**2024**	**2025**	**2026**	**2027**
Collective Agreement Wage Escalation (1)	1.3	2.5	4.8	4.7	4.4
Collective Agreement Signing Bonus- PWU (2)	3.1	(3.1)	-	-	-
Retrospective Wage Adjustments- Bill 124 Moderation Period Settlement (PWU & Society) (3)	10.1	(0.3)	(9.8)	-	-
FTE Changes- (PWU & Society)	2.8	9.4	11.7	2.7	0.3
Non-Wage Related Pension/OPEB Cost & Other Changes (4)	(2.3)	3.2	7.5	5.7	2.8
Total year-over-year change	**15.1**	**11.7**	**14.2**	**13.1**	**7.5**

(1) Wage escalation impact on wage dependent compensation component costs.
(2) Refer to Ex. L-F4-SEC-194.
(3) Represents retrospective wage adjustments and one-time lump sum for the Bill 124 moderation period settlement (refer Ex. F4-3-1, Section 6.2.1 and Ex. L-F4-SEC-194).
(4) Includes non-wage dependent components such as statutory benefits, pension and OPEB (refer to Ex. F4-3-2, p. 20, line 1 to p. 22, line 8), as well as management compensation costs.

Board Staff Interrogatory #174

Interrogatory

Reference:
Ref 1: Exhibit F1 / Tab 3 / Schedule 1 / pp. 1 & 3

Preamble:

At Reference 1, OPG is requesting a project OM&A increase of $46.8 million from the annual average of the 2022-2026 term of $80.2 million, to reflect the increased project OM&A portfolio necessary to maintain aging assets. OPG states that overhaul projects are generally performed every 25-30 years. OPG plans to progress approximately 20 overhaul projects in support of the turbine-generator refurbishment program in the test year.

Question(s):

a) Please clarify if overhaul projects are considered a stand-alone project with separate OM&A cost tracking, or if they form a part of the turbine-generator refurbishment project. Please confirm that costs will be assessed (i.e. capitalized or expensed) according to OPG's capitalization policy.

b) Given the significant term-over-term increase in project OM&A, please confirm that, in 2013-2026, OPG did not change its methodology for classifying overhaul project costs as OM&A.

c) Please provide an approximate breakdown of the $46.8 million increase, showing the amount attributable to market/inflationary-related increases and the amount attributable to an increase in the number of projects in the OM&A portfolio.

Response

a) Overhaul projects are stand-alone projects with separate OM&A cost tracking; they may be executed concurrently with refurbishment projects. OPG confirms that these costs are assessed in accordance with OPG's capitalization policy, in line with US GAAP (refer to Ex. L-F1-Staff-164 for further details).

b) Confirmed.

c) The portion of the referenced term-over-term increase in Project OM&A costs attributable to market/inflationary-related impacts cannot be specifically isolated, as Project OM&A costs are inherently affected by both the variability in scope and composition of project work and the market-driven cost escalation affecting individual project costs. Refer to Ex. L-F1-Staff-177 for further discussion.

OPG notes that, while there has been a nominal increase in the annual number of OM&A projects with actual or planned spend between 2022-2027, the increase in the 2022-2026 annual average spend compared to the 2027 test period is primarily due to the scope and timing of Project OM&A work being executed.

For additional context, OPG provides a breakdown and relative increase of the key categories of Project OM&A spend for the 2022-2026 annual average and 2027 test year, in Chart 1 below. Term-over-term variance explanations are provided in Ex. F1-3-2, pp. 3-4, which include an increase in portfolio projects and higher infrastructure costs from removal work tied to capital refurbishment projects.

Chart 1 – Regulated Hydroelectric OM&A Project Spend (2027 vs. 2022–2026 Average)

Portfolio Composition	2022-2026 Average OM&A Project Spend ($M)	2027 OM&A Project Spend ($M)	Increase ($M)	Reference
Infrastructure	16.8	32.7	15.9	Ex. F1-3-2, Section 2.2
Other Portfolio Projects	17.8	29.2	11.4	Ex. F1-3-2, Section 2.1
Concrete	13.9	25.3	11.4	Ex. F1-3-2, Section 2.1
Turbine-Generator Overhaul	31.7	39.7	8.0	Ex. F1-3-2, Section 2.1
Total	**80.2**	**127.0**	**46.8**	

Board Staff Interrogatory #175

Interrogatory

Reference:
Ref 1: Exhibit F1 / Tab 3 / Schedule 1 / p. 4

Preamble:

At Reference 1, OPG states that it is required to spend significant effort and funding to mitigate the impacts of Alkali-Aggregate Reaction, which has led to increased Project OM&A expenditures.

Question(s):

a) Given there are 30 concrete restoration initiatives in the 2027 test year, please clarify whether the Alkali-Aggregate Reaction concrete mitigation costs are all treated as project OM&A or if they also appear elsewhere in the OM&A and capital budgets.

b) Please provide the Alkali-Aggregate Reaction concrete mitigation-related OM&A expenditures in 2022-2025 (actual) and 2026-2027 (budget and plan), by year.

Response

a) Costs associated with Alkali Aggregate Reaction ("AAR") concrete work may be classified as Base OM&A costs, Project OM&A cost, or capital costs, depending on the specific scope or nature of the work, in accordance with OPG's capitalization policy (see Ex. D4-1-1). Accordingly, AAR-related mitigation costs are not necessarily all treated as Project OM&A costs, and may also appear elsewhere within OM&A and/or capital budgets, as applicable.

b) Routine inspections and minor repairs of concrete are both expensed to Base OM&A costs. These costs can include both regular concrete repairs and those related to AAR mitigation. Base OM&A expenditures directly related to AAR mitigation cannot be isolated from other concrete expenditures. As such, OPG is unable to provide AAR mitigation-related Base OM&A expenditures by year for 2022-2025 (actual) and 2026-2027 (budget/plan) as they are not tracked in a manner that enables discrete identification from other concrete OM&A costs.

Project OM&A costs for work directly related to AAR concrete mitigation are provided in Chart 1 below.

Chart 1: Project OM&A Costs for Alkali Aggregate Reaction Mitigation

2022 Actual ($M)	2023 Actual ($M)	2024 Actual ($M)	2025 Actual ($M)	2026 Budget ($M)	2027 Plan ($M)
6.9	4.3	2.1	0.5	6.5	4.9

Board Staff Interrogatory #176

Interrogatory

Reference:
Ref 1: Exhibit F1 / Tab 4 / Schedule 1 / p. 4

Preamble:

At Reference 1, OPG states that it holds a lease agreement with the St. Lawrence Seaway Management Corporation. The current 30-year lease is in place until 2038, with rates subject to review every five years. The water conveyance payment terms are currently in legal arbitration.

Question(s):

a) Please clarify when the existing rates expire and provide an update on the rates review.

Response

a) The existing rates expired on June 30, 2023. OPG anticipates the rate review, including the arbitration, to be completed by approximately Q4 2026.

Board Staff Interrogatory #177

Interrogatory

Reference:
Ref 1: Exhibit F1 / Tab 5 / Schedule 1 / p. 1

Preamble:

At Reference 1, OPG states that the OM&A purchased services expenditures during the historical period (2016-2024) were $57.1 million in 2016, $53.2 million in 2017, $57.1 million in 2018, $56.5 million in 2019, $49.9 million in 2020, $64.7 million in 2021, $78.3 million in 2022, $80.2 million in 2023, and $71.4 million in 2024.

Question(s):

a) Please explain the increase in purchased services expenditure since 2020. Please provide an estimate of the extent to which the increase is due to purchased services scope change or market/inflationary-related increase. If other factors contributed to the increase, please explain and estimate their contributions.

Response

a) The purchased services expenditures in Reference 1 include both Base and Project OM&A costs, as shown in Chart 1. Base OM&A purchased services increased annually from 2020-2024. Project OM&A purchased services increased annually from 2020-2022 and decreased in 2023-2024.

Chart 1 – OM&A Purchased Services

Purchased Services	2020 ($M)	2021 ($M)	2022 ($M)	2023 ($M)	2024 ($M)
Base OM&A[1]	20.9	24.3	26.2	31.1	32.0
Project OM&A	29.0	40.4	52.1	49.2	39.4
Total (Ex. F1-5-1)	**49.9**	**64.7**	**78.3**	**80.2**	**71.4**

Note 1: Ex. F1-2-1, Table 2, line 6

The primary driver for fluctuations in purchased services OM&A costs is both inflationary increases and the nature and composition of work executed in each year, particularly within Project OM&A, which varies based on the extent of the portfolio of projects executed in a given year (e.g., turbine generator overhaul, concrete), as described in Ex. L-F1-Staff-174 and Ex. F1-3-2, pp. 3-4.

Witness Panel: Hydroelectric Operations and Hydroelectric Projects, and Market Renewal Program

The portion of the increase in purchased services relating to market/inflationary-related increases in historical actuals since 2020 cannot be specifically isolated, as purchased services expenditures are inherently affected by both the variability in the scope of Base and Project OM&A work and the market-driven cost escalation affecting externally procured services.

Overall, the costs of key components have risen significantly since 2020. With many of OPG's commodity-intensive agreements having indexed pricing, Chart 2 summarizes selected Canadian indices from S&P Global and includes the Compounded Annual Growth Rate ("CAGR") calculations for 2020-2024, which are reasonable indicators of market/inflationary impact on costs. For example, turbines are generally tied to steel indices, and transformers are generally tied to steel and copper indices.

Chart 2 - S&P Global Canadian Indices 2026

Category	2020	2021	2022	2023	2024	CAGR
Rolled Steel Products[1]	102.7	130.5	161.7	153.7	140.6	8.2%
Concrete[2]	99.8	101.7	113.0	126.3	133.1	7.5%
Transformers[3]	100.5	104.8	130.1	143.0	158.1	12.0%
Steel Pipe and Tubes[4]	99.3	149.9	124.6	106.8	99.4	0.1%
Engine, Turbine and Transmission[5]	101.7	105.6	114.0	119.7	123.6	5.0%

In addition to inflationary increases, within Base OM&A costs, 2020 was directly impacted by the pandemic with maintenance and project work deferred where possible. The increase in 2022 was a direct correlation to the deferrals from the previous year. The increase in 2023 over 2022 is attributable to maintenance expenses, primarily at R.H. Saunders GS and Sir Adam Beck 1 GS and Sir Adam Beck 2 GS due to environmental remediation (e.g., lead paint and asbestos removal), storm response clean-up, and additional joint works expenditures as described in Ex. F1-2-2, p. 4, lines 1-4. This Base work was completed through the use of purchased services. Refer to Ex. L-F1-SEC-154.

[1] S&P Global: Canada, Producer Price Index, Rolling and Drawing of Purchased Steel
[2] S&P Global: Canada, Producer Price Index, Ready-Mix Concrete
[3] S&P Global: Canada, Producer Price Index, Power, Distribution and Other Transformers, and Transformer Parts
[4] S&P Global: Canada, Producer Price Index, Iron or Steel Pipes and Tubes (Except Castings)
[5] S&P Global: Canada, Producer Price Index, Engine, Turbine and Power Transmission Equipment

Board Staff Interrogatory #321

Interrogatory

Reference:
Ref 1: Exhibit F1 / Tab 1 / Schedule 1 / pp. 21-27

Preamble:

Exhibit F1, Section 4.3 Reliability, presents the station-specific Availability / EFOR charts and supporting narrative for DeCew Falls 2 GS, Abitibi Canyon GS, Otter Rapids GS, Otto Holden GS, R.H. Saunders GS, Sir Adam Beck 1 GS, Sir Adam Beck 2 GS, and the historical Western Region forced-outage discussion for Manitou Falls GS.

Question(s):

a) For the referenced major hydro projects at charted or otherwise reliability-significant facilities, please provide a consolidated facility-by-facility explanation of how OPG determined each project's expected contribution to forecast Availability, reliability, and EFOR under Exhibit F1, Section 4.3. In particular:
   i. For each project, identify whether the principal expected benefit is Availability-side, EFOR-side, or primarily enabling/supporting in nature.
   ii. Identify whether each project's benefit is already embedded in the pre-2025 baseline or is assumed to contribute planned outage burden and/or post-project benefit during the 2025–2031 forecast period.
   iii. Identify the specific failure modes, operating restrictions, hydraulic/control limitations, electrical limitations, or structural/civil conditions being addressed.
   iv. For each charted facility, explain how the project sequencing and expected in-service timing were reflected in the station's forecast Availability and EFOR targets.
   v. Identify what residual reliability risk remains at each facility if the project is delayed, re-scoped, or not completed as planned.
   vi. Explain how OPG distinguished between direct unit-refurbishment projects and indirect enabling/support projects, and how OPG avoided double counting reliability benefits where multiple projects support the same facility.

Response

a)
   i. The turbine-generator overhaul and refurbishment projects are necessary to address the asset condition of an aging fleet; without these investments, asset reliability is expected to decline (refer to Ex. F1-1-1, Section 3.2.1, p. 4).

For the eight stations referenced in the preamble, OPG is forecasting to in-service 21 refurbished units (~1/3 of the units at these eight stations) during the IR period. The principal expected benefit is station availability, which is expected to improve once all the planned unit overhaul and refurbishment activities at the station are complete. For a full description of the methodology to calculate Availability and EFOR, refer to Ex. L-F1-Staff-170.

ii. All outages associated with projects at the eight stations referenced in the preamble are included in the 2025-2031 reliability targets.

iii. OPG interprets “major hydro projects” to mean Tier 1 capital projects. Details on the specific failure modes, operating restrictions, hydraulic/control limitations, electrical limitations, or structural/civil conditions being addressed for these projects are provided in each project’s Business Case Summary.

iv. As described in parts i) and ii) above, the target-setting methodology considers the sequencing of planned outages, which as noted reflect the planned projects, as described in Ex. F1-1-1, p. 22. The estimates for planned outage hours during any year are based on the planned outage schedule, which is used to determine the forecast Availability. OPG continues to optimize the timing and duration of its outages where possible, but as noted these are subject to a number of factors (as described in Ex. E1-1-1, Section 4.0) which could necessitate a change in the timing of planned outages.

v. Risks associated with delaying or not completing the referenced projects are identified in each project’s Business Case Summary.

vi. Forecast targets are not set using project-specific reliability benefits, thus multiple projects being worked on concurrently at the same facility would not result in any double-counting.

VECC Interrogatory #011

Interrogatory

Reference:
Exhibit F1, Tab 4, Schedule 2, Table 1

Question(s):

a) Please provide the letter of June 11, 2024 referred to in note 2 of Table 1 – Gross Revenue Charge – Regulated Hydroelectric.

b) Please update Table 1 to show 2025 actual costs.

Response

a) Refer to Attachment 1, previously filed in EB-2024-0136.

b) Refer to Attachment 2, filed in Microsoft Excel format.

Evelyn Wong
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BY RESS

June 11, 2024

Ms. Nancy Marconi
Registrar
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, Ontario
M4P 1E4

Dear Ms. Marconi:

Re: EB-2024-0136 – Stakeholder Consultation on the Review of OPG Filing Guidelines

Ontario Power Generation Inc. ("OPG") appreciates the opportunity to provide comments on the Ontario Energy Board's ("OEB") proposed update to OPG's filing guidelines (now referred to as filing requirements) ("Filing Requirements"), which outline filing expectations for OPG's payment amount applications under section 78.1 of the *Ontario Energy Board Act*.

OPG agrees with OEB staff that the Filing Requirements are functioning reasonably well, and that updates should be targeted on incremental improvements.

OPG has organized its comments in the same structure as the Filing Requirements. Where OEB staff sought specific feedback, OPG has provided its comments in those particular sections. In conjunction with this letter, OPG is providing as Attachment 1 a detailed mark-up of all proposed changes to the draft Filing Requirements with annotations to explain each change. While this letter explains the more significant changes proposed, OPG respectfully requests that all the changes set out in Attachment 1 be considered, as a number of them are intended to clarify the requirements and to ensure continuity of information to be presented in future applications.

Section 1 Introduction and Overview of Legislative Context

OPG has no concerns with removing specific details in favour of keeping the Filing Requirements evergreen, as drafted by OEB staff. In the same spirit and as OPG believes that it should not be the purpose of the Filing Requirements to prescribe the length of a payment amounts term, OPG recommends removing the second sentence from footnote 1 of this section.

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Section 2.5 Structure of Application

OPG's proposals for this section are mainly focused on clarifying the language referencing allocations of total corporate costs. Specifically, OPG has proposed to clarify that not all exhibits are affected by such allocations and where such allocations occur, they may be made directly to each of the nuclear and regulated hydroelectric categories, rather than as a two-step allocation to the prescribed facilities as a whole and then to each of the regulated categories.

Section 2.6 Key Planning Parameters

OPG's comments for this section are focused on the four areas set out below.

International Financial Reporting Standards

OPG does not have concerns with OEB staff's proposed requirement for OPG to provide information on its transition to International Financial Reporting Standards (from US generally accepted accounting principles), when this transition becomes applicable, including the associated references to the OEB's guidance in this regard.

Year-over-Year and Term-over-Term Analysis

OEB staff have proposed to replace the requirement for the detailed year-over-year variance analysis of operating costs with a requirement for a payment amounts term-over-term variance analysis, while retaining the year-over-year analysis for capital costs. Upon consideration of stakeholder session feedback and OPG's own evidentiary needs to support its application, OPG believes that year-over-year variance analysis of operating costs provides value and should be retained. In view of OEB staff's stated needs, OPG does not object to providing both a year-over-year and a term-over-term variance analysis for operating, maintenance and administration ("OM&A") costs (other than Project OM&A as described below).

On the other hand, OPG believes that year-over-year variance analysis has limited value for capital and Project OM&A. Project portfolios are optimized over multiple years and inherently reflect variability in the composition, nature and timing of projects, as well as the shifts that can occur between years of an individual project over its lifespan. Accordingly, it is OPG's view that term-over-term analysis for capital costs and Project OM&A costs is more meaningful in identifying material trends and drivers of variance. Therefore, OPG proposes that the Filing Requirements replace year-over-year variance analysis with term-over-term variance analysis for capital costs and Project OM&A costs.

Minimum Number of Historical Years and Next Hydroelectric Rebasing Application

With respect to the minimum filling requirements for historical years, OPG believes it is reasonable to limit the historic years to no more than five years as a general rule. OPG's view is that five years of historical actual data should be sufficient to determine any trends, that information going back more than five years likely has limited relevance due to the passage of time, and that requiring the filing of more than five years of historic information can result in excessive effort for OPG to maintain this information on a comparable basis (e.g., due to changes in organizational and cost structures over time). OPG believes it should have the flexibility to determine whether information going back more than five years is necessary to support approvals sought in an application, on a case-by-case basis. This is the basis for OPG's proposal to limit the minimum historical information requirement to five years in the Filing Requirements, on an evergreen basis.

In the current circumstance, however, OPG recognizes that its hydroelectric payment amounts have not been rebased since EB-2013-0321. Specifically, in EB-2016-0152, the OEB approved a price-cap index rate-making methodology for OPG's regulated hydroelectric business, with the payment amounts as approved in EB-2013-0321 used as the basis for the going in payment amounts for the 2017-2021 period. In EB-2020-0290, the OEB approved the hydroelectric payment amount for the 2022-2026 period that is equal to the 2021 payment amount, as required by O. Reg. 53/05. As a result, OPG has not filed historic actual information for its regulated hydroelectric business since 2013.

The draft Filing Requirements suggest that OPG would be required to file 12 years of historical and two years of bridge information for the hydroelectric business assuming the application is filed in 2025. However, OPG does not have the necessary data to normalize the 2013-2015 historical actual OM&A costs and compensation and benefits information for the hydroelectric business on a comparable basis with the rest of the application as a result of the number of organizational structure changes over the last decade. Historical hydroelectric OM&A costs and compensation and benefits data prior to 2016 would therefore have little to no value to the proceeding and could not be meaningfully integrated with the rest of the application.

In consideration of these unique circumstances and stakeholder session feedback, for its next hydroelectric rebasing application, OPG proposes to file the following in addition to the requirements for the five most recent historical years:

1. Hydroelectric rate base continuity tables (including gross plant and accumulated depreciation and amortization) and associated capital projects in-service listings back to 2013 on a total regulated hydroelectric basis only, rather than at a more granular level by geographical designation that OPG expects to use to present such information for the five most recent historical years (expected to be 2020-2024) as well as the bridge and forward-test years.[1]
2. For other applicable tables and information on compensation and benefits, four additional years of historic actual data on a total regulated hydroelectric basis only (expected to be 2016-2019). Where OPG is unable to file such information, it would explain why this is the case in the application.
3. Due to the age of the data, OPG may not be able to produce sufficiently detailed or meaningful variance analysis associated with the years beyond the five most recent historical years. In OPG's view, such analysis would also be of limited value given the passage of time. As such, for information filed beyond the five most recent historical years, OPG proposes not to be required to provide an analysis of year-over-year, term-over-term or OEB-approved variances in the application.

Attachment 1 includes the above proposals as footnote 3 in Section 2.6.

In OPG's view, its proposal is reasonable and sufficient to ascertain trends, which is the main purpose of including past data in a forward test-year rate application. Historical data beyond the nine years would not reflect the current operational needs and circumstances of OPG's hydroelectric business and, in any

[1] OPG's 54 regulated hydroelectric facilities are managed by geographical designations which have been reorganized multiple times over the last decade. OPG's proposal to file data beyond the five most recent historical years on a total regulated hydroelectric basis stems from the goal of reducing the significant manual effort and assumptions that would be required to normalize historical information to account for these reorganizations, including allocations of operational support group costs. Such normalizations would be needed to ensure a comparable set of data across the full time period that would be presented in the application (consisting of nine historical, two bridge and forward-test years). For clarity, OPG would still normalize the nine historical years for organizational structure changes other than changes in the geographical designations, for example, where functions have transferred between corporate costs and operations support costs. It would also provide a functional breakdown of the costs.

event, as discussed above, limitations on comparable data availability significantly limit the utility of such information. OPG believes its proposed approach will meet the objective of ensuring that its application presents appropriate and sufficient information on a consistent basis, while balancing the amount of the information provided with its relative value and effort to prepare.

Excel Tables

Generally, OPG does not have concerns with the proposed requirement to file MS Excel versions of all pre-filed data tables in the application. However, OPG notes that it filed more than 200 tables in its EB-2020-0290 application and will likely have more tables in future applications, including those necessitated by the expected hydroelectric payment amount rebasing. Given that the tables sometimes represent extracts from internal working files and include content that may be linked to various internal data sources, OPG requests that the Filing Requirements allow for the Excel versions to be filed within 7 calendar days after submission of OPG's pre-filed evidence.

Section 3 Exhibit A Administrative Documents and Application Overview

OEB staff have recommended the addition of a list of requirements to be included in OPG's Administration and Overview as well as Background Financial Information evidence to align with Chapter 2 of the Electricity Distribution Rate Applications. OPG generally accepts this list, with three clarifications.

The proposed Filing Requirements have added that OPG is to provide "a list of relevant company policies and regulations". In addition to this not appearing to be a component of the Electricity Distribution Rate Application filing requirements, OPG finds this language to be overly broad in scope. OPG currently files a summary exhibit explaining its legislative and regulatory framework, and proposes that reference to this exhibit be included instead.

With respect to "a statement identifying and describing any changes to methodologies as used in previous applications," consistent with the limitation as set out in the Natural Gas Filing Requirements for material impact on customers, OPG has included a clarification that it would do so for any material changes.

With respect to "a detailed reconciliation of the financial results shown in the AFS [Audited Financial Statements] with the regulatory financial results filed in the application, including a reconciliation of fixed assets" and the "identification of any deviations that are being proposed between the AFS and the regulatory financial results, including the identification of any prior OEB approvals for such deviations", OPG has proposed revised language to clarify based on its understanding of the intent, using language consistent with Section 3.1, and in light of the fact that the OEB does not necessarily approve such deviations but rather the revenue requirement methodologies.

Section 4 Exhibit B Rate Base

OPG proposes several minor edits in this section to better align the requirements with the historical presentation of OPG's evidence, including: removal of a reference to "accrued deferred earnings, and annual amortization of accrued deferred earnings", which do not apply to OPG; clarifications related to the basis of bridge year forecast information; and removal of a reference to a detailed breakdown of plant accounts in the rate base continuity tables, as such information is instead provided in OPG's evidence at a point in time as part of independent depreciation studies.

Section 5 Exhibit C Capitalization, Cost of Capital and Nuclear Liabilities

All of OPG's proposed edits to this section are for clarity, to align with OEB-approved methodologies or to remove obsolete language. The main changes are highlighted below.

Given the passage of time, OPG believes that references to valuation of OPG's assets are obsolete given that the OEB accepted the valuations of OPG's assets upon them entering OEB jurisdiction, based on the audited financial statements at the time as required by O. Reg. 53/05. In the unlikely event OPG were to propose a change in the valuation methodologies, a requirement to discuss changes would be captured by requirements related to changes in methodologies in Section 3.1. As a result, OPG has proposed several deletions in Section 5.1.

Under Section 5.4, OPG has proposed edits to more accurately describe the information presented in its applications in support of the revenue requirement impacts of the nuclear liabilities pursuant to the OEB-approved methodologies and to ensure comparability of information application over application.

Section 6 Exhibit D Capital Projects

OPG's comments in this section are focused on OEB staff's request for feedback on whether the capital project cost thresholds used to determine the information required to be filed remain appropriate given that they were established in 2011, as well as OPG's proposed adjustments to the variance thresholds. As this section has historically also applied to Project OM&A, OPG has included its proposed changes to Project OM&A requirements in this section. OPG's proposal with respect to term-over-term analysis of capital costs and Project OM&A costs is as discussed under Section 3.1.

OPG believes that the 2011 project thresholds are no longer appropriate and should be adjusted to reflect inflationary increases over the 13 years since they were established. As further discussed below, OPG also believes that the necessary adjustments need not be the same as between capital and OM&A projects, recognizing the inherent differences in the work under each portfolio. To enhance regulatory efficiency in an application the size of OPG's, OPG proposes to increase the thresholds as follows:

Capital Projects	Project OM&A
• Tier 1: $40 million or more • Tier 2: Between $10 million and $40 million • Tier 3: Less than $10 million	• Tier 1: $30 million or more • Tier 2: Between $10 million and $30 million • Tier 3: Less than $10 million

For capital projects, OPG derived the proposed Tier 1 threshold by escalating the $20 million threshold from 2011 to the present based on Building Construction Price Indexes.[2] For Project OM&A, OPG derived the Tier 1 threshold by escalating the $20 million threshold from 2011 to the present based on the Consumer Price Index ("CPI"). For Project OM&A, OPG used CPI rather than the Building Construction Price Indexes to approximate the proposed change as costs associated with Project OM&A are typically labour rather than for construction/installation of assets. The proposed corresponding increases in the Tier 2 and 3 thresholds are similarly intended to recognize the escalation of costs due to the passage of time. OPG also observes that the Tier 3 threshold would be made consistent with the historical materiality threshold of $10 million used in OPG's applications generally.

In making this proposal, OPG notes that for nuclear projects alone, the existing thresholds resulted in the filing of 84 capital and project OM&A business cases in the EB-2020-0290 application. This number would

[2] Statistics Canada. (2024). Building Construction Price Indexes (Table 18-10-0276-01).

likely be significantly higher in the upcoming application given that hydroelectric business cases will be included and the general effects of inflation. As each business case requires an extensive review for confidential information prior to filing, limiting the increase in the number of business cases filed with each application would be consistent with the OEB's comments in Section 2.3 of the Filing Requirements.

OPG believes that the proposed thresholds are appropriate as they maintain the status quo of materiality considered in 2011, and would help to enhance regulatory efficiency and manage resourcing requirements for OPG, OEB staff and intervenors by focusing on the more material projects. OPG notes that while the revision in the thresholds would affect the filing of business cases, it would not reduce the level of summary information provided in OPG's tables for projects over $10 million.

OPG also believes that there should be adjustments to the variance analysis thresholds for Tier 1 capital projects and OM&A projects. OPG proposes that written explanation of variances be required where the variance is 20% or more of the project budget, which would be a change from the current 10% threshold. OPG makes this proposal for several reasons. First, for execution business cases, which are intended to align with the Association for the Advancement of Cost Engineering (AACE) Class 3 range of estimate, a project estimate is expected to be within an accuracy range of -20/+30%. The ranges are broader for earlier classes of estimates. Therefore, projects with a 20% variance are still reasonably within the range of expected project outcomes. Second, variance analysis for projects with a 20% or greater variance is more consistent with OPG's governance for variance analysis (also at 20%), at which point a superseding business case is required.

Section 8 Exhibit F Operating Costs

OPG's comments for this section are focused on the areas set out below.

Operating, Maintenance & Administration Costs

OPG's main comments in this section pertain to aligning requirements for the breakdown of OM&A costs with historical presentation in OPG's applications, as well as the appropriate threshold for provision of detailed information for purchased services or products expenses. OPG's feedback with respect to OEB staff's proposal for term-over-term analysis of OM&A costs is as discussed under Section 3.1.

The Filing Requirements generically refer to OM&A statements providing a breakdown of OM&A cost items on a work basis using a quantitative threshold. As discussed at the stakeholder session, in practice, OPG's application has consistently presented OM&A cost information using separate OM&A statements for each of Base, Outage and Project OM&A, with a further breakdown by major function, division or other categories, as applicable. For continued comparability in future applications, OPG has proposed amendments to the language to reflect the manner in which its applications have historically been structured.

With respect to the threshold for detailed information for purchased services and products, and consistent with the rationale for the Project OM&A thresholds set out above under Section 6, OPG proposes to modify and increase the threshold from "the lesser of 1% of total expenses before taxes or $20 million", to $30 million. The removal of the 1% reference simplifies the rule and makes it more comparable application over application. As discussed in Section 6, OPG believes that this threshold is appropriate as it maintains the status quo of materiality considered in 2011 and would help to enhance regulatory efficiency and manage resourcing requirements for OPG, the OEB staff and intervenors by focusing on the more material items.

Depreciation, Corporate Cost Allocation and Taxes

OPG proposes several minor edits in this section to better align the requirements with other Sections and the historical presentation of OPG's evidence, including: clarification to align proposed language around the categories of assets between the rate base continuity tables in Section 4 and depreciation expense in Section 8.3; clarification that corporate costs are allocated to each of nuclear and regulated hydroelectric categories rather than first to the prescribed facilities as a whole in alignment with the proposed edits in Section 2.5; and clarification that income tax calculations are reconciled from regulatory income rather than financial accounting income.

Section 9 Exhibit G Operating Revenue (to be renamed to Other Revenue)

OEB staff observed that OPG's evidence in in this section was organized differently in EB-2020-0290 than in the Filing Requirements. OPG notes that these differences have existed since OPG's first OEB application. As discussed at the stakeholder session, parties agreed that the current evidence structure for this section as reflected in OPG's applications is appropriate, and that it would facilitate comparability application over application to revise the Filing Requirements accordingly. OPG has proposed edits to incorporate this view.

OEB staff also sought feedback on whether year-over-year or term-over-term variance analysis is needed for other revenues. For the same reasons as set out under Section 2.6 for operating costs, OPG believes that year-over-year analysis would be more meaningful. OPG also does not believes that term-over-term analysis is needed in this area.

Section 10 Exhibit H Deferral and Variance Accounts

OEB staff sought feedback on the removal of the list of deferral and variance accounts ("DVA") in keeping the Filing Requirement evergreen. OPG supports this change.

OPG has also proposed to clarify that DVA schedules should be provided only for historical years since the DVA balances are last cleared, in alignment with the practice in OPG's prior applications and the expectation that DVAs are to be cleared on the basis of actual, rather than forecasted, balances. Additionally, OPG proposes to remove the reference to proposals regarding the Nuclear Liability Deferral Account interest rate, as this matter has already been resolved in prior OPG applications.

Should there be any questions regarding these submissions, please do not hesitate to contact me.

Respectfully submitted,

Evelyn Wong

cc: Saba Zadeh, OPG
Aimee Collier, OPG
Charles Keizer, Torys LLP

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

Ontario Energy Board

Filing Requirements for Ontario Power Generation Inc.

Setting Payment Amounts for Prescribed Generation Facilities under Section 78.1 of the *Ontario Energy Board Act, 1998*

MMM DD, 2024

Commented [A1]: Note for stakeholders: The title is proposed to change from Filing Guidelines to Filing Requirements in order to harmonize this document with current practices (i.e., Transmission and Distribution Filing Requirements).

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FILING REQUIREMENTS FOR ONTARIO POWER GENERATION

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1. Introduction

This document sets out specific Filing Requirements for purposes of the setting of payment amounts for certain of Ontario Power Generation Inc.'s (OPG's) generation facilities under section 78.1 of the *Ontario Energy Board Act, 1998* (the Act).[1] The generation facilities in question are identified in O. Reg. 53/05 (*Payments Under Section 78.1 of the Act*) and are collectively referred to herein as the "prescribed generation facilities".

1.1 Overview of Legislative Context

Section 78.1 of the Act authorizes the OEB to set payments to be made to OPG with respect to the output of the prescribed generation facilities. Under O. Reg. 53/05, the OEB's authority in that regard commenced on April 1, 2008.

In addition to identifying the prescribed generation facilities, O. Reg. 53/05 generally empowers the OEB to establish the form, methodology, assumptions and calculations to be used in making an order that determines payment amounts for the purpose of section 78.1 of the Act. It also contains rules that must be followed by the OEB in setting those payment amounts.

O. Reg. 53/05 requires that OPG establish certain deferral and variance accounts and that the OEB ensure recovery of the balance in those accounts subject to certain conditions being met; it also requires that the OEB ensure that certain costs, financial commitments or revenue requirement impacts be recovered by OPG.

Commented [A3]: From the perspective of keeping the filing requirements evergreen, the second sentence in the footnote is unnecessary. The second sentence seemingly sets a firm requirement for a CIR application to be five years, whereas setting a payment amounts term is beyond the scope of the Filing Requirements.

Commented [A4]: Note for stakeholders: The list of generation facilities have been removed with the intention of keeping the Filing Requirements evergreen.

Commented [A5R4]: OK

[1] The working assumption reflected in these Filing Requirements is that OPG will be filing a payment amounts application every five years. ~~If the application is filed under the Custom Incentive Rate-Setting framework, the application is to include a minimum of five years of information for the prospective payment amounts term.~~

2. General Requirements

2.1 Introduction

In addition to the Handbook for Utility Rate Applications, which outlines the key principles and expectations of the OEB when reviewing an application, these Filing Requirements outline relevant information that is necessary for a complete payment amounts application. These Filing Requirements provide the minimum information that OPG must file for a complete payment amounts application. However, OPG should provide any additional information that is necessary to justify the approvals being sought in the application. If circumstances warrant, the OEB may require OPG to file evidence in addition to what is identified in these Filing Requirements.

A clearly written, accurate and complete application that presents information and data consistently across all exhibits, and clearly demonstrates the appropriateness of the relief sought (e.g., approval or permission) is essential for an effective regulatory review and timely decision making. The OEB's examination of an application and its subsequent decision are based on the evidence filed in that case. A complete and accurate evidentiary record is essential to facilitate an efficient regulatory process and a timely decision.

The material presented is OPG's evidence and the onus is on OPG to prove the need for and the basis for the proposed new payment amounts. The supporting information provided by OPG in its prefiled evidence should be scaled to the request that is being sought.

In determining what evidence to file, OPG should consider what reasonable information the OEB and the intervenors are likely to request and provide that information in the prefiled evidence rather than waiting for the request to be made at the hearing. The evidence should be designed to increase the understanding of the parties with the overall objective of reducing the number and scope of interrogatories required. This will ensure a better use of hearing time, and, if required, a more focused and informed cross examination on such evidence.

To the extent that materials are the same or substantially the same as those filed in previous payment amounts applications, OPG should indicate this to improve the efficiency of the review.

2.2 Completeness Review

The filing of a comprehensive application is essential for the development of an

Commented [A6]: Note for stakeholders: Sections 2.1-2.4 have been revised to align with other OEB filing requirements / handbook (Distribution, Transmission, Natural Gas).

Commented [A7R6]: OK

Commented [A8]: "likely to request" captures a broad assortment of potential documentation. OPG believes it is important to limit the requirement to reasonable requests.

accurate Notice of Hearing and for the timely and effective review of an application. Therefore, before the OEB can begin processing the application, it must conduct a preliminary review to determine if the application is complete. The preliminary review determines if the information provided adheres to these Filing Requirements and provides sufficient information to prepare an accurate Notice of Hearing, and if there is any missing information. According to the OEB's performance standards, the OEB has 14 calendar days to complete this preliminary review.

A filing that includes all documentation detailed in these Filing Requirements will be considered complete for purposes of further processing by the OEB. If the Registrar determines that the application is consistent with these Filing Requirements, the Registrar will issue a letter notifying OPG that the OEB has commenced processing the application.

If there are any information gaps in the application, OEB staff will contact OPG and provide OPG with an opportunity to file the missing information. The timing required for filing the missing information is determined by the type of information that is missing.

If the missing information adversely affects the OEB's ability to prepare the Notice of Hearing or materially affects the OEB's ability to assess the application, OPG will be required to file the missing information within the 14-day preliminary review period. If the information cannot be filed within the 14-day review period, the Registrar will issue an "incomplete letter." This letter will list the information that must be provided before the OEB can commence processing the application.

If the missing information does not adversely affect the OEB's ability to prepare the Notice of Hearing or materially affect the OEB's ability to assess the application, the OEB may commence the proceeding before the missing information is filed. In such applications, the Registrar will generally issue a letter directing OPG to file the missing information by the date of the OEB's first procedural order (refer to OEB performance standards for details on the timing of the first procedural order), so that the information is available for the preparation of interrogatories by OEB staff and intervenors. If the information cannot be filed by the noted date and the delay could impact the schedule for the case or the OEB's ability to continue processing the application, the OEB may stop the proceeding and place the application in abeyance until the missing information is filed.

The OEB also conducts an error checking process on a best-efforts basis. If any of the errors affect the OEB's ability to prepare the Notice of Hearing, the OEB expects these will be addressed within the preliminary review period. If the errors do not affect the preparation of the Notice of Hearing, the OEB expects any errors to be addressed before the issuance of Procedural Order No.1.

2.3 Confidential Information

The OEB relies on complete disclosure of all relevant material to ensure that its decisions are well-informed. To ensure a transparent and accessible rate review process, OPG should make every effort to file all material publicly and completely. However, the OEB's Rules of Practice and Procedure and the *Practice Direction on Confidential Filings* (the Practice Direction) allow OPG and other parties to request that certain evidence be treated as confidential. In the event a party is applying for confidentiality, the Practice Direction sets out the guidelines for filing a request for confidentiality and associated timelines.

OPG should be aware that the OEB is required to devote additional resources to the administration, management and adjudication of requests for confidentiality and confidential filings. OPG must ensure that filings for which they request confidential treatment are both relevant to the proceeding and genuinely in need of confidential treatment. A list of the categories of information that will presumptively be considered confidential is set out in Appendix B of the Practice Direction. To reduce the administrative issues associated with the management of those filings, the OEB expects that OPG will minimize, to the extent possible, requests for confidential information.

2.4 Certifications

If desired, the certifications listed in this section can be completed by a single individual within a single document, as long as the requirements set out below are met (i.e., the Chief Executive Officer, or Chief Financial Officer, or equivalent provide all certifications).

2.4.1 Certification Regarding Personal Information

All parties are reminded of the OEB's rules regarding personal information in any filing they make as part of a proceeding. Parties should consult Rule 9A of the OEB's *Rules of Practice and Procedure* (the Rules) (and the Practice Direction, as applicable) regarding how to file documents (including interrogatories) that have personal information in them.

Rule 9A of the OEB's Rules states that "any person filing a document that contains personal information, as that phrase is defined in the *Freedom of Information and Protection of Privacy Act*, of another person who is not a party to the proceeding shall file two versions of the document." There must be one version of the document that is a redacted version of the document from which the personal information has been deleted or stricken, and a second version of the document that is un-redacted (i.e., that includes the personal information) and should be marked "Confidential—Personal Information".

The OEB does not expect that personal information would typically need to be filed. However, if OPG is of the opinion that it does need to file personal information as part of its application, the onus is on OPG to ensure that the application and any evidence filed in support of the application does not include any personal information unless it is filed in accordance with Rule 9A of the OEB's Rules (and the Practice Direction).

An application filed with the OEB must include a certification by a senior officer of OPG stating that the application and any evidence filed in support of the application does not include any personal information unless it is filed in accordance with Rule 9A of the OEB's Rules (and the Practice Direction, as applicable).

OPG is required to provide a similar certification when filing interrogatory responses or other evidence as part of a proceeding.

2.4.2 Certificate of Evidence

An application filed with the OEB must include a certification by a senior officer of OPG that the evidence filed is accurate, consistent and complete to the best of their knowledge.

2.4.3 Certification of Deferral and Variance Account Balances

An application filed with the OEB must include a certification by the Chief Executive Officer, or Chief Financial Officer, or equivalent, that OPG has the appropriate processes and internal controls for the preparation, review, verification and oversight of all deferral and variance accounts, regardless of whether the accounts are proposed for disposition.

2.5 Structure of Application

OPG's payment amounts application should contain the following nine exhibits:

Exhibit A Administrative Documents and Application Overview
Exhibit B Rate Base
Exhibit C Capitalization, Cost of Capital, and Nuclear Liabilities
Exhibit D Capital Projects
Exhibit E Production Forecast
Exhibit F Operating Costs
Exhibit G ~~Operating~~ Other Revenue
Exhibit H Deferral and Variance Accounts
Exhibit I Determination of Payment Amounts

Commented [A9]: Note for stakeholders: Exhibit titles have been revised based on experience from most recent proceedings.

Commented [A10R9]: OK

Commented [A11]: As discussed below in Section 9.

Each exhibit, where applicable, should provide the identified data for each category of prescribed generation facility (nuclear and hydroelectric). As applicable, ~~E~~each exhibit should also explain how allocations have been made from total corporate costs to each category of ~~the~~ prescribed generation facility (nuclear and hydroelectric) ~~is as a whole~~ and the non-prescribed generation facilities ~~as a whole~~. Where allocations are first made to the prescribed generation facilities as a whole, ~~Then from the allocation to the prescribed generation facilities,~~ an exhibit should explain how sub-allocations have been made to each of the nuclear and hydroelectric categories.

Commented [A12]: Not all exhibits are specific to data of a generation facility category.

Commented [A13]: The edits in the last two sentences are intended to clarify that 1) the concept of allocations does not apply to all exhibits, 2) in some instances allocations are made directly to each of the facility categories rather than as a two-step allocation to the prescribed facilities as a whole and then to each of the categories.

Excel spreadsheets should be provided as appropriate to the data in question with formulae indicating on-sheet calculations. As a minimum, OPG should file Excel spreadsheets summarizing the production forecast (as noted in section 7), compensation and benefits (as noted in section 8) and a Revenue Requirement Work Form (RRWF). The RRWF will be filed with the application including data and tables to support the payment amounts order for which OPG is seeking approval.

2.6 Key Planning Parameters

The key planning parameters listed below form the basis of how these Filing Requirements should be applied.

These Filing Requirements are based on a cost of service (single- or multi-) test year application. The OEB does not set out detailed requirements for Custom incentive rate-setting (IR) applications, which are by definition customized. However, these Filing Requirements should be used as a starting point for any Custom IR application by OPG, with additions and modifications as necessary. The filing should be made in accordance with United States Generally Accepted Accounting Principles (US GAAP) until OPG transitions to International Financial Reporting Standards (IFRS).

For IFRS transition guidance, when applicable, OPG should refer to the *Report of the Board: Transition to IFRS dated July 28, 2009* (IFRS Report), and subsequent amendments and addendum. While the IFRS Report was directed to electricity and gas distributors, the OEB will consider OPG's transition to IFRS in the context of the policies established in the IFRS Report as well as transitioning away from capitalizing indirect overheads.[2]

Commented [A14]: Note to stakeholders: A requirement to provide information on OPG's transition to IFRS as well as transitioning from capitalizing indirect overheads has been added.

Commented [A15R14]: OK, but propose a minor clarification that this is a requirement when OPG has plans to transition to IFRS.

In addition, OPG should meet the following requirements in preparing its filing:

- Data for the following years, at a minimum, must be provided:
  - Test Year(s) = prospective year(s)

[2] EB-2020-0200, Decision and Order, December 21, 2023, pp. 98-99.

- Bridge Year = current year (or the year immediately preceding the Test Year(s))
- Historic Years = Three most recent historical years (or for as many years as are necessary to provide actuals back to and including the most recent OEB-approved test year(s), but not less than three years, and not more than five years)[3]

- A summary of the main schedules should be presented on one sheet with multi-year data for the Historic Years, the Bridge Year and the Test Year(s)

- Where applicable, Aa detailed variance analysis should also be provided comparing OEB-approved to actual costs and production for each Historic Year and Bridge Year.[4] The phrase "OEB-approved" in these Filing Requirements refers to the set of data used by the OEB as the basis for approving the most recent payment amounts. This analysis should explain the drivers of the variance and the contribution of each towards the total ~~year-over-year~~ variance

- Cost variance analysis should include a comparison of the total costs for the most recent payment amounts term (i.e., the term sought for approval in the previous payment amounts application) with the total costs for the next payment amounts term (i.e., the term sought for approval in the current payment amounts application) to provide a term-over-term variance analysis. The term-over-term variance analysis should be provided for operating, maintenance and administration (OM&A) costs and capital costs~~all cost categories~~. The term-over-term analysis is not required for production data

- Written evidence should be presented before the data schedules

- With respect to any claimed revenue sufficiency/deficiency, OPG should provide a summary of the drivers of the sufficiency/deficiency for each Test Year, along with how much each driver contributes

[3] OPG's hydroelectric base payment amount has not been rebased since EB-2013-0321. For OPG's next application to rebase the hydroelectric base payment amount (expected to be filed in 2025), OPG is also to provide, going back to 2013, hydroelectric rate base continuity tables (including gross plant and accumulated depreciation and amortization) and associated capital projects in-service listings, on a total regulated hydroelectric basis only. For other applicable tables and information on compensation and benefits, OPG is to file a total of nine years of historical actual data (expected to be 2016-2024) for the hydroelectric business, where for the years beyond the five most recent historical years (expected to be 2016-2019), OPG is required to file such information on a total regulated hydroelectric basis only. Where OPG determines that it is unable to file any of this information beyond the five most recent historical years (expected to be 2020-2024), it will clearly set out the reasons as to why this is the case. For information filed beyond the five most recent historical years, OPG is not required to provide variance analysis.

[4] The requirement for year-over-year variance analysis is excluded for ~~operating, maintenance and administration~~capital costs. See section ~~8~~ 6 for more details.

Commented [A16]: OPG believes it is reasonable to limit the minimum filing requirements for historic years to five years as a general rule. OPG believes, in general, that five years of historical actual data is sufficient to determine any trends, that information going back beyond five years likely has limited relevance due to the passage of time and changes in the business, and that requiring the filing of any more than five years of historic information can result in significant effort to maintain this information on a comparable basis with Test Period information (due to potential for realignment of organizational/cost structures etc over time). OPG should have the flexibility to determine whether information of more than five years is necessary to justify its requests as part of the prefiled evidence, on a case-by-case basis.

Notwithstanding and without prejudice to this general position, with respect to the specific circumstances of the next hydroelectric rebasing application, OPG accepts the intervenors' interest in information spanning beyond the five years and, with certain limitations, generally proposes to file nine years of historical actuals as further set out in the footnote.

Commented [A17]: Re-inserted this language from the existing filing requirements to allow for alignment with the specific nature and requirements in each exhibit section. This will help keep the evidence comparable application over application.

Commented [A18]: Note to stakeholders: The requirement for a detailed variance analysis has been removed for OM&A costs. OEB staff have not found this information needed for its review of the payment amounts application.

Commented [A19R18]: OPG considered feedback from the stakeholder session as well as its own evidence needs. OPG believes that detailed year over year variance analysis for OM&A has value, whereas capital does not. OPG proposes to do detailed variance analysis, including year over year, for OM&A, and term over term for capital.

Commented [A20]: Minor clarification

Commented [A21]: Note to stakeholders: A requirement has been added to provide term-over-term analysis of costs. In past OPG payment amount applications, OEB staff conducted this analysis manually. This analysis was then verified by OPG through interrogatories. The addition of this requirement is intended to enhance regulatory efficiency.

Commented [A22R21]: OPG has no concerns with filing additional term-over-term variance analysis for OM&A and capital, which is where we believe term-over-term analysis would be meaningful. For other cost categories, OPG does not believe that this analysis would be helpful.

- Any documents are to be provided in bookmarked and text-searchable Adobe PDF format
- Within 7 calendar days of the application being filed, ~~Any~~ any tables must also be provided in a working Microsoft Excel spreadsheet format where available and practical~~.~~

Commented [A23]: OPG does not have concerns with filing excel versions of all tables in the application. However, OPG notes that it had more than 200 tables in its EB-2020-0290 application and will likely have more going forward. Given the existence of notes to draft and linkages to internal working files, OPG requests that the Filing Guidelines allow for the excel versions to be filed within 7 calendar days after submission of OPG's prefiled evidence.

3. Exhibit A Administrative Documents and Application Overview

The administrative documents identified in this section provide the background and summary to the filing. There are two sections:

1) Administration and Overview
2) Background Financial Information

The detailed requirements on what should be included for each section are shown below.

3.1 Administration and Overview

- Table of Contents / Exhibit List
- List of relevant statutory provisions (such as any provisions of, or regulations under, the *Ontario Energy Board Act, 1998* or the *Electricity Act, 1998*)
- ~~A list of relevant company policies and regulations~~Summary of OPG's legislative and regulatory framework
- A list of specific approvals requested and relevant section(s) of the legislation must be provided
- Summary of filing (purpose, need and timing of the filing)
- A primary contact for the application, who may be a person within the OPG other than the primary licence contact. The primary contact's name, address, phone number, and email address must all be provided. The OEB will communicate with this person during the course of the application. Identification of any legal or other representation for the application
- Confirmation of OPG's internet address for purposes of viewing the application and related documents, and any social media accounts (with addresses) used by OPG to communicate with its customers
- A statement of where the notice of hearing should be published and the rationale for why the stated publication(s) is/are appropriate
- A statement as to the form of hearing requested (i.e., written or oral) and an explanation for OPG's preference
- The requested effective date
- A list of OEB directions from any previous OEB Decisions and/or Orders, this includes any commitments made as part of an approved settlement. OPG must clearly indicate how these are being addressed in the current application
- A description of the organizational structure, showing the main units and executive and senior management positions within OPG
- A draft issues list – including preliminary prioritization of primary and secondary

Commented [A24]: Note to stakeholders: The items listed in this section have been revised to align with Chapter 2 of the Distribution Filing Requirements.

Commented [A25]: OPG finds this to be an overly broad scope, and this also does not appear to be a requirement for LDCs. OPG currently files a summary exhibit explaining its legislative and regulatory framework. OPG proposes to continue filing that exhibit, which it believes should address the objective here.

issues
- Procedural Orders/motions/correspondence
- Relevant maps (or provide link to webpage where maps can be found)
- List of witnesses and their curriculum vitae
- Budget directives and guidelines (capital and operating budgets), including economic assumptions used
- A schedule of overall revenue sufficiency/deficiency that include:
    - Numerical schedules detailing the drivers of the sufficiency/deficiency
    - Complete and detailed references to the data contained in the detailed schedules and tables should be provided so that parties can map the summary cost driver information to the evidence supporting it
    - A detailed narrative of the causes of the sufficiency/deficiency highlighting the significant issues
- An overview of the allocation methodology for assets, costs and revenues to the prescribed and non-prescribed generation facility assets, and to the nuclear- and hydroelectric-specific businesses
- A statement identifying and describing any material changes to methodologies as used in previous application~~s~~
- A summary or copy of relevant orders from any federal or provincial agency (excluding OEB), Ministerial Directives and Shareholder Directives

Commented [A26]: Minor clarification - Adding a materiality consideration to this requirement given the size of the application, and noting that the comparisons should be application over application (i.e., as compared to the last application, and not an ongoing list of changes across all applications).

3.2 Background Financial Information

- Audited Financial Statements (AFS) approved by OPG's Board of Directors for each of the Historic Years (or provide the webpage address of the location on System for Electronic Document Analysis and Retrieval or Electronic Data Gathering, Analysis, and Retrieval where these audited financial statements can be found)
- AFS should be provided as soon as they are available. If the statements are not available at the time of filing, OPG should provide these as an update during the proceeding
- The most recent four quarterly OPG financial reports
- Rating agency reports for each of the Historic Years and the Bridge Year
- An overview of how the provisions of O. Reg. 53/05 is reflected in the filing compared to data in the AFSs
- A detailed reconciliation of the financial results shown in the AFS with the regulatory financial results filed in the application, including a reconciliation of the fixed assets and the identification of any material changes in the reconciling items used in the previous application. ~~This must include the identification of any deviations that are being proposed between the AFS and the regulatory financial results, including the identification of any prior OEB approvals for such deviations~~
- The most recent OPG Board of Directors-approved Business Plan for the regulated

Commented [A27]: OPG's proposed changes are to clarify the requirement based on our understanding of the intent, and to align with language in the list under section 3.1. For clarity, the OEB does not necessarily approve "deviations between AFS and the regulatory financial results" per se but rather approves OPG's revenue requirement and any underpinning methodologies, which may in turn be based on financial accounting values. The edits align to the presentation of information in OPG's past applications

components of OPG, including hydroelectric business, and the nuclear business. Any previous Business Plans that include part of a Test Year should also be filed.

4. Exhibit B Rate Base

A description of the prescribed generation facilities, and of any associated financial assets, should be provided. For nuclear rate base, a separate presentation of asset retirement costs associated with nuclear liability obligations is required.

Commented [A28]: Minor clarification.

Items used in the computations or derived should include opening and closing balances of the net fixed assets, working capital, accumulated depreciation~~,~~ and changes in working capital~~, accrued deferred earnings, and annual amortization of accrued deferred earnings~~.

Commented [A29]: These items do not apply to OPG.

The information presented here should cover three areas:

1) A list of gross assets (property, plant and equipment), including capital budgets and intangible assets (e.g., computer software) if any, included in rate base
2) Accumulated depreciation and amortization
3) Working capital including cash working capital calculation, fuel inventory (for the nuclear business), and materials and supplies

For each of these areas there will be some common statements that should be provided summarizing the rate base. The schedules for rate base should include the Historic Years, the Bridge Year ~~(actuals to date, balance of year as budgeted)~~ and the Test Year(s).

Commented [A30]: Full year budgeted information may be used for Bridge Year, depending on the circumstances

Additional statements that should be provided for 1 and 2 include:

Continuity statements

The continuity statements must provide year-end balances and annual activity, and include directly attributable costs, for example, capitalized borrowing costs.

Commented [A31]: Minor clarification

Summary variance explanation

A written explanation should be provided to identify the drivers to the variance for rate base. This applies to OPG's rate base for the following comparisons:

- OEB-approved vs. actual for each of the Historic Years
- OEB-approved vs. Bridge Year
- Year-over-year analysis over the Historic Years, the Bridge Year and the Test Year(s)

4.1 Gross Assets – Property, Plant and Equipment and Intangible Assets

Continuity statements should be provided as indicated above.

- ~~Required~~ statements and analysis should be broken down by major function or division
- ~~A detailed breakdown should be provided by major plant account for each functionalized plant item~~ for each of the Historic Years, the Bridge Year and the Test Year(s). For the Test Year(s), each plant item should be accompanied by a written description
- Mid-year averages should be provided

Commented [A32]: These edits align to the presentation of OPG's rate base evidence in past applications and to ensure continuity of such information to be presented in future applications. The indicated statements and analysis in this section are provided on a rolled up basis by several major categories in OPG's applications. Doing so by the detailed plant accounts comprising OPG's fixed asset would not be practical. A detailed breakdown of the plant accounts at a point in time is included as part of independent depreciation studies.

4.2 Accumulated Depreciation and Amortization

Continuity statements and a summary variance explanation should be provided as indicated above for each of the Historic Years, the Bridge Year and Test Year(s) by asset account. Continuity statements should be reconcilable to calculated depreciation costs.

4.3 Working Capital Calculation

A working capital calculation should be provided for the each of the Historic Years, the Bridge Year and the Test Year(s). The results should be provided on a single schedule for comparison. The basis for the calculation of cash working capital must be detailed.

5. Exhibit C Capitalization, Cost of Capital and Nuclear Liabilities

OPG should ensure that the total capitalization in the filing (debt, ~~and~~ equity and as applicable a provision for nuclear liabilities) equates to the total rate base.

Commented [A33]: These edits are to more accurately reflect the OEB approved methodology for capitalization of OPG's prescribed nuclear assets

5.1 Capital Structure – Amounts & Ratios

The following elements of the proposed capital structure should be detailed, with the necessary schedules, for each of the Historic Years, the Bridge Year and the Test Year(s):

- Long-term debt
- Short-term/unfunded debt (to equate total capitalization with rate base)
- Preference shares
- Common equity

Justification for the proposed capital structure is required, including an explanation of the following:

- Non-scheduled retirement of debt or preference shares and buy back of common shares
- Long-term debt, preference shares and common share offerings
- The assumptions and methodology used ~~since the establishment of the prescribed generation facility asset classes~~:

  ~~to develop prescribed generation facility asset valuations~~
  - to allocate OPG's debt to the prescribed generation facilities as a whole
  - to allocate OPG's debt as between the prescribed nuclear and hydroelectric generation facilities

Commented [A34]: This language appears to be obsolete. The OEB accepted the valuations of OPG's assets upon becoming rate regulated. If OPG were to propose any changes in valuation methodologies for rate-setting purposes, this would be captured by the OEB staff's new language in section 3.1.

- A historic accounting of changes to ~~OPG's~~ capital structure including:
  - Non-scheduled retirement of debt or preference shares or buy-back of common shares
  - Issuances of long-term debt, preference shares and common shares
- A discussion of material changes in the proposed capital structure (i.e., increased or decreased equity thickness) of OPG, and the reasons for these changes

Commented [A35]: The deemed capital structure is what is relevant rather than OPG's capital structure.

- All internal or commissioned reports, studies or analyses, from four years to the date

of filing, of ~~how to value OPG's assets and~~ how to allocate debt, by business unit or asset class

Commented [A36]: For clarity - same as above.

5.2 Component Costs of Debt

The following should be provided for each of the Historic Years, the Bridge Year and the Test Year(s):

- A calculation of the cost of each item
- A justification of forecast costs by item including key economic assumptions
- Profit or loss on redemption of debt
- Consensus Forecasts – latest interest rate forecast based on a selection of forecasters that are common to utilities (e.g., the major banks and the Bank of Canada)

5.3 Calculation of Return on Equity

Justification for the proposed return on equity is required, including the filing of supporting documentation, e.g., Global Insight reports.

5.4 Nuclear Waste Management and Decommissioning Costs

This section provides a summary of OPG's obligations for nuclear waste management and decommissioning. This exhibit should also provide the funding responsibilities as described in the Ontario Nuclear Funds Agreement.

Any updates or revisions to the Ontario Nuclear Funds Agreement Reference Plan must be summarized and the financial impacts explained in appropriate detail, including a reconciliation with the OEB-approved amounts for the Historic Years and the Bridge Year. If the reconciliation is summarized elsewhere in the application, the reference should be provided in this section.

Commented [A37]: **Note for stakeholders:** In efforts to keep the Filing Requirements evergreen, reference to specific years have been removed and are kept general.

Commented [A38R37]: OK

The information should be disaggregated to present Darlington and Pickering separate from Bruce.

The information presented should cover the following:

- The revenue requirement treatment and the revenue requirement impact of OPG's liabilities for decommissioning its nuclear stations and nuclear used fuel and low and intermediate level waste management
- The revenue requirement treatment and the revenue requirement impact of OPG's liabilities for decommissioning Bruce

Further, the exhibit should include:

- A summary of net book values of unamortized asset retirement costs for OPG's nuclear stations including Bruce~~, noting amounts of unamortized asset retirement cost,~~ for the Historic Years, the Bridge Year and the Test Year(s)
- Continuity statements providing year-end balances and annual activity for ~~A summary of the forecast pre-tax charge in OPG's income statement due to~~ the nuclear liabilities and the segregated funds

Commented [A39]: These edits are to more accurately describe the information presented in OPG's applications in support of the revenue requirement calculations pursuant to OEB approved methodologies, and to ensure comparability of information presented in future applications.

6. Exhibit D Capital Projects

This section provides details on OPG's capital project costs, including OPG's capitalization policy, accounting treatment of capital costs, capital expenditures and capital cost variance analysis. For clarity, this section will also apply to Project OM&A where relevant, namely, information required for Pproject OM&A and cost variance explanations.

Commented [A40]: This note was always in this exhibit following Table 1. Including it at the top for clarity.

6.1 Policies

OPG's capitalization policy and any changes to that policy should be presented as part of the capital budget evidence.

OPG should provide details on its proposed accounting treatment, including the treatment of costs of funds for capital projects that have a project life cycle greater than one year.

6.2 Capital Expenditures

OPG should provide a summary of capital expenditures for the Historic Years, the Bridge Year and the Test Year(s), including the OEB-approved amounts for the Historic Years and the Bridge Year.

The table below summarizes the information required based on capital project costs.

Table 1: Information Required in Capital Project Summaries

For Capital Projects of	Detail Required
$420 million or more	• Name, description, start date, in- service date, and cost for each project • Business case for each project • Provide actual in-service dates (month and year) for capital projects that closed to rate base in the Historical Years and provide projected in-service dates (month and year) for the Bridge Year and the Test Year(s) • Total cost of all projects in this category

Commented [A41]: **Note for stakeholders:** Seeking feedback on whether these capital project cost thresholds are still appropriate. The thresholds were set in 2011.

Commented [A42R41]: OPG believes that the project thresholds are no longer appropriate given the passage of time, but that the necessary escalations are not the same as between capital and OM&A projects.

Fror capital projects, based on Building Construction Price Indexes, $20 million in 2011 would be equivalent to approximately $40 million today. OPG believes these thresholds are appropriate as they maintain the status quo of materiality considered in 2011 and helps manage regulatory efficiency and better focus on material issues for both OPG and intervenors.

For project OM&A, based on Consumer Price Indices, $20 million in 2011 would be equivalent to approximately $30 million today (OPG used CPI rather than Building Construction Price Indexes to approximate this change as costs associated with Project OM&A are typically labour rather than the construction/installation of assets). OPG believes this threshold is appropriate as it maintains the status quo of materiality considered in 2011 and helps manage regulatory efficiency and better focus on material issues for both OPG and intervenors.

Consistent with the above assessment, OPG has also proposed to increase the third tier to $10 million, while would also be made consistent with the historical materiality threshold of $10 million used in OPG's applications generally.

Between $~~5~~10 million and $~~4~~20 million	• Name, description, start date, in-service date, and cost for each project • Provide actual in-service dates (month and year) for capital projects that closed to rate base in the Historical Years and provide projected in service dates (month and year) for the Bridge Year and the Test Year(s) • Total cost of all projects in this category
Less than $~~5~~10 million	• Number of projects in this category, total cost of all projects in this category and average cost of the projects in this category • Provide the total cost related to projects that will close to rate base in the Test Year(s)

OPG should provide an overall summary table of the business cases filed. The summary table should include the title of the business case, date prepared, the project stage, and status of the business case (~~i.~~e.g., full, partial, developmental), for the current payment amounts proceeding. Where applicable, the table should also indicate the business case's status in the previous payment amounts proceeding. Note that all of the above is also applicable to Project ~~Operating, Maintenance and Administrative (~~OM&A~~)~~ business cases, except Tier 1 is greater than $30 million and Tier 2 ends at $30 million.

For capital projects with a project cost of $~~2~~40 million or more ($30 million or more for Project OM&A), OPG should provide a written explanation of variances where the variance is 20~~10~~% or more of the project budget.

Variance explanations should be provided for the following comparisons:

- OEB-approved vs. actual for each of the Historic Years
- OEB-approved vs. Bridge Year forecast
- ~~Year-over-year~~Term-over-Term analysis ~~over the Historic Years, the Bridge Year and the Test Year(s)~~

OPG should provide a summary table for capital projects and P~~p~~roject OM&A with a project cost of $~~5~~10 million and greater that were projected to go into service or to be completed during the previous payment amounts term. The table should include the project stage as provided in the previous payment amounts application and the current status of the project.

Commented [A43]: Minor clarification.

Commented [A44]: OPG believes that there should be adjustments to the variance analysis thresholds. For capital projects over $40 million and project OM&A over $30 million, OPG proposes to provide a written explanation of variance where the variance is 20% or more of the project budget. Firstly, for execution business cases within the Association for the Advancement of Cost Engineering (AACE) class 3 range of estimate, a project estimate is expected to be within an accuracy range of -20/+30%. The ranges are broader for earlier classes of estimate. Therefore, projects with a 20% variance are still within the range of expected project outcomes. Secondly, focusing the variance analysis on projects with a 20% variance is consistent with OPG's governance which requires a superseding business case at that variance threshold.

Commented [A45]: As noted above, OPG believes that year-over-year analysis of project variances is of limited value given the specific nature of each project and the inherent shifts between years of a project's lifespan that can occur. OPG proposes that term-over-term analysis would be more instructive in this instance.

Commented [A46]: Minor clarification.

7. Exhibit E Production Forecast

The production forecast and any normalization methodology should be provided. A description of outage planning processes and production reliability initiatives should also be provided.

The following information should also be included:

- Explanations of causes and assumptions for the production forecast
- Production for the Historic Years, the Bridge Year and the Test Year(s)
- Weather forecasting and hydrological forecasting methodologies
- All data tables used to determine the forecast should be presented in MS Excel spreadsheet format
- Comparison of historical data with the forecast data in regard to forecasting assumptions
- A variance analysis of production should be provided for the following:
  - OEB-approved vs. actual for each of the Historic Years
  - OEB-approved vs. Bridge Year forecast
  - Year-over-year analysis for the Historic Years, the Bridge Year and the Test Year(s)
- All significant economic assumptions and their sources used in the preparation of the production forecast should be included in this section
- Where ~~available~~applicable, actual and forecast generation losses due to spill should be filed

Commented [A47]: Minor clarification.

Commented [A48]: Minor clarification.

Commented [A49]: For clarity - Clarifying that this information is filed as necessary, e.g., to support clearance of the SBG Variance Account.

Hydroelectric Incentive Mechanism (HIM)

An analysis of the HIM should be provided. The analysis should include an assessment of the benefits of HIM for ratepayers, the interaction between the mechanism and surplus baseload generation, and an assessment of any changes to the mechanism ~~that the OEB may have approved over time and/or any further changes~~ that OPG may wish to propose.

Commented [A50]: For clarity. The assessment of the HIM benefits captured in the first part of the sentence is necessarily inclusive of any changes to the mechanism previously approved by the OEB that are in effect. The edits are intended to make clear that there is no requirement to provide a separate assessment of each past change that may have been approved at any past point.

8. Exhibit F Operating Costs

8.1 Benchmarking Studies

This exhibit should include benchmarking studies that update studies filed in previous applications or new benchmarking studies. Further, this exhibit should include a consolidation of the benchmarking information so that comparisons are evident, e.g., Total Generating Cost, nuclear capacity factors, and other safety, reliability and value for money measures.

The benchmarking should note whether the basis is a forecast or actual results.

8.2 Operating, Maintenance & Administration Costs

For clarity, Project OM&A business cases and variance analysis should follow the requirements set out in Section 6 above.

Details of the budgets for each of the Historic Years, the Bridge Year and the Test Year(s) should be provided.

The OM&A statements for each year should provide:

- Base, outage and project OM&A separately. Where applicable, the information is to include a breakdown by major functions or divisions and the allocations to each of the prescribed nuclear and hydroelectric businesses.~~A breakdown on a work basis of each major item that meets the threshold of the lesser of 1% of total expenses before taxes or $20 million~~
- Detailed information is to be provided for each expense incurred through the purchase of services or products that meets the threshold ~~of the lesser of 1% of total expenses before taxes or~~ $~~2~~30 million. The information is to include, for each such expense:
  - A summary of the tendering process used
  - If a tendering process was not used, an explanation of why that was the case as well as a description of the pricing methodology used
  - The identity of the company transacting with OPG
  - A summary of the nature of the activity transacted

  In addition, the annual dollar value, in aggregate, for all such expenses should be provided.

Commented [A51]: Note for stakeholders: Seeking feedback on whether this OM&A project cost threshold is still appropriate. The threshold was set in 2011.

Commented [A52R51]: OPG addressed the Project OM&A threshold above in Section 6.

Commented [A53]: For clarity - no substantive change relative to current OPG evidence. As discussed at the stakeholder session and agreed to with intervenors present, the prior language did not reflect OPG's historical applications. Parties felt that OPG's existing evidence was appropriate. Accordingly, OPG has proposed amendments for alignment with OPG's existing evidence to ensure comparability of OPG's applications continues going forward.

Commented [A54]: OPG proposes to modify and increase the threshold from "the lesser of 1% of total expenses before taxes or $20 million", to $30 million. The removal of the 1% rule simplifies the rule and makes it more comparable case over case. Based on Consumer Price Indices, $20 million in 2011 would be equivalent to approximately $30 million today. OPG believes this threshold is appropriate as it maintains the status quo of materiality considered in 2011 and helps manage regulatory efficiency for both OPG and intervenors in focusing on material issues in the application.

- A breakdown of employees by the following groups: number of full-time equivalents (FTEs) including contributions from part time employees; total salaries, wages and benefits; and salaries, wages and benefits charged to OM&A. In addition, the following should also be provided:
  - Total compensation by employee group and average level per group
  - Details of any pay-for-performance or other employee incentive program
  - The status of pension funding and all significant assumptions used in the analysis

  Information should be presented in terms of FTEs. In some cases, OPG may choose to provide the information in terms of head count as well as FTEs. The basis for each breakout of compensation data will be specified:
  - Head count or FTE
  - Yearly average, mid-year or year end

  This data should be provided in Excel spreadsheet table format.

- Employee benefit programs, including pensions, and costs charged to O&M should include the following details:

  - Historic actuarial reports
  - Actuarial evidence to support pension and other post-employment benefits (OPEB) expense for the Bridge Year and Test Year(s) including any educational notes or articles issued by the Canadian Institute of Actuaries on methods for determining discount rates used for reporting under Chartered Professional Accountants (CPA) Canada standards
  - CPA Canada guidance, practice notes, etc. that provide information on approaches to selecting discount rates should be filed
  - Discussion and analysis on discount rates used for calculating pensions and OPEB benefit obligations, cost for the year and liabilities
  - A table that summarizes actual accounting expense compared to OEB-approved expense and with amounts actually paid for pensions and OPEBs for the historical years
  - The most recent report filed with Financial Services Regulatory Authority of Ontario

- A variance analysis for OM&A, and components of OM&A (including asset service fees, regulatory affairs costs), should be provided for the following:
  - OEB-approved vs. actual for each of the Historic Years
  - OEB-approved vs. Bridge Year forecast
  - Year-over-year variance analysis

Commented [A55]: Minor clarification. This is not intended to result in any changes to the scope or level of detail of OPG's pension related evidence.

Commented [A56]: As discussed above, OPG can provide both the new term-over-term variance analysis, and also continue to provide year-over-year variance analysis.

- Term-over-term variance analysis (most recent payment amounts application versus the proposed payment amounts application)
- A written explanation is required for any variance greater than or equal to 10% of category expenses

8.3 Depreciation/Amortization/Depletion

This section should include the following:

- An independent depreciation study and summary of changes for depreciation, amortization and depletion by asset group should be provided
- Details of provision for depreciation, amortization and depletion by major ~~asset group~~function or division for each Test Year should be provided, as should comparative data for each of the Historic Years and the Bridge Year, including asset amount and rate of depreciation

Commented [A57]: Minor clarification to align with the proposal for section 4.1 (gross plant). In OPG's past applications, depreciation tables follow the presentation of the rate base schedules given their connectedness. As noted earlier, detailed plant account listing and associated depreciation rates are provided in depreciation studies.

8.4 Corporate Cost Allocation

A summary of the corporate cost allocation should be provided, including information showing the costs incurred at the corporate level, the methodology and assumptions used ~~to allocate these costs to the prescribed and non-prescribed generation facilities and the methodology~~ to allocate these costs to each of the prescribed nuclear and hydroelectric businesses.

Commented [A58]: For clarity. Corporate costs are allocated directly to each of the prescribed nuclear and hydroelectric businesses, not as a two step process.

Details in relation to shared corporate services should include:

- Type of service (IT, office space, etc.) or function/division
- Total annual expense by service or function/division
- Rationale and derivation of cost allocators used for shared costs, for each type of service (square footage/computers/headcount/etc.)
- Any variances for corporate cost allocation for the two most recent years from filing date of the current payment amounts application

Commented [A59]: Minor clarification to align with how OPG's applications present corporate cost information and to ensure comparability in future applications

8.5 Taxes

OPG should file information on its income tax for the Historic Years, the Bridge Year and the Test Year(s) and the detailed calculation supporting the data. The documentation should include copies of the most recent tax returns and notices of assessment, re-assessment and statements of adjustments.

A detailed tax calculation should be provided for each of the Historic Years, the Bridge Year and the Test Year(s), including derivation of interest deducted, capital cost allowance showing differences from depreciation/amortization expense, all other

material differences from regulatory ~~financial statement~~ income, tax rates and payments in lieu of taxes included in deriving the revenue requirement.

Details on the gross revenue tax applicable to the hydroelectric business should be provided either separately or as part of the operating expenses for the hydroelectric business.

Where applicable, ~~All~~ reconciling items should have supporting schedules and calculations.

Commented [A60]: This clarification aligns to the evidence in past applications where some smaller differences are aggregated to help manage information presented.

Commented [A61]: In this exhibit, the starting point for regulatory taxes is regulatory income. Reconciliation between regulatory income and the AFS financial results is captured by the requirements under section 3.2.

Commented [A62]: Currently, OPG is providing supporting schedules and calculations for CCA. This leaves open for other items to have supporting schedules as required.

9. Exhibit G ~~Operating~~Other Revenue

~~The revenue forecast, any normalization methodology and sales activities should be provided here.~~ The information presented in this section should include other revenue derived from the use of the prescribed generation facilities as well as from the Bruce nuclear generating stations, broken down by revenue source.

~~9.1 Energy Revenue~~

~~This section should include the following:~~

- ~~Production and energy revenues for the Historic Years, the Bridge Year and the Test Year(s)~~
- ~~Schedule of production showing volumes, total revenues and unit revenues for each of the Historic Years, the Bridge Year and the Test Year(s)~~

~~9.2~~9.1 Other Revenues

Details of other revenue, broken down by revenue source, should be provided. This should include OPG's revenues and costs associated with the Bruce nuclear generating stations

- A variance analysis of other revenues should be provided for the following:
  - OEB-approved vs. actual for each of the Historic Years
  - OEB-approved vs. Bridge Year forecast
  - Year-over-year over the Historic Years, the Bridge Year and the Test Year(s)
- A detailed explanation of how other revenues are attributed to the prescribed generation facilities should be provided

Commented [A63]: Note for stakeholders: Seeking feedback on the organization of this section. The organization of this exhibit is not consistent with how OPG has structured its most recent payment amounts application (2022-2026 term).

In that application, the exhibit solely focused on other revenues. E.g., Bruce, sale of isotopes etc. The broader pieces on operating revenue were rolled into other Exhibits

Commented [A64R63]: As discussed at the stakeholder session with intervenors, parties agreed that the current evidence structure as reflected in OPG's applications is appropriate, and that it would facilitate comparability application over application to revise the Filing Requirements to reflect the structure of OPG's evidence. The proposed edits reflect this shared view.

Commented [A65]: Minor clarification as Bruce facilities are not prescribed.

Commented [A66]: Note for stakeholders: Seeking feedback on whether year-over-year variance analysis is needed and/or term over term for Other Revenue.

Commented [A67R66]: For the same reasons set out above in section 2.7, OPG believes that year-over-year analysis would be more meaningful in this instance. OPG believes no change is needed.

10. Exhibit H Deferral and Variance Accounts

As described in section 1, O. Reg. 53/05 contains a number of provisions regarding the establishment of deferral and variance accounts (DVAs) and the recovery of balances in those accounts. In this section, OPG should include information necessary to enable the OEB to deal with these accounts in the manner contemplated by O. Reg. 53/05, including OPG's proposals regarding the following, as applicable:

- The end date for entries into the DVAs
- Addressing timing differences between the end date for entries into the DVAs and the effective date of the OEB's order
- The number of years over which balances in the DVAs should be recovered (subject to the maximum set out for each in O. Reg. 53/05)

- ~~The interest rate proposed for the nuclear liability deferral account referred to in section 5.2(1) of O. Reg. 53/05~~

For existing DVAs, this exhibit should include:

- A listing and detailed description (including account definition) of all outstanding DVAs - those required by O. Reg. 53/05 as well as those established by the OEB in previous decisions
- Continuity statements listing opening balances, transaction details including recoveries where applicable, interest rates and carrying charges, and closing balances. The schedules should reflect annualized data for the Historic Years ~~and the Bridge Year~~since the balances were last cleared. ~~Notes~~ Information should be provided for any transactions that are outside the normal course of business for OPG or that otherwise appear to be unusual due to their timing, size, or nature
- A detailed proposal for the disposition of the balances in the DVAs, where applicable.

OPG should also identify any deferral or variance accounts that it may wish to have authorization to establish on and after the date of the OEB's order.

Commented [A68]: Minor clarification as not all of the items would necessarily apply to all account or at all times

Commented [A69]: Cleanup - This has already been resolved in prior applications.

Commented [A70]: Note to stakeholders: The list of DVAs have been removed in efforts to keep the Filing Requirements evergreen.

Commented [A71R70]: OK

Commented [A72]: Edits to clarify that balances are cleared periodically, on an actual basis. Information is therefore not presented on a Bridge Year basis in OPG's application, and Historic Year information goes back to the last OEB approval.

Commented [A73]: Minor clarification as this information in practice may be provided by a combination of notes to the tables and narrative evidence, depending on the nature of the item

11. Exhibit I Determination of Payment Amounts

This exhibit should include the following:

- Calculation of Revenue Deficiency or Sufficiency
  - Determination of regulatory net income
  - Statement of rate base
  - Indicated rate of return
  - Gross and net deficiency or sufficiency in revenue
  - Revenue Requirement Work Form
- Proposed Payment Amounts Schedule and Analysis
  - Proposed payment amounts and revenue adjustments
  - Proposed approach for smoothing payment amounts, if applicable
  - Detailed calculations of revenue under the current payment amounts schedule and the proposed payment amounts schedule
  - Detailed reconciliation of payment amounts revenue and other revenue to the total revenue requirement
  - Analysis of % change in proposed payment amounts vs. current payment amounts
  - Bill impact analysis
- Payment Design (if proposing changes)
  - Analysis of the existing design of payment amounts and whether the design maximized efficient use of the prescribed generation facilities
  - Proposed payment design and rationale
  - Explanation of non-cost factors and their application to payment design
- Payment Implementation

  OPG should provide a description of the settlement process with the IESO, including a description of the timelines associated with the requested effective date.

Commented [A74]: Minor clarification.

Commented [A75]: This section is unnecessary unless changes to payment design are contemplated. It would be repetitive application over application otherwise.

AMPCO Interrogatory #104

Interrogatory

Reference:
F2-1-1 Table 2a

Question(s):

Please split Table 2a into two tables and provide excel versions of each table. In the response breakdown Nuclear Facilities OM&A FTEs between Base OM&A, Project OM&A, and Outage OM&A.

a) Darlington Staff Summary.

b) Pickering Staff Summary.

Response

a) and b)

Refer to Attachment 1.

OPG Nuclear Facilities OM&A FTEs Darlington

Group	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Actual	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 Base OM&A:												
Regular Staff	1,862.0	1,847.7	1,593.2	1,632.4	1,706.3	1,830.6	2,052.5	2,148.7	2,120.5	2,123.4	2,106.5	2,084.6
Non-Regular Staff												
Term and Extended Temporary	38.9	65.8	145.8	210.7	193.0	125.5	100.0	0.0	0.0	0.0	0.0	0.0
Temporary	253.5	231.7	194.4	195.8	182.4	195.0	98.5	62.2	56.8	56.8	56.9	54.6
EPSCA	24.4	22.0	21.3	7.1	17.2	22.4	7.2	7.2	7.2	7.2	7.2	7.2
Total Non-Regular Staff	316.8	319.6	361.5	413.6	392.7	342.8	205.6	69.4	63.9	63.9	64.1	61.8
Subtotal OPG Nuclear Facilities Base OM&A	2,178.7	2,167.3	1,954.7	2,046.0	2,099.0	2,173.4	2,258.2	2,218.1	2,184.4	2,187.3	2,170.5	2,146.3
OPG Nuclear Facilities Outage OM&A:												
Regular Staff	23.1	49.3	63.9	24.2	45.6	30.0	45.5	49.8	43.0	52.3	45.3	40.6
Non-Regular Staff												
Term and Extended Temporary	4.0	8.1	3.5	2.5	1.3	1.4	0.0	0.0	0.0	0.0	0.0	0.0
Temporary	76.0	152.5	33.3	14.1	44.8	10.2	95.2	64.3	51.3	102.6	51.3	51.3
EPSCA	22.4	40.5	48.2	49.5	51.8	28.8	10.4	0.8	0.4	0.4	0.0	0.0
Total Non-Regular Staff	102.4	201.2	84.9	66.0	97.9	40.3	105.6	65.1	51.7	103.0	51.3	51.3
Subtotal OPG Nuclear Facilities Outage OM&A	125.5	250.4	148.8	90.2	143.5	70.3	151.1	114.9	94.7	155.3	96.6	91.9
Pickering Cyclical Maintenance OM&A:												
Regular Staff	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non-Regular Staff												
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
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
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
Total Non-Regular Staff	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal 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	0.0
OPG Nuclear Facilities Project OM&A:												
Regular Staff	81.1	78.2	71.8	68.9	80.7	89.6	119.6	129.4	133.5	114.6	112.4	115.8
Non-Regular Staff												
Term and Extended Temporary	2.6	4.7	2.6	3.9	2.5	1.1	0.0	0.0	0.0	0.0	0.0	0.0
Temporary	23.7	22.9	10.8	5.4	5.3	7.2	11.4	10.0	10.5	12.8	14.5	14.5
EPSCA	9.1	14.3	12.3	11.8	12.8	7.6	4.4	4.6	4.6	4.6	5.8	5.8
Total Non-Regular Staff	35.4	41.9	25.7	21.1	20.6	15.8	15.8	14.6	15.1	17.4	20.3	20.3
Subtotal OPG Nuclear Facilities Project OM&A	116.5	120.1	97.5	90.0	101.3	105.4	135.4	144.0	148.6	132.0	132.7	136.0
Total Nuclear Facilities Base, Outage, Pickering Cyclical & Project OM&A	**2,420.8**	**2,537.8**	**2,201.0**	**2,226.2**	**2,343.8**	**2,349.1**	**2,544.7**	**2,477.0**	**2,427.7**	**2,474.7**	**2,399.9**	**2,374.3**
OPG Nuclear Facilities Capital:												
Regular Staff	145.5	134.0	172.5	185.6	235.6	287.5	383.2	367.0	336.8	279.5	293.0	308.4
Non-Regular Staff												
Term and Extended Temporary	0.7	7.7	17.0	23.5	24.0	9.7	17.0	0.0	0.0	0.0	0.0	0.0
Temporary	36.2	22.8	16.0	0.1	5.6	32.9	73.1	59.0	57.5	40.2	38.5	35.5
EPSCA	21.6	28.0	44.7	43.0	35.5	26.8	28.2	22.4	17.8	7.8	7.0	7.0
Total Non-Regular Staff	58.5	58.5	77.8	66.6	65.1	69.4	118.3	81.4	75.3	48.0	45.5	42.5
Subtotal OPG Nuclear Facilities Capital	203.9	192.5	250.2	252.2	300.7	356.9	501.5	448.4	412.2	327.5	338.5	350.9
Darlington Refurbishment Program:												
Regular Staff	432.5	394.0	404.0	446.7	499.9	440.0	55.8	0.0	0.0	0.0	0.0	0.0
Non-Regular Staff												

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
Temporary	117.0	83.3	69.7	67.2	69.2	41.7	21.6	0.0	0.0	0.0	0.0	0.0
EPSCA	128.6	224.2	252.2	295.1	271.1	221.0	29.3	0.0	0.0	0.0	0.0	0.0
Total Non-Regular Staff	245.6	307.4	321.9	362.3	340.4	262.8	50.9	0.0	0.0	0.0	0.0	0.0
Subtotal Darlington Refurbishment	678.2	701.5	725.9	809.0	840.3	702.8	106.7	0.0	0.0	0.0	0.0	0.0
Pickering Refurbishment Program:												
Regular Staff	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non-Regular Staff												
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
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
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
Total Non-Regular Staff	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal Pickering Refurbishment Program	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Darlington Station	**3,302.9**	**3,431.8**	**3,177.1**	**3,287.4**	**3,484.8**	**3,408.8**	**3,152.9**	**2,925.4**	**2,839.9**	**2,802.1**	**2,738.4**	**2,725.1**

OPG Nuclear Facilities OM&A FTEs Pickering

Group	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Actual	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 Base OM&A:												
Regular Staff	2,292.8	1,975.3	1,877.3	1,947.2	2,156.2	1,930.6	1,645.4	377.7	401.6	426.6	454.8	1,254.8
Non-Regular Staff												
Term and Extended Temporary	524.1	666.0	715.2	692.0	395.8	109.2	74.7	0.0	0.0	0.0	0.0	0.0
Temporary	227.4	226.1	208.6	215.3	179.7	148.8	81.2	26.1	25.0	25.0	25.4	29.5
EPSCA[1]	5.4	9.4	8.9	9.0	11.5	(9.9)	1.1	1.1	1.1	1.1	1.1	1.1
Total Non-Regular Staff	756.9	901.5	932.8	916.3	587.0	248.1	157.0	27.2	26.0	26.1	26.5	30.6
Subtotal OPG Nuclear Facilities Base OM&A	3,049.8	2,876.8	2,810.1	2,863.6	2,743.2	2,178.7	1,802.4	404.9	427.6	452.7	481.3	1,285.4
OPG Nuclear Facilities Outage OM&A:												
Regular Staff	73.4	53.7	19.0	77.8	75.2	27.7	17.0	0.0	0.0	0.0	0.0	0.0
Non-Regular Staff												
Term and Extended Temporary	10.8	14.1	15.1	14.5	5.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Temporary	174.0	175.1	126.1	148.2	109.5	26.8	35.6	0.0	0.0	0.0	0.0	0.1
EPSCA	11.7	6.9	6.2	5.5	5.7	1.7	0.1	0.0	0.0	0.0	0.0	0.0
Total Non-Regular Staff	196.4	196.2	147.4	168.1	120.3	28.7	35.6	0.0	0.0	0.0	0.0	0.1
Subtotal OPG Nuclear Facilities Outage OM&A	269.8	249.9	166.5	246.0	195.5	56.3	52.6	0.0	0.0	0.0	0.0	0.1
Pickering Cyclical Maintenance OM&A:[2]												
Regular Staff	0.0	0.0	0.0	0.0	0.0	0.2	74.9	430.6	422.3	422.5	422.5	260.3
Non-Regular Staff												
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
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
EPSCA	0.0	0.0	0.0	0.0	0.0	0.0	2.1	8.4	8.4	8.4	7.0	6.0
Total Non-Regular Staff	0.0	0.0	0.0	0.0	0.0	0.0	2.1	8.4	8.4	8.4	7.0	6.0
Subtotal Pickering Cyclical Maintenance OM&A	0.0	0.0	0.0	0.0	0.0	0.2	77.0	439.0	430.7	430.9	429.6	266.3

OPG Nuclear Facilities Project OM&A:												
Regular Staff	47.0	34.6	27.3	42.5	32.3	43.6	12.2	5.4	5.4	5.4	5.4	5.6
Non-Regular Staff												
Term and Extended Temporary	4.3	7.9	4.5	3.4	1.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0
Temporary	12.2	4.2	4.7	4.0	3.7	3.5	0.7	0.0	0.0	0.0	0.0	0.0
EPSCA	3.7	1.1	2.4	5.3	0.9	0.3	0.2	0.0	0.0	0.0	0.0	0.0
Total Non-Regular Staff	20.2	13.2	11.6	12.7	6.1	4.3	0.9	0.0	0.0	0.0	0.0	0.0
Subtotal OPG Nuclear Facilities Project OM&A	67.2	47.8	38.9	55.1	38.4	47.9	13.1	5.4	5.4	5.4	5.4	5.6
Total Nuclear Facilities Base, Outage, Pickering Cyclical & Project OM&A	**3,386.8**	**3,174.5**	**3,015.4**	**3,164.7**	**2,977.1**	**2,283.1**	**1,945.0**	**849.3**	**863.7**	**888.9**	**916.3**	**1,557.4**
OPG Nuclear Facilities Capital:												
Regular Staff	76.4	45.2	18.4	16.4	14.1	14.9	57.5	102.0	123.0	180.0	179.0	169.0
Non-Regular Staff												
Term and Extended Temporary	4.5	4.0	2.9	2.2	1.1	0.4	0.0	0.0	0.0	0.0	0.0	0.0
Temporary	14.9	9.2	2.8	1.8	1.4	0.9	21.0	0.0	0.0	0.0	0.0	0.0
EPSCA	4.4	4.7	0.8	4.1	7.0	11.6	0.0	0.0	0.0	0.0	0.0	0.0
Total Non-Regular Staff	23.7	17.9	6.5	8.1	9.6	13.0	21.0	0.0	0.0	0.0	0.0	0.0
Subtotal OPG Nuclear Facilities Capital	100.1	63.1	24.9	24.5	23.6	28.0	78.5	102.0	123.0	180.0	179.0	169.0
Darlington Refurbishment Program:												
Regular Staff	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non-Regular Staff												
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
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
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
Total Non-Regular Staff	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal Darlington Refurbishment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pickering Refurbishment Program:												
Regular Staff	0.0	0.0	0.0	7.6	159.5	455.6	1,177.1	2,258.9	2,281.1	2,306.0	2,265.0	1,623.7
Non-Regular Staff												
Term and Extended Temporary	0.0	0.0	0.0	0.0	0.8	7.0	21.3	7.0	7.0	7.0		
Temporary	0.0	0.0	0.0	0.1	10.3	31.5	128.5	29.0	13.0	13.0	20.0	20.0
EPSCA	0.0	0.0	0.0	0.1	3.2	21.2	109.7	350.2	473.4	419.0	335.0	252.9
Total Non-Regular Staff	0.0	0.0	0.0	0.1	14.3	59.7	259.4	386.2	493.4	439.0	355.0	272.9
Subtotal Pickering Refurbishment Program	0.0	0.0	0.0	7.8	173.8	515.3	1,436.5	2,645.1	2,774.4	2,745.0	2,620.0	1,896.6
Total Pickering Station	**3,486.8**	**3,237.6**	**3,040.4**	**3,196.9**	**3,174.5**	**2,826.3**	**3,460.1**	**3,596.4**	**3,761.1**	**3,813.8**	**3,715.3**	**3,623.0**

1. Credit in 2025 is due to a reversal of historical project postings from prior years

2. FTE related to costs recorded in Ex. F2-1-1 Table 1a, line 19

CCC Interrogatory #070

Interrogatory

Reference:
Exhibit F2, Tab 1, Schedule 1, Attachment 2

Question(s):

Please advise whether OPG completes a nuclear benchmarking report each year. If so, please file the 2025 nuclear benchmarking report assuming it has been completed.

Response

Yes, OPG completes a nuclear benchmarking report each year. See Attachment 1 for the 2025 Nuclear Benchmarking Report.

2025 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: 2026-04-22
EB-2025-0297
Exhibit L
F2-CCC-070
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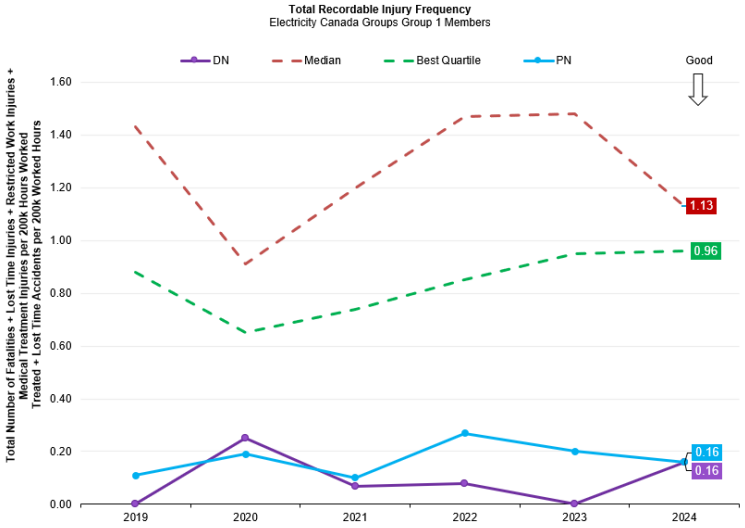
In 2024, Ontario Power Generations (OPG) results reflected strong performance relative to industry peers in multiple critical performance areas, while also identifying expected post-Refurbishment trends which will improve as the station enters steady-state.

Safety

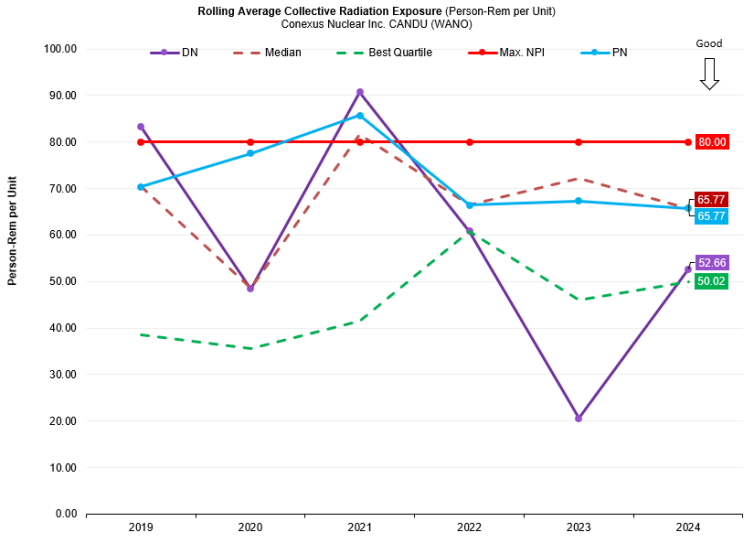
Total Recordable Injury Frequency (TRIF)



Both Darlington Nuclear Generating Station (DNGS) and Pickering Nuclear Generating Station (PNGS) continued to deliver best quartile safety performance in 2024, maintaining excellent TRIF results compared to other Electricity Canada Group 1 members.

To further strengthen safety performance, OPG continues to build on its Fail Safe strategy by building capacity & strengthening safety defences, implementing the Edison Electric 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.

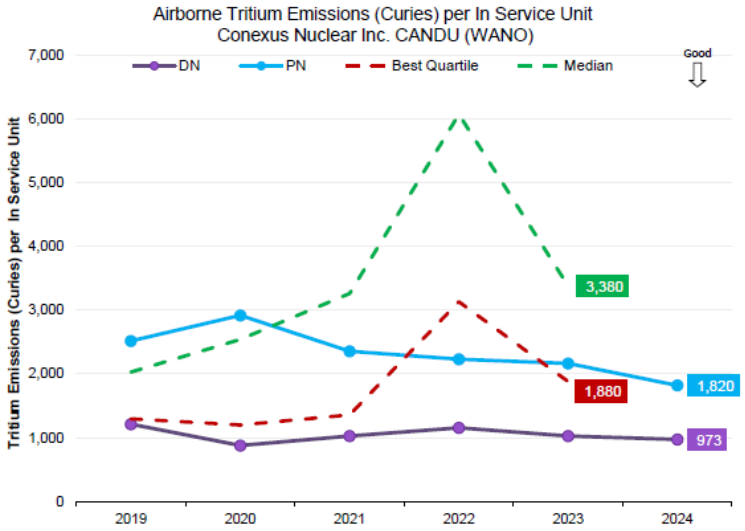
Collective Radiation Exposure (CRE)



DNGS and PNGS continued to achieve maximum WANO Performance Indicator Index (WPII) points in 2024, previously identified as Nuclear Performance Index (NPI). DNGS CRE performance declined as a result of one major planned outage in 2024 compared to zero in 2023. PNGS CRE performance improved due to a reduced number of maintenance, forced and planned unbudgeted outages in 2024 compared to 2023.

DNGS and PNGS have implemented source term controls to reduce worker exposure including improved shielding to reduce dose rates and having dedicated tritium emissions reduction teams. DNGS is also utilizing a new design of channel closure plugs.

Airborne Tritium Emissions

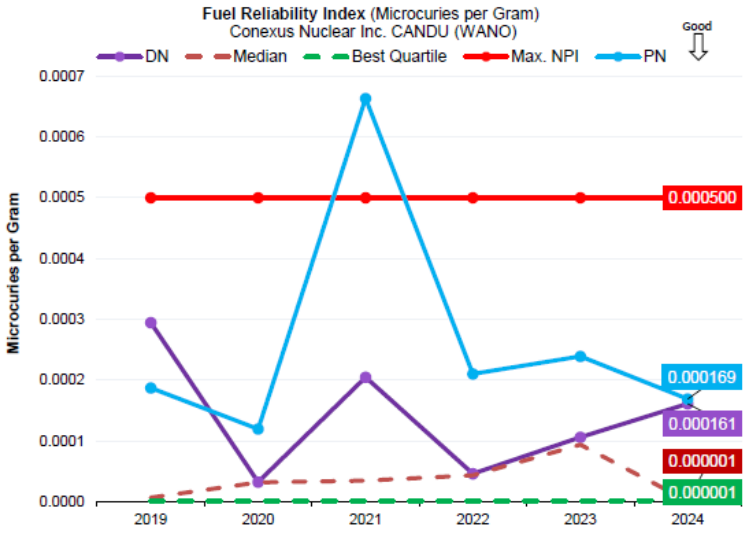


DNGS and PNGS Airborne Tritium Emissions remain at a very small fraction of regulatory limits.

DNGS and PNGS continued to achieve best quartile performance in 2024, largely attributable to ongoing improvements to tritium identification and reduction activities at both sites.

Both sites have continued tritium reduction activities driven by dedicated teams, enhancing focus on tritium sources identification and elimination. In addition, collaboration between both sites to exchange operating experience, innovation activities on tritium mitigation, and benchmark performance.

Fuel Reliability Index (FRI)



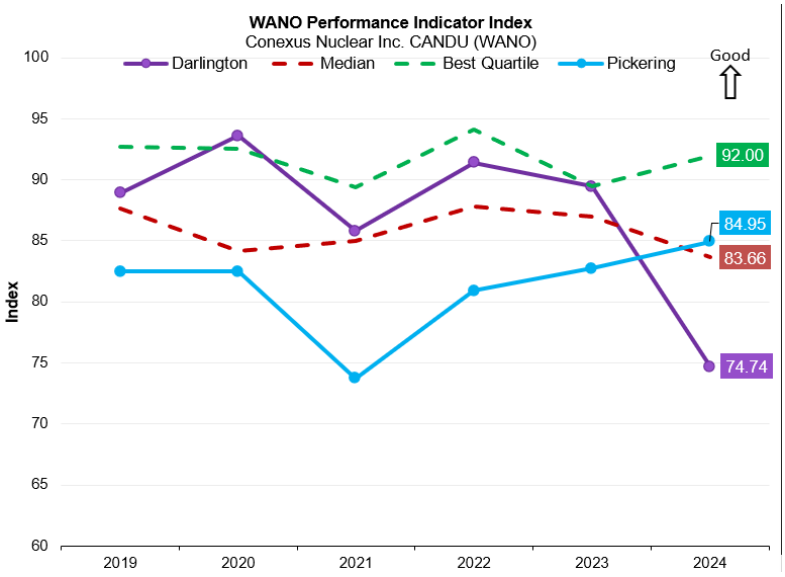
DNGS and PNGS continued to achieve maximum WPII points in 2024.

Three fuel defects were observed at DNGS in 2024 compared to one in 2023. PNGS FRI improved slightly in 2024, due to one fuel defect being observed in 2024 compared to two in 2023. All defects were discharged.

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

The five other safety- related metrics at DNGS and PNGS were favourable and achieved green ratings in 2024. Both DNGS and PNGS achieved maximum World Association of Nuclear Operators (WANO) performance Indicator Index (WPII) results and best quartile performance for all WPII Safety sub-metrics.

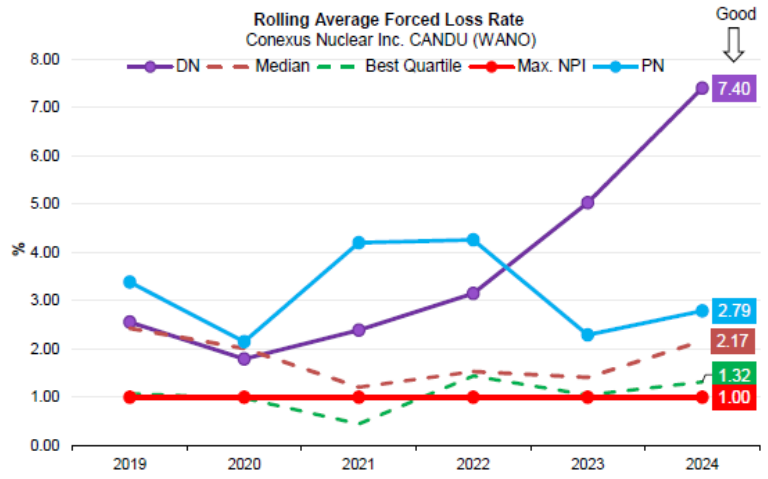
WANO Performance Indicator Index (WPII)



In 2024, DNGS performance was third quartile compared to top quartile in 2023. The decline in performance is attributable to elevated Forced Loss Rate (FLR) and Unit Capability Rate (UCR) performance as a result of two forced outages in 2024. DNGS continued with excellent performance for all seven of the safety metrics.

PNGS performance improved in 2024, achieving second quartile performance compared to third quartile performance in 2023. The improvement in performance is mainly attributed to the industry definition and weighting change from WPII Method 4 to WPII Method 10. PNGS sustained performance for all seven safety metrics and was partially offset by lower Chemistry Performance Index (CPI), Forced Loss Rate (FLR) and Unit Capability Rate (UCR) performance.

Forced Loss Rate (FLR)



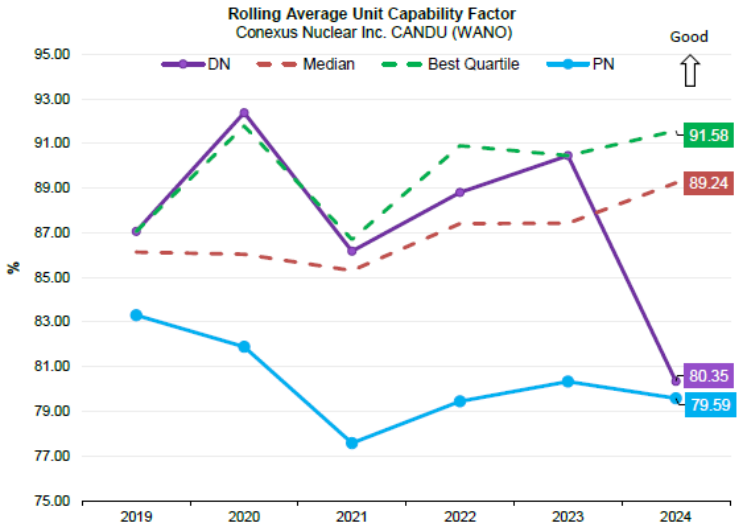
In 2024, FLR performance declined at DNGS due to post-Refurbishment forced outages and PNGS due to forced outages.

DNGS experienced four forced outages attributable to post refurbishment outage events on Unit 2. Increased FLR is expected post refurbishment and will improve with support of ongoing initiatives to strengthen Plant reliability, Human Performance and Equipment reliability. PNGS slight decline in performance is attributable to elevated FLR in 2024 compared to 2022, which is no longer in the rolling window.

Fuel Handling contributions reduced in 2024 and remains a fleet focus area to improve sustainability. Focused initiatives including vulnerability identification and elimination, project execution, and proficiency building at both stations to increase plant reliability.

Unit Capability Factor (UCF)

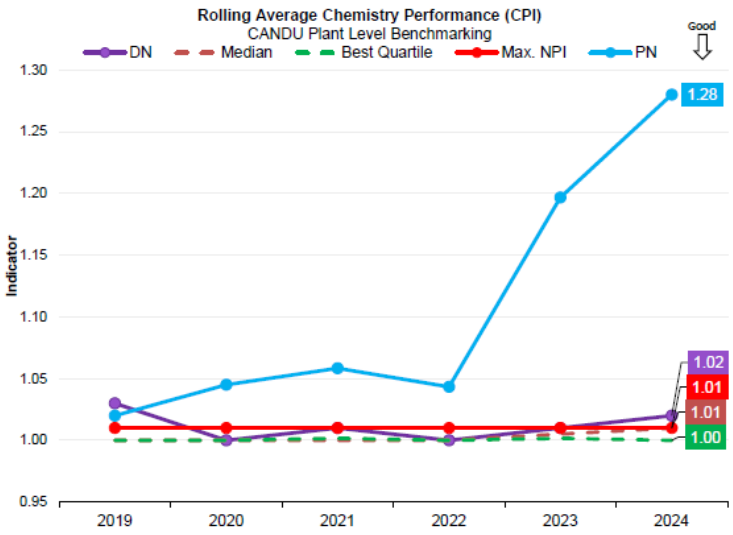
In 2024, both DNGS and PNGS achieved third quartile performance. DNGS and PNGS decline in performance compared to 2023 was attributable to the declined FLR performance at both stations. DNGS performance is attributable to post refurbishment outage events on Unit 2. PNGS slight decline in performance is attributable to elevated FLR in 2024 compared to 2022, which is no longer in the rolling window.



Focused initiatives including vulnerability identification and elimination, proficiency building and project execution at both stations to increase plant reliability.

Chemistry Performance Index (CPI)

DNGS performance was third quartile in 2024 compared to top quartile in 2023. The decline in performance in 2024 compared to 2023 can be attributed to Unit 2 elevated feedwater corrosion product transport post unit start-ups and condenser tube leaks.



PNGS decline in performance in 2024 compared to 2023 can be attributed to start-up boiler sulphates and condenser tube leaks that resulted in elevated boiler ions.

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 start-ups/outages and explore implementing corrosion product transport formation reduction and removal processes. DNGS will improve early detection of condenser tube leaks and improve reliability of condenser equipment. PNGS also aims to improve boiler chemistry during refurbishment to improve boiler ions upon unit start-up.

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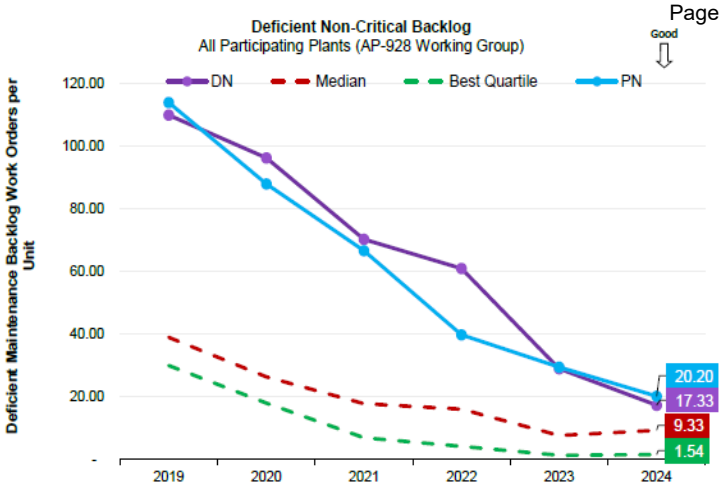
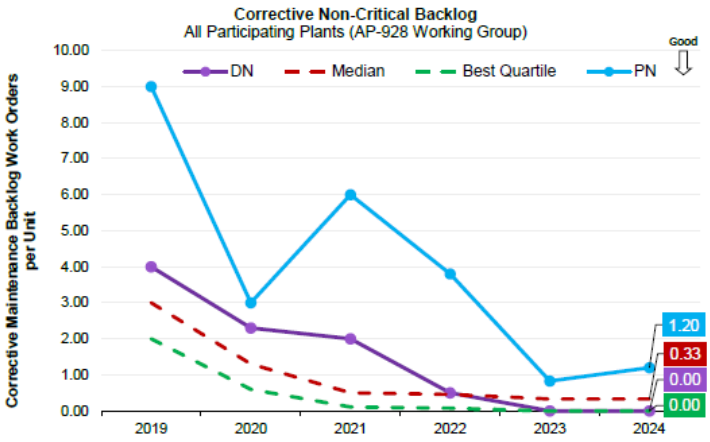
On-Line Deficient Non-Critical Backlog and Deficient Critical Backlog



DNGS improved their On-line Deficient Non-Critical Backlog by 40% compared to 2023 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.

The favourable trend for Backlog performance at PNGS continued into 2024, with improvements for On-line Deficient Non-Critical Backlogs (32% improvement) from fourth in 2023 to third quartile in 2024 and slight improvement for On-line Deficient Critical Backlog compared to 2023 results.

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

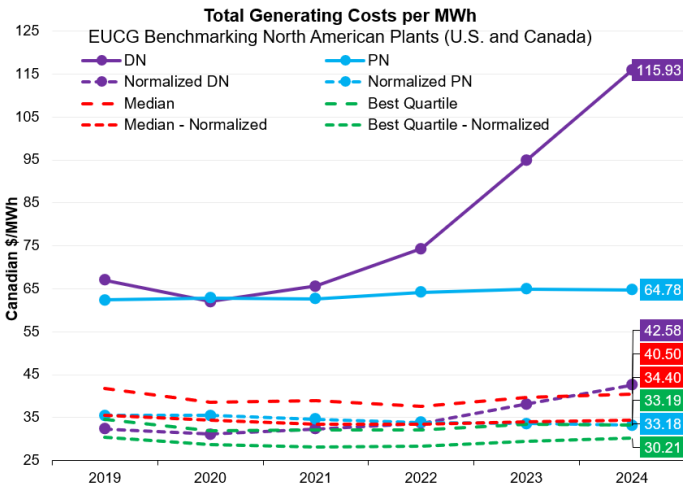


DNGS remained in best quartile score of zero for both Corrective Critical and Corrective Non-Critical Backlog metrics.

PNGS sustained best quartile performance for the Corrective Critical backlog metric with a score of zero and sustained third quartile for On-Line Corrective Non-Critical performance sustained.

Value for Money

TGC/MWh

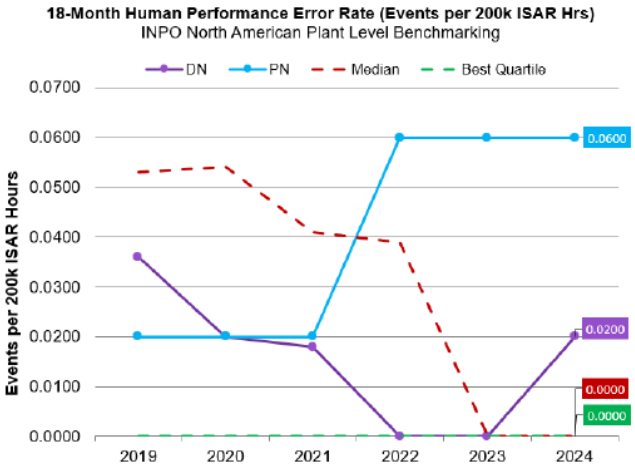


In 2024, normalized Total Generating Cost per Megawatt-hour (TGC/MWh) performance remained in the third quartile for DNGS and second quartile for PNGS after normalizing[1] for refurbishment, technology including outage duration and age-related impacts.

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 Refurbishment for Units 5-8 operations in 2026.

Human Performance

Human Performance Error Rate



In 2024, DNGS performance was third quartile compared to first quartile in 2023. This can be attributed to two Site Event Free Day Resets (S-EFDR) experienced in 2024 compared to zero in 2023. PNGS experienced two S-EFDR's in 2024 compared to one in 2023. Event causes were identified, and corrective actions were implemented to address the gaps.

Human Performance continues to be a focus around the fleet with actions to 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. Human performance is being further enhanced by continuing to build a positive stop culture that recognizes workers who stop work due to unknown or unexpected events.

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

Benchmarking Results – Plant Level Summary

Table 1 provides a complete summary of 2024 performance compared to benchmark results.

Metric	2024 Actuals					
	NPI Max	Best Quartile	Median	Third Quartile	Pickering	Darlington
Safety						
Total Recordable Injury Frequency (#/200k hours worked)		0.96	1.13	1.91	0.16	0.16
Rolling Average[2] Total Industrial Safety Accident Rate TISA) (#/200k hours worked)[1]	0.20	0.00	0.00	0.04	0.00	0.00
Rolling Average[2] Collective Radiation Exposure (Person-rem per unit)[1]	80.00	50.02	65.77	87.53	65.77	52.66
Airborne Tritium Emissions (Curies) per Unit [3]		1,880	3,380	4,595	1,820	973
Fuel Reliability Index (microcuries per gram)[1]	0.000500	0.000001	0.000001	0.000161	0.000169	0.000161
2-Year Reactor Trip Rate (# per 7,000 hours)[1]	0.500	0.000	0.310	0.420	0.382	0.310
3-Year Auxiliary Feedwater System Unavailability (#)[1]	0.0200	0.0000	0.0000	0.0023	0.0000	0.0000
3-Year Emergency AC Power Unavailability (#)[1]	0.0250	0.0001	0.0003	0.0035	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] WPII (Index)[1]		92.00	83.66	74.74	84.95	74.74
Rolling Average[2] Forced Loss Rate (%)[1]	1.00	1.32	2.17	4.21	2.79	7.40
Rolling Average [2] Unit Capability Rate (%)[1]	98.00	98.50	97.83	92.60	96.82	92.60
Rolling Average[2] Unit Capability Factor (%)[1]	92.00	91.58	89.24	79.59	79.59	80.35
Rolling Average[2] Chemistry Performance Indicator (Index)[1]	1.01	1.00	1.01	1.03	1.28	1.02
1-Year Online Deficient Non-Critical Backlog (work orders per unit) [3]		1.54	9.33	28.58	20.20	17.33
1-Year Online Corrective Non-Critical Backlog (work orders per unit) [3]		0.00	0.33	1.33	1.20	0.00
1-Year Online Deficient Critical Backlog (work orders per unit) [1]		0.00	0.00	0.50	0.60	0.00
1-Year Online Corrective Critical Backlog (work orders per unit) [1]		0.00	0.00	0.00	0.00	0.00
Value for Money						
3-Year Total Generating Costs per MWh ($ per Net MWh) [1]		33.19	40.50	50.89	64.78	115.93
Normalized 3-Year Total Generating Cost per MWh ($ per Net MWh)		30.21	34.40	43.20	33.18	42.58
3-Year Total Generating Cost per Unit (M $ per Unit)		285.39	315.55	365.38	231.03	745.77
Normalized 3-Year Total Generating Cost per Unit (M $ per Unit)		251.15	283.59	331.97	134.61	278.21
3-Year Non-Fuel Operating Costs per MWh ($ per Net MWh) [1]		19.63	24.58	32.23	58.44	74.69
3-Year Normalized Non-Fuel Operating Cost per Net MWh ($/MWh)		19.63	24.58	32.23	--	47.88
3-Year Fuel Costs per MWh ($ per Net MWh)[1]		5.93	6.60	7.15	3.98	4.43
3-Year Capital Costs per MW DER (k$ per MW)[1]		38.99	67.13	107.93	16.37	269.70
Normalized 3-Year Capital Cost per MW DER (k$ per MW)		38.99	67.13	107.93	--	115.91
Human Performance						
18-Month Human Performance Error Rate (# per 200k ISAR and contractor hours) [1]		0.0000	0.0000	0.0455	0.0600	0.0200

1. Best Quartile, Median and Third Quartile are from Q4 2024 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 2023 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

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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 WPII safety and reliability metrics reflect multi-year rolling averages based on each station's outage cycle. For WPII 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 Performance Indicator Index (WPII), a maximum score of 100 is possible. The WPII is an operational performance indicator comprised of 10 metrics, 7 of which are analyzed in this section:

- Total Industrial Safety Accident Rate (TISA) [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 WPII metrics are included in the Reliability Section (Section 3.0).

Note: To benchmark performance, Max WPII is used to indicate best quartile performance for metrics that perform better than the Max WPII benchmark. If metric performance is not better than Max WPII, quartile benchmarks are used to benchmark performance.

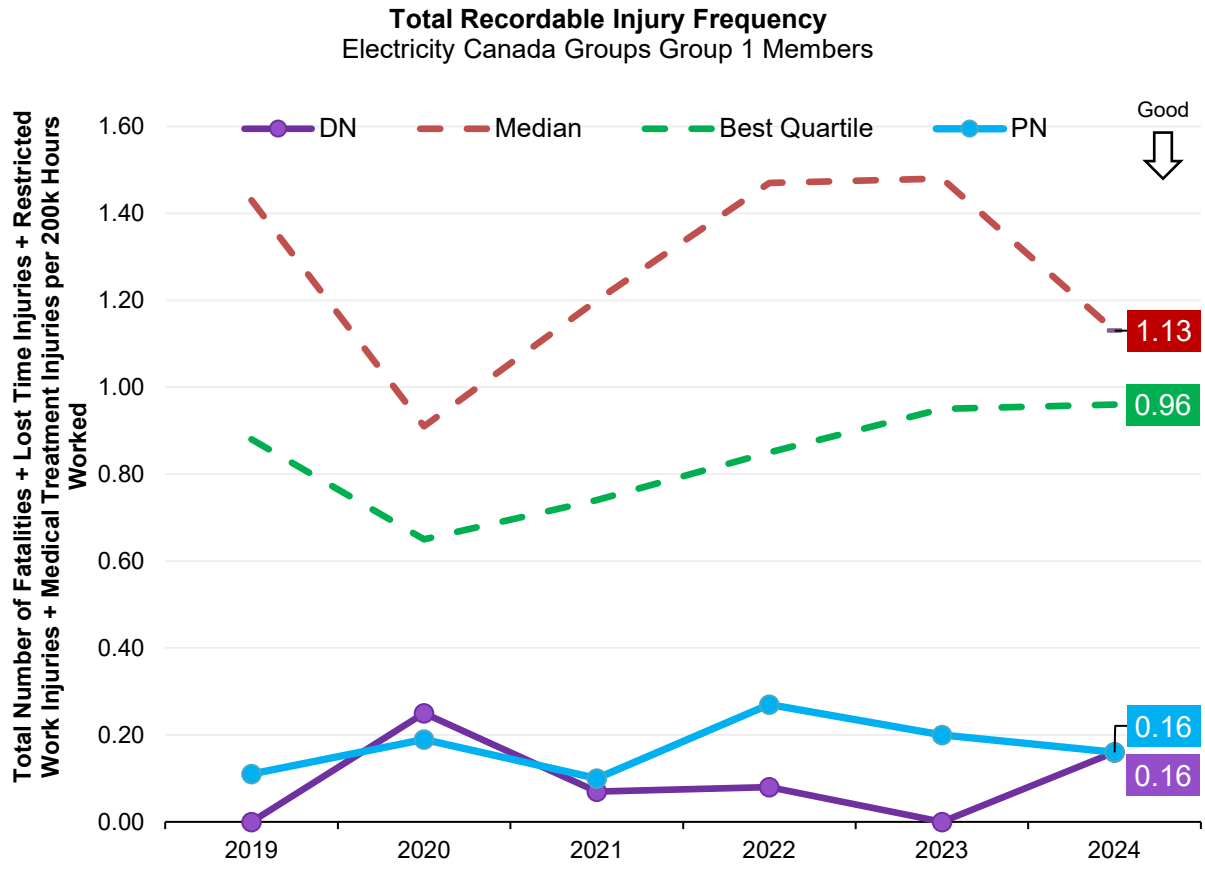
In addition to the WPII safety sub-indicators listed above, Total Recordable Injury Frequency and Airborne Tritium Emissions per In Service Unit are included in this section of the report.

Total Recordable Injury Frequency (TRIF) was calculated using data from 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 2024 Report.

Airborne Tritium Emissions per In Service Unit data was collected from the Conexus Nuclear Inc. The peer group for this metric is all CANDUs who are members of Conexus Nuclear Inc. There is a one-year lag for the industry values associated with this metric.

Total Recordable Injury Frequency (TRIF)



Note: Annual Value

	2024 Value
DN	0.16
PN	0.16
Best Quartile	0.96
Median	1.13

Factors Contributing to Performance

- In 2024, DNGS and PNGS continued to achieve best quartile safety performance, maintaining excellent TRIF results compared to other Electricity Canada Group 1 members (1500+ employees).
- All injuries at DNGS and PNGS in 2024 were low-severity injuries (e.g., cuts, pinches).
- OPG remains focused on advancing safety improvements through its fleetwide fail-safe culture. OPG's fail-safe culture includes ensuring appropriate safety controls are in place to protect employees should an event occur, and sharing knowledge and lessons learned from safety events with particular attention on high-energy incidents that can cause serious injuries or fatalities. DNGS and PNGS have also implemented a Positive Stop culture that recognizes workers who stop work due to unknown or unexpected events.

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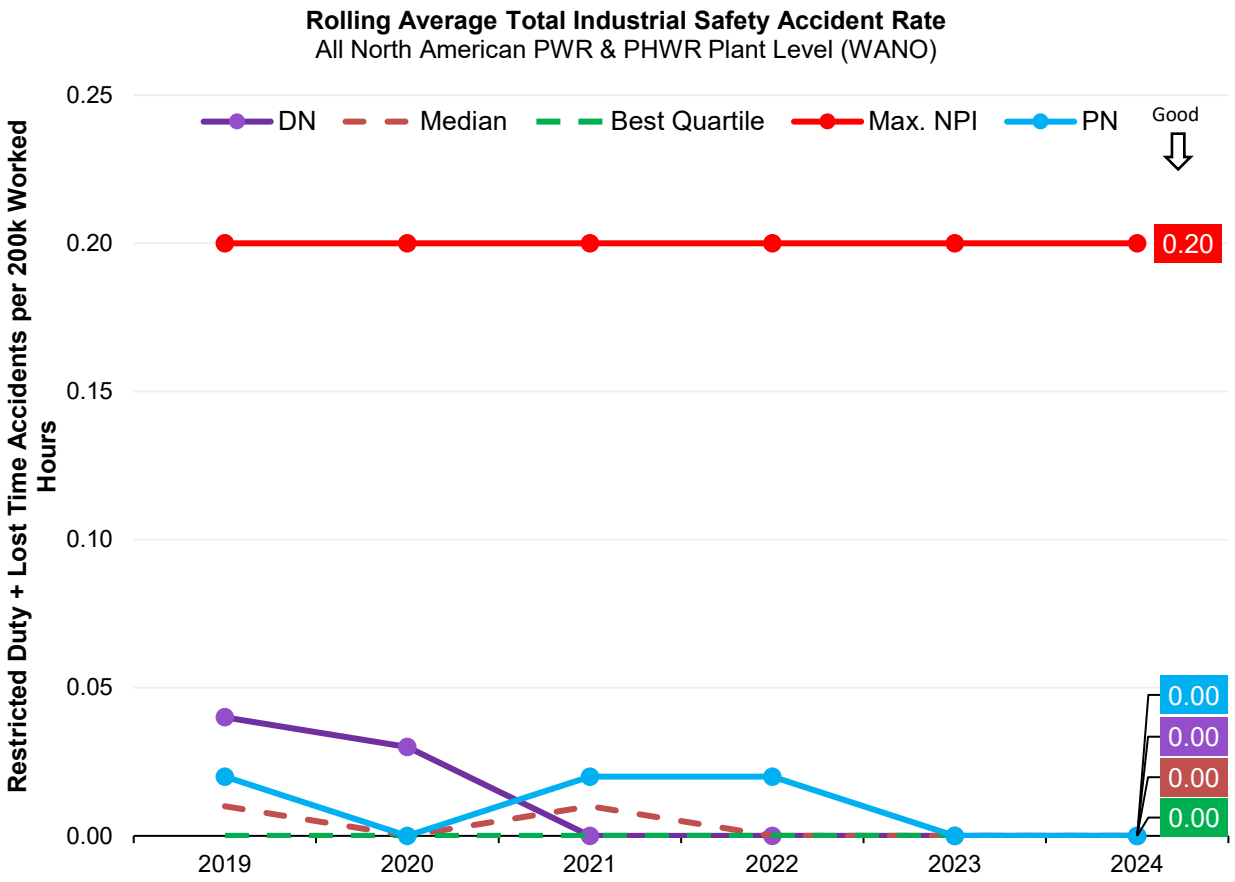
- OPG supports the prevention of injuries through initiatives such job aids to help employees recognize workplace energy hazards, ongoing enhancements to OPG's Electronic Safe Work Planning & Pre-Job Briefing (eSWP) platform, interactive activities and coaching to engage employees and encourage meaningful discussions about safety. The eSWP platform also features the "Energy Wheel" tool designed to help identify 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.

Initiatives to improve and sustain favorable performance include:

- In April 2024, OPG began using the Edison Electric Institute's Safety Classification and Learning (SCL) model. The SCL model helps enable early recognition and mitigation of Serious Injuries & Fatalities (SIF) precursor conditions as well as allows OPG to objectively classify safety events and better learn from events to prevent their recurrence. It also helps OPG identify a wider range of safety trends and will facilitate benchmarking with electrical industry peers. OPG added SCL performance data to its intranet safety reporting dashboards to raise awareness of SCL concepts, measure if barriers/controls were in place when safety events occurred and improve the characterization of exposures to high-energy hazards.
- OPG is committed to continually improving its health and safety managed system in accordance with ISO 45001 requirements, including taking corrective action to address findings from self-assessments, internal and external audits, and industry peer reviews.
- OPG is conducting a detailed self-assessment, including identification of gaps and actions plans, of the World Association of Nuclear Operators' (WANO) significant operating experience report for "Leadership in Preventing Fatalities and Severe Injuries" (SOER 2024-1).

Rolling Average Total Industrial Safety Accident Rate (TISA) * +



Sub-indicator for WPII
+ 3-year avg DNGS - Unit 2 (U4 in Refurbishment. Unit 3 RTS Q3 2023 & Unit 1 RTS Q4 2024, not online for 3 years), 2-year avg PNGS - Unit 4 & 5-8 (U1 end of commercial life Q3 2024)
** Previously ISAR (2019-2023), 2024 onwards is TISA*

	2024 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 WANO Performance Indicator Index (WPII) points.
- DNGS achieved best quartile performance in 2024, with zero TISA events during the last three-year rolling average reporting period.
- PNGS achieved best quartile performance in 2024, with zero TISA events recorded during the last two-year rolling average reporting period.

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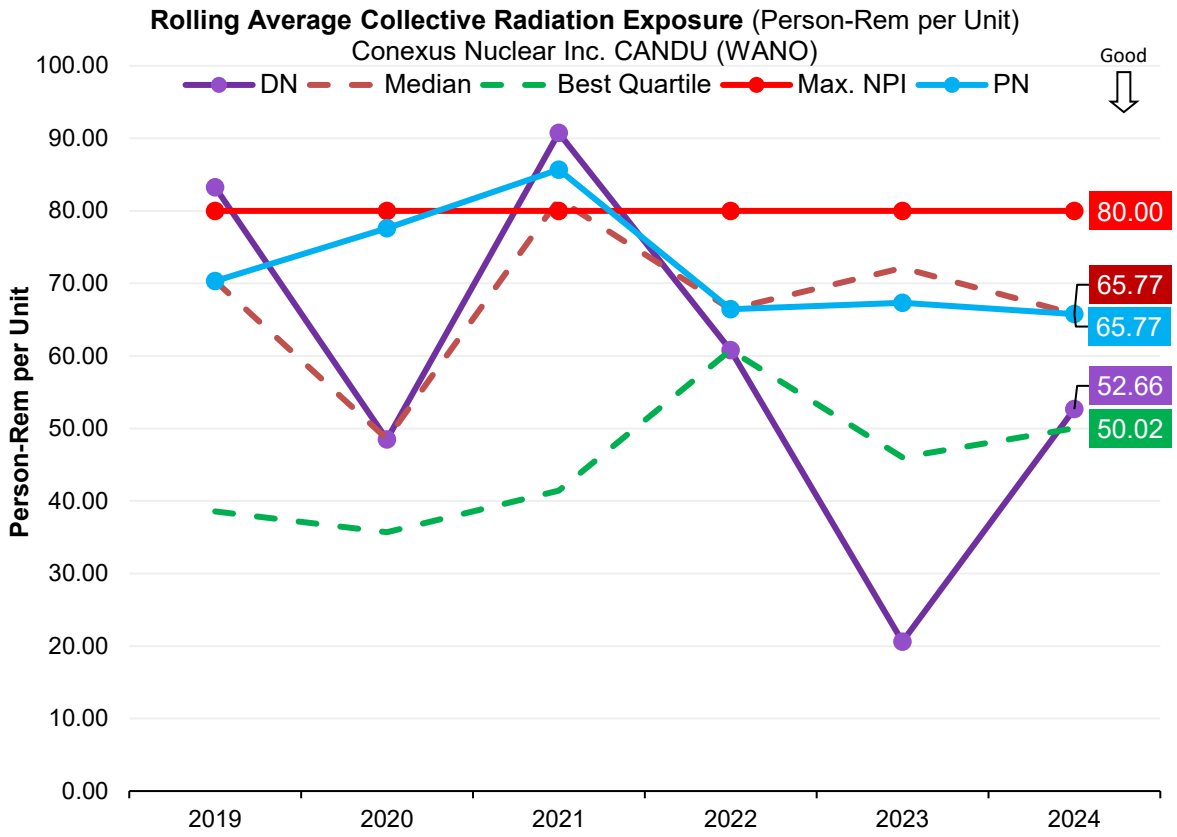
Initiatives to Improve and Sustain Favorable Performance:

- Continued implementation of the "Fail Safe" health and safety program, focusing on high-energy work, sequential control measures, event learning, and a variety of targeted strategies:
  - Use of Electronic Safe Work Planning (eSWP), which assesses and applies direct controls to address high-energy hazards during work execution.
  - Ongoing use of the Edison Electric Institute Safety Classification and Learning (SCL) model to identify additional learning opportunities through safety classifications and enable more effective industry benchmarking.
  - Use of Quality of Safety Practices (QSP) as a leading indicator to monitor high and low energy conventional safety risks to identify vulnerabilities and opportunities for improvement.
  - Continuous oversight to monitor performance for prevention and early intervention, with increased focus on addressing behaviors and program gaps through Observation and Coaching (O&C's), performance metrics, audits and assessments, benchmarking, and event learning.
  - Advancement of safety innovation through technology, including Peer-to-Peer Coaching Kiosks, Confined Space Application, Hazardous Material Application, Housekeeping Application, Lighting Application, Signage Kiosks, and Remote Temperature Monitoring Systems.

- These efforts collectively support the ongoing achievement of high standards in safety, reliability, and overall operational performance in the nuclear industry.

Rolling Average Collective Radiation Exposure (CRE) * +



Sub-indicator for WPII
+ 3-year avg DNGS - Unit 2 (U4 in Refurbishment. Unit 3 RTS Q3 2023 & Unit 1 RTS Q4 2024, not online for 3 years), 2-year avg PNGS - Unit 4 & 5-8 (U1 end of commercial life Q3 2024)

	2024 Value
DN	52.66
PN	65.77
Best Quartile	50.02
Median	65.77

Factors Contributing to Performance:

- DNGS and PNGS continued to achieve maximum WANO Performance Indicator Index (WPII) points.

- DNGS performance declined in 2024 compared to 2023 was a result of a major planned outage for Unit 2 in 2024 and zero planned outages in 2023.
  - A major planned maintenance outage on Unit 2 following unit refurbishment was executed which contributed to dose. Work included feeder inspections, reactor area bridge and carriage maintenance, calandria rupture disc replacements, various period inspection programs, and pressurizer heater replacements. CRE from this planned outage was 23% below target.

- PNGS performance improved in 2024, as a result of:

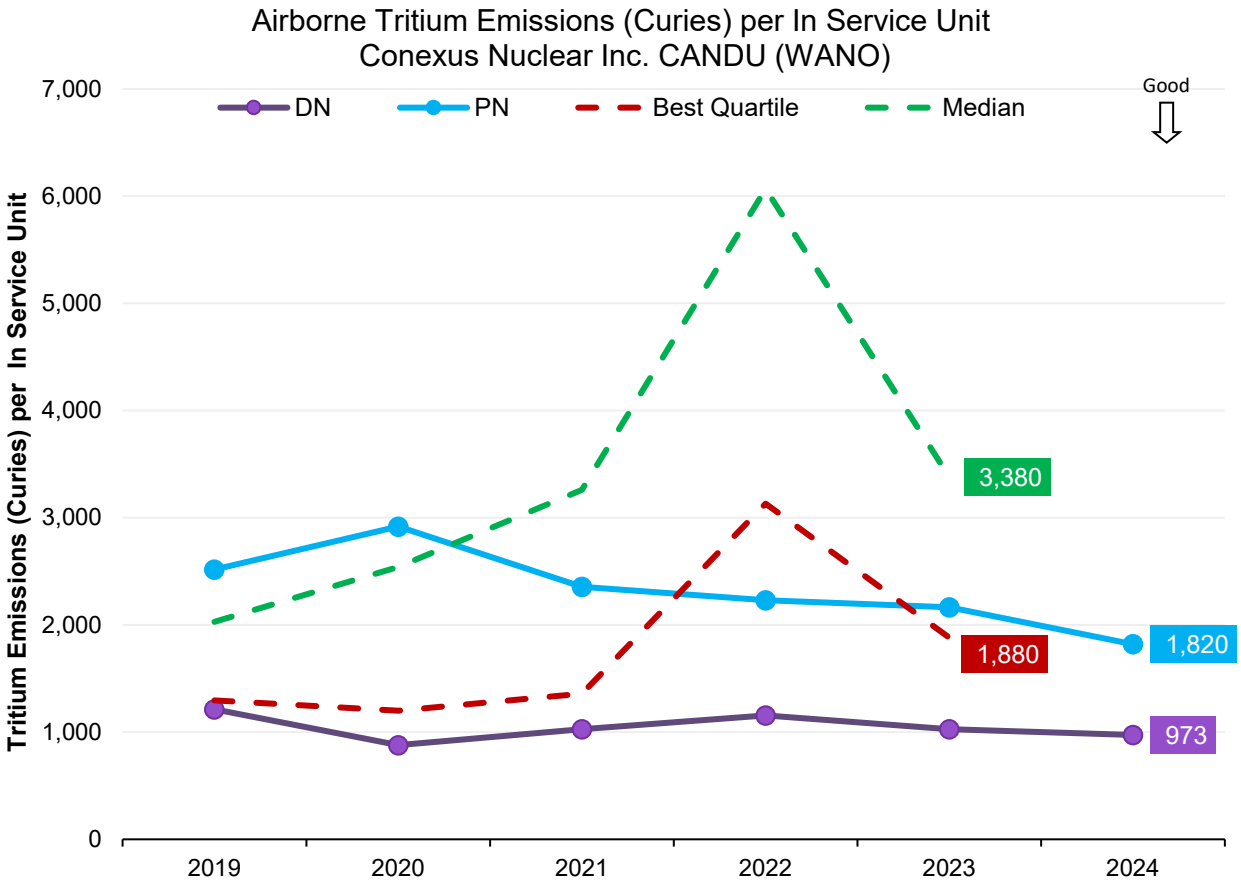
- Two planned maintenance outages, one forced outage and one planned unbudgeted outage in 2024, compared to three planned maintenance outages, two planned unbudgeted outages and six forced outages in 2023.
- Work programs for the planned maintenance outages which contributed to dose included fuel channel components periodic inspection, boiler inspections and a Single Fuel Channel Replacement (SFCR).
- Scope of work for the planned unbudgeted outage was to repair vault Air Conditioning Unit (ACU) leaks and recovery of stuck irradiated fuel bundles, and the forced outage was to address emergent conditions.
- Unit 1 was shut down for safe storage in September and Unit 4 at the end of December.

Initiatives to Improve and Sustain Favourable Performance Include:

- DNGS is undertaking various opportunities to reduce worker exposures and keeping collective doses As Low As Reasonably Achievable (ALARA). This includes, but is not limited to, the following initiatives and programs:
  - Utilizing a new design of channel closure plugs that effectively manage D_2O channel leakage. As a result, tritium levels in the vault decrease significantly. Thus, this also reduces worker tritium exposure.
  - Upcoming deployment of enhancing fuel channel inspection techniques by utilizing a Rapid Delivery Machine (RDM) to perform Advanced Non-Destructive Examination (ANDE), ANDE replication and Machine Delivered Scrape (MDS). Utilizing these systems reduces worker exposure by eliminating ice plug work inside feeder cabinets and workers performing channel inspection in front of the reactor face, which will also aid in tritium recovery in containment by maximizing performance on the Vault Vapour Recovery System (VVRS).
  - Modifying Emergency Coolant Injection (ECI) steel band to facilitate shielding on all units, outstanding installation on Unit 3 to be completed by 2026 during the planned maintenance outage. The expected benefit from this initiative will reduce worker exposure while working or traversing near the ECI lines.
  - A tritium oversight committee provides weekly updates on site tritium recovery systems to ensure tritium emission to environment is maintained ALARA.

- PNGS CRE for 2024 received maximum WANO Performance Indicator Index (WPII) points due to the initiatives and activities conducted in the last calendar year to improve the control of worker exposure and radiological hazards. Some of these initiatives and activities include:
  - Use of shielded canopy platform and customized shielded transport flasks during the Unit 7 Single Fuel Channel Replacement (SFCR) project contributed to reduction in dose rates to workers.
  - Dedicated Tritium emissions reduction team contributed to the lower than target performance for tritium emissions and lower internal collective radiation exposure for the year by ensuring proper dryer maintenance and revised procedures to optimize equipment performance.
  - ALARA initiatives, such as improved shielding, source term reduction initiatives and work methods improvements and efficiencies, contribute to improvements in dose performance.
  - Application 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.

Airborne Tritium Emissions



Annual Value
Median and Best Quartiles are plotted until 2023 as the 2024 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 Conexus Nuclear benchmark results).*
Unit 1 and Unit 4 refurbishment periods, and the Retube Waste Processing Building (RWPB)

	2024 Value
DN	973
PN	1,820
Best Quartile	1,880
Median	3,380

Factors Contributing to Performance:

- DNGS and PNGS Airbourne Tritium Emissions remain at a very small fraction of regulatory limits.
- Both sites have continued tritium reduction activities driven by dedicated teams that focus 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.

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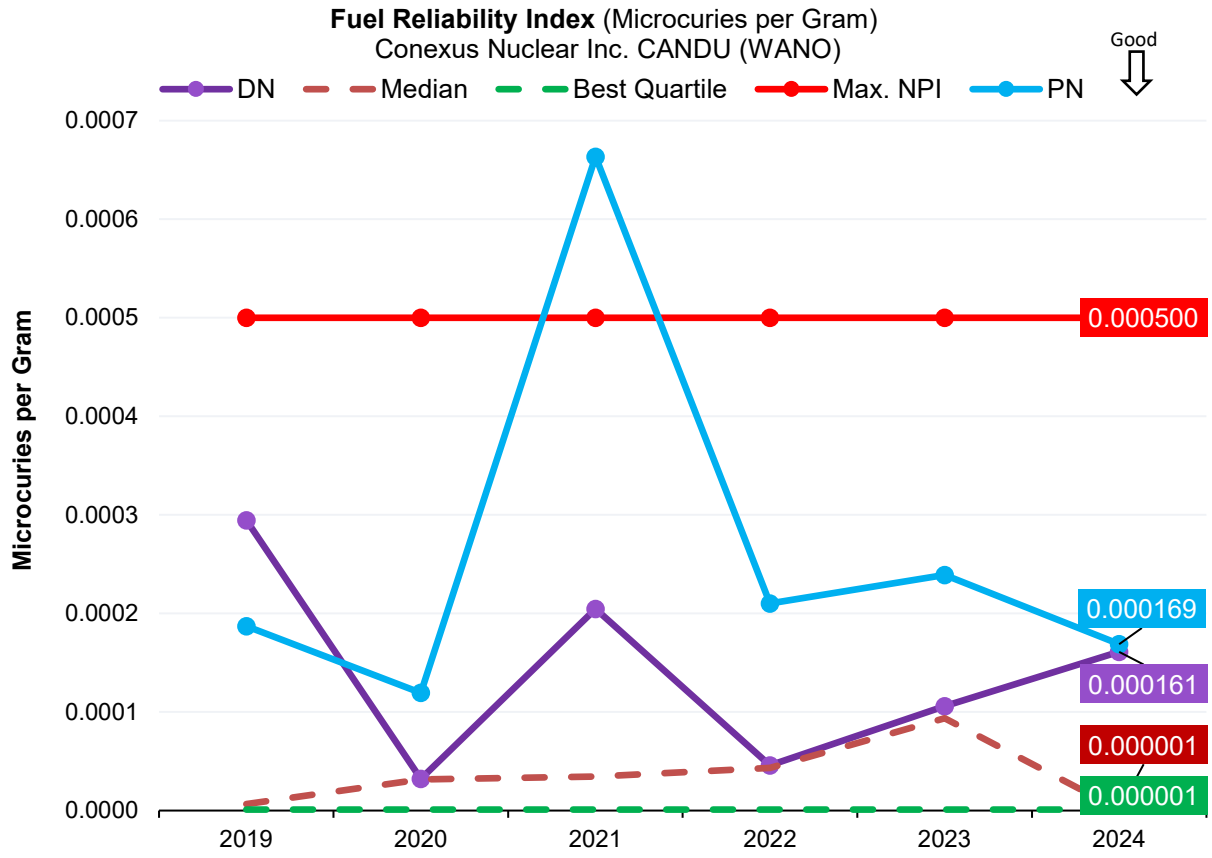
- DNGS continues to achieve best quartile performance in 2024. This was mainly attributed to efforts by the station to focus on tritium identification and reduction activities such as prioritizing repairs of leaking equipment and driers, utilizing enhanced monitoring system station-wide to provide real-time tritium monitoring capability, and ensuring Operations responded promptly to field deficiencies to minimize airborne tritium emission impacts.

- PNGS continued to achieve industry best quartile performance in 2024. This can be attributed to the efforts made by dedicated teams 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:

- Dedicated teams at both sites focus on identifying and eliminating tritium sources, including improving drier performance and repairing heavy water leaks.
- Continued management oversight and communication of priorities to focus tritium reduction activities daily at Integrated Station Brief (ISB) meetings at both sites.
- Collaboration between both sites to share operating experience and benchmark tritium mitigation efforts to improve performance.
- Source term reduction on heat transport and moderator water.
- Tritium Oversight Committee at DNGS develops long-term plans, provide oversight, and proactively schedules preventive maintenance activities.
- Incorporated tritium reduction discussions during the re-occurring Operations United meeting at DNGS, enabling risk identification and constructive challenges to further improve performance.
- Ongoing participation in Conexus Nuclear Inc. environmental benchmarking of participating CANDU stations to determine best environmental practices.

Fuel Reliability Index (FRI) *



Sub-indicator for WPII
Note: 2024 Most Recent Operating Quarter
+ DNGS – Unit 2 (U4 in Refurbishment. Unit 3 RTS Q3 2023 & Unit 1 RTS Q4 2024, not online 3 years), PNGS - Unit 4 & 5-8 (U1 end of commercial life Q3 2024)

	2024 Value
DN	0.000161
PN	0.000169
Best Quartile	0.000001
Median	0.000001

Factors Contributing to Performance

- DNGS and PNGS continued to achieve maximum WANO Performance Indicator Index (WPII) points.
- Three fuel defects were observed and discharged at DNGS in 2024, compared to one in 2023.
- One fuel defect was observed at PNGS in 2024 and discharged in 2025, compared to two fuel defects observed in 2023 that were discharged in 2024.

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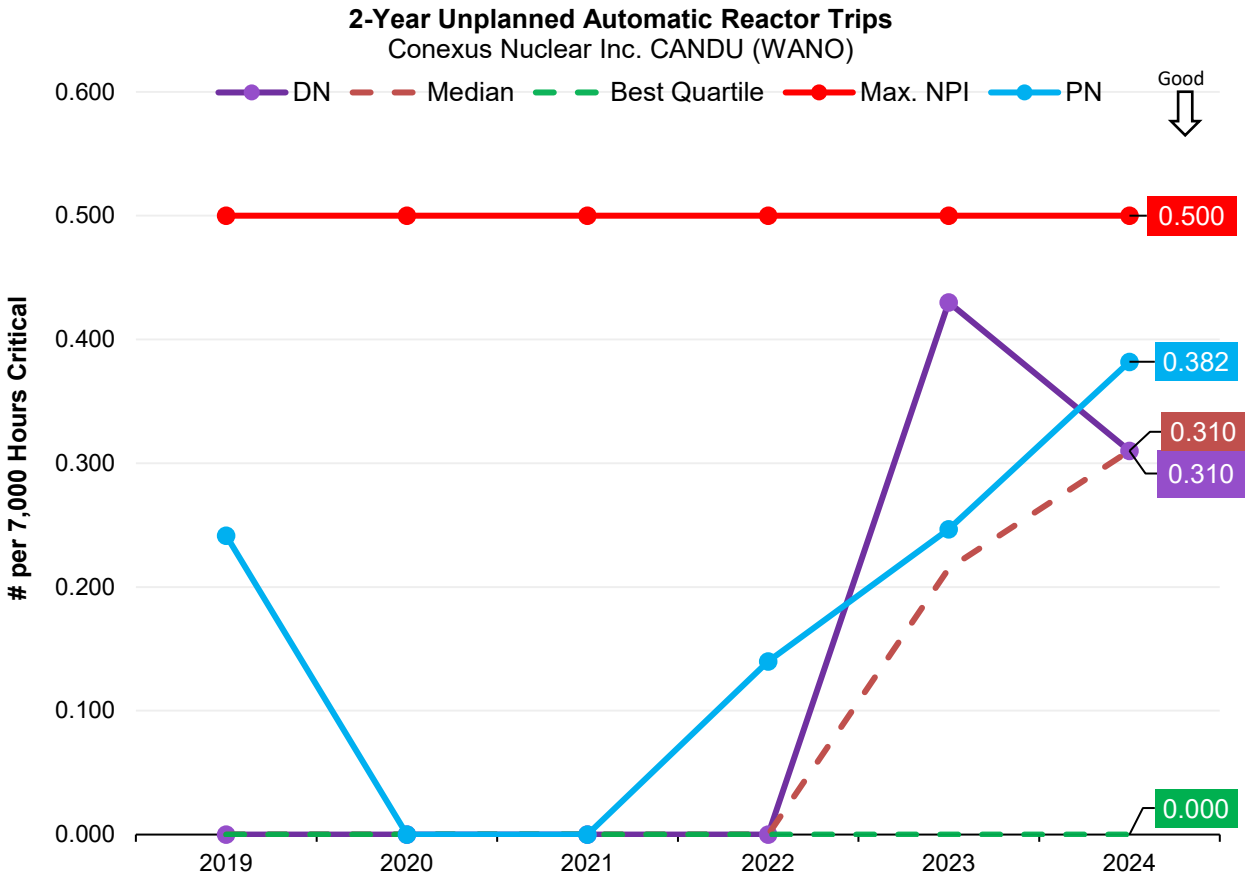
Initiatives to Improve and Sustain Favourable Performance Include:

- Both sites maintained their respective fuel design manuals and fuel drawing sets. 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 (FME) practices continue to mitigate debris fretting fuel failures as shown by the low number of defects following DNGS reactor refurbishment activities. Proactive measures are in place in an effort to avoid FME shutdowns with a planned post-Refurbishment outage on D2512.
  - Improving and sustaining awareness that the impact foreign material, specifically micro-debris potentially introduced through Fuel Handling and Outage activities, has on fuel performance.

- PNGS improvement initiatives include:
  - Enhancing surveillance by increasing the scope of Primary Heat Transport System (PHTS) grab sampling and analysis when defects are in-core continues to assist in earlier detection and removal minimizing the risk of foreign materials.
  - Improving and sustaining awareness of the impact foreign material in the PHTS, specifically micro-debris potentially introduced through Fuel Handling and Outage activities, has on fuel performance.
  - Improved capability among Units 5 to 8 of detecting defected fuel bundles following discharge from the fuelling machines continues to assist in re-directing failed fuel to the inspection area in support of root cause analysis and driving corrective actions.
  - Initiated planning for a confirmatory out-of-reactor test series to address risks associated with prolonged crossflow exposure during fueling incidents.

2-Year Unplanned Automatic Reactor Trips *



Sub-indicator for WPII
+ DNGS – Unit 2 (U4 in Refurbishment. Unit 3 RTS Q3 2023 & Unit 1 RTS Q4 2024, not online 3 years), PNGS - Unit 4 & 5-8 (U1 end of commercial life Q3 2024)
Note 3: Reactor Trip Rate was replaced by Reactor Automatic & Manual Trip Rate following the WPII 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, includes both automatic and manual scrams.

	2024 Value
DN	0.310
PN	0.382
Best Quartile	0.000
Median	0.310

Factors Contributing to Performance:

- DNGS and PNGS continued to achieve maximum WANO Performance Indicator Index (WPII) points.

- DNGS had no unplanned automatic or manual reactor trips in 2024 compared to one trip occurring in 2023. Improved performance is due to the excellence in Human Performance and Operator and Maintenance fundamentals.

- PNGS decline in performance in 2024 was impacted by the following unplanned automatic or manual reactor trips:

    - Unit 8: A manual Shutdown System (SDS)1 trip occurred due to the loss of Liquid Zone Control zones. The cause of this event was a passing liquid zone traps that resulted in compressors short cycling and high cover gas hydrogen levels.
    - Unit 4: A reactor trip on Heat Transport Low Flow (HTLF) trip parameter associated with the Reactor Protective System (SDS) and Shutdown System Enhancement (SDSE), which was caused by a failure of protection circuit in Hydro 1 switchyard, Unit 4 was load rejected, leading to a total loss of Class IV power.
    - Unit 5: During the warm-up of Heat Transport System (HTS), reactor trip occurred on Boiler Low Level (BLL) trip parameter (SDS2). This event is due to the heat sink challenge, which was not recognized nor resolved during turnover following ending of HTS warm up.

Initiatives to Improve and Sustain Favourable Performance Include:

The following measures are being implemented at DNGS and PNGS:

- On-going performance monitoring and improvement activities by Station Operations, Engineering, and Maintenance organizations.
- OPEX and lessons learned from the continuous exchange of information among Canadian utilities are incorporated into the OPG governance and governance support documents.
- 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.

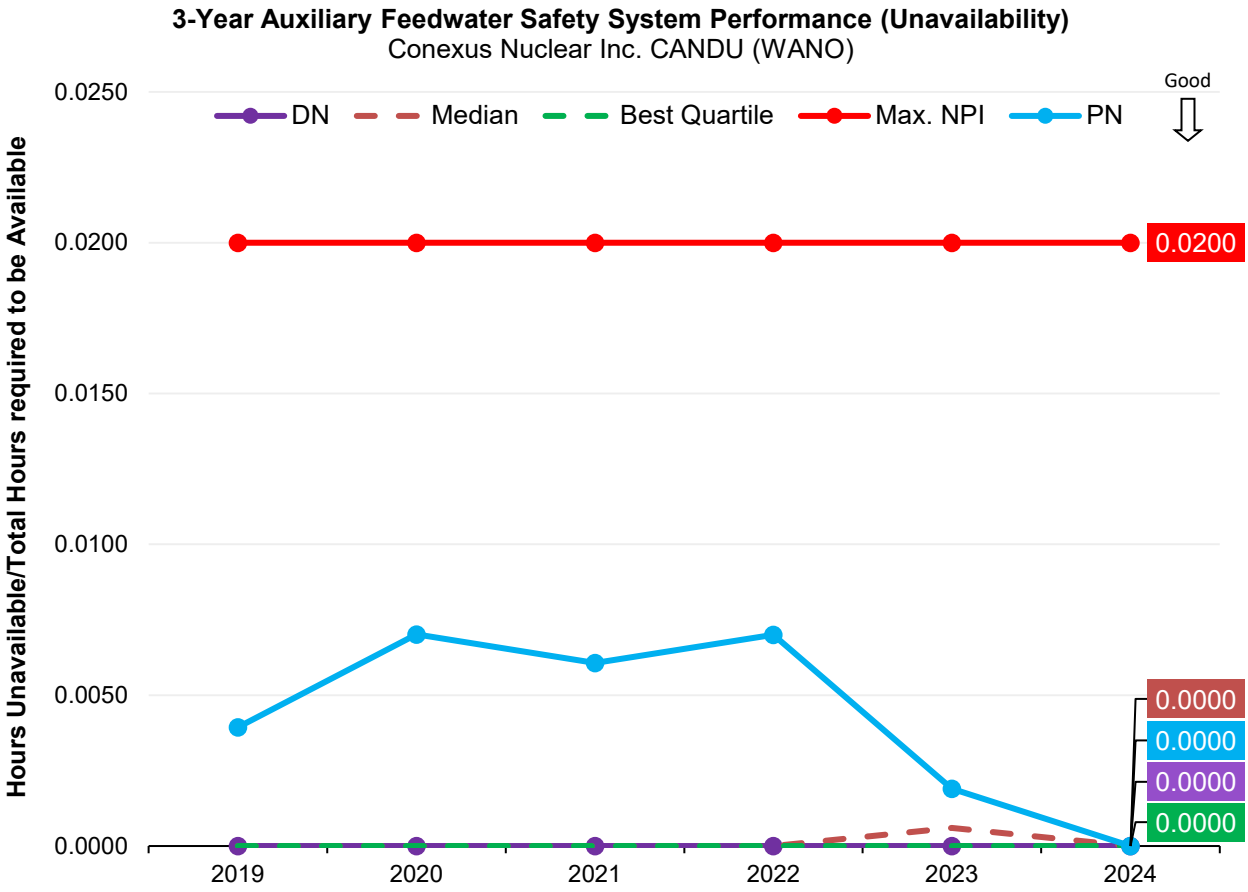
DNGS planned actions are as follows:

- Continuous actions, such as, Engineering Technical Surveillance Program, are being implemented in Darlington to ensure the best performance through Safety Related System Tests.

PNGS planned actions are as follows:

- Establish clear criteria for maintaining effective supervisory oversight during critical unit activities over turnover.
- Revise the Overall Unit Manual for HT pressurization and warm-up.
- Perform a focused roll-out of Conduct of Control Room Turnover.
- Provide control room operations staff with key information in preparation for unit warm-up tasks.
- Reduce the number of equipment-related challenges in the control room during critical evolutions.
- Address knowledge gaps in Authorized Training for HT pressurization
- Isolation of all traps on all units.
- Continuous monitoring of Liquid Zone chemistry and compressor cycle.
- Organizational Effectiveness Group leads paired learning sessions to drive risk elimination behaviors with chosen station work groups (Engineering, Maintenance, Operations, Chemistry and Fuel Handling).

3-Year Auxiliary Feedwater Safety System Performance (Unavailability)*



Sub-indicator for WPII
+ DNGS – Unit 2 (U4 in Refurbishment. Unit 3 RTS Q3 2023 & Unit 1 RTS Q4 2024, not online 3 years), PNGS - Unit 4 & 5-8 (U1 end of commercial life Q3 2024)

	2024 Value
DN	0.0000
PN	0.0000
Best Quartile	0.0000
Median	0.0000

Factors Contributing to Performance:

- DNGS and PNGS continued to achieve maximum WANO Performance Indicator Index (WPII) points.
- DNGS achieved best quartile performance of zero unavailability. Factors contributing to performance 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.

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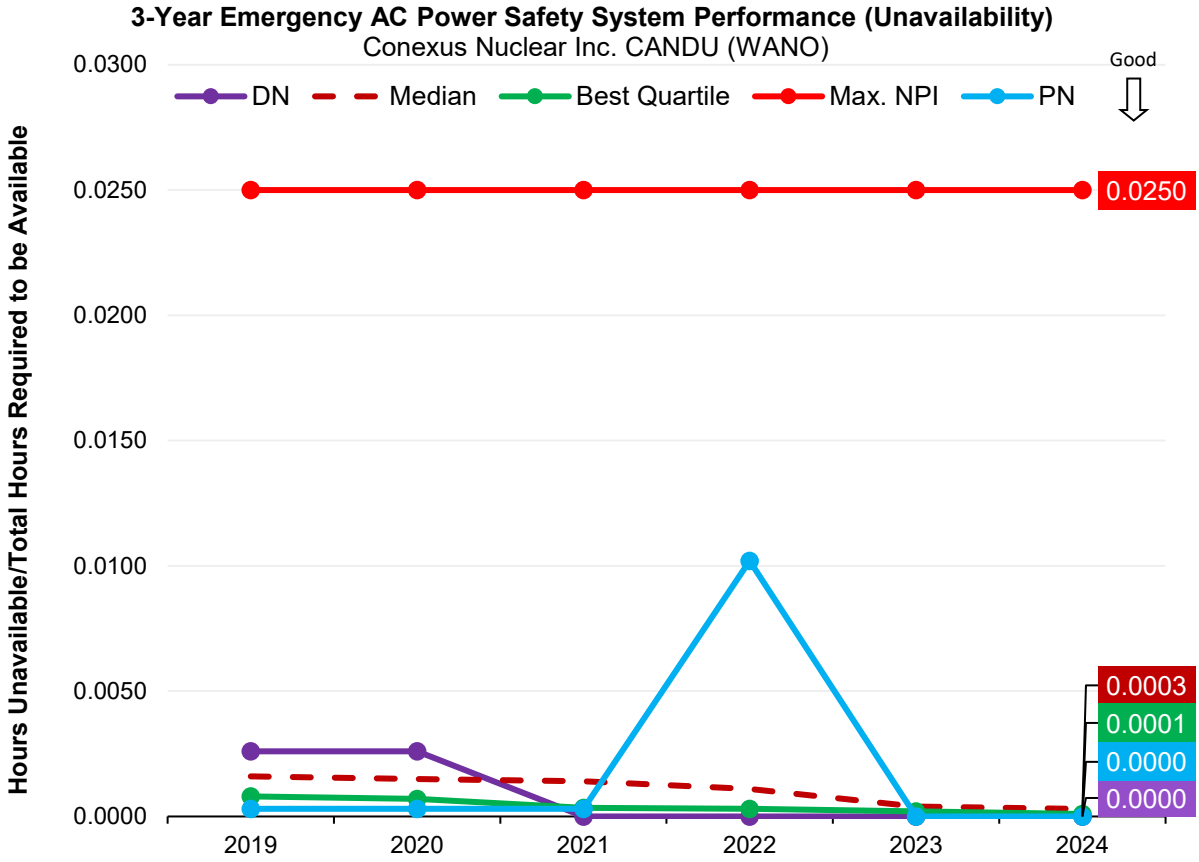
- PNGS achieved the best quartile performance of zero unavailability due to ongoing improvement actions.

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 on PNGS to improve the ABF system performance:
  - Perform 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 WPII
+ DNGS – Unit 2 (U4 in Refurbishment. Unit 3 RTS Q3 2023 & Unit 1 RTS Q4 2024, not online 3 years), PNGS - Unit 4 & 5-8 (U1 end of commercial life Q3 2024)

	2024 Value
DN	0.0000
PN	0.0000
Best Quartile	0.0001
Median	0.0003

Factors Contributing to Performance:

- DNGS and PNGS continued to achieve maximum WANO Performance Indicator Index (WPII) points.
- DNGS Emergency AC Power system achieved the best quartile performance of zero unavailability. Factors contributing to performance include:
  - 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 (SGs) and Health Report Improvement Plan.
  - Following the System Performance Monitoring Plan.
  - Adhering to the Health Report 10-Year Improvement Plan.

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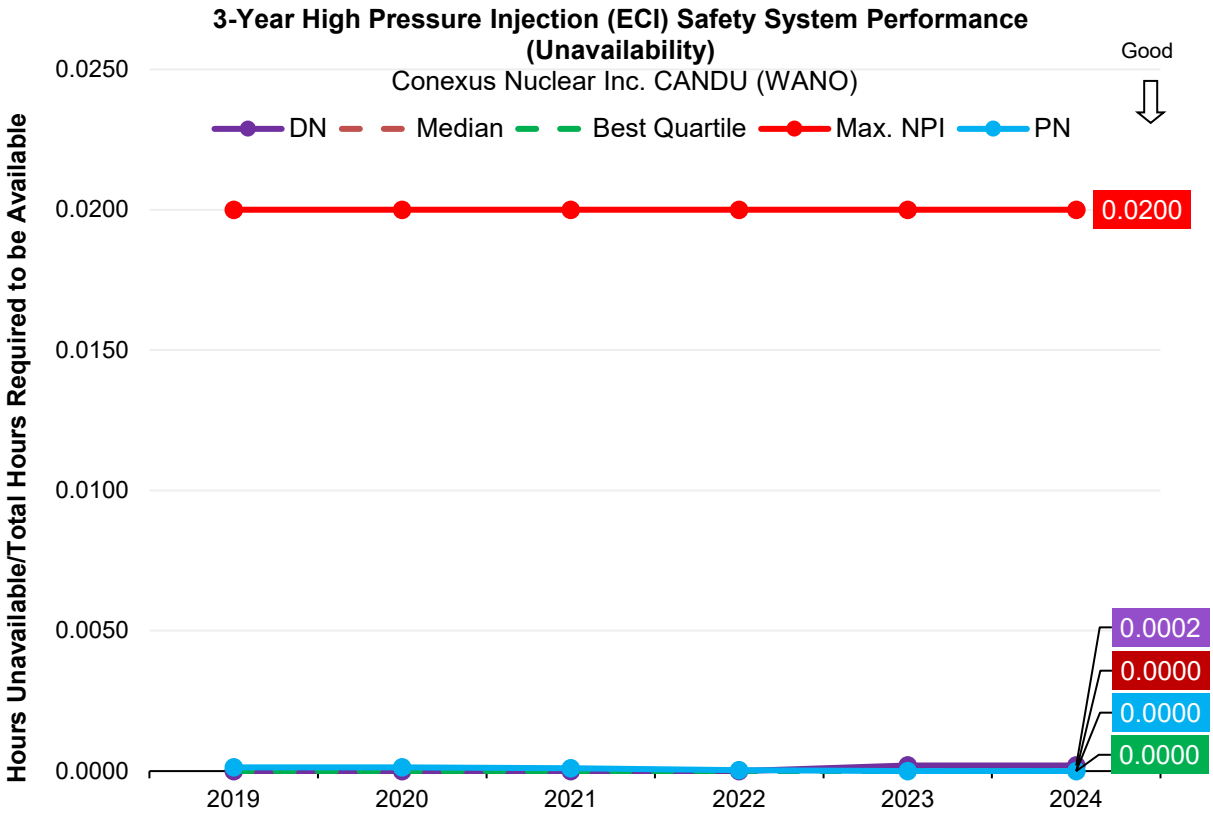
- PNGS Emergency AC Power system achieved the best quartile performance of zero unavailability. Factors contributing to performance include:
  - Inspection of 058 Standby Generators (SGs) for power turbine cracking failures, repairing SGs as required.

Initiatives to Improve and Sustain Favourable Performance Include:

- DNGS planned actions include
  - A 10-year project is in progress on the SG protective relays to replace all the old electro-mechanical relays with modern digital versions directly proceeding the end of each SG outage. Installation and commissioning for SG3 is complete. SG1, SG2, and SG4 will proceed in 2024 and 2025

- PNGS planned actions include:
  - Actions to ensure timely review/implementation of the corrective and routine maintenance.
  - Cracked power turbine casings will be repaired or replaced.

3-Year High Pressure Injection (ECI) Safety System Performance (Unavailability) *



Sub-indicator for WPII
+ DNGS – Unit 2 (U4 in Refurbishment. Unit 3 RTS Q3 2023 & Unit 1 RTS Q4 2024, not online 3 years), PNGS - Unit 4 & 5-8 (U1 end of commercial life Q3 2024)

	2024 Value
DN	0.0002
PN	0.0000
Best Quartile	0.0000
Median	0.0000

Factors Contributing to Performance

- DNGS and PNGS continued to achieve maximum WANO Performance Indicator Index (WPII) points.
- DNGS High Pressure Safety Injection (HPSI) unavailability was 0.0002. The factors contributing to performance includes:
  - Reducing fault occurrences by improving equipment reliability through Preventative Maintenance Optimization, Performance Monitoring and Life Cycle Management programs.
  - Planned maintenance on ECIs is being managed to ensure the target is met, providing unplanned faults/maintenance remain at historical levels.

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- Improving scheduling of discretionary maintenance so that equipment unavailability is reduced during quarters with lower reactor critical hours.

- PNGS continued with the best High Pressure Safety (HPSI) quartile performance of zero unavailability. Continuous improvement through mitigation of aggregate risk to maintain system redundancy contributed to PNGS performance.

Initiatives to Improve and Sustain Favourable Performance Include:

- Darlington HPSI related activities include the following:
  - Units 1-4 injection valve internals were overhauled.
  - On-going equipment reliability improvement work.
  - Performing preventive maintenance on schedule to reduce component failures and unplanned unavailability hours and scheduling maintenance work to maximize availability.
  - Overhaul or replacement of critical components during outages to increase equipment reliability (i.e., ECI Hydraulic Power Unit (HPU)/ECI Accumulator Control Module (AMCA)).
  - Completion of equipment reliability improvement work is driven via the 52-week cycle plan and Plant Reliability List (PRL) initiatives.

- Pickering HPSI related activities include the following:
  - Placing an additional Calandria face cooling fan to rectify erroneous moderator level indications.
  - Fixing the leaking H_2O injection valve.
  - Mitigating the leakage to the miscellaneous collection tank from a motorized valve.
  - Due to drift issues, 40V DC power supplies to ECI channel S logic instrumentation are being replaced on all units.
  - Engineering Change Request (ECR) has been approved to address the incorrect logic associated with ECI storage tank low level annunciation.

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 Performance Indicator Index (WPII), a maximum score of 100 is possible. The WPII is an operational performance indicator comprised of 10 metrics, three of which are analyzed in this section:

- Forced Loss Rate (FLR) [Rolling Average]
- Rolling Average Unit Capability Rate (UCR) [Rolling Average]
- Chemistry Performance Indicator (CPI) [Rolling Average]

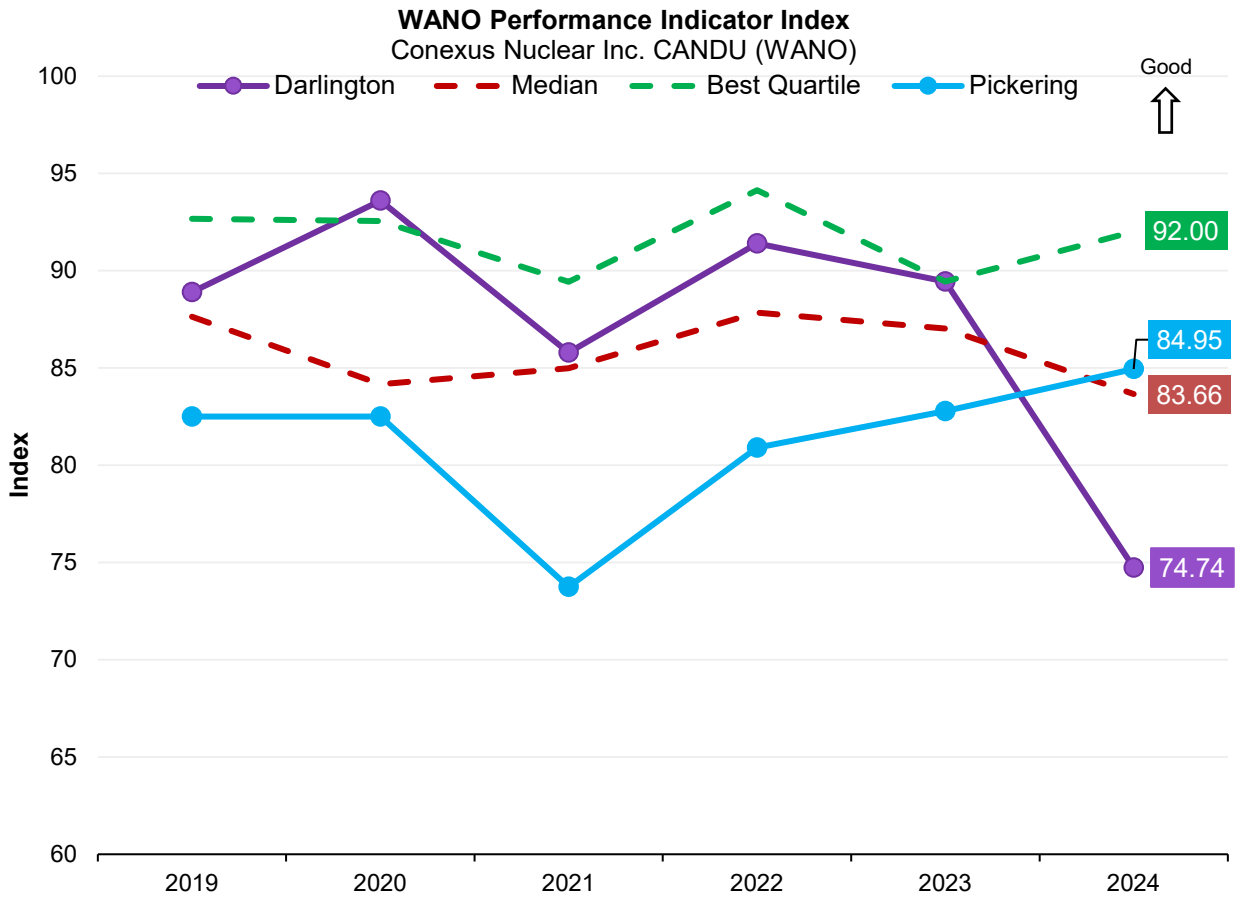
The other seven WPII components are shown in the Safety Section (Section 2.0).

Note: To benchmark performance, Max WPII is used to indicate best quartile performance for metrics that perform better than the Max WPII benchmark. If metric performance is not better than Max WPII, benchmark quartiles are utilized to indicate quartile performance.

In addition to the WPII indicators listed above, Unit Capability Factor (UCF) is also included in this section, and the calculations utilize data from WANO. Data points benchmarked for UCF are a rolling average.

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.

WANO Performance Indicator Index (WPII) +



+ 3-year avg DNGS - Unit 2 (U4 in Refurbishment. Unit 3 RTS Q3 2023 & Unit 1 RTS Q4 2024, not online for 3 years), 2-year avg PNGS - Unit 4 & 5-8 (U1 end of commercial life Q3 2024)

** WPII methodology changed from Method 4 to Method 10 starting in 2024. This adjustment affects both the metric's definition and index weighting. Data from 2019 through 2023 was calculated using Method 4, 2024 onward will reflect Method 10.*

	2024 Value
DN	74.74
PN	84.95
Best Quartile	92.00
Median	83.66

Factors Contributing to Performance:

- DNGS WPII performance declined in 2024 compared to 2023. The decline in performance is attributed to elevated Forced Loss Rate (FLR) and Unit Capability Rate (UCR) performance as result of two forced outages in 2024. Since FLR and UCR have the most significant weighting (15 and 10 points respectively) in the WPII method 10 calculation, the resulting score of WPII was reduced. DNGS continued with excellent performance for all seven safety metrics.

- PNGS performance improved by 2.17 points primarily due the industry definition and weighting change from WPII method 4 to WPII method 10.
  - UCR and FLR have the most significant weighting in the WPII calculation.

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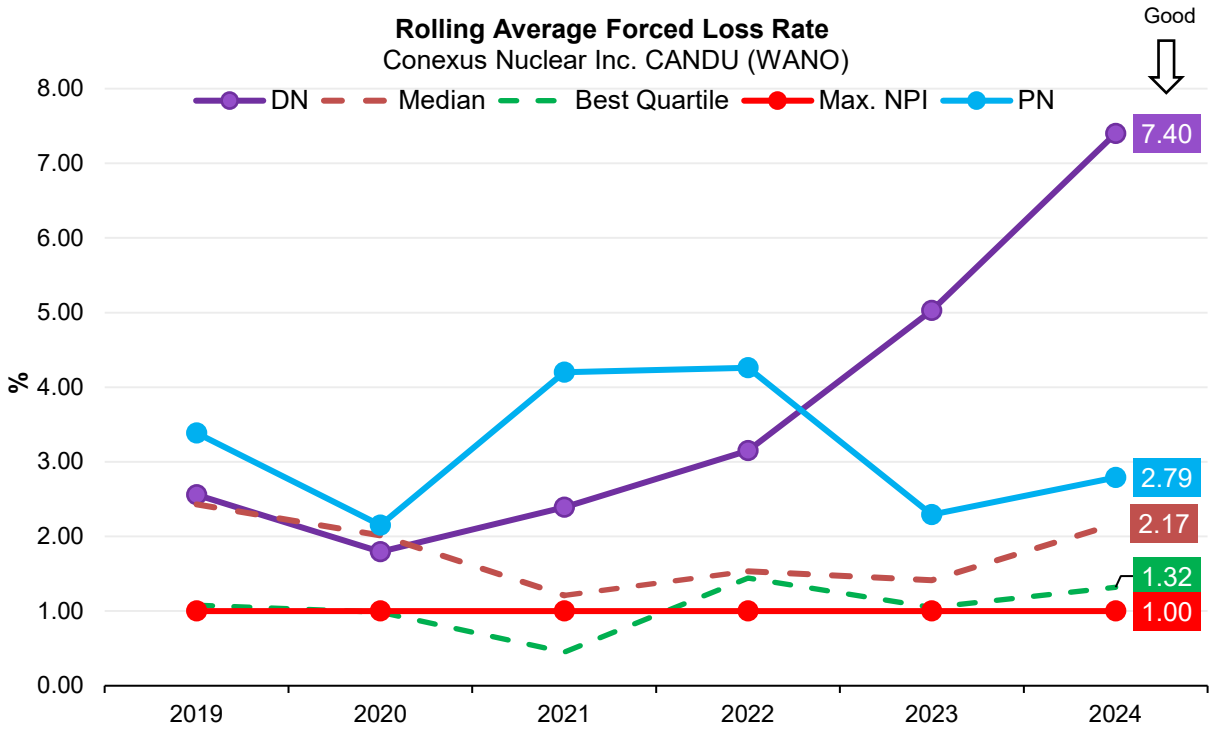
- Sustained performance for all seven safety was partially offset by lower Chemistry Performance Index (CPI), Forced Loss Rate (FLR) and Unit Capability Rate (UCR) performance.

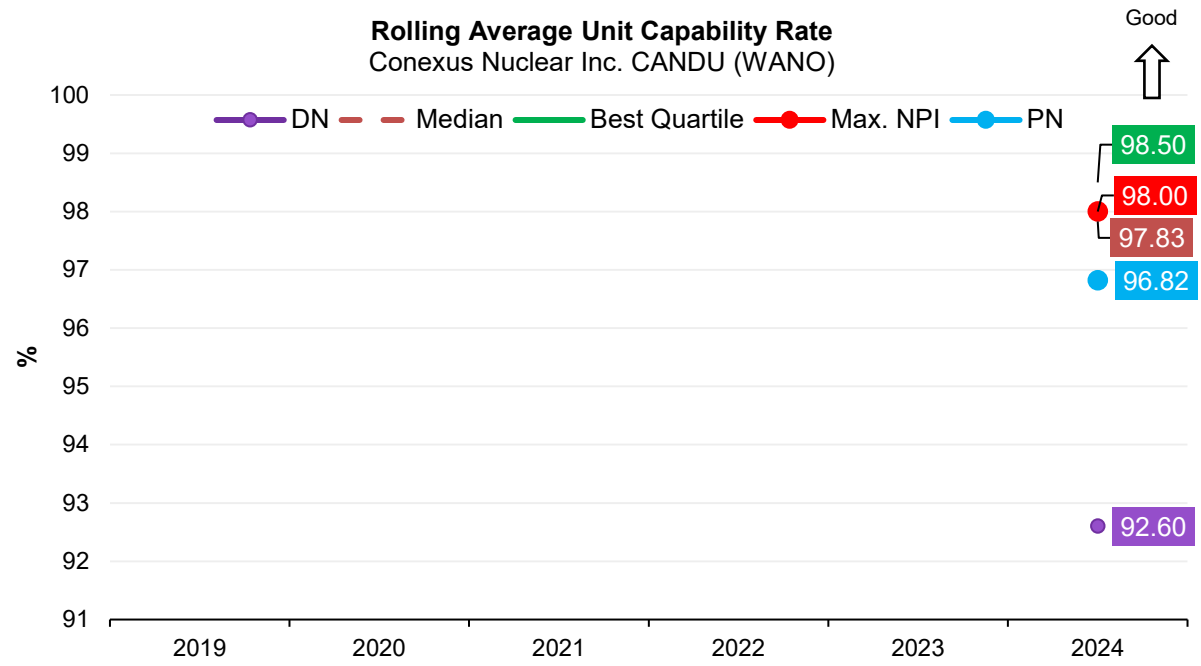
Further details on factors contributing to performance and initiatives to improve and sustain favourable performance are discussed within each respective WPII sub-metric in this report.

Rolling Average Forced Loss Rate (FLR) * +



Sub-indicator for WPII
+ 3-year avg DNGS - Unit 2 (U4 in Refurbishment. Unit 3 RTS Q3 2023 & Unit 1 RTS Q4 2024, not online for 3 years), 2-year avg PNGS - Unit 4 & 5-8 (U1 end of commercial life Q3 2024)

Rolling Average Unit Capability Rate (UCR) * +



Note: New metric for WPII Method 10, replacing Unit Capability Factor (UCF) for WPII Method 4

	2024 FLR	2024 UCR
DN	7.40	92.60
PN	2.79	96.82
Best Quartile	1.32	98.50
Median	2.17	97.83

Factors Contributing to Performance:

- DNGS decline in performance is attributable to post-Refurbishment forced outages. As the metric is a rolling average, in 2023 & 2024 only Unit 2 results are included (Units 1, 3, 4 were in refurbishment during all or part of the window), compared to only Unit 4 being included prior to entering Refurbishment in 2022. Increased FLR is expected post refurbishment and will improve with support of ongoing initiatives to strengthen Plant reliability, Human Performance and Equipment reliability. DNGS experienced four forced outage events related to Unit 2 post-Refurbishment on Generator (2024), Primary Heat Transport (2023), and Turbines & Main Power Output (2022).

- PNGS slight decline in performance is attributable to elevated FLR in 2024 compared to 2022, which is no longer included in the rolling window. In 2024, there were three forced outages related to Primary Heat Transport, Liquid Zone Control and Generator systems, and six forced outages related to Turbine, Boiler Feedwater, Main Output, and Human Performance in 2023. Unit 6 obtained Industry Best Quartile FLR in 2024.

Initiatives to Improve and Sustain Favourable Performance Include:

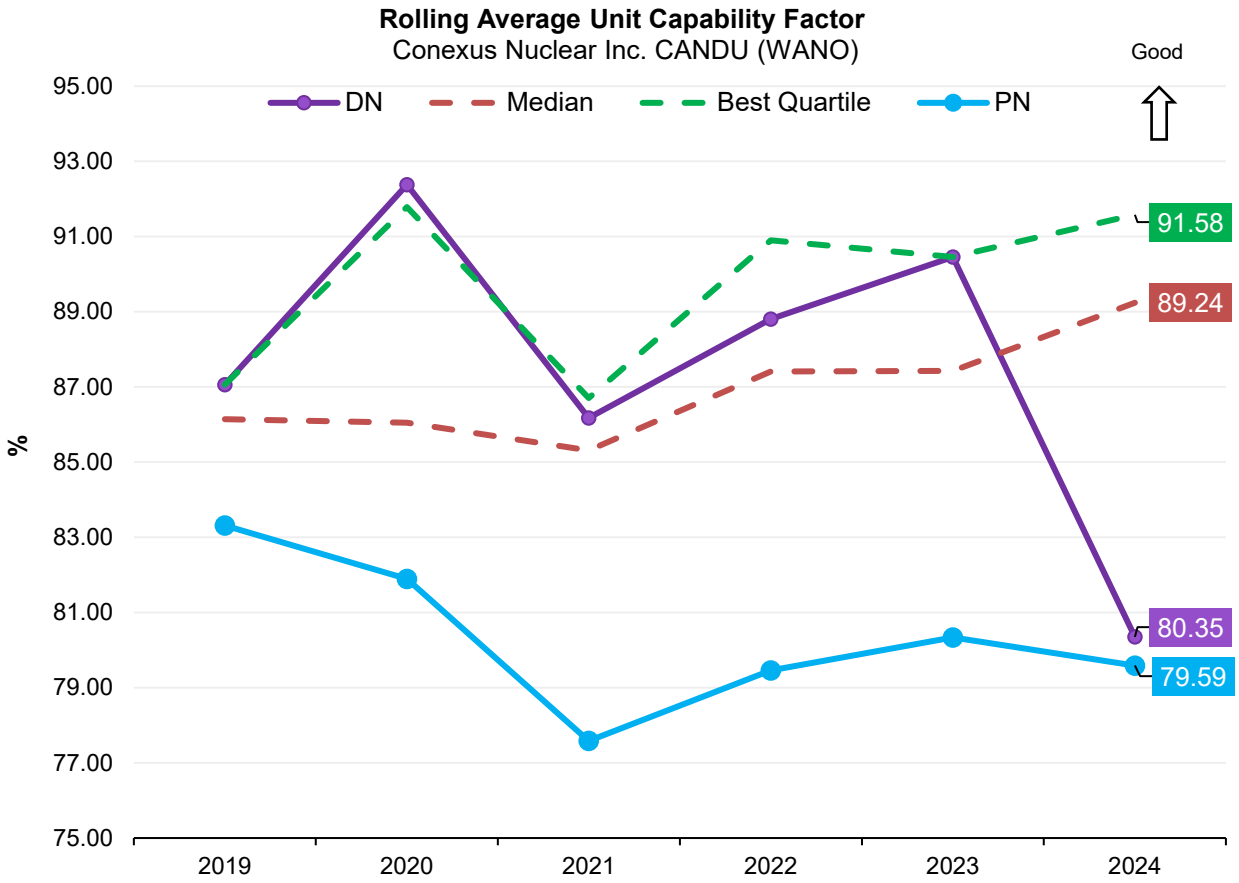
- Focused actions, including vulnerability identification and elimination, project execution, and building proficiency at both the fleet and site level to increase plant reliability, have been implemented for identified systems that are contributing to historical and industry forced loss events.

- Major projects installed during Darlington Refurbishment have improved reliability, and major projects are scoped for Pickering Refurbishment to improve reliability of contributing systems.

- Fuel Handling fleet and industry peer teams have continued to reduce or eliminate FLR contribution year over year and remains a fleet focus area to build sustainability. DNGS has achieved industry best performance with no contributing Fuel Handling FLR.

- Internal peer teams, industry benchmarking, fleet assessments against industry best practice, enhanced participation in industry working groups are in place to help manage risks going forward. Continued actions building proficiency at both the fleet and site level have been implemented for top fleet contributors, supported by industry peers.

Rolling Average Unit Capability Factor (UCF) * +



+ 3-year avg DNGS - Unit 2 (U4 in Refurbishment. Unit 3 RTS Q3 2023 & Unit 1 RTS Q4 2024, not online for 3 years), 2-year avg PNGS - Unit 4 & 5-8 (U1 end of commercial life Q3 2024)

	2024 Value
DN	80.35
PN	79.59
Best Quartile	91.58
Median	89.24

Factors Contributing to Performance:

- DNGS decline in performance is attributable to a decline in FLR performance in 2024, which is expected post-Refurbishment. As the metric is a rolling average, only Unit 2 results are included in 2023 & 2024 (Units 1, 3 and 4 were in refurbishment during all or part of the window). 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 two years).

- PNGS decline in performance is attributable to decline in FLR performance in 2024 compared to 2022, which is no longer in the rolling window. Unit 7 achieved Industry Best Quartile in 2023.

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Initiatives to Improve and Sustain Favourable Performance Include:

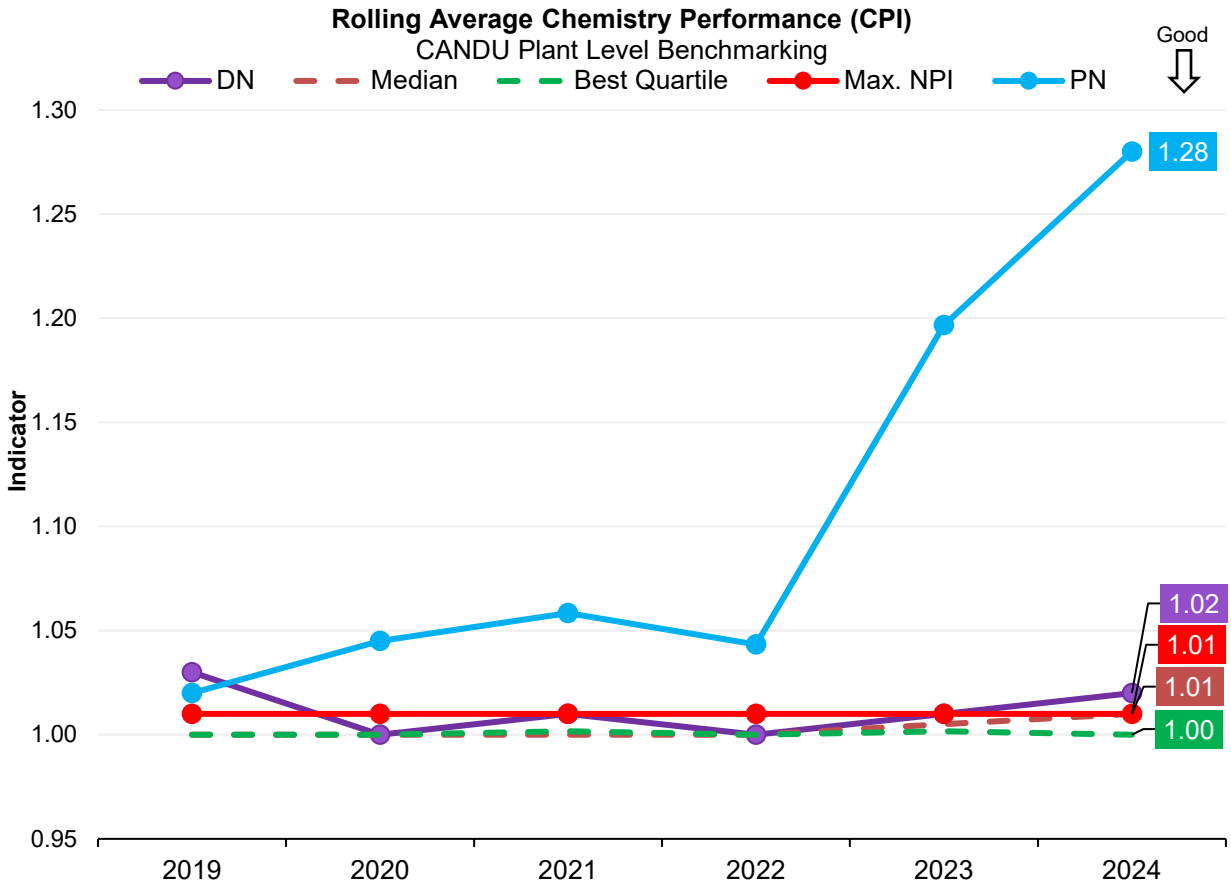
- Focused actions, including vulnerability identification and elimination, project execution, and building proficiency at both the fleet and site level have been implemented for identified systems contributing to historical and industry forced loss events.

- Major projects installed during Darlington Refurbishment have improved reliability, and major projects are scoped for Pickering Refurbishment to improve reliability of contributing systems.

- Fuel Handling fleet and industry peer teams have continued to reduce or eliminate FLR contribution year over year and remains a fleet focus area to build sustainability. DNGS has achieved industry best quartile with no contributing Fuel Handling FLR.

- Internal peer teams, industry benchmarking, fleet assessments against industry best practice, enhanced participation in industry working groups are in place to help manage risks going forward. Continued actions focused on building proficiency at both the fleet and site level have been implemented for top fleet contributors, supported by industry peers.

Rolling Average Chemistry Performance Indicator (CPI) *+



+ 3-year avg DNGS - Unit 2 (U4 in Refurbishment. Unit 3 RTS Q3 2023 & Unit 1 RTS Q4 2024, not online for 3 years), 2-year avg PNGS - Unit 4 & 5-8 (U1 end of commercial life Q3 2024)

	2024 Value
DN	1.02
PN	1.28
Best Quartile	1.00
Median	1.01

Factors Contributing to Performance:

The decline in performance at DNGS in 2024 compared to 2023 can be attributed to the following:

- Unit 2 Feedwater corrosion product transport post unit start-ups and elevated boiler ions upon unit start-ups (2024).
- Condenser tube leak on Unit 2 (2023).

The decline in performance at PNGS in 2024 compared to 2023 can be attributed to the following:

- Post Unit 7 start-up boiler sulphates for ~ 9 months (2024)
- Post Unit 5 start-up boiler sulphates for ~ 5 months (2024)

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- Post Unit 8 Condenser Tube Leak that resulted in boiler ions in Action Level 3 high (2023)
- Multiple condenser tube leaks on Unit 8 (2023)
- Post Unit 6 start-up boiler sulphates for ~ 6 months (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.

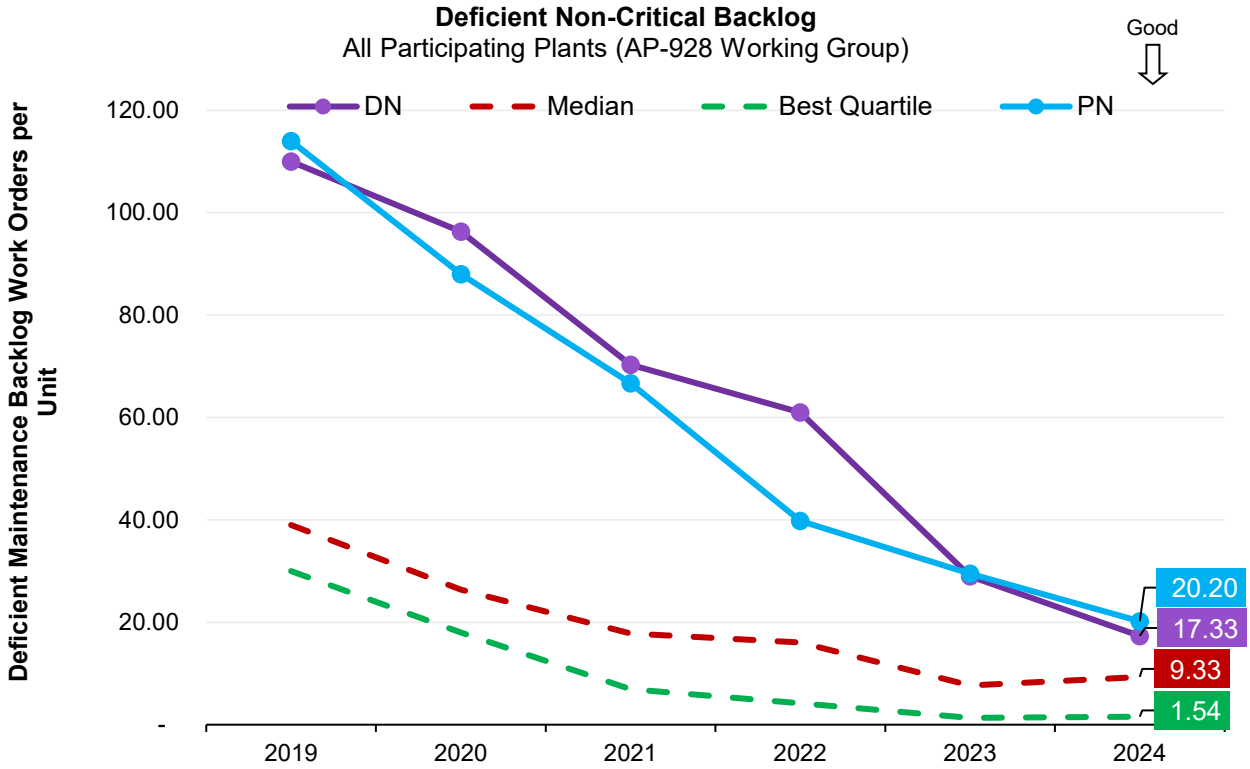
DNGS**:**

- Explore implementing film forming amine injection for corrosion product transport formation reduction.
- Explore further enhanced corrosion product transport removal processes via larger side stream filtration and/or condensate polisher.
- 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.

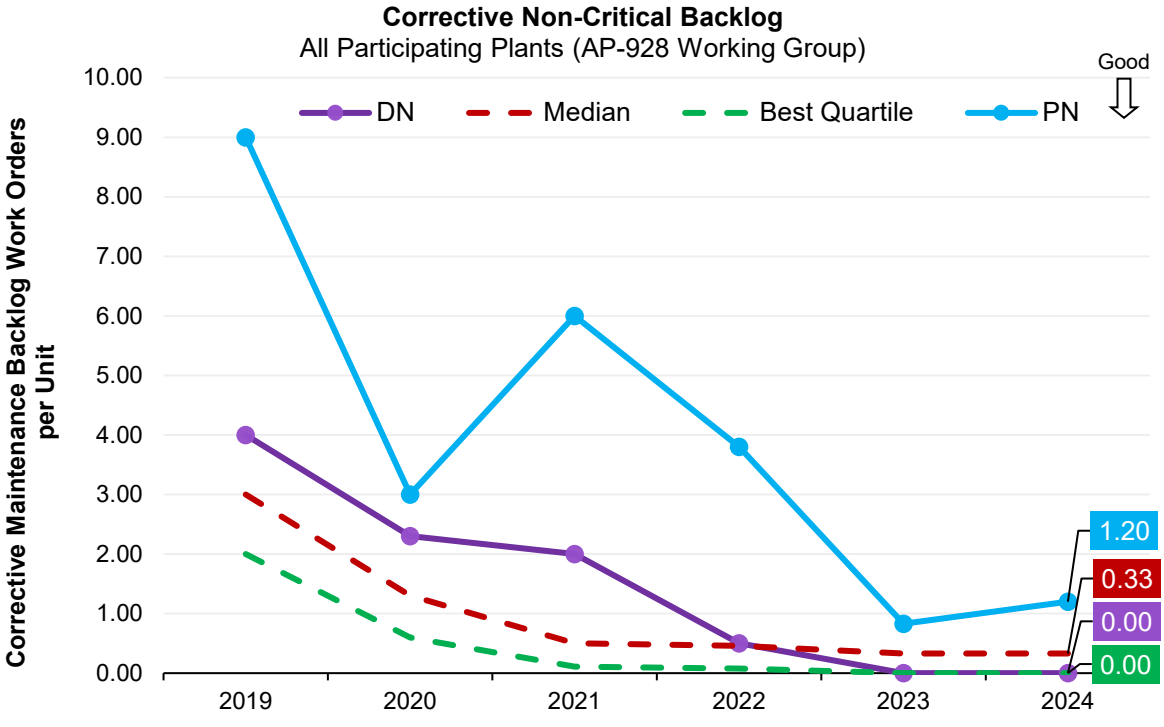
PNGS**:**

- Explore implementing film forming amine injection for corrosion product transport formation reduction.
- To improve boiler chemistry, a modification is planned during refurbishment to increase the continuous boiler blowdown capacity. This will help improve boiler ions upon unit start-up.
- Improve planning and execution of chemistry start-up activities through integration of Chemistry, Outage, and Operations.

On-Line Deficient & Corrective Non-Critical Backlog
On-Line Deficient & Corrective Critical Backlog



Note: Annual



Note: Annual

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	Deficient Non-Critical Backlog	Deficient Critical Backlog	Deficient Maintenance Backlog	Corrective Non-Critical Backlog	Corrective Critical Backlog	Corrective Maintenance Backlog
DN	17.33	0.00	17.33	0.00	0.00	0.00
PN	20.20	0.60	20.80	1.20	0.00	1.20
Best Quartile	1.54	0.00	1.54	0.00	0.00	0.00
Median	9.33	0.00	9.33	0.33	0.00	0.33

Factors Contributing to Performance:

- DNGS and PNGS continue to achieve industry best quartile for Corrective Critical Backlog.
- DNGS continues to achieve industry best quartile for Deficient Critical Backlog.
- PNGS performance improved for Deficient Critical Backlog.
- Both sites experienced performance improvement for Deficient Non-Critical Backlog, PNGS 32%, and DNGS 40% compared to 2023.

- Factors contributing to performance:
  - Continued focus on reducing backlog using Fix It Now (FIN) and Work Management (WM) processes.
  - Actions completed to make FIN process sustainable for Live Zero backlog, including enhancements for long-lead parts and grace periods.
  - Weekly cross-functional meetings to review all current backlog work orders and ensure proper coding quality.
  - Initiated cross-functional Backlog Recovery Teams.
  - Oversight of Refurbishment and Safe Storage activities requires strengthening to reduce online backlog impacts
  - Not all station backlog targets were set to Industry Top Quartile for 2024.

Initiatives to Improve and Sustain Favorable Performance Include:

- Continued review of opportunities to execute online work during unit shutdowns and specific unit configurations.
- Improved oversight and support for Safe Storage activities that impact online Backlogs and Refurbishment Backlogs to ensure targets are met.
  - DNGS and PNGS FIN Managers coordinate with the Refurbishment Maintenance and Work Management teams to ensure targets are met during the transfer of Backlog work orders into/out of Refurbishment and Online.

- Improved oversight at New Work Screening to ensure proper coding of work orders.
- Monitor and track actions as well as metrics via weekly Integrated Station Briefing meetings (DNGS), monthly Senior Work Management meetings, and monthly Station Management 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) in an effort to adjust all values across national borders. The primary function of the PPP value is attempting to adjust for currency exchange rate fluctuations, but also attempting to 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.

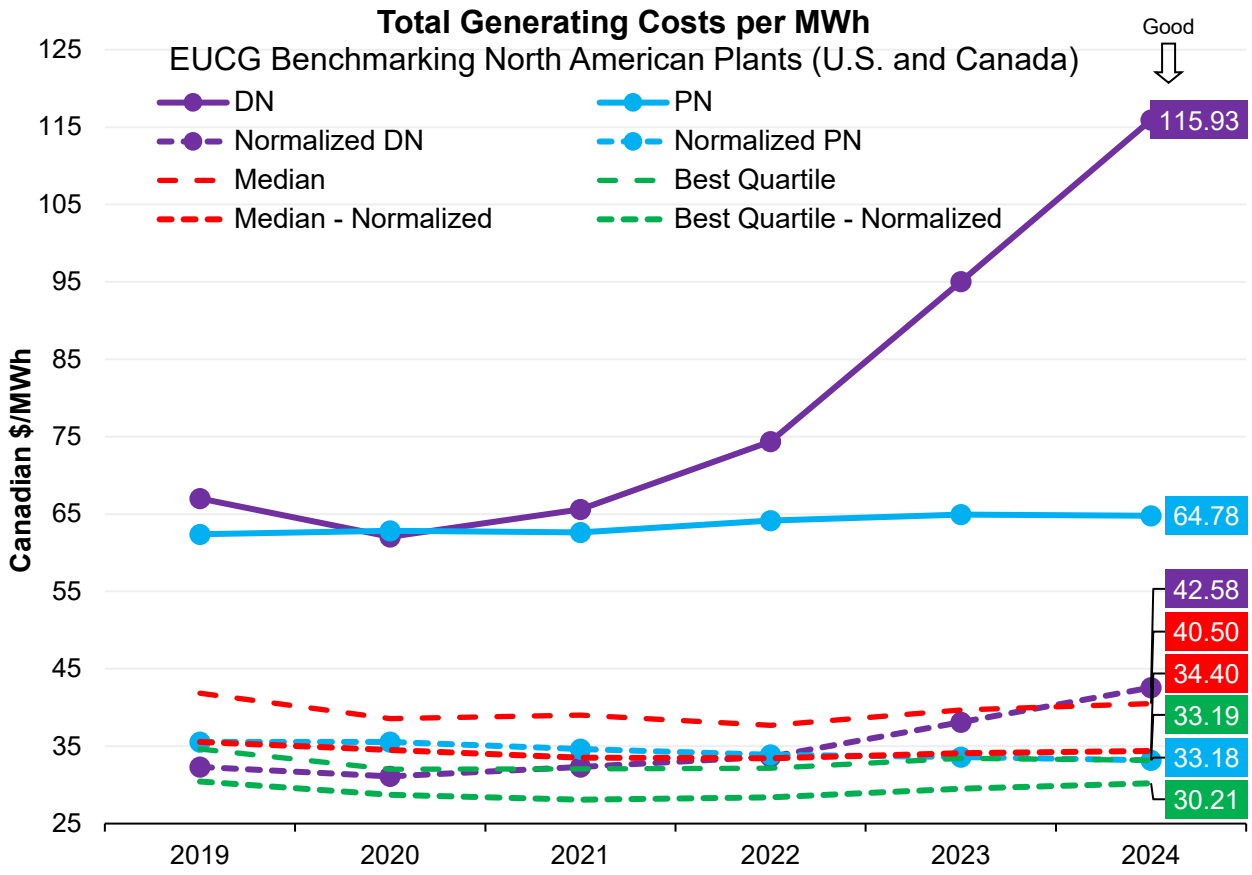
Darlington's TGC/MWh, TGC/Unit, Non-Fuel Operating Costs (NFOC)/MWh and Capital Cost/MW DER performance have also been normalized for refurbishment. The refurbishment normalization methodology allows OPG to adjust the distribution of actual operating and capital costs to reflect Darlington's number of 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*

3-Year Total Generating Cost (TGC) per MWh



+ DNGS – Unit 2 RTS Q2 2020, Unit 3 RTS Q3 2023, Unit 1 RTS Q4 2024. (U4 in Refurbishment)
** Utilizing the updated technology, age-related and outage duration normalization methodology from ScottMadden*

	2024 Non-Normalized Value	2024 Normalized Value
DN	115.93	42.58
PN	64.78	33.18
Best Quartile	33.19	30.21
Median	40.50	34.40

Factors Contributing to Performance

- DNGS normalized performance declined in 2024 compared to 2023 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 2024 (Unit 4 full year, Unit 1 offline until Q4 2024) compared to one unit in 2021 (Unit 3 offline full year), increasing spending on sustaining investments to ensure long term reliability, and higher OM&A costs in 2024 from increased unionized compensation as a result of the Ontario Superior court decision finding unconstitutional provincial legislation that set limits on compensation increases for employees in the Ontario public sector in which the maximum annual increase in both wages and total compensation to one percent for a three-year period (Bill 124 Court Decision), partially offset by lower fuel & OM&A costs due to refurbishment schedule.

- DNGS non-normalized performance declined in 2024 compared to 2023 due to reduced 3-year generation related to the Refurbishment outage schedule (as per above), higher OM&A costs in 2024 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 2024 performance is similar to 2023, reflecting reduced capital spending while maintaining reliable operations in the period leading up to the Refurbishment of Units 5-8 in 2026, 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.

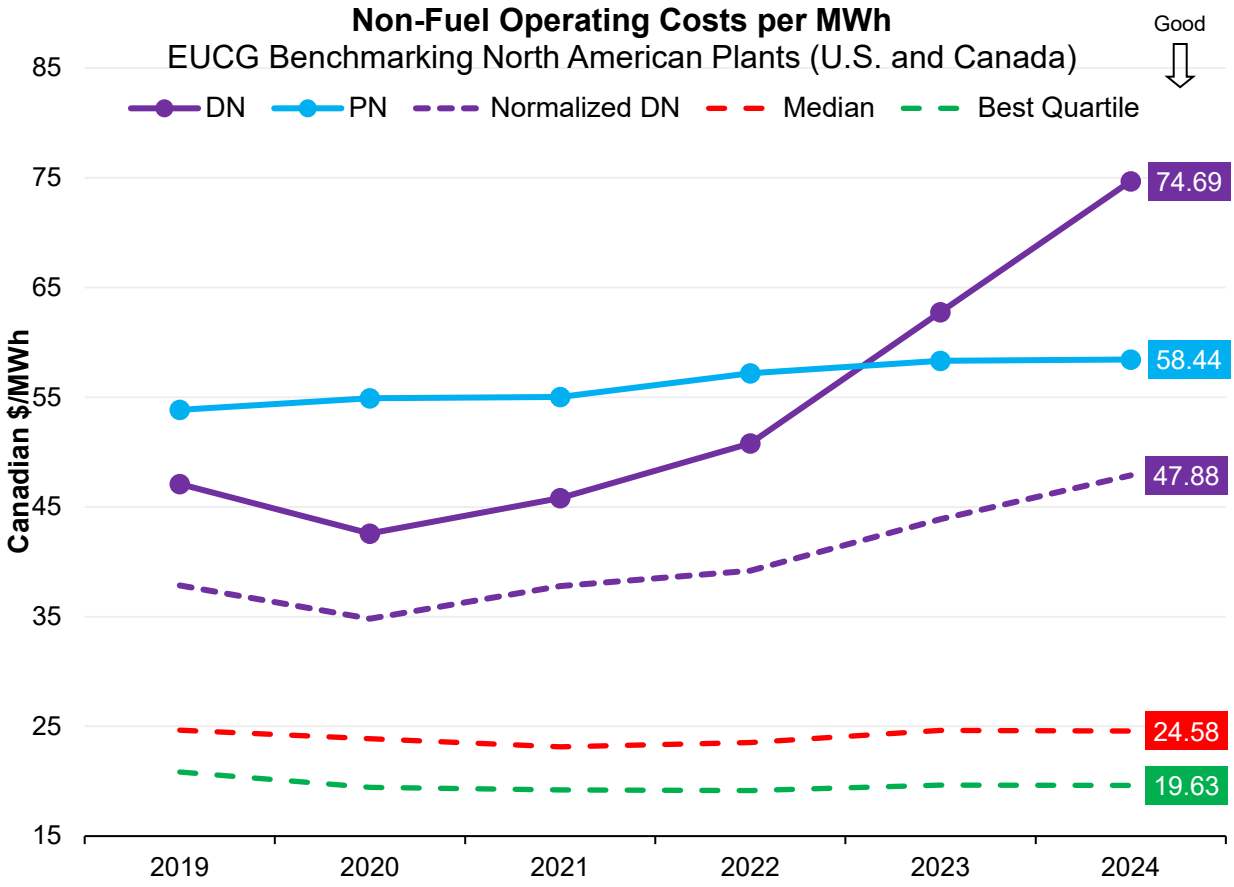
Initiatives to Improve and Sustain Favourable Performance Include:

- 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.

3-Year Non-Fuel Operating Cost per MWh



+ DNGS – Unit 2 RTS Q2 2020, Unit 3 RTS Q3 2023, Unit 1 RTS Q4 2024. (U4 in Refurbishment)

	2024 Non-Normalized Value	2024 Normalized Value
DN	74.69	47.88
PN	58.44	-
Best Quartile	19.63	19.63
Median	24.58	24.58

Factors Contributing to Performance

- DNGS normalized performance declined in 2024 compared to 2023 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 2024 (Unit 4 full year, Unit 1 offline until Q4 2024) compared to one unit in 2021 (Unit 3 offline full year), higher OM&A costs in 2024 from increased unionized compensation as a result of the Ontario Superior court decision finding unconstitutional provincial legislation that set limits on compensation increases for employees in the Ontario public sector in which the maximum annual increase in both wages and total compensation to one percent for a three-year period (Bill 124 Court Decision).

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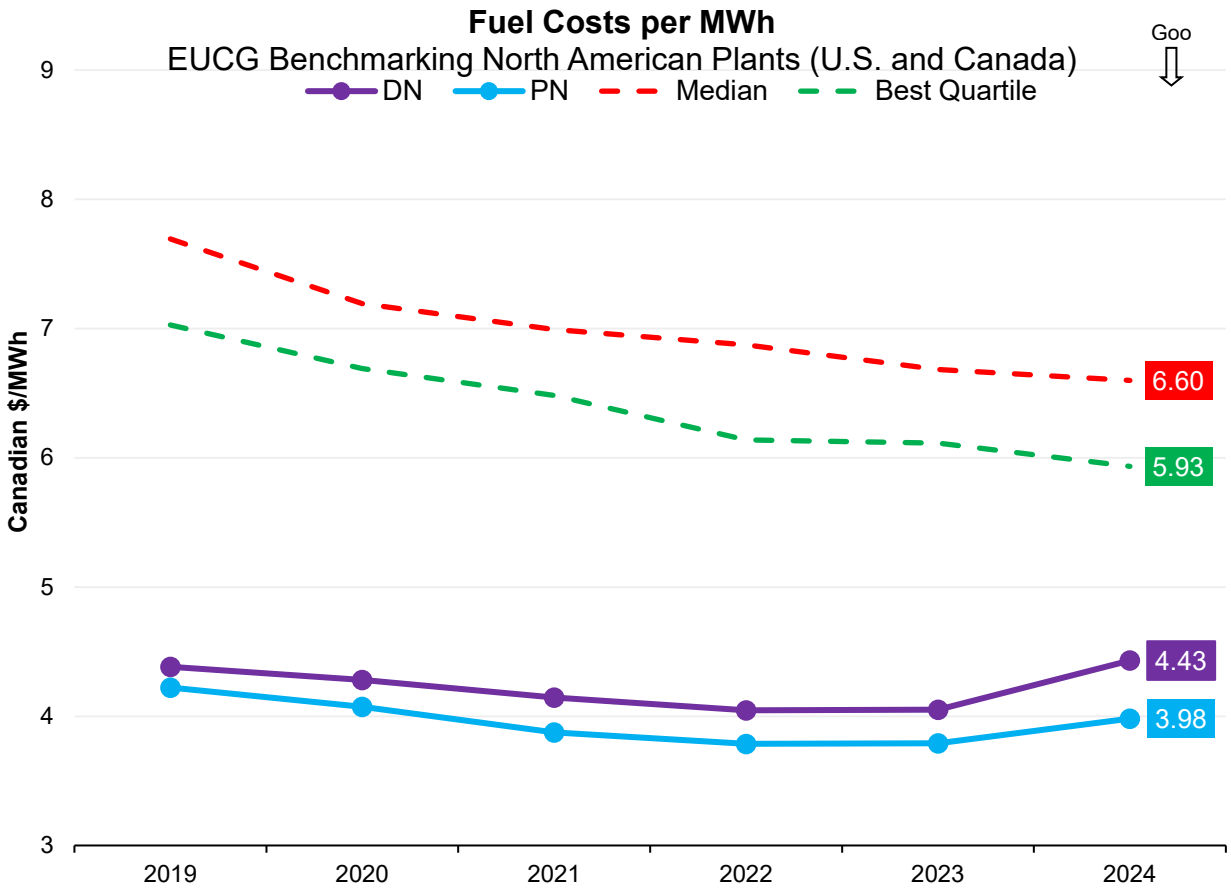
- PNGS non-normalized performance reflects higher OM&A costs in 2024 from increased unionized compensation as a result of the Bill 124 court ruling (as per above).

- 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.

3-Year Fuel Cost per MWh



+ DNGS – Unit 2 RTS Q2 2020, Unit 3 RTS Q3 2023, Unit 1 RTS Q4 2024. (U4 in Refurbishment)

	2024 Value
DN	4.43
PN	3.98
Best Quartile	5.93
Median	6.60

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 2022, 2023 and 2024, have allowed OPG to take deliveries of uranium on 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.

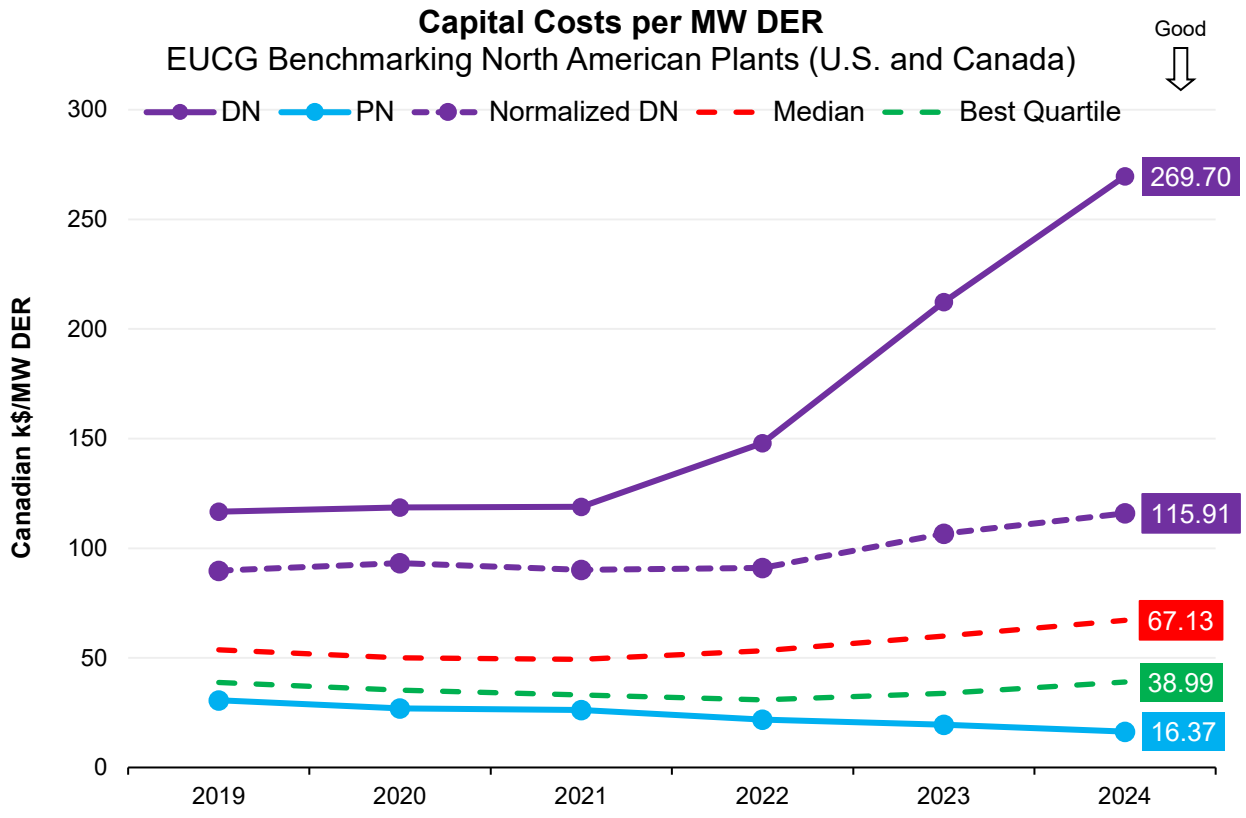
- In 2017, the uranium spot market price reached its cyclical low point and has continued an increasing trend up to the present, and this trend is projected to continue. Over the coming years, as historical uranium contracts are completed and new contracts are entered into, the effect of the more recent increasing uranium price trend is expected to place upward pressure on the 3-year rolling average fuel cost per MWh. The increase in fuel costs at PNGS and DNGS from 2023 to 2024 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 favourable comparative fuel costs, while also ensuring a resilient and robust nuclear fuel supply chain, given recent and ongoing geopolitical and economic events

3-Year Capital Cost per MW DER (Design Electrical Rating)



+ DNGS – Unit 2 RTS Q2 2020, Unit 3 RTS Q3 2023, Unit 1 RTS Q4 2024. (U4 in Refurbishment)

	2024 Non-Normalized Value	2024 Normalized Value
DN	269.70	115.91
PN	16.37	-
Best Quartile	38.99	38.99
Median	67.13	67.13

Factors Contributing to Performance:

- DNGS performance in 2024 remained the same on a normalized basis compared to 2023, as the station remained in the third quartile. The large increase in the absolute DNGS Capital Cost per MW in 2024 is mainly due to the reduction in available MW as 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 changes over the trend period reflects increased spending, steam generator replacements, sustaining investments, and infrastructure. 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.

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- 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. Once these investments have been made, DNGS performance is expected to improve.

- PNGS is performing in the first quartile with a slight improvement in 2024 and improvement over the trend period. This reflects reductions in spending while maintaining reliable operations leading up to the end of commercial operations (Units 1 & 4) which is consistent with spending trends observed at other nuclear facilities approaching their end of commercial operations and a planned refurbishment of four generating units (Units 5-8). However, as with investments related to DNGS and its refurbishment, this trend is not expected to continue as planned investments in PNGS are expected to increase with the plant life extension.

Initiatives to Improve and Sustain Favourable Performance Include:

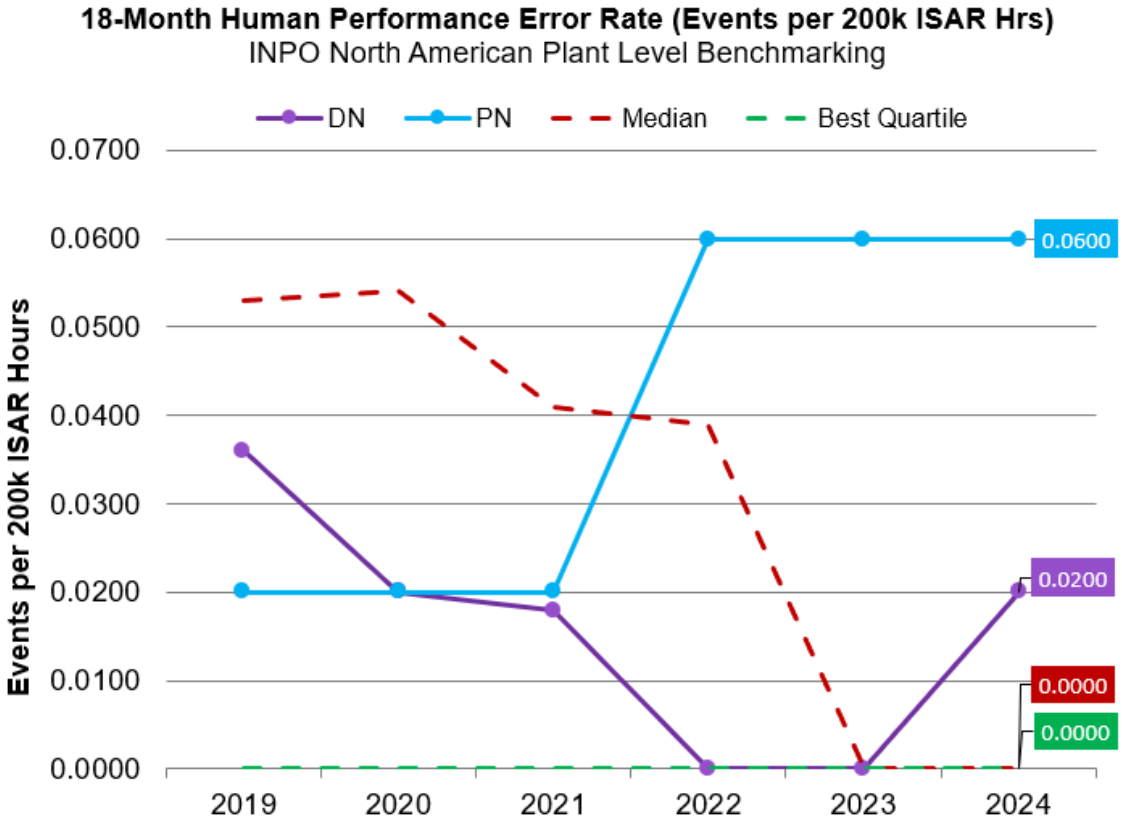
- OPG continues to prioritize an integrated portfolio and asset management approach to assess, prioritize, and deliver all nuclear operations projects which are developed to meet regulatory commitments (i.e. from the Canadian Nuclear Safety Commission), increase system or unit reliability, address system obsolescence, optimize station generation, focus on investments in life extension and critical system upgrades, and enhanced project delivery practices.

- Enhanced project management practices, combined with the adoption of digital technologies and continuous improvement efforts, enable OPG to deliver capital projects more efficiently.

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



	2024 Value
DN	0.0200
PN	0.0600
Best Quartile	0.0000
Median	0.0000

Factors Contributing to Performance:

- DNGS performance declined from best quartile in 2023 to third quartile in 2024 due to two Site Event Free Day Resets (S-EFDR) compared to zero in 2023. Event causes were identified, and corrective actions were implemented to address the gaps.
- PNGS experienced two Site Event Free Day Resets (S-EFDR) compared to one in 2023. Event causes were identified, and corrective actions were implemented to address the gaps.

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Initiatives to Improve and Sustain Favourable Performance Include:

- Use of Trend Vision to provide key insights and trends based on Station Condition Records (SCR) and Observation & Coaching (O&C) for stations.
- Continuing to build upon Fail Safe Strategies across the fleet through Pre-Job Briefs (PJB) and O&C programs.
- Renewed Trigger training licenses to end of 2026 for DNGS & PNGS
- PNGS continued to complete the "Coaching to Enhance Performance" training for Supervisors.
- Proactive strategies and actions taken around heightened periods of risk, such as Holiday and Outage planning, as well as more proactive activities including Safety Light and communications.
- Continued focus on the Stop When Unsure campaign as part of O&C improvement plan.
- TPI (Trending, Prevention, and Intervention) program to provide additional oversight on identified trends, with key actions put in place.
- Utilization of Validation of Trend (VOT) process to proactively identify and verify emerging trends adverse to safety and quality.
- Human performance is being further enhanced by continuing to build a positive stop culture that recognizes workers who stop work due to unknown or unexpected events.

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
AMCA	Accumulator Control Module
ANDE	Advanced Non-Destructive Examination
BLC	Boiler Level Control
BLL	Boiler Low Level
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
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
FME	Foreign Material Exclusion
FRI	Fuel Reliability Index
GWH	Gigawatt Hours
HIT	High Impact Team
HPER	Human Performance Error Rate

Acronym	Meaning
HPSI	High Pressure Safety Injection
HPU	Hydraulic Power Unit
HTHT	Heat Transport High Temperature
HTLF	Heat Transport Low Flow
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
MDS	Machine Delivered Scrape
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
SDSE	Shutdown System Enhancement
S-EFDR	Site event free day resets
SFCR	Single Fuel Channel Replacement
SG	Standby Generators
SPNMDI	System Does Not Meet Design Intent

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Acronym	Meaning
SIF	Serious 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
TISA	Total Industrial Safety Accident Rate
TPI	Trending, Prevention, and Intervention
TRF	Tritium Removal Facility
TRIF	Total Recordable Injury Frequency
UCF	Unit Capability Factor
UCR	Unit Capability Rate
VOT	Validation of Trend
VVRS	Vault Vapour Recovery System
WANO	World Association of Nuclear Operators
WM	Work Management
WPII	WANO Performance Indicator Index

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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.

Total Industrial Safety Accident Rate (TISA)
This indicator is defined as the number of accidents for personnel at the station, including all utility personnel (permanent or temporary staff and except contractor personnel) assigned to the station, contractors, supplemental personnel and all other non-utility personnel working onsite that result in one or more days away from work (excluding the day of the accident) or one or more days or restricted work (excluding the day of the accident) or fatalities per 200,000 person-hours worked. TISA will combine site Industrial Safety Accident (ISA) rate and Contractor Safety Industrial Accident (CISA) rate.

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.

Reactor Automatic & Manual Trip Rate
The number of unplanned automatic reactor trips (reactor protection system logic actuations) and unplanned manual trips that occur per 7,000 hours of critical operation. For the purposes of the WANO Performance Indicator Index, the indicator is calculated over a rolling two years, on a unit basis. It is noted that to attain the maximum allotted points towards the WANO Performance Indicator Index, the Reactor Trip indicator must be less than or equal to 0.5. The Reactor Automatic and Manual Trip indicator contributes a maximum of 15% towards the WANO Performance Indicator Index.

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).

WANO Performance Indicator Index (WPII)

INPO sponsored performance measure and is a weighted composite of 10 WANO Performance Indicators related to safety and production performance reliability. Effective January 01, 2024, Method 10 is replacing the previous Method 4.

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 Rate (UCR)
Ratio of the available energy generation over a given time period to the reference energy generation over the same time period but not counting planned energy losses in the denominator. UCR, like UCF, is expressed as a percentage. All 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.

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.

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

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.

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)

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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 contractors, 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.

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.

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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

	Conexus Nuclear Inc. CANDU (WANO)	All North American PWR and PHWRs	INPO AP-928 Workgroup	INPO	EC	EUCG North American Plants (US and Canada)
Safety						
Total Recordable Injury Frequency					X	
Rolling Average Total Industrial Safety Accident Rate*+x		X				
Rolling Average Collective Radiation Exposure*+x	X					
Airborne Tritium Emissions	X					
Fuel Reliability Index*x	X					
2-Year Reactor Trip Rate*x	X					
3-Year Auxiliary Feedwater System Unavailability*x	X					
3-Year Emergency AC Power Unavailability*x	X					
3-Year High Pressure Safety Injection Unavailability*x	X					
Reliability						
Rolling Average WANO WPII *x	X					
Rolling Average Forced Loss Rate*+x	X					
Rolling Average Unit Capability Rate*+x	X					
Rolling Average Unit Capability Factor*+x	X					
Rolling Average Chemistry Performance Indicator*+x	X					
1-Year On-line Deficient Maintenance Backlogx			X			
1-Year On-line Deficient Critical Backlogx			X			
1-Year On-line Corrective Maintenance Backlogx			X			
1-Year On-line Corrective Critical Backlogx			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 Ratex				X		

** Sub-indicator of WANO WPII*

+ Rolling 2 Year Average PNGS ; Rolling 3 Year Average DNGS

x Metric data is available in the INPO PIC/IRIS software systems.

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 Conexus Nuclear Inc. 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.

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- *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.

Panels/Members

Table 3: WANO Panel

Operator	Plant
Ameren Missouri	Callaway
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 ANO
Constellation Energy	Braidwood Byron Calvert Cliffs R.E. Ginna
American Electric Power Co.	Cook
International CANDU	Cernavoda Embalse Qinshan 3 Wolsong A Wolsong B
New Brunswick Power	Point Lepreau
NextEra Energy Inc	Point Beach Seabrook St Lucie Turkey Point
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
Vistra Corp	Beaver Valley Comanche Peak Davis-Besse
Wolf Creek Generating Station	Wolf Creek
Xcel Energy Inc	Prairie Island

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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 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

Table 5: Conexus Nuclear Inc. CANDU (WANO)

Operator	Plant
Bruce Power	Bruce A Bruce B
China (CNNO)	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.
AltaLink
ATCO Electric (Alberta Power Ltd.)
BC Hydro
Bluewater Power Distribution Corporation
Canadian Power Holdings
Capital Power
City of Medicine Hat
City of Red Deer
Clearlight Energy
Elexicon
ENMAX Corporation
EPCOR Utilities Inc.
Evolugen
FortisAlberta Inc.
FortisBC Inc.
FortisOntario
Hydro One Inc.
Hydro Ottawa
Hydro-Québec
IESO
Invenergy

Companies
London Hydro
Manitoba Hydro
Maritime Electric
New Brunswick Power
Newfoundland and Labrador Hydro
Newfoundland Power Inc.
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 Corporation
TransAlta Corporation
Utilities Kingston
Wataynikaneyap Power
Yukon Energy Corporation

Table 7: INPO Members for On-Line Maintenance Backlogs

Plant	
Arkansas Nuclear One (ANO)	McGuire
Barakah	Millstone
Beaver Valley	Monticello
Braidwood	Nine Mile Point
Browns Ferry	North Anna
Bruce	Oconee
Brunswick	Oyster Creek
Byron	Palo Verde
Callaway	Peach Bottom
Calvert Cliffs	Perry
Catawba	Pickering
Clinton	Pilgrim
Columbia Gen	Point Beach
Comanche Peak	Point Lepreau
Cook	Prairie Island
Cooper	Quad Cities
Darlington	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
Koeberg	Watts Bar
LaSalle	Wolf Creek
Limerick	

Table 8: INPO Members for Human Performance Error Rate

Plant	
Arkansas Nuclear One (ANO)	McGuire
Barakah	Millstone
Beaver Valley	Monticello
Braidwood	Nine Mile Point
Browns Ferry	North Anna
Bruce	Oconee
Brunswick	Oyster Creek
Byron	Palo Verde
Callaway	Peach Bottom
Calvert Cliffs	Perry
Catawba	Pickering
Clinton	Pilgrim
Columbia Gen	Point Beach
Comanche Peak	Point Lepreau
Cook	Prairie Island
Cooper	Quad Cities
Darlington	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
Koeberg	Watts Bar
LaSalle	Wolf Creek
Limerick	

CCC Interrogatory #071

Interrogatory

Reference:
Exhibit F2, Tab 1, Schedule 1, Attachment 4
EB-2020-0290, Exhibit F2, Tab 1, Schedule 1, Attachment 5

Question(s):

a) Please explain why ScottMadden's 2018 study (filed in EB-2020-0290) used EUCG data starting in 2009 and now, in its 2025 study, it uses EUCG data starting in 2006.

b) Please advise whether using the same starting point for the EUCG data as previously applied (i.e., 2009 and now extending to 2023) in the current study changes the outcome of ScottMadden's analysis. If so, please provide the revised results from that analysis.

c) Please explain, and provide the detailed reasons for, the very significant increase in the base adjustment for CANDU reactor type ($539M) relative to the 2018 study. As part of the response, please also explain the difference between the $250M adjustment for CANDU reactor type shown at page 5 of Exhibit F2, Tab 1, Schedule 1, Attachment 5 in EB-2020-0290 and the value of $284M shown in footnote 3 of the current study. If there was a subsequent version of the ScottMadden study filed in EB-2020-0290 after the filing of the pre-filed evidence, please provide a reference to where that study can be located on the EB-2020-0290 record.

d) Please explain, and provide the detailed reasons for, the significant decrease in the base adjustment for average unit age ($346k) relative to the 2018 study ($77k).

e) With respect to the unit age adjustment, please advise whether unit age resets to zero after refurbishment. If not, please explain why.

f) With respect to the additional "annual factor" adjustment to the Darlington refurbishment cost, please explain why that was not applied in the previous 2018 study.

g) Please advise whether ScottMadden believes that the additional "annual factor" adjustment that captures the proportion of total generating costs that are refurbishment-related would have improved its 2018 study. As part of the response, please provide the quintile that OPG would have been in using the same data as the 2018 study and the same methodologies that were applied in the 2018 study with the only change being the inclusion of the new "annual factor" adjustment.

h) Please provide the directional impact on Darlington's TGC/MWh of applying an adjustment for site capacity (which was not actually applied in the study). As part of the response, please further explain the "complex adjustment to generation" that is required to allow for a site capacity adjustment to be used in the overall model.

i) Please provide the charts on pages 4, 11 and 13 in tabular format. As part of the table, please provide both quartile and quintile values. Separate from the table, please provide the detailed calculations supporting each of the quartile and quintile values.

j) Please provide revised versions of the charts on each of pages 4, 11 and 13 that overlay lines showing quintiles.

k) To the extent that 2024 actual information is available for OPG and the peer group nuclear plants, please file an updated study based on the 2022-2024 historical period using ScottMadden's proposed approach for normalization and benchmarking.

l) Please provide separate tables for each of Darlington and Pickering that shows the benchmarked results in dollars and the associated quintile placement based on the following:

    i. 2018 study
        1. No normalization adjustments
        2. Normalized for technology type and unit age
        3. Normalized for technology type, unit age and refurbishment
        4. Normalized for technology type, unit age, refurbishment and outages

    ii. 2025 study (2021-2023 average)
        1. No normalization adjustments
        2. Normalized for technology type and unit age
        3. Normalized for technology type, unit age and refurbishment
        4. Normalized for technology type, unit age, refurbishment and outages

    iii. 2025 updated study (2022-2024 average if available)
        1. No normalization adjustments
        2. Normalized for technology type and unit age
        3. Normalized for technology type, unit age and refurbishment
        4. Normalized for technology type, unit age, refurbishment and outages

Response

The following responses (a-j) were prepared by ScottMadden Management Consultants:

a) Refer to Ex. L-F2-Staff-324, part a).

b) Yes. Using the same starting point as the prior study (i.e., 2009) and extending the dataset through 2023 does change the outcome of ScottMadden's analysis.

To assess this, ScottMadden performed sensitivity analysis using a consistent model specification across multiple time periods. The results are summarized below (values in C$ thousands):

Regression Term / Model Coefficient	Current Study 2009-2023 (2023$Ck)	Current Study 2006-2023 (2023$Ck)
Age	-106	77
Capacity	288	291
CANDU (to BWR Baseline)	555,768	539,467
PWR (to BWR Baseline)	9,595	17,309

These coefficient differences alone do not indicate how OPG's normalized cost performance relative to peers would change. To determine that impact, the alternate model would need to be applied across the full peer dataset, adjusted TGC/MWh values would need to be recalculated for all sites, and the comparative rankings would need to be recreated. Without re-running that full normalization and benchmarking exercise, it is not possible to determine how OPG's adjusted cost performance relative to peers would be affected.

c) Refer to Ex. L-F2-Staff-324, part e).

d) Refer to Ex. L-F2-Staff-324, part d).

e) While refurbishment replaces or improves the condition of systems and components in the nuclear plant and thus impacts future maintenance requirements, it is not equivalent to constructing a new nuclear plant. The unit age would not reset to zero.

f) The additional "annual factor" adjustment was not applied in the 2018 study because that study did not incorporate the same approach of scaling the econometric adjustments based on the proportion of total generating costs attributable to refurbishment in each year.

In the 2025 study, ScottMadden introduced this refinement to ensure that the econometric adjustments (e.g., for technology type and unit age) are applied only to the portion of costs not associated with refurbishment. This is done by calculating the share of total generating costs attributable to refurbishment in each year and proportionally reducing the model-based adjustments to avoid overstating their impact.

While one could reasonably apply the same approach to the prior study, this enhanced approach was developed in the current study to address the fact that Darlington's offline unit-days due to Refurbishment were much higher than in the prior study. This more conservative approach reduces the downward cost adjustment provided to Darlington.

g) As noted above in part f), the "annual factor" adjustment introduced in the 2025 study reflects a refinement to the methodology intended to avoid overstating econometric adjustments in years where a significant portion of total generating costs is attributable to refurbishment.

While ScottMadden did not apply this approach in the 2018 study, doing so would be expected to improve the accuracy of the treatment of refurbishment by better isolating the portion of costs to which the econometric model is intended to apply. However, ScottMadden has not re-performed the 2018 study using the same 2009–2017 dataset and methodology with the addition of the "annual factor" adjustment. Accordingly, the resulting quintile placement under that hypothetical scenario is not available.

h) As discussed in Ex. F2-1-1, Attachment 4, p. 6, 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.

i) Chart 1 provides Total Generating Costs per megawatt-hour ("TGC/MWh") for 2023 3-Year rolling average for the requested normalization methodologies.

Chart 1: 2023 3-Year TGC/MWh (2021-2023)

Indicator	Station	Non-Normalized	Refurb Normalization	Technology & Unit Age Normalization	Technology, Unit Age, & Refurb Normalization	Technology, Unit Age, & Outage Duration Normalization	Technology, Unit Age, Outage Duration, & Refurb Normalization
TGC/ MWh	PN	$64.93	N/A	$38.98	N/A	$33.62	N/A
	DN	$95.04	$62.11	$60.41	$39.58	$58.17	$38.11
TGC/MWh Quartiles							
1st Quartile		*$33.44*	*$33.44*	*$29.56*	*$29.56*	*$29.51*	*$29.51*
2nd Quartile		*$39.66*	*$39.66*	*$36.69*	*$36.69*	*$34.09*	*$34.09*
3rd Quartile		*$49.23*	*$49.23*	*$42.93*	*$42.93*	*$41.78*	*$41.78*
TGC/MWh Quintiles							
1st Quintiles		*$32.08*	*$32.08*	*$28.46*	*$28.46*	*$27.77*	*$27.77*
2nd Quintile		*$36.72*	*$36.72*	*$33.80*	*$33.80*	*$32.76*	*$32.76*
3rd Quintile		*$45.37*	*$45.37*	*$40.22*	*$40.22*	*$38.64*	*$38.64*
4th Quintile		*$49.97*	*$49.97*	*$44.67*	*$44.67*	*$42.52*	*$42.52*

See Attachment 1 (confidential) detailed calculations supporting each of the quartile and quintile values.

j) Charts 2, 3, 4 are the revised versions of the charts on each of pages 4, 11 and 13 with overlayed lines showing quintiles

Chart 2: TGC/MWh performance 2021-2023 for EUCG Panel with DNGS Adjusted for Refurbishment

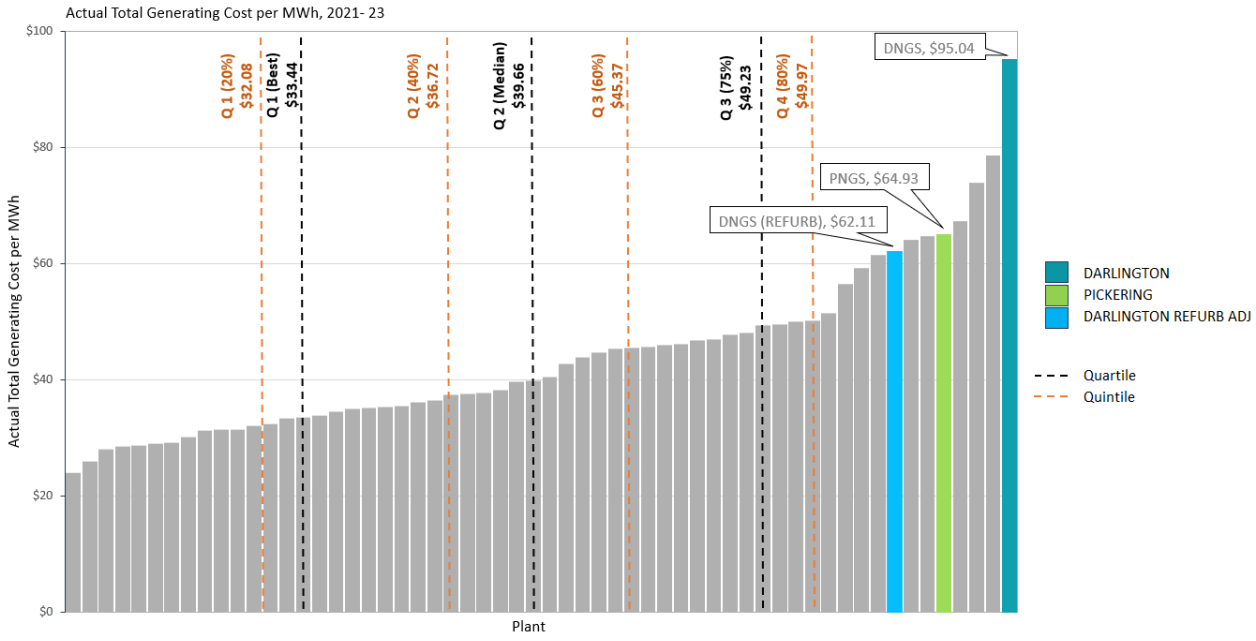


Chart 3: TGC/MWh performance 2021-2023 for EUCG Panel with All Sites Adjusted Based on Econometric Analysis and DNGS Also Adjusted for Refurbishment

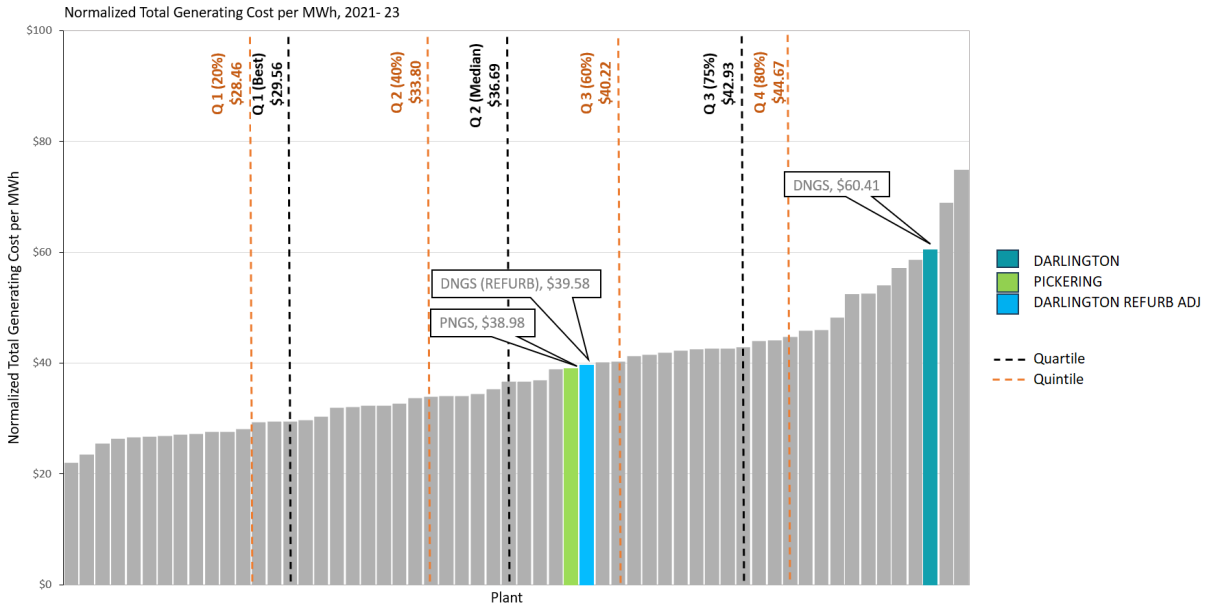
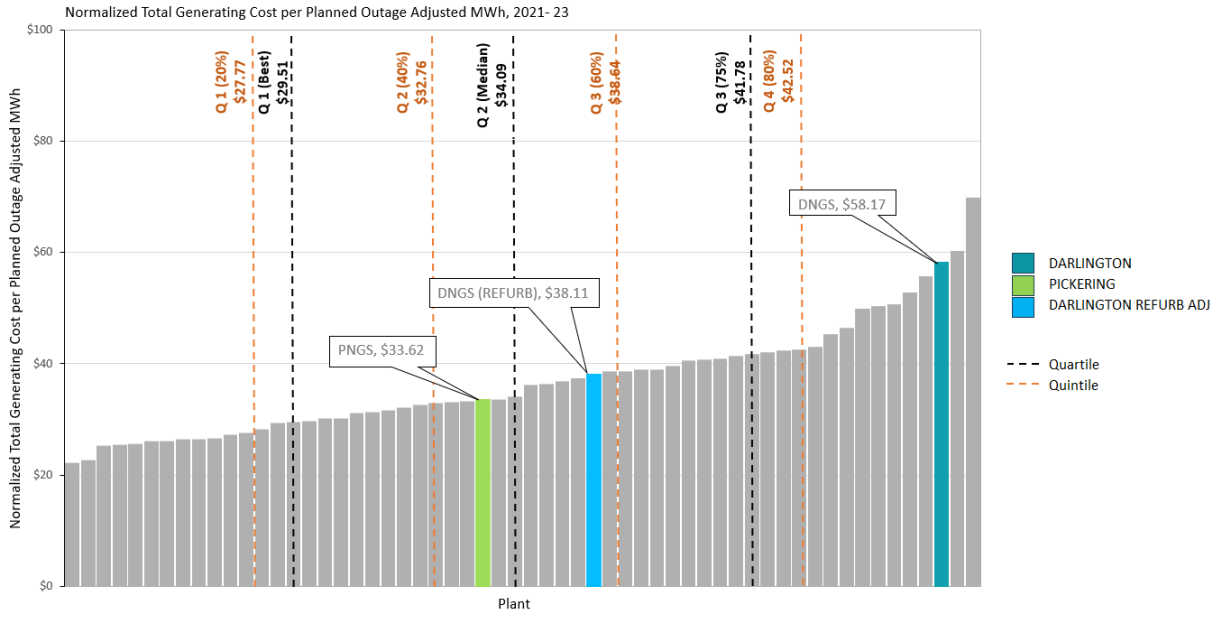


Chart 4: TGC/MWh performance 2021-2023 for EUCG Panel with All Sites Adjusted Based on Econometric Analysis and Outage Analysis and DNGS Also Adjusted for Refurbishment



The following responses (k-l) were prepared by OPG:

k) OPG interprets this question to be requesting to apply the updated TGC normalization methodology (i.e., 2025 Study) to the 2022-2024 actual results. Refer to response to part l) below.

l) i) ii) iii) Chart 5 provides Darlington's and Chart 6 provides Pickering's 3-Year rolling average TGC/MWh for the requested years and normalization methodologies.

Chart 5: Darlington – 3-Year TGC/MWh

Darlington	2018 Study (2015-2017)	2025 Study (2021-2023)	2025 Study (2022-2024)
Non-Normalized	54.40 *Quintile 4*	95.04 *Quintile 5*	115.93 *Quintile 5*
Technology & Unit Age Normalization	43.63 *Quintile 4*	60.41 *Quintile 5*	73.58 *Quintile 5*
Technology, Unit Age & Refurbishment Normalization	39.77 *Quintile 3*	39.58 *Quintile 3*	43.25 *Quintile 4*
Technology, Unit Age, Refurbishment & Outage Duration Normalization	37.94 *Quintile 3*	38.11 *Quintile 3*	42.58 *Quintile 4*

Chart 6: Pickering – 3-Year TGC/MWh

Pickering	2018 Study (2015-2017)	2025 Study (2021-2023)	2025 Study (2022-2024)
Non-Normalized	67.22 *Quintile 5*	64.93 *Quintile 5*	64.78 *Quintile 5*
Technology & Unit Age Normalization	53.13 *Quintile 5*	38.98 *Quintile 3*	37.75 *Quintile 3*
Technology, Unit Age & Outage Duration Normalization	49.26 *Quintile 4*	33.62 *Quintile 3*	33.18 *Quintile 3*

1

Exhibit L-F2-CCC-071, Attachment 1

Detailed calculations supporting each of the Quartile and Quintile Values

This Attachment was filed as confidential information in its entirety.

CCC Interrogatory #072

Interrogatory

Reference:
Exhibit F2, Tab 1, Schedule 1, Attachment 4
EB-2020-0290, Exhibit F2, Tab 1, Schedule 1, Attachment 5

Question(s):

a) Please provide the number of OPG purchased services-related FTEs that were excluded from the study.

b) Please further explain why a comparison of Purchased Service-related FTEs between OPG and the peer group was possible in the previous study (2020) and is no longer possible.

c) Please advise whether IT-related FTEs are included in the current study.

d) Please provide the detailed calculations, and explanations, with respect to the "work week" normalization and the "reactor count" normalization in the current study. Please explain any differences in the methodology applied in the current study relative to the previous study.

e) Please further explain Appendix C in the current study. More specifically, please explain how the FTE ratio was determined.

f) Please explain the main drivers for the difference between the current benchmarked OPG FTEs (4,458) and the previous benchmarked OPG FTEs (5,016).

g) Please explain the main drivers for the difference between the current benchmarked peer FTEs (4,913) and the previous benchmarked peer FTEs (5,255).

Response

a) Refer to Ex. L-F2-Staff-180.

b) Refer to Ex. L-F2-SEC-165, part b).

c) Refer to Ex. L-F2-Staff-191, part a) i).

The following responses (d-f) were prepared by Indeavor:

d) **Work Week:** OPG's 35-hour work week was normalized against the US 40-hour standard. Functions involving administrative/professional staff received the adjustment; maintenance trades and operations shift staff (where staffing is driven by coverage requirements) did not. This is the same treatment as all prior studies.

Reactor Count: 2-unit benchmark scaled to 4-unit using 1.8x (most functions), 2.0x (Operations and related), "Ratio" (Admin and related). Pickering A stays at 2-unit with an additional 16 FTE for cross-tied systems. The “Ratio” was utilized in the previous studies and represents proportional scaling factor used to size and allocate support functions (such as Admin and Accounting) based on the total staff they support; as site staffing rises or falls, these support roles adjust accordingly.

Differences from prior study: None. All normalization factors carried forward identically. The only thing that changes the output is the different 2-unit PWR baseline (different peer data).

Refer to Attachment 1 for the detailed scaling amounts for “work week” and “reactor count” by function.

e) The Appendix C ratios convert EUCG Account Level data to Indeavor Functions. The FTE Ratio was needed because five of eight sites provided data at the EUCG level. The FTE ratios (e.g., EUCG "Engineering" split into Design/Drafting 0.03, Eng-Computer 0.09, Eng-Mods 0.31, Eng-Plant 0.39, Eng-Reactor 0.09, Eng-Technical 0.10) were derived from historical Goodnight data that was shared with Indeavor before the database closed. These FTE ratios were applied to the peer groups' EUCG level data in order to map to the Indeavor Functions. The functional definitions have not changed.

f) Chart 1 provides a breakdown of OPG’s current and previously benchmarked FTEs. The chart below includes external purchased services (“PS”) as identified in column (b) which were excluded from the current staff benchmarking study, as discussed in Ex. L-F2-Staff-180. Inclusion of these FTEs enables a more appropriate comparison to the prior study amount of 5,016 FTEs, which included external purchased services as identified in column (d). For clarity, the decreases shown in the Chart include the effects of the permanent shutdown of Pickering Units 1 and 4 in 2024.

Chart 1: OPG Benchmarked FTEs – 2024 Benchmarked OPG FTEs vs 2019 Benchmarked OPG FTEs

Process Area Summary	2024 Total OPG Benchmarked FTEs (a)	2024 External PS (not included in Study) (b)	2024 Total OPG FTEs (including excluded PS) (c)	2019 Total OPG Benchmarked FTEs (d)	Var FTEs (c)-(d)	% Change
Administrative Services	92	-	92	105	(13)	-12%
Configuration Management	207	13	220	205	15	8%
Equipment Reliability	390	27	417	461	(44)	-10%
Loss Prevention	168	42	210	176	34	20%
Operate The Plant	840	11	851	1,031	(180)	-17%
Personnel Services	654	22	676	685	(9)	-1%
Plant Maintenance	1,283	167	1,450	1,470	(20)	-1%
Radiation Protection	150	2	152	158	(6)	-4%
Supply Chain	183	2	185	186	(1)	0%
Work Management	373	22	395	392	3	1%
Below the Line[1]	118	2	120	147	(27)	-18%
Total OPG FTEs	**4,458**	**310**	**4,768**	**5,016**	**(248)**	**-4.9%**

1. Below the line, is a Nuclear Staff Benchmarking term, which contains Fire Department and Management Support as well as Security Support FTEs (2019 study).

g) Refer to Ex. L-F2-SEC-164, parts b) and d).

CCC Interrogatory #073

Interrogatory

Reference:
Exhibit F2, Tab 2, Schedule 1, Table 1a

Question(s):

a) With respect to the Pickering base OM&A costs proposed for recovery for the 2027-2030 period ($8.1M to $24.6M), please further explain the rationale for those costs in the context that the station is offline during that period.

b) Please provide a breakout of the detailed operations and project support cost categories (e.g., enterprise engineering, integrated fleet management, etc.) for 2020-2031 as between Darlington and Pickering.

Response

a) The forecast Pickering Station Base OM&A costs for the 2027-2030 period primarily reflect regular labour costs associated with Nuclear Operator trainee cohorts required to support post-refurbishment station operations. During this period, the station is expected to see a net reduction in experienced Nuclear Operators driven by workforce attrition. The planned trainee cohorts are therefore required to maintain an adequate supply of qualified operators to support a safe, reliable transition back to commercial operations upon Unit 5 returning to service in 2031. The training program includes, as applicable to role and qualification requirements, CNSC-required simulator training and station qualifications necessary to support staffing for the main control room and station operations in accordance with regulatory and site requirements.

b) Refer to Attachment 1.

Numbers may not add due to rounding.

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EB-2025-0297
Exhibit L
F2-CCC-073
Attachment 1

Base OM&A - OPG Nuclear Facilities - Darlington ($M)

Line No.	Function	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Actual	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Operations and Project Support												
4	Enterprise Engineering	91.9	94.8	88.0	101.3	116.9	116.8	112.7	118.3	118.6	124.6	125.5	126.9
5	Integrated Fleet Management	92.6	89.3	81.7	83.8	99.6	99.1	110.3	119.2	121.8	126.3	127.6	131.5
6	Environment, Health & Safety	10.3	13.0	9.0	7.5	7.3	7.0	6.9	6.7	6.6	6.2	6.4	6.9
7	Enterprise Projects	8.9	9.1	9.3	8.4	9.8	3.8	2.9	2.4	2.3	1.6	1.4	1.9
8	Other Support	28.2	32.1	33.6	37.5	40.5	42.3	47.3	49.0	51.2	51.5	49.8	48.1
9	Low and Intermediate Level Waste	3.5	3.5	8.2	2.7	4.8	2.0	2.4	3.6	3.4	2.6	2.7	2.8
10	**Total Operations and Project Support**	235.4	241.7	229.9	241.2	278.9	271.1	282.6	299.2	303.9	312.8	313.4	318.1

Base OM&A - OPG Nuclear Facilities - Pickering ($M)

Line No.	Function	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Actual	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Operations and Project Support												
4	Enterprise Engineering	125.3	114.5	127.7	141.1	136.0	108.1	105.1	45.7	46.2	49.3	51.5	90.7
5	Integrated Fleet Management	95.6	89.6	91.8	104.8	122.2	96.0	90.0	46.6	47.7	49.7	55.5	73.7
6	Environment, Health & Safety	7.7	8.9	7.0	6.4	6.2	5.1	7.3	7.3	7.7	7.5	8.1	8.6
7	Enterprise Projects	6.6	7.8	8.4	7.7	6.6	3.9	6.5	4.0	4.6	4.9	5.0	5.1
8	Other Support	40.5	40.0	33.8	44.0	43.6	37.0	32.3	20.5	19.2	19.7	21.1	24.6
9	Low and Intermediate Level Waste	3.4	3.2	8.0	9.6	6.8	7.1	7.3	0.0	0.0	0.0	0.0	1.3
10	**Total Operations and Project Support**	279.1	264.0	276.7	313.6	321.5	257.2	248.6	124.1	125.3	131.1	141.3	204.0

CCC Interrogatory #074

Interrogatory

Reference:
Exhibit F2, Tab 2, Schedule 1, Table 2

Question(s):

Please provide a breakout of the base OM&A by resource type for the 2020-2031 period between Darlington and Pickering.

Response

Refer to Attachment 1. The amounts shown in each chart contain the station direct costs and operations and project support costs for each station.

Darlington OPG Facilities Base OM&A - Nuclear ($M)

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	Actual	Actual	Actual	Actual	Actual	Actual	Plan	Plan	Plan	Plan	Plan	Plan
Labour	351.1	357.9	325.4	357.3	369.0	386.8	442.2	485.9	495.4	525.9	527.0	536.8
Non-Regular Labour	36.5	36.3	44.1	52.9	53.7	42.1	24.5	7.4	6.7	7.1	7.2	7.0
Overtime	34.2	29.8	37.8	37.0	39.8	36.7	28.7	31.8	33.0	34.2	35.5	37.3
Augmented Staff	5.4	5.3	4.0	3.7	4.1	4.9	0.3	1.5	1.3	1.3	1.3	1.3
Materials	46.0	43.5	45.8	33.8	41.4	46.0	42.4	51.6	50.0	52.6	54.2	56.1
License Fees	13.5	16.1	15.0	17.2	20.0	17.8	21.7	23.7	24.1	24.6	25.1	25.6
Other Purchased Services	58.4	71.7	74.2	61.8	89.4	71.6	79.3	86.5	78.8	79.2	79.9	80.5
Other	19.0	19.5	25.1	18.3	22.9	25.9	16.7	19.9	20.3	20.1	20.6	21.1
Total Base OM&A	564.2	580.1	571.4	581.9	640.2	631.6	655.9	708.2	709.8	745.1	750.8	765.8

Pickering OPG Facilities Base OM&A - Nuclear ($M)

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	Actual	Actual	Actual	Actual	Actual	Actual	Plan	Plan	Plan	Plan	Plan	Plan
Labour	440.0	399.0	383.5	428.1	465.7	401.5	363.1	84.1	92.5	103.0	111.9	323.3
Non-Regular Labour	89.7	104.2	108.8	123.0	82.1	30.1	20.0	2.7	2.6	2.7	2.8	3.3
Overtime	36.2	40.6	41.3	47.3	49.7	33.8	25.8	4.6	4.9	4.8	5.0	24.3
Augmented Staff	8.1	7.9	5.8	5.6	4.1	3.2	0.3	0.1	0.0	0.0	0.0	0.1
Materials	59.5	58.0	60.6	76.4	73.2	56.8	40.3	2.3	2.4	2.3	2.4	29.8
License Fees	18.1	18.3	18.5	19.9	20.7	16.2	13.9	0.0	0.0	0.0	0.0	5.3
Other Purchased Services	71.8	79.4	85.4	81.7	75.5	53.5	75.3	31.0	31.5	31.9	34.5	61.0
Other	26.3	28.4	30.5	55.1	22.2	23.6	15.6	7.4	7.1	8.6	9.4	12.6
Total Base OM&A	749.7	735.9	734.2	837.0	793.2	618.7	554.3	132.2	140.9	153.4	166.0	459.7

CCC Interrogatory #075

Interrogatory

Reference:
Exhibit F2, Tab 3, Schedule 3, Table 4

Question(s):

For each unallocated portfolio project shown in Table 4, please provide a detailed description of the project and the estimated cost per year over the duration of the project.

Response

Refer to Ex. L-D2-SEC-56, Attachment 4, for detailed project descriptions and Attachment 1 for estimated costs per year over the IR term.

As discussed in Ex. L-D2-SEC-61, part a), the unallocated capital portfolio includes potential projects expected to start in the future, as selected and prioritized through the asset management process described in Ex. D2-1-1, Section 3.2, and recognizes that these proposed investments have not yet been fully scoped and are based on pre-Class 5 estimates. These considerations also apply to the unallocated Project OM&A portfolio.

Additionally, as the project portfolios are reviewed as part of the annual business planning process based on risk and business need, some investments in the unallocated portfolio may not proceed as anticipated at the time of the approved plan or may be replaced by new investments necessary to address an emerging risk. Notwithstanding the inherently dynamic nature of these early-stage candidate investments, they inform the reasonableness of the overall unallocated Project OM&A envelope.

Attachment 1
Nuclear OM&A Projects - Portfolio Projects (Unallocated)

Project Number	Project Name	Potential Project Start date	Potential Project End date	Estimated Investment Cost	Estimated Investment Cash Flow (2025)	Estimated Investment Cash Flow (2026)	Estimated Investment Cash Flow (2027)	Estimated Investment Cash Flow (2028)	Estimated Investment Cash Flow (2029)	Estimated Investment Cash Flow (2030)	Estimated Investment Cash Flow (2031)	Notes
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(n)
Darlington NGS - Projects With Potential Cost >$5M and < $20M												
86299	DN HFD & LISS D2O Feed Line Cut & Cap	2025	2031	12.7	0.3	1.2	2.1	2.5	3.6	1.3	1.7	
89680	DN CANDU 6 Fuel Channel Surveillance	2025	2031	11.8	-	-	0.8	5.4	2.9	2.7	-	Note 1
Darlington NGS - Projects With Potential Cost ≥ $20M												
89223	DN U2 Primary Heat Transport Pump Motors Oil Leak Repairs	2025	2031	29.2	-	4.1	8.6	8.9	7.6	-	-	
Pickering NGS - Projects With Potential Cost >$5M and < $20M												
89802	PN Pickering For The Future (P4F)	2026	2031	8.9	-	0.5	1.2	1.4	1.9	1.8	2.1	
89807	PN Primary Heat Transport & Auxiliaries Inspections	2029	>2031	10.2	-	-	-	-	0.9	1.5	2.0	
89808	PN Buried Piping Inspections	2027	>2031	12.0	-	-	1.3	1.5	1.3	1.9	3.2	
Pickering NGS - Projects With Potential Cost ≥ $20M												
89800	PN Vacuum Building Civil Structures	2026	2031	13.3	-	0.3	0.7	2.7	4.4	4.7	0.5	
Advanced Inspection and Maintenance - Projects With Potential Cost ≥ $20M												
89282	AIM End of Life Fuel Channel Component Retrieval	2027	>2031	16.3	-	-	1.8	6.0	4.5	4.0	-	
Total Estimated Investment Cash Flows					**0.3**	**6.1**	**16.5**	**28.3**	**27.0**	**17.9**	**9.5**	

Notes:

1 In F2-3-3 Table 4, Project 89280 – DN Software Inventory Management 69000 was incorrectly included in the table and should be replaced with 89680 – DN Candu 6 Fuel Channel Surveillance. Project 89280 is under $5M and has no planned costs within the 2027-3031 period.

CCC Interrogatory #076

Interrogatory

Reference:
Exhibit F1, Tab 1, Schedule 1, Table 1

Preamble:

The evidence sets out the proposed Outage and Cyclical maintenance costs planned by OPG from 2027 to 2031.

Question(s):

a) Please describe what happens when a planned outage is avoided or deferred, i.e. are the planned outage costs entirely obviated?

b) Please confirm that the scope and timing of outages and cyclical maintenance included in this category of cost are defined by regulatory requirements, and that neither the scope nor the timing of either can be changed without regulatory approval. If not confirmed, please split the costs for the 2027 to 2031 period included on Table 1 between costs relating to work that the scope and timing of which is dictated by regulatory requirements, and work that the scope and timing of which is determined by OPG.

c) How much outage OM&A was included on a forecast basis for the Darlington Unit 2 Turbine Control and Auxiliary Systems Upgrade originally scheduled for 2025?

d) How much outage OM&A is included in the 2027 forecast for the Darlington Unit 2 Turbine Control and Auxiliary Systems Upgrade originally scheduled for 2025?

Response

OPG understands the question is referring to OPG Nuclear Facilities Outage OM&A in Ex. F2-1-1, Table 1a, line 3 and not Ex. F1-1-1, Table 1 cited in the Reference.

a) Planned outages and associated outage costs cannot be avoided. There is a regulatory requirement to perform a Periodic Inspection Program on major components (e.g., fuel channels, feeders, steam generators), which require outages to be taken at regular intervals. The CNSC-approved outage interval is 30-months for Pickering and 36-months for Darlington and OPG is required to demonstrate fitness-for-service to operate to the next planned outage. Planned

outages are also required to execute necessary maintenance and replacements or modifications of equipment that can only be performed when the unit is shut down, as described in Ex. E2-1-1, Section 2.2, p. 3, lines 11-16. Although a planned outage cannot be avoided, there have been instances where an outage start time has been changed (i.e., typically within six months of the planned outage) and the corresponding planned outage costs would be incurred based on execution at that time.

b) Partially confirmed. A portion of the scope of each outage and the timing of each outage is defined by regulatory requirements, and the remaining portion of the scope of each outage is within OPG's discretion. As discussed in part a), outage timing is defined by regulatory requirements for preventative maintenance and inspections and requires regulatory approval to change. This typically represents 40-60% of each outage's scope; the remainder is comprised of additional preventative maintenance, corrective maintenance, and projects to sustain and improve plant reliability.

   Due to the level of complexity and nature of outage planning, OPG is unable to split 2027-2031 Outage OM&A costs included in Ex. F2-1-1, Table 1, line 3 between regulatory and non-regulatory scope requirements. As documented in Ex. E2-1-1, Section 2.2, p. 3, lines 4-8, a typical outage has up to 20,000 work activities. As each outage scope is different and scope freeze milestones are one to two years in advance of an outage start, OPG is unable to provide the requested outage cost split.

c) Zero outage OM&A costs was included on a forecast basis for the Darlington Unit 2 Turbine Control and Auxiliary Systems Upgrade originally scheduled for 2025 as that scope is a capital project.

d) Zero outage OM&A costs is included in the 2027 forecast for the Darlington Unit 2 Turbine Control and Auxiliary Systems Upgrade as that scope is a capital project.

CCC Interrogatory #077

Interrogatory

Reference:
Exhibit F2, Tab 5, Schedule 1, pp. 2-3, 10-12

Question(s):

a) Please provide a comparison, in the same format as shown in Chart 1 (including the attribution factors for the variances), of the actual nuclear fuel bundle costs for the 2017-2021 period and the forecast provided in EB-2020-0290.

b) Please provide a comparison, in the same format as shown in Chart 1 (including the attribution factors for the variances), of the actual nuclear fuel bundle costs for the 2017-2021 period and the actual costs / updated forecasts for the 2022-2026 period.

c) Please provide an expanded version of Chart 4 (Uranium Spot Prices) that extends the historical period to at least 2017 (or prior if OPG has that information readily available).

d) Please discuss which aspects of the nuclear fuel costs (i.e., Uranium concentrate, Uranium conversion, and manufactured fuel bundles) are impacted by commodity cost volatility.

e) With respect to the Uranium Concentrate Pricing Provisions and Fuel Contracts:

   i. Please expand chart 3 to include the pricing mechanism associated with those term contracts.
   ii. Please further explain the extent to which fixed pricing contracts are used (including the percentage of total purchases).
   iii. Please provide further details regarding base-escalated arrangements. As part of the response, discuss whether there is a difference between the “escalator formulas” applied and inflation index escalators.
   iv. Please explain the need for spot purchases in the context of the known production levels.

Response

a) Comparison of the actual nuclear fuel bundle costs for the 2017-2021 period to the forecast period 2022-2026 as provided in EB-2020-0290 (before OEB-approved settlement adjustments) is shown in Chart 1:

Chart 1 – Comparison of Nuclear Fuel Bundle Costs (EB-2020-0290)

Comparison Periods	Amounts in CAD ($M)
IR Term (2022-2026) OEB-Approved Cost	637.9
2017-2021 Actual Cost	862.9
Net Variance	(225.0)
Attribution Factors of Net Variance:	
Uranium Concentrate, Conversion Services, and Nuclear Fuel Bundle Manufacturing Costs	2.1
Energy Production (together with Fuel Utilization Efficiency)	(227.1)
Net Variance	(225.0)

b) Comparison of the actual nuclear fuel bundle costs for the 2017-2021 period to actual costs / updated forecasts for the 2022-2026 period as provided in Ex. F2-5-1 is shown in Chart 2:

Chart 2 – Comparison of Nuclear Fuel Bundle Costs (EB-2025-0297)

Comparison Periods	Amounts in CAD ($M)
IR Term (2022-2026) Actual/Budget Cost	818.5
2017-2021 Actual Cost	862.9
Net Variance	(44.4)
Attribution Factors of Net Variance:	
Uranium Concentrate, Conversion Services, and Nuclear Fuel Bundle Manufacturing Costs	72.6
Energy Production (together with Fuel Utilization Efficiency)	(117)
Net Variance	(44.4)

c) An expanded version of Ex. F2-5-1, Chart 4 (Uranium Spot Prices) that extends the historical period to at least 2017 is provided as Attachment 1.

d) Nuclear fuel cost drivers, including uranium concentrates, uranium conversion services and fuel bundle manufacturing services, are all impacted by commodity cost volatility. This volatility may reflect the cost of underlying commodities,

including uranium concentrates, nuclear-grade zirconium, and inputs associated with production, such as energy and labour.

e)

i. Refer to Ex. L-F2-SEC-170.

ii. Refer to Ex. F2-5-1, Section 4.2, p. 9, lines 11-15 and Ex. F2-5-1, Section 6.2, p. 16, lines 16-21 for discussion on OPG's financial coverage limits for uranium concentrates.

iii. Base-escalated pricing typically references a U.S. gross domestic product implicit price deflator ("GDP-IPD") index, which is similar to, but not exactly the same as, a U.S. CPI index. Base-escalated arrangements typically set a starting base price as of a specific calendar quarter, and the starting base price is then escalated by the ratio of the GDP-IPD index value on the delivery date divided by the starting GDP-IPD index value (where the starting GDP-IPD index value is usually defined in the same calendar quarter as the starting base price).

iv. While OPG has not conducted spot purchasing of uranium concentrate in recent years, it may use spot purchases if near term (i.e., one to two years) demand profiles change such that additional short-term uranium physical coverage is needed to maintain inventory level targets. OPG may also evaluate, during RFP processes, options to purchase uranium concentrate on the spot market with prompt delivery and carry such inventory into the future, as compared to the cost of purchasing under a term contract with future deliveries aligned with consumption years.

Uranium (USD/Lbs) 84.300 -0.100 (-0.12%)
100
84.300
60
40
20
2018
2020
2022
2024
2026
1Y
5Y
10Y
25Y
All

CCC Interrogatory #078

Interrogatory

Reference:
Exhibit F2, Tab 6, Schedule 1, p. 1

Preamble:

As detailed in Ex. F2-2-1, Section 3.1, OM&A purchased services represent the costs of specialized external services, primarily for construction and maintenance services supporting work programs. An overview of OPG's procurement processes is presented in Ex. F3-3-1. Total OM&A purchase services expenditures for all contractors for the historical period (2020-2024) was $247.6M in 2020, $300.5M in 2021, $255.5M in 2022, $287.4M in 2023, and $275.6M in 2024. The average annual OM&A purchased services for the regulated nuclear facilities for all contractors over the period of 2020-2024 was $273.3M.

Question(s):

a) What are the budgeted OM&A purchased services expenditures for 2025, 2026, 2027, 2028, 2029, 2030 and 2031?

b) What was the average number of separate contracts/providers per year?

Response

a) Chart 1 below indicates the 2025 actual and 2026 to 2031 budgeted purchased services expenditures.

Chart 1 - OPG Nuclear Facilities Purchased Services 2025 to 2031 ($M)

OPG Nuclear Facilities Cost Category	2025 Actual	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan	Reference
Base OM&A	125.2	154.5	117.5	110.3	111.2	114.4	141.5	Ex. L-A1-CCC-001, Att. 1, Table 41
Project OM&A	26.9	N/A	N/A	N/A	N/A	N/A	N/A	Not Available[1]
Outage OM&A	69.5	113.7	128.6	56.6	119.8	63.1	77.4	Ex. F2-4-1, Table 2
Pickering Cyclical Maintenance OM&A	0.0	0.0	28.8	34.7	35.7	35.1	19.1	Ex. F2-4-1, Table 3
Pickering Refurbishment OM&A	0.0	4.2	93.8	79.1	68.0	38.0	38.2	Reflected in Ex. F2-8-1, Table 1
Total OM&A Purchased Services	221.6	272.4	368.7	280.7	334.7	250.6	276.2	

[1] Projects funded through OM&A expenditures are managed through the Project and Portfolio Management process as explained in Ex. D2-1-1. Consistent with previous IR terms, planned purchased service costs in 2026-2031 for Project OM&A are not available due to projects being in various phase gates.

b) OPG interprets this question as being the average number of distinct providers with spend, per year, between 2020-2024. The average number of separate providers per year was 402.

CCC Interrogatory #079

Interrogatory

Reference:
Exhibit F2, Tab 7, Schedule 1, pp. 1-2

Question(s):

Please provide a more detailed explanation regarding the reason for, including any relevant excerpts from the EB-2020-0290 evidence, regarding the TG Execution Project and Strainer Project write-offs. As part of the response, please advise whether these write-offs are part of the recovery sought in the current proceeding (including as an offset to any credits recorded in the relevant deferral and variance accounts).

Response

The Strainer Project write-off was reflected as a non-capital cost in 2020, as previously described in EB-2020-0290, Ex. F2-7-1, p.1, lines 27-31. As noted in that evidence, the 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.

The TG Execution Project write-off occurred at the end of 2020 and resulted from the business decision to change the stator scope from a stator swap to an in-situ rewind. Per EB-2020-0290, Tr. Tech. Conf., May 3, 2021, p. 19, lines 11-22, the benefits of shifting to the in-situ rewind included reducing the complexity and safety issues related to rigging, hoisting and moving the stator as well as potential mechanical fit issues.

The Strainer Project write-off amount was $6.4M and the TG Execution write-off amount was $8.8M. These amounts represent non-capital costs prudently incurred as part of completing the four-unit refurbishment and are included in the forecast cost of $12.7B for completing the DRP provided in the pre-filed evidence, which remains within the approved budget of $12.8B. The year-end 2024 DRP-related balance in the CRVA includes these non-capital costs, for which recovery is sought in this Application.[1]

As noted in Ex. D2-2-1, p. 2, lines 1-13, the EB-2020-0290 OEB-approved settlement proposal provides that the OEB will review the prudence of any DRP amounts sought by OPG in excess of the $12.8B total.

[1] As presented at Ex. H1-1-1, Table 15, line 2, col. (g), which aligns to Ex. F2-7-1, Table 2, line 1, col. (c).

CCC Interrogatory #080

Interrogatory

Reference:
Exhibit F1, Tab 1, Schedule 1, pp. 1-2

Preamble:

The PRP 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.

The removal costs are associated with the replacement of existing assets in the period in which they are incurred. They include costs associated with disassembling and removal of a component to gain access to a subcomponent to be replaced. Removal costs encompass direct execution removal activities plus any specific execution indirect cost related to the removal program. These costs have been forecasted as part of the PRP Release Quality Estimate.

Question(s):

a) Please confirm that the L&ILW variable expenses are included in the calculated nuclear liability expense. If not confirmed, please provide further explanation as to why these L&ILW costs are incremental to the costs tracked as part of the nuclear liability expense.

b) Please explain why the removal costs are considered OM&A costs and not capital costs, since they relate to the refurbishment. Please explain whether or not the removal costs involve the permanent removal of assets, or only the temporary removal of assets in order to access assets that are being replaced, with the "removed" assets ultimately being put back in place.

Response

OPG confirms that all low & intermediate level waste ("L&ILW") variable expenses within Project OM&A expenses for the Pickering Refurbishment Program are included in the calculation of the revenue requirement of OPG's nuclear liabilities, which is shown at Ex. C2-1-1, Table 1.[1]

[1] In preparing the response to this interrogatory, OPG identified that the amount of PRP-related L&ILW variable expenses included in the total forecast L&ILW variable expenses at Ex. C2-1-1, Table 2 differs by a net amount of $3M from the amounts reflected in Ex. F2-8-1 based on the PRP RQE. The revenue requirement impact of correcting these amounts at Ex. C2-1-1 is less than

a) As noted in Ex. F2-8-1, p. 2, lines 13-16, removal costs include the permanent removal of existing assets along with costs associated with disassembling and temporary removal of a component to gain access to a subcomponent to be replaced. Removal costs encompass direct execution of removal activities plus any specific execution of indirect cost related to the removal program.

Removal costs are accounted for as OM&A costs in accordance with US GAAP. This treatment is consistent with how OPG's other projects, including the Darlington Refurbishment Program, have accounted for such costs.

$0.1M annually, on average, over the 2027-2031 IR term. OPG does not propose to adjust the proposed revenue requirement for these differences.

Minogi Corp Interrogatory #008

Interrogatory

Reference:

- **Exhibit F2, Tab 2, Schedule 1**
- **Exhibit F2, Tab 3**
- **Exhibit F2, Tab 6**
- **Exhibit F2, Tab 7, Schedule 1**
- **Exhibit F2, Tab 8, Schedule 1**
- **Exhibit F3, Tab 3, Schedules 1 and 2**

Question(s):

a) Please identify all forecast OM&A, corporate, HR, IT, or compliance costs for implementing, administering, monitoring, or reporting on procurement requirements, including *Buy Ontario Act*.

b) For each cost identified in part a), please provide:

(i) amounts by year for 2027 to 2031;
(ii) business unit/cost centre;
(iii) nature of cost; and
(iv) rationale for cost.

c) Please outline outreach measures for local and First Nation rightsholder suppliers near Pickering and Darlington to ensure visibility and practical access to procurement opportunities.

d) Please provide any internal analyses on local and First Nation rightsholder participation reducing mobilization, logistics, or schedule risks for Pickering refurbishment or DNNP.

Response

a) Based on the *Buy Ontario Act* and the requirements issued to date, related administrative costs are embedded within OPG's existing procurement process and does not result in incremental or material costs beyond those already reflected in OPG's 2025-2031 Business Plan. The Applicants will continue to monitor additional requirements issued by the Province of Ontario and assess any impacts at that time.

b) Not applicable.

c) OPG's supplier outreach strategies focus on expanding awareness of procurement opportunities and improving access for a broad and diverse supplier base. This includes sharing upcoming contracting opportunities through supplier information sessions and industry days, maintaining clear procurement information, and engaging with the market to explain requirements, timelines, and how to do business with OPG. OPG works with Indigenous and other diverse suppliers by promoting networking and capability-building opportunities, with the aim of increasing participation, competition, and value in its supply chain. Refer to Ex. L-F3-MC-011 for information regarding outreach and economic inclusion initiatives.

d) Refer to Ex. L-D3-MC-005.

OAPPA Interrogatory #012

Interrogatory

Reference:
Exhibit F2 / Tab 5 / Schedule 1 / Page 5 of 18, Chart 2 – "Fuel Costs per MWh (2024 Benchmark Report)"

Question(s):

a) Please reconcile the $4.43/MWh for Darlington and $3.98/MWh for Pickering shown in this chart, versus the $4.65/MWh otherwise shown as the cost average for both, in the other Exhibit F2 Tables (for e.g. in F2 / Tab 5 / Schedule 1 / Tab 1b, line 2).

Response

a) The benchmarked amounts ($4.43/MWh for Darlington and $3.98/MWh for Pickering) shown in Ex. F2-5-1, p. 5, Chart 2 and the $4.65/MWh total CANDU fuel bundle cost in Ex. F2-5-1, Table 1a are calculated on different bases, which prevents these amounts from being reconciled. The benchmarked amounts are calculated for each station for 2023 based on a three-year rolling average (i.e., 2021-2023), whereas the $4.65/MWh total CANDU fuel bundle cost reflects a single-year (2024) average for both stations combined.

OAPPA Interrogatory #013

Interrogatory

Reference:
Exhibit F2 / Tab 5 / Schedule 1 / Page 6

Preamble:

"The OPG nuclear fuel supply objectives are to:

- Ensure security of supply: OPG must minimize the risk of its reactors being shut down due to lack of fuel bundles, including the risk that any step in the supply chain is substantially delayed due to a lack of materials from an earlier step.

- Minimize cost: OPG seeks to obtain its fuel supply at the lowest cost, consistent with its fuel quality requirements".

Question(s):

a) How does OPG quantify and consequently manage the supply risk associated with the DNNP, GE-Hitachi's BWRX-300 fuel supply from foreign-controlled sources, if different from domestic Candu fuel sources?

b) Is there any reliance on the current NAFTA, or other trade agreements that will ensure that the reliability of GE-Hitachi's BWRX-300 fuel supply? If so, please explain. Please describe any contingency plans.

c) Will the GE-Hitachi's BWRX-300 fuel supply be subject to tariffs or duties from the US? If there is a risk, how significant is it? Please describe any contingency plans.

d) Are the transportation requirements for the GE-Hitachi's BWRX-300 fuel supply different than those required for the Candu fuel bundles? Is so, please describe.

e) How does the current costing mechanism share nuclear fuel price risk between OPG and rate payers?

Response

a) As discussed in Ex. F2-5-1, the nuclear fuel for the DNNP BWRX-300 reactors requires low-enriched uranium whereas the nuclear fuel for CANDU reactors requires natural uranium. This difference means that the DNNP facilities require

several services as part of their nuclear fuel supply chain which are currently not available in Canada, including uranium enrichment services, low-enriched uranium hexafluoride deconversion services and low-enriched fuel fabrication services.

OPG identifies and assesses foreign nuclear fuel supply chain risks through nuclear fuel planning, sourcing and procurement process that draws on market intelligence and ongoing engagement with key suppliers and industry stakeholders. OPG manages supply chain risks across the short, medium, and long term through a deliberate set of mitigating measures, including diversifying suppliers across jurisdictions. Additional details can be found at Ex. C1-1-1, Attachment 3, pp. 23-27. OPG is also working with government and industry partners to support ongoing efforts to strengthen Canadian supply chain sovereignty for low-enriched fuel.

b) and c)

There is a reliance on the Canada – United States – Mexico Agreement ("CUSMA") to facilitate transportation of nuclear material in various forms between Canada and the United States and vice versa. For example, natural uranium hexafluoride will be transported from Canada to the United States for enrichment, and finished fuel assemblies will be transported from the United States to Canada at the DNNP site. Additionally, imports of uranium into the United States from Canada are currently exempt from tariffs.

OPG monitors and assesses the trade environment between Canada and the United States to identify and mitigate associated risks. OPG is unable to speculate on the specific extent of impacts that may arise in the future trade environment between Canada and the United States. Refer to the part a) for a discussion of risk mitigation.

d) Yes, the transportation requirements for GE-Hitachi BWRX-300 fuel supply are different than those required for CANDU fuel bundles. There are differences in import license requirements, transportation packaging and packing licensing requirements, transportation license requirements and insurance coverages as between the two types of nuclear fuel.

e) Under the proposals in the Application, the Applicants assume all nuclear fuel price risk for the IR term, with the exception of any such risks covered by the proposed Change of Laws Deferral Accounts. Refer to Ex. L-F2-OAPPA-014 for additional discussion.

OAPPA Interrogatory #014

Interrogatory

Reference:
Exhibit F2 / Tab 5 / Schedule 1 / Page 9

Preamble:

"OPG's financial coverage limits specify the maximum and minimum portion of supply to be under fixed-price or base-escalated arrangements, expressed as a percentage of OPG's aggregate amount under contract. OPG's financial coverage limits are unchanged from EB-2020-0290, with a minimum to maximum range of 45% to 65%".

Question(s):

a) Acknowledging that fixed-price arrangements are effective price insurance mechanisms, it is understood that they inherently include a cost, or premium, for mitigating volatile market price risk. Consequently, fixed price arrangements are more likely to affect higher fuel costs, over the longer term, all other things being equal. Could OPG opine on an alternative mechanism – perhaps, but not necessarily, analogously to how Enbridge currently manages its natural gas purchases for its "system gas" rate payers - such that both OPG and Rate Payers could be protected from market price volatility and lower fuel costs in the longer term?

Response

a) The Applicants are not in a position to opine on how Enbridge Gas Distribution currently manages its natural gas purchases. As discussed in Ex. F2-5-1, Section 4.2, OPG maintains prudent physical and financial coverage limits for uranium procurement with a view to managing cost, supply and other risks.

   The Applicants have considered the possibility of requesting a nuclear fuel cost variance account similar to the one granted to OPG in EB-2007-0905[1]; however, having considered the OEB's decision in EB-2010-0008[2] that discontinued the account, have not made this request in this Application.

[1] EB-2007-0905 Payment Amounts Order, App. F, pp. 5-6.
[2] EB-2010-0008 Decision with Reasons, March 10, 2011, p. 55.

SEC Interrogatory #157

Interrogatory

Reference:
F2-1-1
EB-2020-0290, F2-Staff-196

Question(s):

With respect to OPG's nuclear benchmarking performance:

a) Please provide a table that compares OPG's actual performance between 2021-2025, against its annual targets provided in EB-2020-0290, F2-Staff-196, Charts 3 and 4. Please ensure the same methodology used for the targets is used for actual performance.

b) Please provide a comparison of OPG's actual performance between 2021-2025, against the annual targets for Normalized Total Generation Cost Per MWh and Normalized Total Generation Cost Per Unit provided in EB-2020-0290, F2-Staff-196, Charts 3 and 4. In doing so please, a) use the same methodology for the targets that is used for actual performance, b) revise the annual targets to reflect the actual in-service dates as a result of the DRP, as compared to what was forecast when setting the targets, c) revise the annual targets to reflect Pickering extended operations and extension timing, compared to what was forecast when setting the targets. For each of (b) and (c) please explain the specific calculations made and their basis.

c) For each of OPG's Value For Money metric scores, please provide all underlying calculations of the scores, and provide direct reference to amounts included in the cost and production tables in its pre-filed evidence for those numbers. If adjustments were made from information included in the various cost and production forecast included in the evidence, please provide a full explanation.

Response

a) Chart 1 and Chart 2 below show 2021-2025 annual actual results and such annual targets provided in EB-2020-0290, Ex. L-F2-Staff-196, Charts 3 and 4 for Pickering and Darlington, respectively.

Chart 1 - Pickering 2021-2025 Annual Actuals and Targets

Benchmarking Indicators	Pickering									
	2021		2022		2023		2024		2025	
	Actual	Target	Actual	Target	Actual	Target	Actual	Target	Actual	Target
Safety										
Total Recordable Injury Frequency (#/200k hours worked)	0.10	0.13	0.27	0.10	0.20	0.09	0.20	0.09	0.07	0.08
Total Industrial Safety Accident Rate (#/200k hours worked)[1]	0.03	0.10	0.00	0.10	0.00	0.10	0.00	0.10	0.00	0.10
Collective Radiation Exposure (person-rem per unit) [6]	67.74	94.50	69.99	101.00	67.17	99.50	47.02	72.70	34.14	19.50
Airborne Tritium Emissions (Curies) per unit	2,331	2,250	2,229	2,200	2,164	2,200	1,820	2,070	1,392	2,000
Fuel Reliability Index (microcuries per gram)	0.0008	0.0005	0.0002	0.0005	0.0003	0.0005	0.0002	0.0005	0.0009	0.0005
Reactor Automatic and Manual Trip Rate (# per 7,000 hours)[2]	0.00	0.50	0.139	0.50	0.247	0.50	0.32	0.50	0.36	0.50
Auxiliary Feedwater System Unavailability (#)	0.0085	0.02	0.001	0.02	0.00	0.02	0.00	0.02	0.00	0.02
Emergency AC Power Unavailability (#)	0.00	0.025	0.00	0.025	0.00	0.025	0.00	0.025	0.00	0.025
High Pressure Safety Injection Unavailability (#)	0.00	0.02	0.00	0.02	0.00	0.02	0.00	0.02	0.00	0.02
Reliability										
WANO Performance Indicator Index (%)[3]	73.80	74.70	80.9	76.90	81.20	75.70	84.95	80.30	88.11	85.60
Forced Loss Rate (%)	6.22	3.50	1.81	3.50	2.78	3.50	2.56	3.50	2.96	3.50
Unit Capability Rate (%) [4]	-	-	-	-	-	-	96.36	-	96.72	-

Unit Capability Factor (%) [4]	78.92	80.00	80.01	74.10	80.66	79.40	83.30	83.30	91.49	93.20
Chemistry Performance Indicator (Index)	1.06	1.01	1.03	1.03	1.18	1.01	1.22	1.01	1.08	1.00
On-line Deficient Non-Critical Backlog (work orders / unit)	68.00	57.00	39.80	52.00	29.50	46.00	20.20	39.00	12.75	39.00
On-line Deficient Critical Backlog (work orders /unit)	1.30	0.00	0.80	0.00	0.67	0.00	0.60	0.00	0.00	0.00
On-line Corrective Non-Critical Backlog (work orders /unit)	6.30	2.00	3.80	2.00	0.83	2.00	1.20	2.00	0.25	2.00
On-line Corrective Critical Backlog (work orders /unit)	0.30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Value for Money [5]										
Normalized Total Generating Cost per Net MWh - Updated Methodology ($/MWh)**	33.36	-	30.06	-	37.36	-	32.03	-	32.04	-
Normalized Total Generating Cost per Net MWh - Original Methodology ($/MWh)**	44.76	45.31	39.55	47.49	48.02	42.12	41.74	37.62	41.78	23.48
Total Generating Cost per Net MWh ($/MWh)**	64.75	64.50	60.05	68.72	69.98	61.76	64.30	57.02	70.53	46.61
Normalized Total Generating Cost per Unit - Updated Methodology ($/MWh)**	140.45	-	121.17	-	153.88	-	128.77	-	135.95	-
Normalized Total Generating Cost per Unit - Original Methodology ($/MWh)**	169.54	173.85	151.79	169.43	184.98	160.43	159.69	144.39	183.29	69.39

Total Generating Cost per Unit ($M/unit)**	227.59	229.93	214.11	226.44	250.49	218.38	228.49	203.31	290.23	129.29
Non-Fuel Operating Cost per Net MWh ($/MWh)**	57.24	57.18	54.40	62.09	63.24	55.77	57.65	51.06	59.56	40.96
Fuel Cost per Net MWh ($/MWh)	3.72	3.83	3.75	3.90	3.90	4.01	4.29	4.17	5.12	4.52
Capital Cost per MW DER ($k/MW)***	25.79	24.10	13.12	17.45	19.71	13.54	16.27	12.33	46.69	6.07
Human Performance										
18-month Human Performance Error Rate (#/200k ISAR and contractor hours)	0.02	0.07	0.06	0.07	0.06	0.04	0.00	0.04	0.03	0.04

*** 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: Industrial Safety Accident Rate (ISAR2) has been replaced by Total Industrial Safety Accident Rate (TISA2) in Q1 2024 to align with WPII 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 2: Reactor Trip Rate was replaced by Reactor Automatic & Manual Trip Rate following the WPII 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 3: The WANO Performance Indicator Index (WPII) Method 10, previously known as the Nuclear Performance Index (NPI), is a 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). WPII is calculated using a 2-year rolling average for PN and a 3-year rolling average for DN.

Note 4: UCR replaced UCF due to WPII 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 5: All metrics, including Value for Money targets 2021 – 2025 in EB-2020-0290 are reviewed annually and updated as required as part of the business planning process.

Note 6: CRE 2024 Actuals have been corrected.

Chart 2 - Darlington 2021-2025 Annual Actuals and Targets

Benchmarking Indicators	Darlington									
	2021		2022		2023		2024		2025	
	Actual	Target	Actual	Target	Actual	Target	Actual	Target	Actual	Target
Safety										
Total Recordable Injury Frequency (#/200k hours worked)	0.07	0.17	0.08	0.10	0.00	0.09	0.20	0.09	0.08	0.08
Total Industrial Safety Accident Rate (#/200k hours worked)[1]	0.00	0.10	0.00	0.10	0.00	0.10	0.00	0.10	0.00	0.10
Collective Radiation	110.47	126.20	29.90	21.10	15.64	73.90	65.05	40.00	11.26	78.20

Exposure (person-rem per unit) [6]										
Airborne Tritium Emissions (Curies) per unit	905	970	1,157	970	1,000	970	958	970	1,060	970
Fuel Reliability Index (microcuries per gram)	0.0002	0.0005	0.0001	0.0005	0.0001	0.0005	0.0029	0.0005	0.0016	0.0005
Reactor Automatic and Manual Trip Rate (# per 7,000 hours)[2]	0.00	0.50	0.000	0.50	0.100	0.50	0.10	0.50	0.10	0.50
Auxiliary Feedwater System Unavailability (#)	0.0000	0.02	0.000	0.02	0.00	0.02	0.00	0.02	0.00	0.02
Emergency AC Power Unavailability (#)	0.00	0.025	0.00	0.025	0.00	0.025	0.00	0.025	0.00	0.025
High Pressure Safety Injection Unavailability (#)	0.00	0.02	0.00	0.02	0.00	0.02	0.00	0.02	0.00	0.02
Reliability										
WANO Performance Indicator Index (%)[3]	85.80	84.30	91.4	93.10	89.40	77.54	74.74	86.90	71.11	84.75
Forced Loss Rate (%)	3.52	3.79	7.51	2.12	1.44	1.20	12.07	5.99	2.01	6.42
Unit Capability Rate (%) [4]	-	-	-	-	-	-	86.97	-	97.18	-
Unit Capability Factor (%) [4]	82.66	76.00	86.99	85.80	96.99	78.10	74.58	81.80	95.69	68.20
Chemistry Performance Indicator (Index)	1.01	1.01	1.00	1.01	1.01	1.01	1.03	1.01	1.05	1.01
On-line Deficient Non-Critical Backlog (work orders / unit)	70.33	90.00	61.00	75.00	29.00	65.00	17.33	60.00	12.33	41.00
On-line Deficient Critical Backlog (work orders /unit)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
On-line Corrective Non-Critical Backlog (work orders /unit)	2.00	2.00	0.50	2.00	0.00	2.00	0.00	2.00	0.00	2.00
On-line Corrective Critical Backlog (work orders /unit)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Value for Money [5]										
Normalized Total Generating Cost per Net MWh - Updated Methodology ($/MWh)**	36.49	-	37.49	-	41.10	-	49.37	-	35.14	-
Normalized Total Generating Cost per Net MWh -	45.59	58.15	33.88	45.83	36.60	60.24	51.27	42.92	37.28	59.81

Original Methodology ($/MWh)**[6]										
Total Generating Cost per Net MWh ($/MWh)**	79.27	94.47	101.52	105.67	108.85	153.08	141.94	115.22	71.66	109.04
Normalized Total Generating Cost per Unit - Updated Methodology ($/MWh)**	257.48	-	237.33	-	292.34	-	305.77	-	246.14	-
Normalized Total Generating Cost per Unit - Original Methodology ($/MWh)**	297.90	348.94	238.91	313.25	287.92	377.55	308.25	280.05	282.44	323.34
Total Generating Cost per Unit ($M/unit)**	489.03	532.35	663.52	667.78	796.56	861.14	780.21	688.64	516.67	545.31
Normalized Non-Fuel Operating Cost per Net MWh ($/MWh)**	47.29	55.93	41.51	47.51	41.83	71.30	63.04	52.78	36.81	63.53
Non-Fuel Operating Cost per Net MWh ($/MWh)**	57.64	66.89	64.98	70.02	67.14	109.38	95.70	80.61	47.13	79.78
Fuel Cost per Net MWh ($/MWh)	4.00	4.08	3.82	4.10	4.32	4.35	5.29	5.16	5.23	5.11
Normalized Capital Cost per MW DER (k$/MW)***	90.52	119.86	104.28	139.75	133.09	140.56	111.39	170.48	114.84	102.52
Capital Cost per MW DER ($k/MW)***	123.88	150.87	243.57	227.16	311.66	252.11	256.36	276.82	158.52	135.48
Human Performance										
18-month Human Performance Error Rate (#/200k ISAR and contractor hours)	0.02	0.04	0.00	0.04	0.00	0.02	0.00	0.02	0.02	0.02

** *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: Industrial Safety Accident Rate (ISAR2) has been replaced by Total Industrial Safety Accident Rate (TISA2) in Q1 2024 to align with WPII 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 2: Reactor Trip Rate was replaced by Reactor Automatic & Manual Trip Rate following the WPII 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 3: The WANO Performance Indicator Index (WPII) Method 10, previously known as the Nuclear Performance Index (NPI), is a 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). WPII is calculated using a 2-year rolling average for PN and a 3-year rolling average for DN.

Note 4: UCR replaced UCF due to WPII 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 5: All metrics, including Value for Money targets 2021 – 2025 in EB-2020-0290 are reviewed annually and updated as required as part of the business planning process.
Note 6: CRE 2024 Actuals have been corrected.

b) OPG is unable to revise 2021-2025 annual targets to reflect (i) actual DRP in-service dates, and (ii) actual Pickering extended operations and extension timing. Doing so would require a complex adjustment to various total generating cost categories predicated on a multitude of assumptions and such a targeted revision based on hindsight would not be appropriate.

c) Chart 3 below shows the derivation of the Value for Money metric calculations, with references to amounts reflected in evidence and adjustments applied to arrive at the 2026-2031 targets shown in Chart 1 of Ex. L-F2-Staff-179 part (c) for Darlington and Chart 1 of Ex. L-F2-Staff-183 for Pickering, which represent such final targets for this business planning cycle for the reasons discussed in those interrogatory responses.

Chart 3 - Pickering and Darlington Derivation of 2026-2031 Value for Money Metric Calculations

Line #	2025-2031 BP ($M unless otherwise noted)	2026 Target			2027 Target	2028 Target	2029 Target	2030 Target	2031 Target	Source
		DN	PN		DN	DN	DN	DN	DN	
1	Generation (TWh)	21.1	11.4		18.7	26.7	25.1	26.8	27.1	Ex. E2-1-1 - Table 1, col. (g-l), line 1-2
2	Capacity (MW DER)	3,256	2,064		3,512	3,512	3,512	3,512	3,512	Ex. A1-4-3 Chart 1; Darlington: 3,512 adjusted to remove capacity undergoing refurbishment [2026 Unit 4: 3.5 months / 48 months (all 4 units) = 7.3%]
3	OPG Nuclear Facilities Base OM&A	656	554		708	710	745	751	766	Ex. F2-2-1 - Table 1a, col. (g-l), line 15 and Table 9-14, col. (a-b), line 13
4	OPG Nuclear Facilities Outage OM&A	156	53		224	113	219	122	116	Ex. F2-4-1 - Table 1, col. (g-l), lines 3 & 6
5	OPG Nuclear Facilities Project OM&A	55	18		58	59	59	57	59	Ex. F2-3-1 - Table 1, col. (g-l), line 16 – DN/PN Portion
6	PN Cyclical Maintenance OM&A	0	25		0	0	0	0	0	Ex. F2-4-1 - Table 1, col. (g-l), line 14
7	Support Services OM&A	201	215		214	206	215	215	222	Ex. F3-1-1 - Table 3a, 3b, col. (g-l), line 10
8	Centrally Held Costs	(22)	(25)		(10)	(12)	(23)	(12)	(8)	Ex. F4-4-1, Table 3, col. (g-l), line 7 – DN/PN Portion
9	Fuel-Fuel Oil	2	3		3	2	2	2	2	Ex. F2-5-1 - Table 1a, col. (g-l), line 6 – DN/PN Portion
10	Total - OM&A Prior to Value for Money Metric Adjustments	1,047	844		1,197	1,077	1,217	1,134	1,157	Sum of lines 3-9
11	Cost Allocations	(9)	10		(6)	(0)	(3)	(2)	(7)	Cost allocation adjustments (e.g., Pickering utilization of Tritium Removal Facility)
12	Exclusions per EUCG governance	63	73		62	62	68	63	58	Exclusions from TGC/MWh calculation (e.g., IESO Non-Energy Charges, Pension/ OPEB Related Costs, L&ILW Storage & Disposal)
13	Total Adjustments	54	83		57	61	65	61	51	Sum of lines 11 & 12
14	**Total OM&A for Value for Money Metrics**	**1,101**	**926**		**1,254**	**1,138**	**1,282**	**1,195**	**1,208**	Sum of lines 10 & 13

15	OPG Nuclear Facilities Capital	727	134		873	791	891	771	548	Ex. D2-1-2 - Table 2, col. (g-l), line 22 – DN/PN Portion
16	Exclusions per EUCG governance	(207)	(4)		(291)	(334)	(526)	(399)	(297)	Exclusion from TGC/MWh calculation per EUCG Governance (e.g. specified projects, new fuel load, capital interest)
17	Net Nuclear Capital	520	130		582	457	365	371	251	Sum of lines 15 and 16
18	Support Services Capital	93	81		185	130	136	139	114	Ex. D3-1-1 - Table 1, col. (g-l), line 3
19	Exclusions per EUCG governance	(40)	(47)		(127)	(89)	(103)	(120)	(106)	Exclusion from TGC/MWh calculation per EUCG Governance
20	Net Corporate Allocated Capital	53	33		58	41	33	19	8	Sum of lines 18 & 19
21	**Total Capital for Value for Money Metrics**	**573**	**164**		**640**	**498**	**398**	**391**	**259**	Sum of lines 17 & 20
22	**Fuel-Uranium**	**128**	**65**		**121**	**182**	**184**	**209**	**222**	Ex. F2-5-1 - Table 1a, col. (g-l), lines 1 & 2 Used Fuel Storage & Disposal is excluded from TGC/MWh calculation per EUCG Governance
23	**Total Generating Costs for Value for Money Metrics**	**1,801**	**1,155**		**2,014**	**1,818**	**1,863**	**1,794**	**1,690**	Sum of lines 14, 21 & 22
	Value for Money Metrics - 1 Year									
24	Total Generating Costs per MWh ($/MWh)	85.43	101.57	91.10	107.77	68.11	74.34	66.90	62.39	Line 23 / Line 1
25	Non-Fuel Operating Costs per MWh ($/MWh)	52.23	81.44	62.46	67.07	42.65	51.14	44.53	44.62	Line 14 / Line 1
26	Fuel per MWh ($/MWh)	6.05	5.75	5.95	6.49	6.80	7.33	7.80	8.19	Line 22 / Line 1
27	Capital per MW DER (k$/MW)	175.85	79.25	138.40	182.11	141.84	113.24	111.21	73.84	Line 21 / Line 2

** PN 2026 Value for Metrics Target as per Ex. F2-Staff-183 part a). DN 2026-2031 Value for Money Targets as per Ex. F2-Staff-179 part c).*

SEC Interrogatory #158

Interrogatory

Reference:
F2-1-1, p. 19-25, Chart 3 and 4

Question(s):

Please provide a revised version of Charts 3 and 4 using the existing 2018 benchmarking methodology (as applied in EB-2020-0290).

Response

The requested information can be found at Ex. F2-1-1, pp. 19-25, Chart 3 and 4 as 'Normalized Total Generating Cost per MWh – Original Methodology ($/MWh)' and 'Normalized Total Generating Cost per Unit – Original Methodology ($/MWh)'.

SEC Interrogatory #159

Interrogatory

Reference:
F2-1-1

Question(s):

Please provide a copy of the 2025 Benchmarking Report. If it is not available, please provide OPG's benchmarking results.

Response

Refer to Ex. L-F2-CCC-070, Attachment 1.

SEC Interrogatory #160

Interrogatory

Reference:
F2-1-1, p. 27-32

Question(s):

For each of the current fleet-wide improvement initiatives for the nuclear business, please provide for each year between 2025 and 2031, a) the annual costs, and b) any quantified benefit (in cost savings or increased output). Please provide all calculations including any details regarding methodology and assumptions made.

Response

Refer to Ex. L-F2-Staff-178, part (b).

SEC Interrogatory #161

Interrogatory

Reference:
F2-1-1, Attachment 1

Question(s):

For each of the fleet-wide initiatives identified in EB-2020-0290 implemented for the nuclear business, please provide for each year between 2021 and 2031, (a) the annual costs, (b) any quantified benefit (in cost savings or increased output). Please provide all calculations including any details regarding methodology and assumptions made.

Response

Refer to Ex. L-F2-Staff-178, part a) for the requested information, where applicable. OPG has not quantified annual costs or benefits for these initiatives during the IR term as the prior initiatives have been superseded by the current fleetwide improvement initiatives, as described at Ex. F2-1-1, pp. 27-32.

SEC Interrogatory #162

Interrogatory

Reference:
F2-1-1, Attachment 4

Question(s):

With respect to the ScottMadden, *OPG Nuclear Cost Performance Benchmarking* Report*:*

a) [F2-1-1, Attachment 7, p.2] ScottMadden was asked to "[c]conduct a new, holistic study of nuclear cost performance" in part by "determining cost metric normalizations and peer group changes to account for non-controllable factors and facilitate more reasonable benchmark comparisons."[emphasis added] Please explain how and on what basis did OPG determine that the current methodology required, at the very least, was a "more reasonable" benchmarking comparison.

b) [p.11] Please provide a separate version of the Figure on p.11 for each specific adjustment separately.

c) [p8-9] Please explain why ScottMadden believes that it can find statistically significant impact on cost for CANDU technology when it only makes up 3 of the 57 nuclear sites in its sample.

d) [p.9] Please explain why it is appropriate to consider age from the initial in-service date of the unit as opposed from the date of its full refurbishment.

e) [p.12] Please provide the outage-adjustment working papers used to calculate adjusted MWh for all 57 sites for the years 2006 to 2023. If any special treatment was applied to any plant-year in the outage adjustment (including any adjustments related to refurbishment periods), please identify the plant-years and show exactly how that treatment was implemented in the working papers.

f) [p.12] Please identify the benchmark plant use and provide its planned outage % by year and its 2006 to 2023 average (the value used as the benchmark)

g) Did ScottMadden undertake any analysis of the relationship between the number of units on a site and total generating costs? If, so please provide details.

Response

a) Consistent with the OEB-approved settlement proposal in EB-2020-0290, OPG asked ScottMadden to conduct a new nuclear benchmarking approach review using the most current available data. As part of that request, OPG asked ScottMadden to consider what normalization, if any, would facilitate a more accurate comparison between OPG and its peers, therefore, improving the reasonableness of that view.

The following responses (b-g) were prepared by ScottMadden Management Consultants:

b) Chart 1, 2, and 3 provides the 3-Year Total Generating Cost per Mega-watt hour (TGC/MWh) Updated Methodology results and quartile performance for each adjustment.

Chart 1: 2023 3-Year Technology Adjusted TGC/MWh (2021-2023)

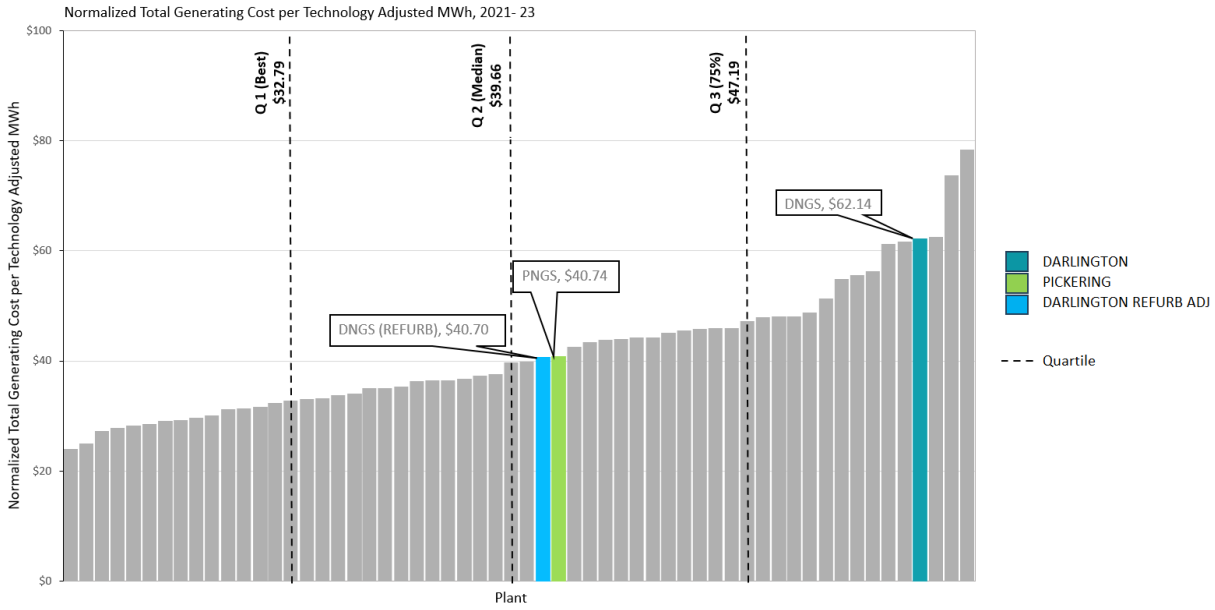


Chart 2: 2023 3-Year Unit Age Adjusted TGC/MWh (2021-2023)

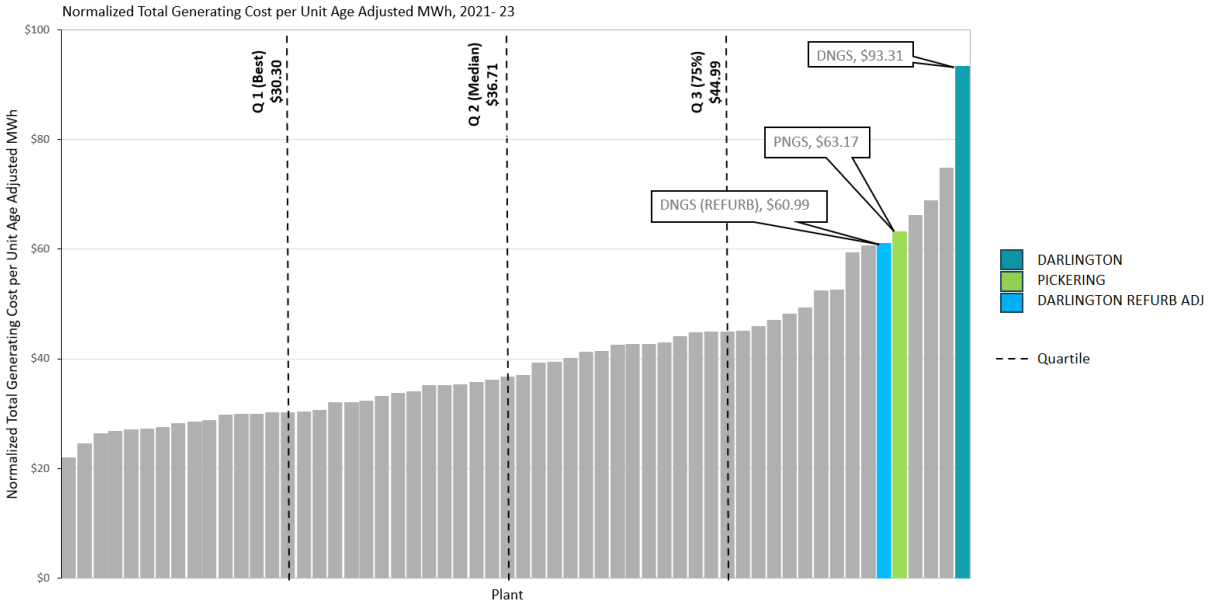
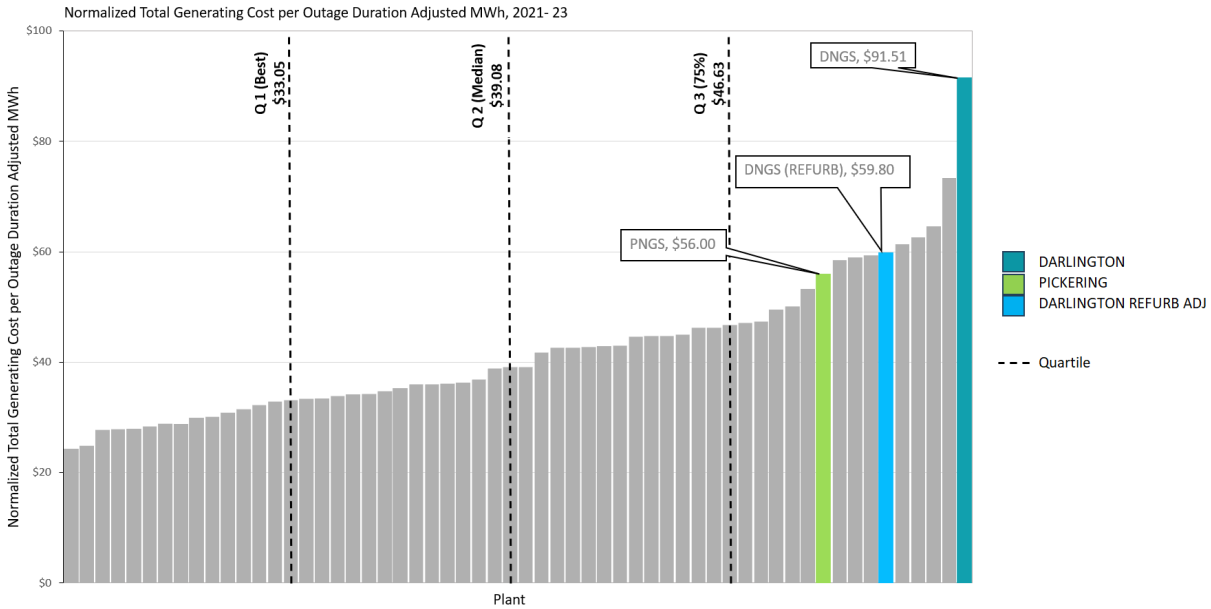


Chart 3: 2023 3-Year Outage Duration Adjusted TGC/MWh (2021-2023)



c) Refer to Ex. L-F2-Staff-324, part f).

d) Refer to Ex. L-F2-CCC-71, part e).

e) Refer to Ex. L-F2-Staff-327, part d) and Ex. L-F2-Staff-328, parts a) & b).

f) The benchmarked plant is Plant ID 278. Chart 4 below shows Plant 278's annual planned outage percentage and its average 2006-2023 planned outage percentage of 2.67% that was utilized as the benchmark.

Chart 4: 2006-2023 Planned Outage Percentage by Year For the Benchmarked Plant

Year	Planned Outage %
2006	2.74%
2007	2.88%
2008	2.47%
2009	4.15%
2010	3.53%
2011	3.47%
2012	3.23%
2013	2.82%
2014	2.47%
2015	2.19%
2016	2.33%
2017	2.63%
2018	2.05%
2019	2.48%
2020	1.74%
2021	1.92%
2022	2.54%
2023	2.42%
Average	**2.67%**

g) ScottMadden did not include the number of units as a separate variable in the final econometric model. Instead, the impact of the number of units on total generating costs is considered to be effectively captured through the site capacity (MW) variable that is included in the model.

SEC Interrogatory #163

Interrogatory

Reference:
EB-2020-0290, JT 1.27, Attachment 1

Question(s):

Please provide a revised version of EB-2020-0290 JT 1.27, Attachment 1, to include 2020-2024 actual data.

Response

See Chart 1 below.

Chart 1: EB-2020-0290 JT1.27 Updated with 2020-2024 Actual Results for Selected Nuclear Benchmarking Metrics

	Rolling – Actual Results																
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Darlington	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	((p)	(q)
WANO Nuclear Performance Index (%) [1]	95.67	95.10	94.10	92.80	96.30	90.80	92.10	83.70	87.80	82.00	90.70	88.90	93.60	85.80	91.40	89.44	74.74
Unit Capability Factor (%) [2]	91.99	90.20	89.40	89.60	92.00	90.44	89.41	83.96	86.16	82.17	86.89	87.06	92.38	86.18	88.81	90.46	80.35
3-Year Average Total Generating Costs ($/Net MWh)	30.08	32.77	33.55	33.05	31.67	34.42	37.73	44.38	45.63	54.40	59.06	67.00	62.06	65.60	74.38	95.04	115.93
3-Year Average Normalized Total Generating Costs ($/Net MWh)[3]										37.94	37.65	38.84	36.37	38.09	37.09	38.11	42.58
Pickering																	
WANO Nuclear Performance Index (%) [1]	60.90	67.17	64.30	66.10	64.70	67.50	64.30	68.50	76.30	76.70	74.90	82.50	82.49	73.74	80.90	82.78	84.95
Unit Capability Factor (%) [2]	67.65	74.47	74.57	72.50	75.62	75.77	74.50	77.32	77.03	77.36	79.55	83.31	81.90	77.58	79.46	80.34	79.59
3-Year Average Total Generating Costs ($/Net MWh)	69.82	65.81	65.00	65.86	67.16	67.18	67.93	67.36	68.06	67.22	67.76	62.39	62.84	62.62	64.17	64.93	64.78
3-Year Average Normalized Total Generating Costs ($/Net MWh)[3]										49.27	49.29	44.85	44.64	43.98	44.03	33.62	33.18
Pickering A																	
WANO NPI (Index)[2]	60.84	61.10	47.70														
Unit Capability Factor (%)	56.60	68.00	63.30														
3-Year Average Total Generating Costs ($/Net MWh)	92.27	95.41	90.21														
Pickering B																	
WANO NPI (Index)[2]	60.93	70.20	72.60														
Unit Capability Factor (%)	73.17	77.70	80.20														
3-Year Average Total Generating Costs ($/Net MWh)	58.68	54.64	54.79														

Note 1: 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 2: Indicates a 2-Year Rolling Average for Pickering and a 3-Year Rolling Average for Darlington.
Note 3: Original TGC/MWh normalization methodology applied for years 2017-2022, updated methodology applied for 2023 &2024.

1st Quartile Performance
2nd Quartile Performance
3rd Quartile Performance
4th Quartile Performance
Not Applicable

SEC Interrogatory #164

Interrogatory

Reference:
F2-1-1, Attachment 5

Question(s):

With respect to the Indeavor, *OPG Nuclear Staff Benchmarking* Report:

a) [p.6] The Report states "OPG reviewed EUCG (Electric Utility Cost Group) staffing data for 2024, and allocated staffing headcount to corresponding Indeavor functions." Does this mean OPG allocated its employees or that it allocated all EUCG employees to the corresponding Indeavor function? Please explain why OPG, and not Indeavor, was responsible for this task.

b) Please explain all changes to the data collection approach and study methodology used in the previous Goodnight Studies.

c) [p.8] The study excluded the capital staffing function. How many OPG FTEs fall into this category and does the exclusion include all capital-related work and staff involved in any projects set out in Exhibit D2, including support functions?

d) [p.10] The peer group included 4 companies, and 9 sites.
   a. For each site, please provide the number of units, and MWs.
   b. How does this compare to previous staff benchmarking studies included in the last three OPG applications?

e) [p.10] OPG currently operates two sites with more than 2 units per site. Please explain how Indeavor normalized for the difference in sites per company and units per site.

f) [p.14] Please provide the chart, "Site Headcount – Indeavor Functions", in a tabular format in Excel.

g) [p.16] Please provide OPG's views on the drivers of the material variances (both positive and negative) in certain functions compared to the benchmark.

h) [p.17] Please provide a revised version of "Headcount Variance by Function", reflecting variances as a percentage of the benchmark, as opposed to variance in the headcount number.

Response

The following responses were prepared by Indeavor (with the exception of parts (c) and (g)):

Indeavor has issued a revised version of the OPG Nuclear Staff Benchmarking Report (Ex. F2-1-1, Attachment 5) to address an error in the original peer group composition. The original report inadvertently included a 3-unit BWR site that does not align with the intended 2-unit PWR benchmark group. The revised report now excludes this site, and the updated benchmark is based on eight 2-unit PWR sites. Please refer to Attachment 1 for the OPG Nuclear Staff Benchmarking Rev 1 Report.

a) The statement on p.6 refers to the allocation of OPG's own staffing data to Indeavor functions, not the allocation of peer data. OPG allocated its own employees because OPG has the best knowledge of its organizational structure, job descriptions, and departmental assignments. Allocations were determined using EUCG account mappings, department-level information, job titles, and business unit classifications, then reviewed and approved through multiple rounds of validation between Indeavor and OPG.

   For the PWR peer data, sites self-reported directly to Indeavor in either EUCG Account Level or Indeavor Functional Level format. EUCG data was converted to Indeavor functions using historical ratios (Attachment 1, p. 22). Prior Goodnight studies drew peer data from the standalone Goodnight staffing database rather than directly from sites. For this study, Indeavor built a custom staffing database for OPG using the survey responses.

b) Changes from the prior Goodnight Consulting studies (2011, 2013, 2014, 2019):

   Benchmark Data Sources and Peer Group Methodology:
   Previous Goodnight studies relied on a proprietary Nuclear Plant Staffing Database, which is no longer available following Goodnight's closure in 2021. The current Indeavor study uses a survey-based approach, with PWR sites self-reporting staffing data. The 2024 benchmark includes eight 2-unit PWR sites across four companies, compared to 17 sites across 11 companies in previous studies. Only one site is common to both benchmarks (see part (d)). Additionally, five of the eight peer sites submitted data at the EUCG Account level, which required conversion to Indeavor Functional levels using historical allocation ratios (Attachment 1, p. 22); prior studies collected data directly at the functional level.

Scope of Benchmarking and Inclusion/Exclusion of Functions:
Goodnight's methodology included detailed contractor (purchased services) data, but such data was not available from Indeavor survey participants. Therefore, purchased services were excluded from both OPG and peer site data in the 2024 benchmark. Scope changes also occurred: Security Support and Management Support, included in the 2019 benchmark, are excluded from the 2024 benchmark, while Information Technology (excluded in 2019) is now included (see Ex. L-F2-Staff-191).

c) Refer to Ex. L-F2-Staff-189, which provides the total number of OPG FTEs that were excluded for the capital staffing function. This number relates to FTEs, including support functions, who are dedicated to major capital projects (plant refurbishments), which would be included in Exhibit D.

d)

a. Eight sites across four companies provided data. See Chart 1 below for the full site list with unit counts and approximate MW ratings.

Chart 1 - OPG Nuclear Staffing Benchmarking Study Participants

Company	Site	Units	Type	~MWe/Unit *	Previous Participant
NextEra	1	2	PWR	~1,000	Y
NextEra	2	2	PWR	~800	N
NextEra	3	2	PWR	~600	N
Duke	4	2	PWR	~1,100	N
Duke	5	2	PWR	~1,100	N
Entergy	6	2	PWR	~900 avg	N
TVA	7	2	PWR	~1,150	N
TVA	8	2	PWR	~1,150	N

** MW ratings are approximate (publicly available NRC data).*

b. The prior Goodnight studies drew from the proprietary Goodnight database of large (>800 MWe) 2-unit PWRs. The peer group from the previous study as noted in EB-2020-0290 Ex. L-F2-SEC-124 was 17 sites across 11 companies. All sites were contacted for the 2024 study; only the ones noted above responded.

e) The normalization methodology is performed at the site level and not by company. Details of the methodology are provided in Ex. L-F2-CCC-072, part (d).

f) Refer to Attachment 2.

g) While the exact reasons for specific variances cannot be determined without more granular information on the organizational structures at peer utilities, OPG provides

the following perspectives on possible drivers for variance in the functions highlighted in Attachment 1, p. 16:

Variances above benchmark:

- Facilities: Variance driven by a large number of off-site facilities maintained by OPG, with future consolidation planned.

- Maintenance – Support: Includes insulators, scaffolders, procedure writers, and stores support. US plants may utilize a different operating model where different functions are contracted out, specifically during outages where a substantial portion of the work is done. Although Maintenance Support is above benchmark, it is offset by Maintenance - Electrical/I&C being below the benchmark.

- Safety Programs: Includes internal safety staff, which may differ in scope from other utilities.

- Project Management: Reflects OPG's capital investment program and the need for critical project management oversight.

- Fire Department: OPG provides certain internal services such as its own fire department and emergency response teams that many US utilities outsource to municipalities or have integrated with operating crews.

Variances below benchmark:

- RP Applied: Lower staffing levels in this function are offset by line personnel qualified to provide self-monitoring and, if qualified, monitoring of activities of groups

- Maintenance – Electrical/I&C, Engineering – Plant, Operations: The below-benchmark staffing levels in these areas are driven in part by Pickering Units 1 and 4 end of commercial operations in 2024 and the transition towards Pickering Units 5-8 preparation for the four-unit refurbishment.

h) Refer to Attachment 2.

INDEAVOR

April 2026

Ontario Power Generation (OPG) - Nuclear Staff Benchmarking Rev 1

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 1% below the benchmark of 4,502.
- Operations and Facilities remain the largest variance categories, consistent with prior benchmarks: −189 in Operations and +166 in Facilities.

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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

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PWR Data Survey Participants

NEXTera ENERGY	DUKE ENERGY	entergy	TVA
3 Sites Provided *EUCG Account Level*	**2 Sites Provided** *Indeavor Functional Level*	**1 Site Provided** *Indeavor Functional Level*	**2 Sites Provided** *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.

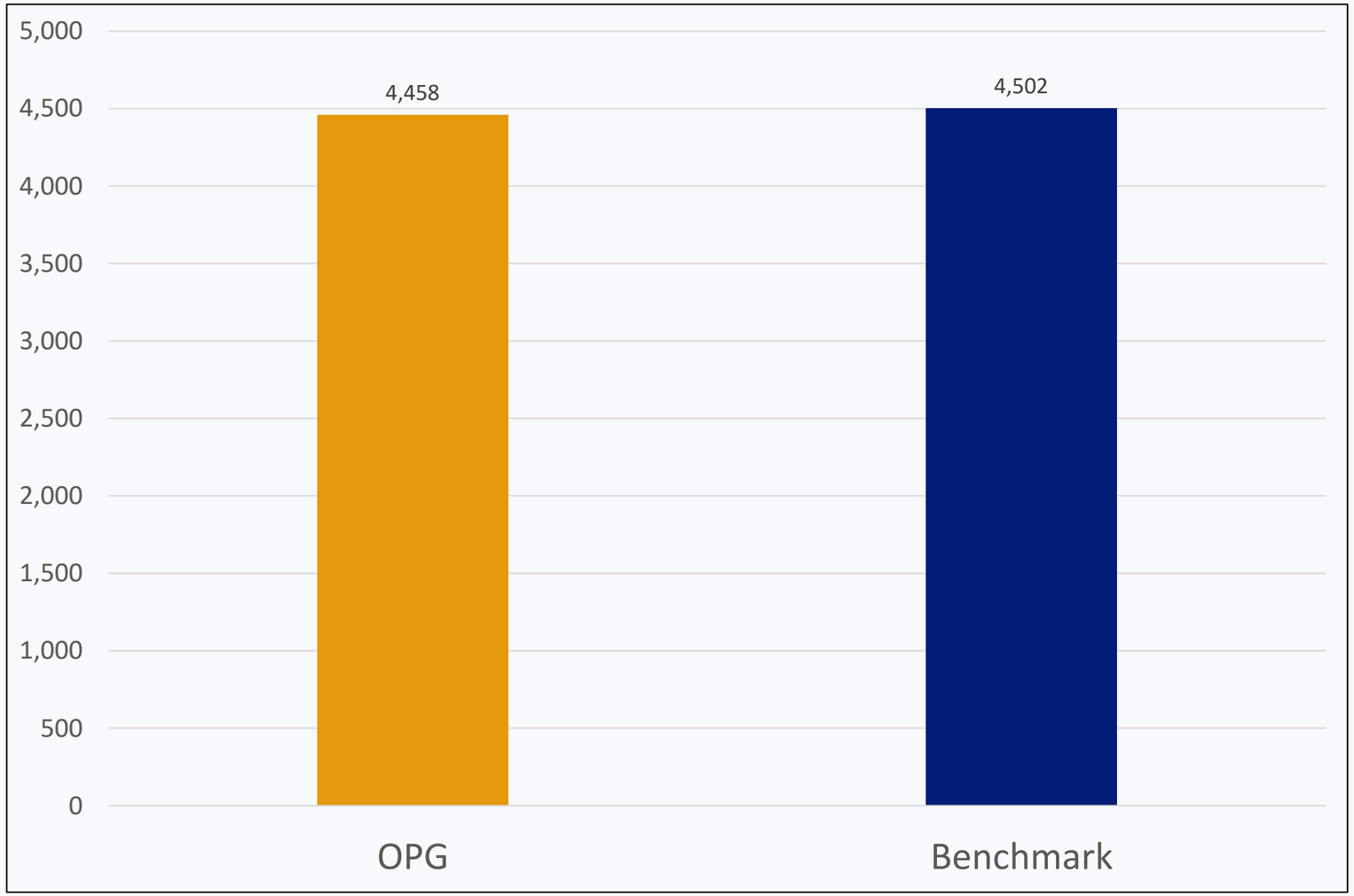
C – Full list in Appendix
** Exclusion list provided on slide 8*

INDEAVOR

Benchmark Data

INDEAVOR

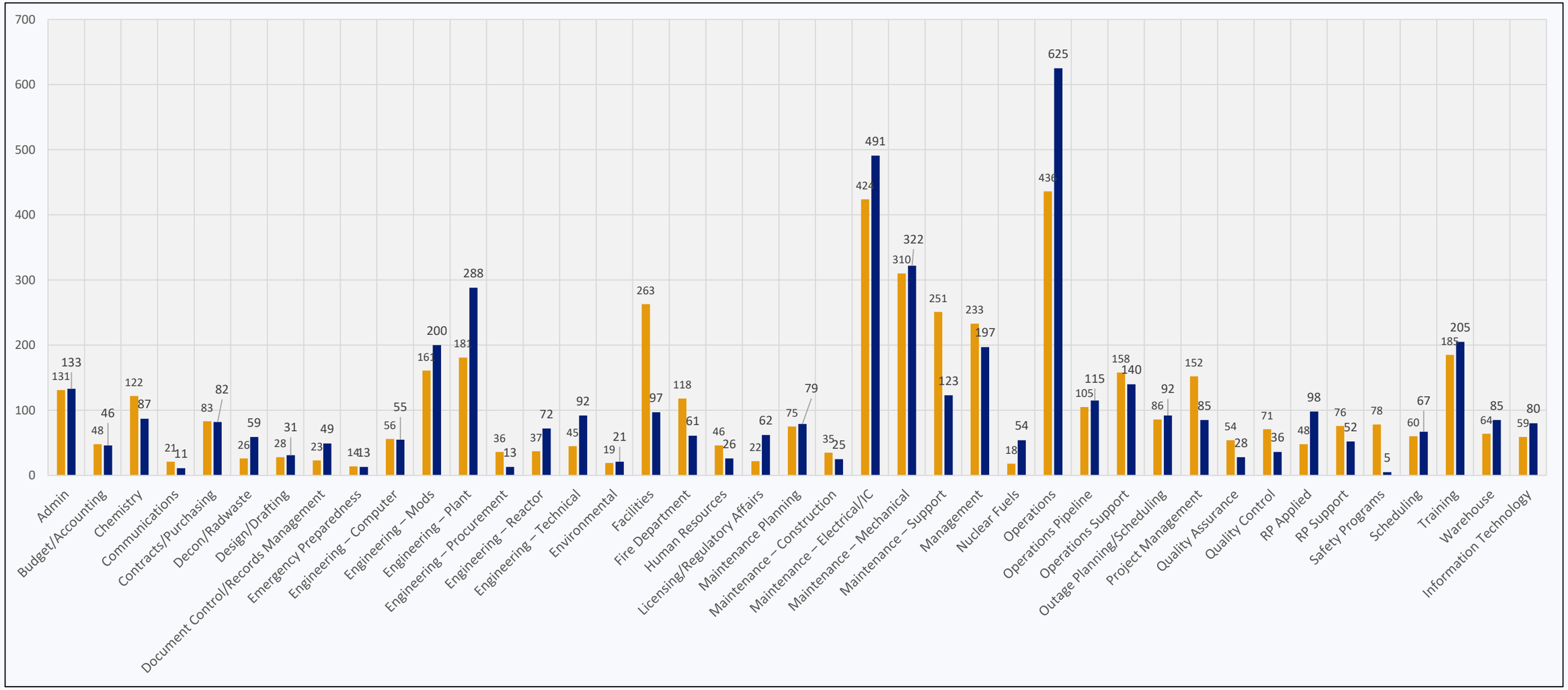
Site Headcount – Total



OPG Headcount is 44 (-1.0%) below benchmark

INDEAVOR

Site Headcount – Indeavor Functions



OPG

Benchmark

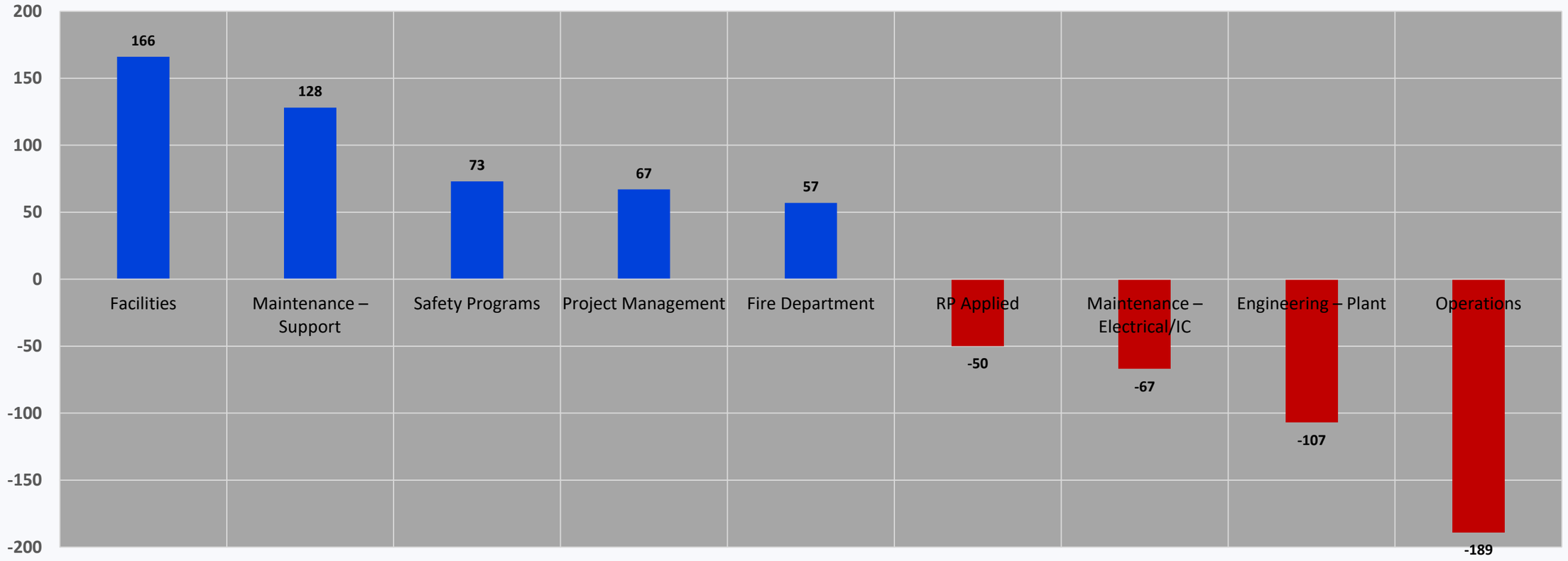
INDEAVOR

Variance Analysis

INDEAVOR

Headcount Variance by Function – Highlights

***5 Functions were above** the benchmark by 50+ headcount;*
***4 Functions were below** the benchmark by 50+ headcount.*



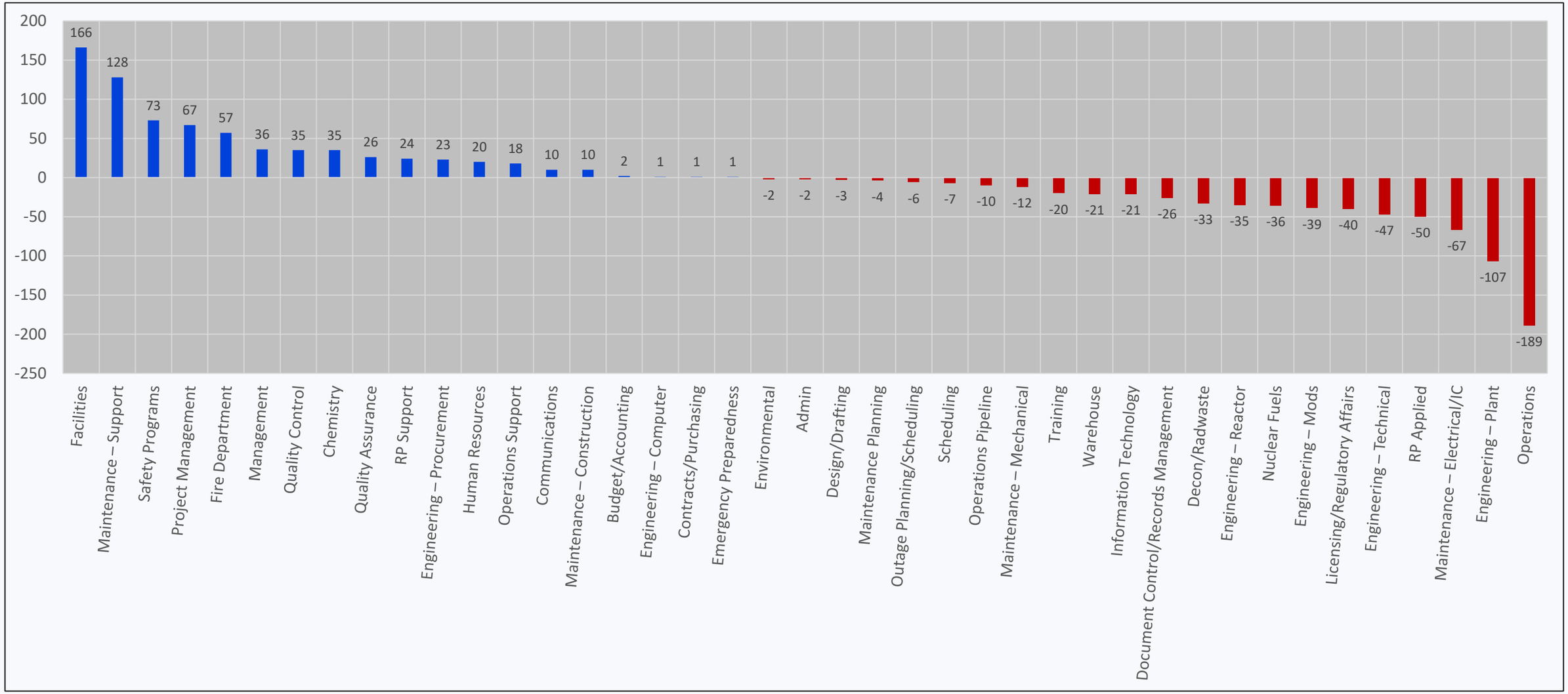
Above Benchmark

Below Benchmark

The 9 functions shown represent ~60% of the total headcount variance across all functions.

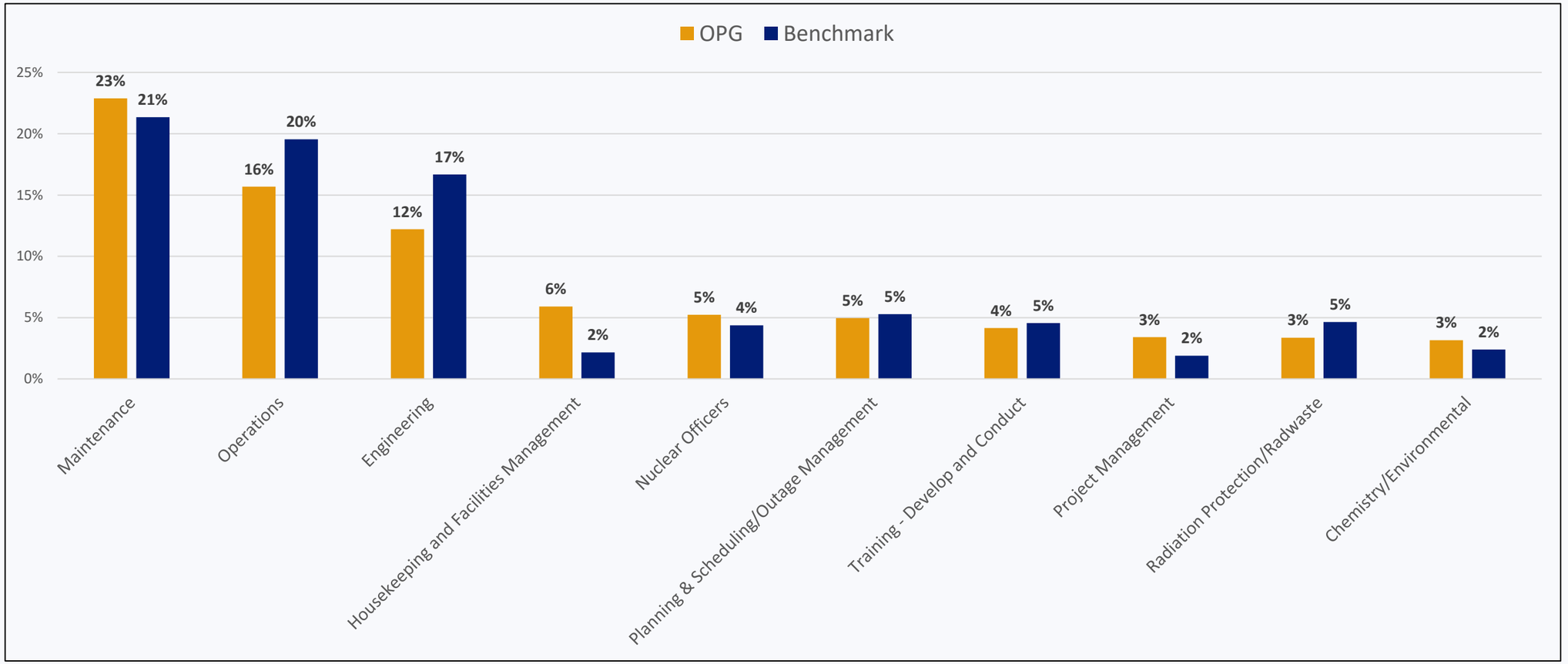
INDEAVOR

Headcount Variance by Function



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 1.6%

INDEAVOR

Appendix

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	1.00
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

Indeavor Function	OPG	Updated PWR Benchmark	HC Variance	% Variance
Admin	131	133	-2	-2%
Budget/Accounting	48	46	2	4%
Chemistry	122	87	35	40%
Communications	21	11	10	91%
Contracts/Purchasing	83	82	1	1%
Decon/Radwaste	26	59	-33	-56%
Design/Drafting	28	31	-3	-10%
Document Control/Records Management	23	49	-26	-53%
Emergency Preparedness	14	13	1	8%
Engineering - Computer	56	55	1	2%
Engineering - Mods	161	200	-39	-20%
Engineering - Plant	181	288	-107	-37%
Engineering - Procurement	36	13	23	177%
Engineering - Reactor	37	72	-35	-49%
Engineering - Technical	45	92	-47	-51%
Environmental	19	21	-2	-10%
Facilities	263	97	166	171%
Fire Department	118	61	57	93%
Human Resources	46	26	20	77%
Information Technology	59	80	-21	-26%
Licensing/Regulatory Affairs	22	62	-40	-65%
Maintenance - Planning	75	79	-4	-5%
Maintenance - Construction	35	25	10	40%
Maintenance - Electrical/IC	424	491	-67	-14%
Maintenance - Mechanical	310	322	-12	-4%
Maintenance - Support	251	123	128	104%
Management	233	197	36	18%
Nuclear Fuels	18	54	-36	-67%
Operations	436	625	-189	-30%
Operations Pipeline	105	115	-10	-9%
Operations Support	158	140	18	13%
Outage Planning/Scheduling	86	92	-6	-7%
Project Management	152	85	67	79%
Quality Assurance	54	28	26	93%
Quality Control	71	36	35	97%
RE Applied	48	98	-50	-51%
RP Support	76	52	24	46%
Safety Programs	78	5	73	1460%
Scheduling	60	67	-7	-10%
Training	185	205	-20	-10%
Warehouse	64	85	-21	-25%
Total	**4,458**	**4,502**	**-44**	**-1%**

Note 1: Safety Programs shows +1,460% because the PWR benchmark is very small (5 HC). PWR sites often use Safety Programs as a catch-all, and this low average is consistent with what we see in a broader PWR data set. Percentage variances for small functions should be read with caution.

SEC Interrogatory #165

Interrogatory

Reference:
F2-1-1, Attachment 5, p. 8

Question(s):

With respect to the Indeavor, *OPG Nuclear Staff Benchmarking* Report, the study excluded Purchased Services, which is a change from previous studies. Indeavor says: "Without the ability to interview benchmark sites and fully analyze PWR contract staffing, the data was excluded from both data sets."

a) [EB-2020-0290, F2-1-1, Attachment 6, p.11] Using the FTE categories used by Goodnight in previous studies, please explain what is included in the Purchased Services exclusion.

b) Please explain how its ability to interview benchmark sites and analyze PWR contract staffing differs from what Goodnight was able to do in previous studies?

c) On the same basis that it has calculated OPG FTEs in other functions, how many FTEs does OPG have in Purchased Services?

Response

a) Refer to Ex. L-F2-Staff-180.

b) *The following response was prepared by Indeavor:*

The question implies that Goodnight interviewed benchmark sites to collect contractor data as part of its OPG engagements. That is not how it worked. Goodnight maintained a proprietary Nuclear Plant Staffing Database as a standalone product, independent of any specific client engagement. Sites participated in the database voluntarily on an annual basis, and there was regular communication between Goodnight and participants to validate the data, including contractor staffing. The OPG benchmarking studies simply drew from that existing database. The detailed contractor data was available because it was already being collected as part of an established annual process that sites had participated in for years.

Goodnight ceased operations in 2021 and the database was closed. That annual reporting infrastructure no longer exists and cannot be recreated through a one-

off survey. Indeavor does not maintain a staffing database. When surveyed for the current study, peer sites would not provide their long-term contractor data without the ongoing relationship and mutual benefit that the Goodnight database provided. Purchased Services were excluded from both OPG and peers to maintain comparability.

c) Refer to Ex. L-F2-Staff-180.

SEC Interrogatory #166

Interrogatory

Reference:
F2-1-1, Attachment 5

Question(s):

With respect to the Indeavor, *OPG Nuclear Staff Benchmarking* Report:

a) [p.13] What is the total OPG FTE nuclear headcount (including those excluded from the study), including all the categories of FTEs included in the previous Goodnight Study (regular, term, non-regular, augmented, Oncore, contractor, and other purchased services). Please reconcile your answer with the information provided in F2-1-1, Table 2a.

b) [EB-2020-0290, F2-1-1, Attachment 6, p.11] Please provide the OPG FTEs and benchmark FTEs, on a similar basis as provided in EB-2020-0290, F2-1-1, Attachment 6, p.11, which shows the categorizing of OPG FTEs by type (regular, term, non-regular, augmented, Oncore, contractor, etc.). Please also include Purchased Services FTEs on a similar basis, even if they are not included in the Total OPG FTEs.

Response

a) Refer to Ex. L-F2-Staff-181 for the reconciliation of OPG FTEs to Ex. F4-3-1, Attachment 1, p. 1, which is the same FTE amount that is provided in Ex. F2-1-1, Table 2a. The reconciliation does not include Oncore Hourly or External Purchased Services because they are not OPG FTEs and would not be included in Ex. F2-1-1, Table 2a.

b) Refer to Attachment 1. Security and Security Support staff FTEs have been excluded to remain compliant with OPG security policy. Since Oncore Hourly and External Purchased Services were not part of the Benchmark Study, they also have not been included in Attachment 1. However, refer to Ex. L-F2-Staff-180, which shows this requested breakdown with the same categorizations as EB-2020-0290, Ex. F2-1-1, Attachment 6, p. 11.

OPG FTE & Benchmark FTE by Process Area

Process Area Summary	Regular	Term/ ETE	Total Employee HC	Non-Regular	Augmented Staff	Oncore Hourly	Other Purchased Services	Total Contractor FTEs	Total OPG FTEs	2024 Updated Indeavor Benchmark [1]	Var	%
Administrative Services	89		89	2	1			3	92	106	(14)	-13%
Configuration Management	204		204	2	1			3	207	285	(78)	-27%
Equipment Reliability	373	11	384	2	4			6	390	543	(153)	-28%
Loss Prevention	165		165	3				3	168	108	60	56%
Operate The Plant	744	90	834	5	1			6	840	988	(148)	-15%
Personnel Services	584	27	611	19	24			43	654	641	13	2%
Plant Maintenance	1,011	135	1,146	135	2			137	1,283	1,058	225	21%
Radiation Protection	119	20	139	11				11	150	209	(59)	-28%
Supply Chain	173	3	176	6	1			7	183	180	3	2%
Work Management	342	15	357	6	10			16	373	323	50	15%
Below the Line	116	2	118						118	61	57	93%
Benchmarked Total	**3,920**	**303**	**4,223**	**191**	**44**			**235**	**4,458**	**4,502**	**(44)**	**-1%**

[1] Refer to Ex. L-F2-SEC-164

SEC Interrogatory #167

Interrogatory

Reference:
F2-2-1, Tables 1a, 1b

Question(s):

Please provide the number of FTEs per function per year.

Response

Refer to Attachment 1 for OPG Nuclear Facilities Base OM&A FTEs per function per year for 2020-2031.

Refer to Attachment 2 for DNNP Facilities Base OM&A FTEs per function per year for 2026-2031.

Base OM&A - OPG Nuclear Facilities and Operations and Project Support FTEs by Function

Line No.	Function	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Actual	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	Darlington NGS	1,331.9	1,330.6	1,194.3	1,198.3	1,181.7	1,238.8	1,306.4	1,250.0	1,231.4	1,240.6	1,240.4	1,235.4
2	Pickering NGS	1,952.2	1,891.1	1,776.6	1,777.4	1,626.5	1,295.4	1,002.0	25.5	54.3	75.5	81.8	712.5
3	**Total OPG Nuclear Facilities**	3,284.1	3,221.7	2,970.9	2,975.7	2,808.2	2,534.3	2,308.5	1,275.5	1,285.6	1,316.1	1,322.2	1,947.9
	Operations and Project Support												
4	Enterprise Engineering	917.9	886.8	855.4	922.5	941.9	865.7	766.2	547.5	532.5	539.1	530.4	626.3
5	Integrated Fleet Management	785.5	721.9	717.2	783.5	856.0	761.2	805.7	634.4	630.0	620.9	636.9	694.4
6	Environment, Health & Safety	53.4	57.8	57.4	56.9	55.8	49.1	43.7	43.6	43.4	42.5	43.8	47.5
7	Enterprise Projects	67.0	67.1	79.4	77.5	71.8	36.7	28.5	23.1	23.0	23.8	22.8	23.2
8	Other Support	100.0	82.6	80.8	89.2	100.2	104.9	107.9	98.9	97.5	97.6	95.8	92.4
9	Low and Intermediate Level Waste	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	**Total Operations and Project Support**	1,923.9	1,816.2	1,790.3	1,929.6	2,025.7	1,817.6	1,752.1	1,347.5	1,326.4	1,323.9	1,329.7	1,483.9
	CRVA Eligible Costs												
11	Fuel Channel Life Extension Project	10.1	0.5	0.0	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Pickering Extended Operations	9.2	3.7	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	1.2	2.1	3.6	3.9	8.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0
14	**Total CRVA Eligible Costs**	20.5	6.3	3.6	4.2	8.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0
15	**Total Base OM&A**	5,228.5	5,044.1	4,764.8	4,909.5	4,842.1	4,352.1	4,060.5	2,623.0	2,612.0	2,640.0	2,651.9	3,431.7

Base OM&A - DNNP Facilities FTEs by Function

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	18.4	101.8
2	**Total DNNP Facilities**	0.0	0.0	0.0	0.0	18.4	101.8
	Operations and Project Support						
3	Enterprise Engineering	1.7	1.8	1.9	2.0	11.4	42.5
4	Integrated Fleet Management	0.3	0.5	0.6	0.6	17.1	75.6
5	Environment, Health & Safety	1.4	2.0	2.4	2.5	2.8	2.5
6	Enterprise Projects	4.5	4.1	4.6	5.0	5.4	4.4
7	Other Support	3.2	4.1	4.5	3.8	7.0	13.3
8	Low and Intermediate Level Waste	0.0	0.0	0.0	0.0	0.0	0.0
9	**Total Operations and Project Support**	11.2	12.5	14.1	13.9	43.6	138.2
10	**Total Base OM&A**	11.2	12.5	14.1	13.9	62.0	240.0

SEC Interrogatory #168

Interrogatory

Reference:
F2-3-1

Question(s):

With respect to unallocated project budget:

a) [p.2] Please explain how the unallocated budget was determined and how the OEB can assess the reasonableness of those amounts where no supporting information, besides the project name, has been provided regarding the potential expenditures.

b) [F2-3-3, Table 4] For each project, please provide a detailed description, justification for the project, and the preliminary cost estimate.

Response

a) Refer to Ex. L-D2-SEC-061, part a), which also applies to Project OM&A.

b) Refer to Ex. L-D2-SEC-056, Attachment 4.

SEC Interrogatory #169

Interrogatory

Reference:
F2-5-1, p. 9

Preamble:

The evidence states that: "OPG's financial coverage limits are determined using a quantitative risk management model that applies efficient frontier analysis to optimize the balance between cost risk and opportunity risk associated with uranium pricing."

Question(s):

Please provide details of the quantitative risk management model details and outputs underlying the statement that it balances between cost and opportunity risk, including but not limited to the definition of "cost risk" and "opportunity risk", and what is meant by "optimize the balance".

Response

Uranium pricing can fluctuate according to market supply and demand. OPG's purchases of forward fixed price uranium contracts provides certainty in uranium fuel costs.

The decision to buy forward fixed price uranium contracts is based on the trade-off of cost risk versus opportunity risk:

- Cost risk exists if a company does not contract at a fixed price for the future and higher future uranium prices materialize.
- Opportunity risk is the opposite; at inception, a company locks into a fixed future price and spot prices materialize at a lower level at that future date.

The referenced quantitative statistical model is used to predict the future movement of uranium prices. Coupled with the OPG uranium fuel usage forecast, and a variety of scenarios regarding the proportion of fixed-price contracts versus floating-price contracts that OPG could procure, the model informs a variety of fuel cost risk outcomes with the volume of fuel required.

The quantitative statistical model's variables include OPG uranium fuel usage forecasts and UxC uranium price outlook and volatilities. The Monte-Carlo method is used to generate possible future uranium price paths, since future uranium price paths

may differ from the UxC uranium price outlook. The result for each scenario is calculated as a net gain or loss, depending on price movements. This is measured as the price difference between the UxC uranium price outlook and the simulated path.

After many simulations conducted through the Monte-Carlo method, a distribution of possible price differences is created.

- Cost risk is based on the 95th percentile of the distribution, where simulated uranium prices are higher than the UxC price outlook (Chart 1, column 2). This is a "high-cost, but still plausible" outcome (or alternatively, that costs could be higher only 5% of the time); and
- Opportunity risk is based on the 5th percentile of the distribution, where simulated uranium prices are lower than the UxC price outlook (Chart 1, column 3). This focuses on the downside of the "opportunity" side (or alternatively, where results could be lower only 5% of the time).

Cost and opportunity risks are then weighted per each scenario of contract mixes, resulting in a total expected fuel cost risk value. The combination of fixed and floating contracts resulting in the lowest total expected fuel cost risk is defined as the optimal balance.

For each contract mix scenario, the two risk measures are scaled to reflect how much of the portfolio is exposed to each type of risk. For example, a 20% fixed / 80% floating scenario would have 20% opportunity risk / 80% cost risk. The scaled risk measures are then combined into a single overall risk score using root-sum-of-squares (RSS), an estimate of standard deviation (Chart 1, column 4):

$$RiskScore = \sqrt{CostRisk^2 + OpportunityRisk^2}$$

The combination of fixed and floating contracts resulting in the lowest risk score is defined as the optimal balance.
The following Chart 1 is an illustrative output of the quantitative model, showing the 50% fixed / 50% floating mix as optimal.

Chart 1: Risk Scores for Uranium Contract Mix Scenarios

% Fixed	Cost Risk (a)	Opportunity Risk (b)	Risk Score $\sqrt{a^2 + b^2}$
0%	325	0	325
25%	260	66.6	268.4
40%	195	133.2	236.2
45%	178.8	149.8	233.3
50%	**162.5**	**166.5**	**232.7**
55%	146.3	183.1	234.4

60%	130	199.8	238.4
75%	65	266.4	274.2
100%	0	333	333

1

SEC Interrogatory #170

Interrogatory

Reference:
F2-5-1, p. 11

Question(s):

Please expand Chart 3 to provide the price/pricing methodology for each contract.

Response

Ex. F2-5-1, Chart 3 has been expanded, as requested, in Chart 1 below.

Chart 1 – Expanded Pricing Methodology by Contract per Pre-filed Evidence

Contract	Contract Award	Date of First Delivery	Delivery Period	Total Quantity (000 kgU)	Pricing (MR = Market related; BE = Base escalated)
A	2019 2nd Q	2020	8 years	1,019	MR / Fixed
B	2020 3rd Q	2021	6 years	846	MR / Fixed
C	2024 1st Q	2027	6 years	671	MR / BE
D	2023 1st Q	2023	7 years	490	MR / Fixed
E	2024 1st Q	2024	3 years	298	MR / Fixed
F	2023 1st Q	2024	6 years	202	MR / Fixed
G	2024 1st Q	2028	1 year	73	MR
H	2024 2nd Q	2029	4 years	138	MR / BE
I	2024 1st Q	2026	2 years	119	MR / Fixed
J	2024 2nd Q	2026	4 years	257	MR / BE
K	2025 1st Q	2026	2 years	136	MR
L	2025 4th Q	2030	11 years	2,923	MR / BE

In the course of responding to this interrogatory, OPG identified an error in Ex. F2-5-1, Chart 3, and is showing a correction in Contract G's time of contract award from 2024 2nd Q to 2024 1st Q, as well as adding Contract M shown in Chart 2 below, which was inadvertently excluded in pre-filed evidence.

Chart 2 – Additional Contract

Contract	Contract Award	Date of First Delivery	Delivery Period	Total Quantity (000 kgU)	Pricing (MR = Market related; BE = Base escalated)
M	2021 3rd Q	2023	6 years	538	MR / Fixed

SEC Interrogatory #171

Interrogatory

Reference:
F2-5-1, p. 12-13

Question(s):

With respect to the uncontracted uranium requirements:

a) Please provide a copy of the forecast UxC High-Price Midpoint and the Mid-Price Midpoint curve.

b) If OPG had used the UxC Mid-Price Midpoint, what would be the change in forecast fuel costs each year between 2027 and 2031? Please provide all calculations.

Response

a) Refer to Chart 1 below for the requested UxC forecast data for years 2027-2031.

Chart 1 – UxC Uranium Market Forecasts (US$/lb)

UxC Uranium Forecast Curve	2027	2028	2029	2030	2031
High-Price Midpoint	[redacted]				
Mid-Price Midpoint					

b) As discussed at Ex. F2-5-1, p. 11, line 9 to p. 13, line 2, given the observed increase in uranium price volatility and elevated risk of continued increases during the IR term, OPG used the UxC High-Price Midpoint curve to forecast nuclear fuel costs for the 2027-2031 period. Chart 2 below compares the resulting nuclear fuel costs to such hypothetical forecast costs had OPG used the UxC Mid-Price Midpoint curve.

Chart 2 – Comparison of OPG's Nuclear Fuel Costs for Uranium Market Price Forecasts

Nuclear Fuel Costs ($M)	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
Using UxC High-Price Midpoint Curve (A) (Ex. F2-5-1, Table 1a, line 3)	121.2	181.6	183.9	209.3	250.2
Using UxC Mid-Price Midpoint Curve (B)	119.8	178.0	177.9	199.5	236.6
Change (B)-(A)	(1.4)	(3.6)	(6.0)	(9.8)	(13.6)

Board Staff Interrogatory #178

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Attachment 1 / pp. 1-6
Ref 2: Exhibit F2 / Tab 1 / Schedule 1 / pp. 27-32 (Section 3.4.2)

Preamble:

At Reference 1, OPG describes the results of three prior gap closure initiatives (Right Work, Right Time, Right Value; Leaders Driving Business Results; People Powering the Future) using qualitative descriptions and operational metrics such as backlog reductions and work protection index trends, but does not quantify the OM&A cost savings or cost avoidances attributable to these initiatives.

At Reference 2, OPG describes five current fleetwide improvement initiatives for the 2025-2031 Business Plan in similar qualitative terms, with anticipated results described as expected improvements in operational metrics rather than dollar-value cost impacts.

Question(s):

a) For each of the three prior gap closure initiatives described in Attachment 1, please quantify the annual OM&A savings or cost avoidances (in $ millions) achieved in each year from 2022 to 2025. If OPG has not tracked the financial impact of these initiatives separately, please explain why not and how OPG assesses whether its gap-based business planning process is delivering measurable cost benefits for ratepayers.

b) For each of the five current fleetwide improvement initiatives described in Section 3.4.2, please provide: (a) the estimated annual cost to implement each initiative over the IR term, and (b) the projected annual OM&A savings or cost avoidances expected from each initiative, expressed in dollar terms.

Response

a) A full description of the three prior gap closure initiatives identified in EB-2020-0290, Ex. F2-1-1, Section 3.4 and the corresponding benefits realized are provided in Ex. F2-1-1, Attachment 1. These initiatives did not require incremental funding and have been delivered using existing departmental resources and budgets. The following is a summary of the cost savings or cost avoidances for each initiative

where it is available, or an explanation for why OPG has not quantified such cost savings or cost avoidances.

Right Work, Right Time, Right Value

Performance improvements realized from this initiative over the previous IR term include zero corrective critical backlogs for both Pickering and Darlington stations, zero corrective non-critical and deficient critical backlogs at Darlington and less than one work order per unit at Pickering, deficient non-critical backlogs showing significant decline at both stations since 2020, and the maintenance and work management index at industry best 100% for both stations. While such various performance improvements have been realized, OPG is unable to attribute discrete cost savings or cost avoidances to this initiative, as overall performance reflects the interacting effects of multiple initiatives and other operational factors. The primary benefits are improving the prioritization of maintenance activities, increasing agility in executing work, and optimizing existing resources to strengthen plant reliability, rather than target resource reduction.

Leaders Driving Business Results

Performance improvements realized from this initiative over the previous IR term include enhanced reporting capability to support managerial oversight, improved work protection metrics, and the implementation of industry defined excellence standards. While such performance improvements have been realized, as with the Right Work Right Time Right Value initiative, OPG is unable to attribute discrete cost savings or cost avoidances to this initiative, as overall performance reflects the interacting effects of multiple initiatives and other operational factors. The main benefits focus on providing managers with information, tools and training to make sound risk-based decisions that help improve the performance of their teams, rather than target resource reduction.

People Powering the Future

Performance improvements realized from this initiative over the previous IR term include those related to leadership development, employee engagement, and workforce proficiency. 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 cessation of Pickering commercial operations. Towards this end, several strategies were utilized including the use of PWU-represented Term employees, which cost savings are discussed in Ex. L-F4-SEC-194.

b) A full description of the five nuclear fleetwide initiatives is available at Ex. F2-1-1, Section 3.4.2. These initiatives are intended to strengthen operational performance and cost effectiveness of the nuclear fleet, helping drive improvements needed to

meet the 2025-2031 Business Plan commitments, as described further below for each initiative.

OPG is unable to attribute discrete cost savings or cost avoidances to individual initiatives, as overall performance reflects the interacting effects of multiple initiatives and other operational factors.

These initiatives do not require incremental funding and will be delivered using existing departmental resources and budgets.

Improving Safety as a Core Value

This initiative focuses on maintaining a fail-safe mindset, advancing workforce proficiency, and elimination of at-risk behaviours. Key improvements for this initiative include identifying and strengthening 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. Anticipated results from this initiative include sustaining performance in work protection, minimizing or eliminating human performance consequential events (i.e., event free day resets), and achieving industry best performance associated with conventional safety (i.e., serious injury incident rates).

Building Talent for Today & Tomorrow

This 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 for this initiative include enhancing team proficiency through leadership field presence, resourcing work programs appropriately while minimizing the organizational and operational impacts associated with transition to the Pickering Refurbishment Program (“PRP”) and both Pickering and Darlington post-refurbishment operations, and cultivating a high-performance culture that strives for excellence through industry learnings and benchmarking. Anticipated results from this initiative include enhanced employee engagement and strong succession planning.

Leading Reliability of Plant Equipment

This initiative focuses on the prevention and detection of vulnerabilities so actions can be taken to eliminate or mitigate equipment reliability events. Key improvements for this initiative include preventative maintenance (“PM”) reductions through sensor installations, maintenance strategies and plant reliability processes, and optimizing PM processes by implementing technology and data-driven solutions and innovative equipment reliability tools. Anticipated results from this initiative include improving and sustaining forced loss rates, reducing equipment reliability consequential events, improving fuel handling equipment reliability index, and achieving various PM metrics.

Strengthening How Work is Planned and Executed

This initiative focuses on excellence in maintenance, outage and project planning. Key improvements for this initiative include leveraging lessons learned, integrating technology to maximize effective maintenance tool time and PM strategies through use of high-performance diagnostic tools, and resource balancing across project and maintenance functions to enable efficient online, outage and project planning and execution. Anticipated results from this initiative include improving or meeting online maintenance backlogs, work management index, and planned outage duration targets.

Advancing Continuous Improvements to Support Growth

This initiative focuses on excellence in operations supporting future opportunities. Key improvements for this initiative include strengthening Indigenous relations and business partnership to develop new growth opportunities, having a “Fit for Purpose” innovative mindset to drive efficiencies and plant reliability perspectives into our processes and culture, leadership and talent development, and strengthening external relationships with local communities and industry organizations in developing plans that support Pickering Units 1 and 4 safe store, the PRP and the Darlington New Nuclear Program. Anticipated results from this initiative are improving performance and enhanced transition planning and succession planning.

Board Staff Interrogatory #179

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Chart 4 / pp. 24-25
Ref 2: Exhibit F2 / Tab 1 / Schedule 1 / pp. 26-27 (Section 3.3)

Preamble:

At Reference 1, Darlington's non-normalized Non-Fuel Operating Cost per MWh target is $66.61 for 2027, which is more than double the industry median of $24.64 and more than triple the best quartile of $19.64. The normalized Non-Fuel Operating Cost per MWh and normalized Capital Cost per MW Design Electrical Rating (DER) targets for 2027-2031 are all marked N/A. Note 6 to Chart 4 states that "Value for Money targets are indicative and will be updated for final cost allocations reflected in this Application."

At Reference 2, OPG attributes elevated Darlington Total Generating Cost per MWh during the IR term to higher project-related investments, reduced generation from the Vacuum Building Outage in 2027, and emergent work associated with the Primary Moisture Separator Replacements and Turbine Rotors Replacement but does not disaggregate the cost impact of these individual factors

Question(s):

a) Please provide normalized Non-Fuel Operating Cost per MWh and normalized Capital Cost per MW DER targets for each year of the IR term. If they are not available, please explain.

b) Please provide a breakdown of the Darlington Non-Fuel Operating Cost per MWh target of $66.61 for 2027 into its major cost components (e.g., base OM&A, outage OM&A, project OM&A, support services allocations), and for each component identify the gap to the industry median.

c) Note 6 to Chart 4 states that Value for Money targets are "indicative." Please confirm when final Value for Money targets will be established. If the targets have since been established, please provide them.

Response

a) Normalized Non-Fuel Operating Cost per MWh and Normalized Capital Cost per MW DER targets for each year in the IR term cannot be provided. The normalization for these metrics is only performed to adjust for the impact of Darlington Refurbishment in accordance with ScottMadden's OPG Nuclear Cost Performance Benchmarking – Methodology to Adjust for Refurbishment and Validation of Implementation (Ex. F2-1-1, pp. 7-8). Since all Darlington Units have returned to service from refurbishment, such normalization is not applicable during the 2027-2031 IR term. As stated in Ex. F2-1-1, p. 10, OPG does not apply CANDU and age-related normalization, consistent with ScottMadden's methodology, to the sub-components of Total Generating Cost per MWh (i.e., Non-fuel Operating Cost per MWh or Capital Cost per MW DER).

b) Darlington's final Non-Fuel Operating Cost per MWh target for this business planning cycle is $67.07/MWh for 2027, as set out in part c) below. A breakdown of this target into the major cost components is provided in the table below. For clarity, the target reflects exclusions as per EUCG governance. Industry data is not broken down by the cost components below; therefore, a cost component comparison to the industry median is not possible.

2027 Major Cost Components related to Non-Fuel Operating Costs – Darlington	$ Amount per MWh
Darlington Base OM&A	37.25
Darlington Outage OM&A	11.97
Darlington Project OM&A	3.15
Allocation of Corporate Costs – Darlington	11.33
Allocation of Centrally Held Costs – Darlington	3.37
Total Non-Fuel Operating Costs – Darlington	**67.07**

c) Chart 1 below provides Darlington's final 2025–2031 Value for Money targets, which do not materially differ from the indicative targets provided in Chart 4 at Ex. F2-1-1, pp. 24-25). Consistent with past practice, the 2025–2031 Value for Money targets shown in Chart 4 were developed using support cost allocations determined through the previous year's business planning process and were therefore presented as indicative. The update to the Value for Money metrics was anticipated in OPG's 2025-2031 Business Plan, which indicated that the Value for Money targets were "indicative and will be updated once cost allocations and assumptions are finalized" (Ex. A2-2-1, Attachment 1, p. 39, footnote 4). The cost allocations based on the approved 2025–2031 Business Plan were subsequently finalized, in accordance with OPG's cost allocation methodology (Ex. F3-1-4) and are reflected in Chart 1 below.

Chart 1 – Annual Financial Targets for Darlington

Benchmarking Indicators	Best Quartile	Median Quartile	Third Quartile		Darlington Annual Targets						
					2025	2026	2027	2028	2029	2030	2031
Value for Money											
Normalized Total Generating Cost per Net MWh - Updated Methodology ($/MWh)	29.51	34.09	41.78		34.78	43.76	48.75	41.09	42.33	39.15	34.67
Normalized Total Generating Cost per Net MWh - Original Methodology ($/MWh)	27.95	33.51	42.57		37.52	59.72	82.08	50.90	55.27	48.81	44.13
Total Generating Cost per Net MWh ($/MWh)	33.44	39.66	49.23		72.18	85.43	107.77	68.11	74.34	66.90	62.39
Normalized Total Generating Cost per Unit - Updated Methodology ($/Unit)	257.91	284.3	328.93		240.83	301.07	345.63	293.11	300.97	280.12	250.30
Normalized Total Generating Cost per Unit - Original Methodology ($/Unit)	236.12	276.78	320.69		277.54	357.17	406.07	353.62	361.53	340.70	310.87
Total Generating Cost per Unit ($/Unit)	283.01	313.31	358.44		507.52	485.71	503.61	454.52	465.87	448.60	422.42
Normalized Non-Fuel Operating Cost per Net MWh ($/MWh)	N/A	N/A	N/A		37.78	49.76	N/A	N/A	N/A	N/A	N/A
Non-Fuel Operating Cost per Net MWh ($/MWh)	19.64	24.64	32.22		48.35	52.23	67.07	42.65	51.14	44.53	44.62
Fuel Cost per Net MWh ($/MWh)	6.11	6.68	7.44		5.02	6.05	6.49	6.80	7.33	7.80	8.19
Normalized Capital Cost per MW Design Electrical Rating ($/MW)	N/A	N/A	N/A		110.4	161.2	N/A	N/A	N/A	N/A	N/A
Capital Cost per MW Design Electrical Rating ($/MW)	33.87	60.01	107.3		150.71	175.85	182.11	141.84	113.24	111.21	73.84

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

Board Staff Interrogatory #180

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / p. 11

Preamble:

At Reference 1, OPG states that 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.

Question(s):

a) Please provide the external purchased services FTE number that otherwise would be included in the current study for 2024 year.

Response

a) Chart 1 provides the external purchased services (managed tasks) FTEs, that were excluded from the current staff benchmarking study, in the same format used in EB-2020-0290, Ex. F2-1-1, Attachment 6, p. 11. In the course of responding to this interrogatory, it was determined that the 203 Oncore FTEs referenced in Figure 1 in Ex. F2-1-1, p. 13 is incorrect as this number represents the total Oncore vendor amount for the year, inclusive of both benchmarkable and non-benchmarkable amounts. The correct number of benchmarkable Oncore FTEs is 158 as shown in Chart 1 below.

Chart 1: 2024 External Purchased Services by Process Area

Process Area Summary	Oncore Hourly	Other Purchased Services	Total Oncore Hourly and Other Purchased Services
Administrative Services	-	-	-
Configuration Management	8	6	14
Equipment Reliability	12	14	26
Loss Prevention	21	21	42
Operate The Plant	-	11	11
Personnel Services	9	14	23
Plant Maintenance	98	68	166
Radiation Protection	2	1	3
Supply Chain	1	1	2
Work Management	7	14	22
Below the Line	-	2	2
Benchmarked Total	**158**	**152**	**310**

Board Staff Interrogatory #181

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / p. 12
Ref 2: Exhibit F4 / Tab 3 / Schedule 1 / Attachment 1, p.1

Preamble:

At Reference 1, OPG states that 4,458 OPG Nuclear staff were benchmarked and 2,386 were excluded from benchmarking consistent with the methodology applied in prior studies. The information is as of December 2024. OEB staff infer from these two values that the number of OPG Nuclear staff in 2024 was 6,844.

Reference 2 states that the number of direct nuclear facilities FTEs in 2024 was 7,507.3.

Question(s):

a) Please reconcile with difference between the value inferred by OEB staff from Reference 1 with the value at Reference 2.

Response

a) Chart 1 below reconciles the OPG FTE data provided to Indeavor for benchmarking purposes, to OPG Nuclear Facilities direct FTEs provided at Reference 2. In the course of responding to this interrogatory, it was determined that the 2,386 FTEs referenced at Ex. F2-1-1, p. 12 is incorrect and the number should have been 2,563, as shown below.

Chart 1 – Reconciliation of FTE Numbers

	2024 OPG FTEs
2024 Staff Benchmarked by Indeavor	4,458.0
2024 Staff Not Benchmarked by Indeavor	2,563.0
Total data provided for Benchmarking Study	**7,021.0**
Less: Augmented staff benchmarked	(386.0)
Plus: Adjustments to align with Electric Utility Cost Group (EUCG) staffing definitions, OPG Security policy, and timing differences[1, 2]	1,618.3
Less: Allocated Corporate Support Staff	(746.0)
2024 OPG Nuclear Facilities direct FTEs per Ex. F4-3-1, Attachment 1, p. 1, line 6	**7,507.3**

[1] Provided on an aggregated basis, as OPG is unable to disclose information separately Security Staff.
[2] Examples include Short Term Non-Regular Capital/Outage Labour, New Nuclear, Nuclear Waste & Decommissioning.

Board Staff Interrogatory #182

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Chart 2 - Comparison of OPG Nuclear Performance to Industry Benchmarks, p. 14

Preamble:

At Reference 1, there are eight metrics under the Reliability area, nine metrics under the Value for Money area and one metric under the Human Performance area.

Question(s):

a) Please clarify whether Darlington's best-quartile performance in 2023 on six of the Reliability metrics reflects any benefit of the completed refurbishments as of that time.

b) Please clarify whether Darlington's below median and below third quartile performance in 2023 on most Value for Money metrics is expected to improve post refurbishment.

Response

a) Completed refurbishments did not provide significant benefits to the six Reliability metrics for which Darlington achieved best-quartile performance in 2023. Rather, strong performance on the six Reliability metrics was attributable to other factors, as described in Ex. F2-1-1, Attachment 2, pp. 29-35 (e.g., Nuclear Performance Index ("NPI") was in first quartile due to excellent performance on all seven NPI safety sub-metrics, Unit Capability Factor performance was driven by reduced planned outage days in 2023, and backlogs improved as a result of continued station focus, maintenance efficiency, and improved schedule quality).

b) Yes, as per Ex. F2-1-1, pp. 26-27, Darlington's Value for Money metrics are expected to improve post-refurbishment. For example, Darlington's normalized total generating costs per megawatt-hour ("TGC/MWh") is expected to achieve second quartile performance toward the end of the IR term.

Board Staff Interrogatory #183

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Chart 3 – Annual Operational and Financial Targets for Pickering, pp. 20-22

Preamble:

At Reference 1, most metric target settings under Value for Money area are unavailable in Chart 3. Note 6 states "the Value for Money targets are indicative and will be updated for final cost allocations reflected in this Application."

Question(s):

a) Please provide the annual targets for the Value for Money metrics that are stated to be unavailable in Reference 1, if they have since become available.

Response

a) Due to the Pickering Refurbishment Program and resulting lack of forecast generation over the 2027-2030 period, Pickering's annual Value for Money metrics targets identified as unavailable in Ex. F2-1-1 (Chart 3, pp. 20-22) cannot be established for this period. In addition, given the significant diseconomies of scale associated with a single online unit for a partial year, OPG does not expect Value for Money targets to be meaningful measures of performance during 2031 and has not established such targets (Ex. A2-2-1, Attachment 1, p. 39, footnote 5). Normalized Non-Fuel Operating Cost per MWh and Normalized Capital Cost per MW DER are Darlington metrics used to normalize for the Darlington Refurbishment (refer to Ex. L-F2-Staff-179, part a)) and, in turn, are not applicable to Pickering.

   Consistent with past practice, the 2025-2026 Value for Money targets shown in Chart 4 (Ex. F2-1-1, pp. 20-21) were developed using support cost allocations determined through the previous year's business planning process and were therefore presented as indicative. The update to the Value for Money metrics was anticipated in OPG's 2025-2031 Business Plan, which indicated that the Value for Money targets were "indicative and will be updated once cost allocations and assumptions are finalized" (Ex. A2-2-1, Attachment 1, p. 39, footnote 4). The cost allocations based on the approved 2025–2031 Business Plan were subsequently finalized, in accordance with OPG's cost allocation methodology (Ex. F3-1-4).

Accordingly, the Value for Money targets have now been established. Chart 1 below provides Pickering's updated 2025-2026 Value for Money targets, which do not materially differ from the indicative targets previously provided.

Chart 1 – Annual Financial Targets for Pickering

Benchmarking Indicators	Best Quartile	Median Quartile	Third Quartile		Pickering Annual Targets						
					2025	2026	2027	2028	2029	2030	2031
Value for Money											
Normalized Total Generating Cost per Net MWh - Updated Methodology ($/MWh)	29.51	34.09	41.78		32.77	45.67	N/A	N/A	N/A	N/A	N/A
Normalized Total Generating Cost per Net MWh - Original Methodology ($/MWh)	27.95	33.51	42.57		42.06	57.25	N/A	N/A	N/A	N/A	N/A
Total Generating Cost per Net MWh ($/MWh)	33.44	39.66	49.23		71.57	101.57	N/A	N/A	N/A	N/A	N/A
Normalized Total Generating Cost per Unit - Updated Methodology ($/Unit)	257.91	284.3	328.93		131.81	131.20	N/A	N/A	N/A	N/A	N/A
Normalized Total Generating Cost per Unit - Original Methodology ($/Unit)	236.12	276.78	320.69		178.70	178.39	N/A	N/A	N/A	N/A	N/A
Total Generating Cost per Unit ($/Unit)	283.01	313.31	358.44		284.63	288.81	N/A	N/A	N/A	N/A	N/A
Normalized Non-Fuel Operating Cost per Net MWh ($/MWh)	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	N/A
Non-Fuel Operating Cost per Net MWh ($/MWh)	19.64	24.64	32.22		59.67	81.44	N/A	N/A	N/A	N/A	N/A
Fuel Cost per Net MWh ($/MWh)	6.11	6.68	7.44		5.15	5.75	N/A	N/A	N/A	N/A	N/A
Normalized Capital Cost per MW Design Electrical Rating ($/MW)	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	N/A
Capital Cost per MW Design Electrical Rating ($/MW)	33.87	60.01	107.3		34.71	79.25	N/A	N/A	N/A	N/A	N/A

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

Witness Panel: Nuclear Operations and Nuclear Projects

Board Staff Interrogatory #184

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Chart 4 - Annual Operational and Financial Targets for Darlington, pp. 23

Preamble:

At Reference 1, Darlington's annual target is set as 0.0005 throughout 2031 on the Fuel Reliability (microcuries per gram) metric under Safety.

At Reference 1, Darlington's annual target is set as 0.50 throughout 2031 on the Reactor Automatic and Manual Trip Rate (# per 7,000 hours) metric under Safety.

Question(s):

a) Please confirm if a higher value in Fuel Reliability (microcuries per gram) metric means a lower performance, and that the annual target at 0.0005 means Darlington's performance would be expected to be below the third quartile throughout 2031.

b) Please confirm if a higher value in Reactor Automatic and Manual Trip Rate (# per 7,000 hours) metric means a lower performance, and that the annual target at 0.50 means Darlington's performance would be expected to be below the third quartile throughout 2031.

c) Please explain if the above-mentioned two metrics' performance are expected to improve to the third quartile or better beyond 2031.

Response

a) and b) Partially confirmed. As shown in Ex. F2-1-1, Attachment 2, pp. 19-22, higher values in the Fuel Reliability Index ("FRI") and Reactor Trip metrics mean a lower performance. However, annual targets set at 0.0005 microcuries per gram for FRI and 0.50 trips per 7,000 hours throughout the IR term would achieve maximum WANO NPI points ("Max NPI") (refer to Ex. F2-1-1, p. 23 and Ex. F2-1-1, Attachment 2, pp. 19-21). As discussed in Ex. F2-1-1, Attachment 2, p. 11, 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.

c) As noted in parts a) and b), FRI and Reactor Trip metrics are expected to achieve Max NPI during the IR term. Information for this metric beyond 2031 is not available as it goes beyond the forecasted planning period that underlies this proceeding.

Board Staff Interrogatory #185

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Chart 4 – Annual Operational and Financial Targets for Darlington, p. 24

Preamble:

At Reference 1, Darlington's annual target is set as 95.3-96.8 throughout 2031 on the Unit Capability Rate (%) metric under Reliability.

Question(s):

a) Please confirm if a lower value in Unit Capability Rate (%) metric means a lower performance, and that the annual target at 95.3-96.8 means Darlington station's performance would be expected to be below the third quartile throughout 2031.

b) Please explain if the Unit Capability Rate (%) metric's performance is expected to improve to the third quartile or better beyond 2031.

Response

a) Confirmed. A lower Unit Capability Rate ("UCR") value indicates lower performance.

In preparing this interrogatory, OPG identified that the UCR set out in Ex. F2-1-1, for both Pickering and Darlington in Charts 3 and 4, were incorrectly stated. The correct UCR targets are set out in Chart 1 below.

Chart 1 – Corrected UCR Targets for Pickering and Darlington

	2026	2027	2028	2029	2030	2031
PN UCR	96.50	-	-	-	-	88.00
DN UCR	96.47	97.11	97.82	98.00	98.00	98.00

The corrected UCR targets reflect expected performance in the third quartile (97.35) for 2028 through 2031 for Darlington. For clarity, the corrected UCR target does not impact the production forecast.

b) The requested information is not available as it goes beyond the forecasted planning period that underlies this Application.

Board Staff Interrogatory #186

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Chart 4 - Annual Operational and Financial Targets for Darlington, pp. 24-25
Ref 2: Exhibit F2 / Tab 1 / Schedule 1 / p. 10

Preamble:

At Reference 1, there are eleven metrics under the Value for Money area, and nine metrics have annual targets in 2025-2031.

At Reference 1, two targets under Value for Money in 2027-2031 are unavailable in Chart 4. Note 6 says that the Value for Money targets are indicative and will be updated for final cost allocations reflected in this Application.

At Reference 2, OPG states that in the case of Darlington, this (refresh) 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 the Darlington Refurbishment Program (DRP) is completed.

Based on the References, OEB staff produced Table 1, comparing the original and updated normalization methodologies.

Table 1 – Comparison of Normalized Total Generating Cost (TGC) Methodologies ($/MWh)

	2027	2028	2029	2030	2031
Normalized Total Generating Cost per MWh – Updated Methodology	**51.58**	41.14	42.21	39.14	34.68
Normalized Total Generating Cost per MWh – Original Methodology	**81.36**	50.7	55.08	48.74	44.08
Difference between the original and updated methodology	**-29.78**	-9.56	-12.87	-9.6	-9.4

Question(s):

a) Please confirm that the values in Table 1 are correct. If not confirmed, please provide the corrected values.

b) Please confirm that the updated normalization methodology in annual TGC calculation does not include any refurbishment costs beyond 2026.

c) Please explain why the Normalized TGC/MWh metric value differs significantly in 2027 between the original methodology and updated methodology.

d) Please provide the 2027-2031 annual targets for the two Value for Money metrics that are stated to be unavailable in Reference 1, if they have since become available.

Response

a) OPG has updated Table 1 below to reflect Darlington's final 2025-2031 Value for Money metrics, as discussed and set out in Ex. L-F2-Staff-179, part (c):

Table 1 – Comparison of Normalized Total Generating Cost ("TGC") Methodologies ($/MWh)

	2027	2028	2029	2030	2031
Normalized Total Generating Cost per MWh – Updated Methodology	**48.75**	41.09	42.33	39.15	34.67
Normalized Total Generating Cost per MWh – Original Methodology	**82.08**	50.90	55.27	48.81	44.13
Difference between the original and updated methodology	**-33.33**	-9.82	-12.95	-9.66	-9.46

b) Confirmed.

c) The difference in 2027 between the original and updated Normalized TGC/MWh metric methodologies for Darlington is primarily due to the outage adjustment.

Under the original methodology, the outage adjustment was based on a Nuclear Outage Benchmarking Study conducted by ScottMadden and added an average incremental annualized outage days assumption by reactor/outage cycle to generation (refer to EB-2020-0290, Ex. F2-1-1, Attachment 5, pp. 11-12). For Darlington's 36-month outage cycle, this would produce an adjustment of 13 days

(approximately 1,096 GWh) being added to the generation annually, including 2027, resulting in normalized generation of 19.8 TWh for 2027.

Under the updated methodology, the outage adjustment developed by ScottMadden is based on historical EUCG data and benchmarks planned outage durations to the most efficient plant in the peer group with the lowest planned outage percentage (2.67%) (refer to Ex. F2-1-1, Attachment 4, pp. 11-12). For 2027, since Darlington's planned outage percentage is 31.42%, which is significantly higher than for other years in the IR term due to higher expected planned outage days and the Darlington Vacuum Building Outage, the adjustment adds a proportionately higher amount (9,666.2 GWh), resulting in a normalized generation of 28.4 TWh.

d) Refer to Ex. L-F2-Staff-179, part (a).

Board Staff Interrogatory #187

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / p. 33
Ref 2: Exhibit F2 / Tab 2 / Schedule 2 / pp. 3-4
Ref 3: Exhibit H1 / Tab 1 / Schedule 1 / pp. 52-53

Preamble:

At Reference 1, OPG states that it records, in the Pickering B Variance Account, the revenue requirement impact resulting from actual capital and non-capital costs incurred for extension activities. The Pickering B Variance Account also allows OPG to record costs incurred for preserving resources and supporting infrastructure to enable potential refurbishment and subsequent operation of the Pickering units beyond September 30, 2026.

At Reference 2, OPG states that planned Base OM&A costs in 2026 are $1,210.2 million, which is $588.5 million or 94.7% higher than the 2026 OEB-approved budget of $621.7 million. The reportable variances are largely due to Pickering Units 5-8 not ending commercial operation in 2025 as was assumed in EB-2020-0290.

Reference 3 describes and details the Pickering B Variance Account

Question(s):

a) Please provide, for the increased base OM&A costs in 2026 (i.e. $588.5 million or 94.7% higher than the 2026 OEB-approved budget of $621.7 million) the level of costs that would be recovered through additional revenues generated from the output of Pickering Units 5-8 during the period from January 1, 2026-September 30, 2026.

Response

a) OPG expects the revenues generated from the output of Pickering Units 5 to 8 from January 1, 2026-September 30, 2026 to exceed the forecasted increase in Base OM&A costs of $588.5 million during 2026.

Board Staff Interrogatory #188

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / p. 36
Ref 2: Exhibit F2 / Tab 1 / Schedule 1 / Table 1a

Preamble:

At Reference 1, OPG states that historical and bridge year amounts, identified in Reference 2 at Line 9, primarily relate to preparation for potential new nuclear generation. These costs are being recorded in the Nuclear Development Variance Account.

At Reference 2, Line 9 shows the 2025 budget amount at $62.1 million and 2026 budget amount at $136.4 million.

Question(s):

a) Please provide the 2025 actual amount for Other New Nuclear OM&A.

Response

a) The 2025 actual amount for Other New Nuclear OM&A is $39.4 million (refer to Ex. L-A1-CCC-001).

Board Staff Interrogatory #189

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Attachment 5, p. 8

Preamble:

At Reference 1, the table provides a list of job function categories that were excluded from the 2024 OPG nuclear staffing benchmarking methodology.

Question(s):

a) How many FTEs are in each of the excluded categories?

Response

a) Based on Indeavor's benchmarking methodology and EUCG data provided to Indeavor for benchmarking purposes, total OPG FTEs not benchmarked is 2,563 (refer to Ex. L-F2-Staff-181). Chart 1 below shows the breakdown of these FTEs based on the exclusion categories in Reference 1.[1] In addition, the External Purchased Services that were excluded from the staff benchmarking study (refer to Ex. L-F2-Staff-180) are included in Chart 1.

Chart 1 – OPG Nuclear Staff Benchmarking Exclusions by Function

Function	FTEs
Capital Staffing	1,084
Outage Execution Activities	399
Nuclear Waste and Decommissioning	10
CANDU Specific Activities	788
Total Exclusions by Function	**2,281**
Other [1]	282
Total EUCG Exclusions	**2,563**
Purchased Services (Managed Task)	310
Total Staff Benchmarking Exclusions including External Purchased Services	**2,873**

[1] Represents security support and other exclusions that do not fit into the above classifications.

[1] To remain compliant with OPG security policy, the FTE amount for OPG security staff cannot be specified and are additional to the FTE amounts shown in Chart 1 while security support FTEs have been included in the Other category in Chart 1.

Board Staff Interrogatory #190

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Attachment 5, p. 11
Ref 2: EB-2020-0290 Exhibit F2 / Tab 1 / Schedule 1 / Attachment 6

Preamble:

At Reference 1, Indeavor states that data provided at the Electric Utility Cost Group (EUCG) Account level was normalized using historical ratios to split the EUCG account groups into the respective Indeavor functions.

OEB staff notes that the question below is directed to Indeavor.

Question(s):

a) Indeavor: Please confirm that the normalization methodology described at Reference 1 is the same as that followed by Goodnight Consulting at Reference 2? If not confirmed, please explain.

Response

This response was prepared by Indeavor:

a) Confirmed, with the following clarification:

The normalization methodology used in the 2024 Indeavor benchmarking study is the same as that followed by Goodnight Consulting in the 2019 study — historical ratios were used to split EUCG Account-level data into the respective benchmarking functions. One additional step was required in the 2024 study: as the Goodnight Staffing Database no longer exists, PWR survey data provided at the EUCG Account level was allocated to the corresponding Indeavor (which are the same as what Goodnight Consulting previously used) functions using the historical FTE ratios before proceeding with the normalization. This additional step was necessary to replicate the same functional mapping that was previously handled directly through the Goodnight database. The underlying methodology and ratios are otherwise consistent with those applied in the 2019 study.

Board Staff Interrogatory #191

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Attachment 5, p. 21
Ref 2: EB-2020-0290 Exhibit F2 / Tab 1 / Schedule 1 / Attachment 6, p. 9

Preamble:

At Reference 1, Indeavor provides a list of job functions in the 2024 OPG nuclear staffing benchmarking.

At Reference 2, Goodnight Consulting provides a list of job functions in the 2019 OPG nuclear staffing benchmarking.

OEB staff notes that the question below is directed to Indeavor.

Question(s):

a) Indeavor: OEB staff compared the job functions in Indeavor's 2024 benchmarking and in Goodnight Consulting's 2019 benchmarking. Please explain the following differences:
   i. The "Information Technology" function is in the 2024 benchmarking but is not in the 2019 benchmarking,
   ii. The "Security Support" function is in the 2019 benchmarking but is not in the 2024 benchmarking,
   iii. The "Management Support" function is in the 2019 benchmarking but is not in the 2024 benchmarking.

Response

a) *The following response was prepared by Indeavor:*

   i. The Information Technology function was appropriately not included in the 2019 benchmarking because part of the function was outsourced at that time. Rather, this function was benchmarked via a different method external to the 2019 Goodnight benchmarking study, as noted in EB-2020-0290 Ex. F2-1-1, Attachment 6, p. 16. With the repatriation of Information Technology employees from New Horizon System Solutions to OPG in 2022 (refer to Ex. F3-1-1, p. 7), these employees are part of OPG headcount, and the IT function is now appropriately included in the 2024 nuclear staff benchmarking study.

ii. The Security Support function was not included in the 2024 benchmarking as OPG Security Support staff benchmarking data were excluded to remain compliant with OPG security policy, as noted in Ex. F2-1-1, Attachment 5, p. 8. Such benchmarking data were also not provided by benchmarking peers in 2024.

iii. The Management Support function is in fact included in the 2024 study within the broader "Management" function for benchmarking reporting purposes, as per the EUCG-to-Indeavor function mapping in Ex. F2-1-1, Attachment 5, p. 22, although it is not presented as a separate line item in the benchmarking results due to the de minimis size of this function.

Board Staff Interrogatory #193

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Table 2a

Preamble:

At Reference 1, the table shows nuclear facilities FTE information.

Question(s):

a) Please explain the difference in classification between "Term and Extended Temporary" staff and "Temporary" staff.

b) Please explain what the OPG Nuclear Non-Energy Direct staff covers (lines 41, 42, 43 and 44).

Response

a) Term employees are PWU-represented employees that can be hired instead of Regular employees in circumstances where employees are likely to be laid off as a result of the planned shutdown of Pickering (refer to Ex. F4-3-1, Section 5.1.1). Extended temporary employees are Society-represented employees that can be hired to avoid adding regular staff in circumstances where additional regular employees are likely to be laid off as a result of the planned shutdown of Pickering (refer to Ex. F4-3-1, p. 6, footnote 2). Temporary employees are hired for a fixed time period with a start and end date, which for clarity is not tied to the planned shutdown of Pickering. Temporary employees include students and other fixed term employees hired into PWU, Society or non-represented positions.

b) OPG Nuclear Non-Energy Direct staff are associated with producing a product or providing a service that is non-energy, which is discussed in Ex. G2-1-1.

Board Staff Interrogatory #194

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 2 / Schedule 1 / Table 2a
Ref 1: Exhibit F2 / Tab 2 / Schedule 1 / Table 2b

Preamble:

References 1 and 2 set out Base OM&A by resource type for OPG's nuclear facilities and for the Darlington New Nuclear Program (DNNP) facilities, respectively.

Question(s):

a) Please provide a few examples of the types of costs in the Other Purchased Services category and explain why Other Purchased Services makes up a higher percentage of Base OM&A for the DNNP facilities than for the OPG nuclear facilities.

b) Please provide the quantum of contracted labour costs to be procured through Other Purchased Services for the DNNP facilities in 2027-2031.

Response

a) Refer to Ex. F2-2-1, p.7, lines 5-8 for examples of the types of costs in the Other Purchased Services category for the OPG Nuclear Facilities Base OM&A. The simplified DNNP BWRX-300 design, digital technology and managed systems are designed to optimize labour resources, with staff trained and qualified on a wider scope of tasks and disciplines. As such, labour costs represent a smaller percentage of base OM&A costs in DNNP compared to OPG's nuclear facilities, which increases the percentage of purchased services work.

b) DNNP may purchase services to accomplish certain tasks. Purchased services typically include both labour and a mix of other items (e.g., equipment, materials, etc.) necessary to deliver the required service. OPG does not track purchased services on a labour only basis. Additionally, a number of such contracts are yet to be established as DNNP approaches operation. For these reasons, the quantum of contracted labour that is included under Other Purchased Services is not possible to separate.

Board Staff Interrogatory #195

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 2 / Schedule 1 / Attachment 1, p. 7
Ref 2: Exhibit F1 / Tab 2 / Schedule 1 / Attachment 1, p. 7

Preamble:

At Reference 1, OPG states that Renewable Generation Operations functions provide support for the Nuclear fleet, such as Energy Markets, with costs shown in Nuclear Base OM&A actuals and plan.

At Reference 2, OPG states that the Energy Markets team offers and optimizes OPG's generation assets in the IESO-administered electricity market, ensuring compliance with all legal, regulatory, environmental, and operational requirements.

Question(s):

a) Please provide, for each of 2027-2031, the amount of Renewable Generation Operations support costs allocated to Nuclear Base OM&A.

b) Please confirm that the historical and 2027 Renewable Generation Operations support costs that are allocated to Nuclear Base OM&A were not also allocated to the Hydroelectric businesses' revenue requirements. If not confirmed, please explain.

Response

a) The amount of forecast Renewable Generation Operations support costs allocated to OPG Nuclear and DNNP Facilities Base OM&A costs by year is provided in Chart 1:

Chart 1 – Renewable Generation Operations Allocated Support Costs ($M)

	2027	2028	2029	2030	2031	Total
OPG Nuclear Facilities	$6.3	$6.1	$6.4	$6.2	$6.3	$31.3
DNNP Facilities	$0.5	$0.6	$0.7	$0.9	$1.0	$3.7

b) Confirmed.

Board Staff Interrogatory #196

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 2 / Schedule 1 / Table 1a
Ref 2: Exhibit F2 / Tab 1 / Schedule 1 / Table 2a
Ref 3: Exhibit F2 / Tab 2 / Schedule 1 / Table 2a

Preamble:

At Reference 1, Base OM&A - OPG Nuclear Facilities table shows that the total Base OM&A increases from $840.4 million in 2027 to $1,225.4 million in 2031.

At Reference 2, Staff Summary - Subtotal OPG Nuclear Facilities OM&A (excluding DNNP LP) FTEs increases from 3,283.9 in 2027 to 3,882.6 in 2031.

At Reference 3, the Base OM&A - OPG Nuclear Facilities ($M) resource type table shows labour costs (Labour, Non-Regular Labour, Overtime and Augmented Staff) in Base OM&A.

Using the information in the References, OEB staff produced following table:

Table 1 – Base OM&A Change 2027-2031

	2027	**2031**	**% change**
Nuclear Facilities OM&A (excluding DNNP Facilities) FTE count - Ref 2 Line 6	**3,283.9**	**3,882.6**	**18.23%**
Labour ($ millions) - Ref 3 Line 1	570.03	860.12	50.89%
Non-Regular Labour ($ millions) - Ref 3 Line 2	10.07	10.36	2.81%
Overtime ($ millions) - Ref 3 Line 3	36.42	61.62	69.20%
Augmented Staff ($ millions) - Ref 3 Line 4	1.53	1.33	-12.78%
Sum of Labour costs within Base OM&A ($ millions):	**618.05**	**933.43**	**51.03%**

Total Base OM&A ($ millions)- Ref 1 Line 15	**840.4**	**1,225.4**	**45.80%**

Question(s):

a) Please confirm that the four categories of labour listed in Table 1 reflect all labour costs within Base OM&A. If not confirmed, please explain.

b) Please confirm that the values in Table 1 are correct. If not confirmed, please provide the corrected values.

c) Please explain why the increase in the sum of labour costs (i.e., 51.03%) is higher than the increase in FTE counts (i.e. 18.23%) between 2027 and 2031.

d) Please provide any non-compensation cost drivers which contribute to the total Base OM&A costs increase (i.e. 45.8%) from 2027-2031.

Response

a) Not confirmed. Labour, Non-Labour and Overtime are considered labour compensation costs within Base OM&A costs. Generally, augmented staff are brought in for specialized expertise on a fixed-term basis and/or to help manage peak workload periods (Ex. F2-4-1, p. 7, lines 13-23) and are not considered a labour cost.

b) The values in Table 1 are correct. However, Nuclear Facilities OM&A FTEs and Base OM&A labour costs are not equivalent, as Nuclear Facilities OM&A FTEs includes FTEs for Project OM&A and Outage OM&A in addition to the Base OM&A. Additionally, OPG has filed a revision at Ex. L-F2-Staff-199, correcting the FTE amounts in Reference 2, which affects the total Nuclear Facilities OM&A FTEs. The revised forecast Nuclear Facilities OM&A FTEs are 3,326.3 for 2027 and 3,931.6 for 2031.

c) The comparison between labour costs and FTEs using information from Table 1 is inaccurate for the reasons set out in part a) and b). Chart 1 is provided below to enable a more meaningful comparison between Nuclear Facilities Base OM&A FTEs and Nuclear Facilities Base OM&A labour costs between 2027 and 2031, which shows an increase of 30.8% in the Base OM&A FTEs compared to a 51.2% increase in the Base OM&A labour costs. The percentage increase in the labour costs is higher than the percentage increase in FTEs, primarily due to cumulative

wage escalation assumptions between 2027 and 2031 (Ex. L-F4-Staff-227), and higher overtime in 2031. Overtime does not contribute to the total number of FTEs.

Chart 1 – Base OM&A Change 2027 - 2031

OPG Nuclear Facilities Base OM&A (excluding DNNP Facilities)	2027 Plan	2031 Plan	% Change
Nuclear Facilities Base OM&A FTE count	**2,623.0**	**3,431.7**	**30.8%**
Labour (M$) - Ref. 3 Line 1	570.0	860.1	50.9%
Non-Regular Labour (M$) - Ref 3 Line 2	10.1	10.4	2.9%
Overtime (M$) - Ref 3 Line 3	36.4	61.6	69.2%
Sum of Labour costs within Base OM&A (M$):	**616.5**	**932.1**	**51.2%**
Total Base OM&A (M$)- Ref 1 Line 15	**840.4**	**1,225.4**	**45.8%**

d) The higher FTEs and overtime costs in 2031 reflect the temporary decrease in these cost levels in 2027 as Pickering Units 5-8 enter the four-unit refurbishment outage and begin to restore toward normal operating levels in 2031 when Pickering Unit 5 returns to service. For the same reason, as shown in Ex. F2-2-1 Table 2a, also contributing to this trend in the Nuclear Facilities Base OM&A costs is the temporary decrease in Materials and Other Purchased Services until Pickering Units 5 returns to service.

Board Staff Interrogatory #197

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Table 1a

Preamble:

At Reference 1, the Operating Costs Summary – OPG Nuclear Facilities ($M) table shows the Nuclear Facilities OM&A (excluding Darlington New Nuclear Program (DNNP) Facilities).

Question(s):

a) Please provide the planned external purchased service costs in 2027-2031 in the following OPG Nuclear Facilities OM&A categories:
   i. OPG Nuclear Facilities Base OM&A
   ii. OPG Nuclear Facilities Project OM&A
   iii. Pickering Cyclical Maintenance OM&A
   iv. Pickering Refurbishment OM&A

Response

a) Refer to Ex. L-F2-CCC-078.

Board Staff Interrogatory #198

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 2 / Schedule 2 / p. 2
Ref 2: Exhibit F2 / Tab 1 / Schedule 1 / Table 2a
Ref 3: Exhibit F2 / Tab 2 / Schedule 1 / Table 2

Preamble:

At Reference 1, OPG states that Planned Base OM&A costs in 2029 are $898.4 million, which is $47.8 million or 5.6% higher than the 2028 planned Base OM&A costs of $850.7 million. The higher OM&A costs include the impact of the 53rd fiscal week in 2029.

At Reference 2, Staff Summary - Subtotal OPG Nuclear Facilities OM&A (excluding DNNP LP) FTEs increase from 3,246.8 in 2028 to 3,317.7 in 2029.

OEB staff calculates that, at Reference 3, labour categories (Labour, Non-Regular Labour, Overtime and Augmented Staff) make up 75.2% of Base OM&A costs in the IR term.

OEB staff also calculates that the 53rd fiscal week, combined with the increase in FTEs could be expected to cause an increase in Base OM&A of approximately 3% between 2028 and 2029. That is:

- 53rd Fiscal Week adds approximately 2% (due to one extra week of compensation costs 1/52=2)
- OPG's projected FTE count increase adds approximately 2.1% (3,317.7/3,246.8 – 100%=2.1% compensation costs increase)

Applying the 2.0 + 2.1% increase to the labour categories' 75.2% contribution to Base OM&A results in an increase of approximately 3% in 2029 compared to 2028.

Question(s):

a) Please comment on the reasonableness of OEB staff's calculation that 2029 Base OM&A could be expected to be 3% higher than 2028 Base OM&A.

b) Please provide the 2028 to 2029 annual wage escalation and general inflation assumed in the Planned Base OM&A which results in the 5.6% Base OM&A costs increase from 2028 to 2029.

Response

a) Not confirmed. The calculated 3% is not a reasonable approximation of the Base OM&A costs increase between 2028 and 2029, as it does not consider wage escalation, which is provided at Ex. L-F4-Staff-227. Once wage escalation assumptions are added, the resulting approximation would be reasonable.

In addition, the FTEs in Reference 2 include all OPG Nuclear Facilities OM&A costs, whereas the costs at Reference 1 and 3 are planned Base OM&A costs only.

b) The 2028 to 2029 annual wage escalation assumptions are provided in Ex. L-F4-Staff-227 and general inflation assumed in the planned Base OM&A costs is provided in Ex. A2-2-1, Attachment 2, pp. 9-10.

Board Staff Interrogatory #199

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Table 2a

Preamble:

At Reference 1, Staff Summary - Regular and Non-Regular (FTEs) - OPG Nuclear Facilities table breaks out the FTEs accounted as OM&A and accounted as Capital.

Question(s):

a) Please provide the FTEs split between OM&A and Capital in Darlington Refurbishment Program's FTEs.

b) Please provide the FTEs split between OM&A and Capital in Pickering Refurbishment Program's FTEs.

c) Please provide the FTEs split between OM&A and Capital in Nuclear Provision FTEs.

Response

a) All DRP FTEs are Capital funded.

b) All PRP FTEs are Capital funded.

In the course of responding to this interrogatory, OPG identified that certain FTEs were incorrectly categorized under the PRP OM&A and should have been shown in the Nuclear Facilities OM&A and Nuclear Facilities Capital categories. A corrected version of Ex. F3-1-1, Table 18 is provided in Attachment 1, where lines 18 and 20-23 have been corrected to be included in lines 1, 3-6, 7 and 9-12. This also impacted Ex. F2-1-1, Table 2a, where lines 19, 21, 23-24 have been corrected to be included in lines 1, 3, 5 and 6 in the updated version of that table provided in Ex. L-F1-Staff 171, Attachment 1. These corrections do not impact the Applicants' proposed revenue requirements or other approvals sought in this Application.

c) Nuclear Provision FTEs are not split into OM&A and Capital, as they are not funded by either of those two categories and are instead funded by nuclear liabilities (refer to Ex. C2-1-1).

Numbers may not add due to rounding.

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Exhibit L
F2-Staff-199
Attachment 1

Staff Interrogatory #199 - Revised Ex. F3-1-1, 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	998.1	993.1	996.0	1,003.0	1,055.3
	Non-Regular Staff												
2	Term/ETE/PECO Temporary	57.4	76.1	79.2	61.9	53.0	39.0	33.3					
3	Temporary	146.9	156.0	168.5	186.2	152.1	102.5	73.4	55.4	55.5	53.2	54.9	58.0
4	EPSCA	24.6	25.3	22.1	21.6	15.7	27.1	28.1	23.1	23.1	23.1	23.0	26.9
5	**Total Non-Regular Staff**	229.0	257.3	269.8	269.7	220.8	168.6	134.7	78.5	78.5	76.2	78.0	85.0
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	1,076.6	1,071.7	1,072.3	1,081.0	1,140.2
	Nuclear Capital:[1]												
7	**Regular Staff**	14.7	14.2	21.5	42.5	45.5	111.2	116.3	155.7	153.1	156.0	152.0	144.5
	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		3.2	3.2	3.2	3.2	3.2
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	4.1	4.1	4.1	4.1	4.2
12	**Subtotal Nuclear Capital**	29.0	25.7	23.6	58.8	63.9	112.9	117.2	159.8	157.2	160.1	156.1	148.6
	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	244.4	234.9	234.9	229.1	167.9
	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	3.0	1.0	1.0	1.0	1.0
21	EPSCA	0.0	0.0	0.0	0.0	4.5	3.0	8.0	13.0	13.0	13.0	13.0	10.3
22	**Total Non-Regular Staff**	0.0	0.0	0.0	0.0	11.0	3.0	9.0	16.0	14.0	14.0	14.0	11.3
23	**Subtotal Pickering Refurbishment**	0.0	0.0	0.0	0.9	40.7	107.7	154.7	260.4	248.9	248.9	243.1	179.2
	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

Notes:
1 Includes Asset Service Fee projects

Board Staff Interrogatory #200

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Table 1b
Ref 2: Exhibit F2 / Tab 1 / Schedule 1 / Table 2b

Preamble:

At Reference 1, the Operating Costs Summary - DNNP Facilities ($M) table shows the Darlington New Nuclear Program (DNNP) Facilities OM&A.

At Reference 2, the Regular and Non-Regular (FTEs) - DNNP Facilities table shows the DNNP Facilities OM&A Staff FTEs number.

OEB staff created the following table to compute year over year changes to DNNP staffing across 2027-2031.

Table 1 – DNNP Facilities OM&A Year over Year

	2027	**2031**	**YoY % change**
DNNP Facilities OM&A ($ millions) - Ref 1 table Line No. 4	50.2	167.6	**233.86%**
DNNP Facilities OM&A Staff FTEs number - Ref 2 table Line No. 6	144.9	238.5	**64.60%**

Question(s):

a) Please confirm that the values calculated in Table 1 are correct. If not confirmed, please provide the corrected values.

b) Please provide any non-compensation cost drivers that lead to the DNNP Facilities OM&A ($ millions) increase.

Response

a) Confirmed.

b) DNNP Unit 1 will not be operating in 2027 but is planned to be in commercial operation for a full year in 2031, which is the reason for the higher DNNP facilities OM&A costs in 2031 relative to 2027. The 2031 DNNP facilities OM&A costs reflect the full suite of Base and Outage labour and non-labour resources and expenditures necessary for the safe and reliable operation of a new nuclear generating facility. The resource type breakdown of DNNP facilities OM&A costs can be found at Ex. F2-2-1, Table 2b.

For clarity, non-compensation OM&A expenses for the DNNP facilities in 2031 include:

- $45.3M in planned contracting services for the 12-month cycle outage in 2031, which consists of refueling, inspection and maintenance activities. As explained at Ex. F4-2-1, Section 4.2, contracting services will be used for the maintenance scope of that outage;
- $30.1M in Base OM&A purchased services. Refer to Ex. L-F2-Staff-194 for additional information;
- $10.6M in materials costs; and
- $10.3M for planned costs including Canadian Nuclear Safety Commission licence fees, World Association of Nuclear Operators fees, and other costs such as Boiler Water Reactor engineering membership fees.

Board Staff Interrogatory #201

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Table 1b

Preamble:

At Reference 1, the Operating Costs Summary - DNNP Facilities ($M) table shows the Darlington New Nuclear Program (DNNP) Facilities OM&A.

Question(s):

a) Please provide the external purchased service costs treated as DNNP Facilities OM&A in 2026-2031, with breakdowns into Base, Outage and Operational Readiness OM&A.

Response

The requested information is provided in Chart 1 below.

Chart 1 - DNNP Facilities OM&A Purchased Services 2026 to 2031 ($M)

Line No.	DNNP Facilities Cost Category	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1	Base OM&A	0.5	0.3	0.4	0.5	11.8	30.1
2	Outage OM&A	0.0	0.0	0.0	0.0	0.0	45.3
3	Operational Readiness OM&A	7.5	10.7	11.2	7.7	1.9	0.0
4	DNNP Facilities Purchased Services OM&A	**8.0**	**11.0**	**11.6**	**8.2**	**13.8**	**75.4**

Refer to Ex. L-F2-Staff-194 and Ex. L-F2-Staff-200 for further discussion of DNNP facilities purchased services OM&A costs.

Board Staff Interrogatory #202

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 3 / Schedule 1 / Table 1
Ref 2: Exhibit F2 / Tab 1 / Schedule 1 / Table 2a

Preamble:

At Reference 1, Project OM&A Summary - OPG Nuclear Facilities ($M) table shows the 2020-2031 Project OM&A.

At Reference 2, the Staff Summary - Regular and Non-Regular (FTEs) - OPG Nuclear Facilities table shows the 2020-2031 OPG Nuclear Facilities Capital FTEs.

OEB staff created the following table showing year over year changes to OM&A.

Table 1 – Nuclear Facilities OM&A Year over Year

	2024	**2025**	**YoY % Change**
Total Project OM&A - OPG Nuclear Facilities (excluding Darlington New Nuclear Program (DNNP) Facilities) ($ millions) - Ref 1 table Line No. 16	107.9	75.6	**-29.94%**
OPG Nuclear Facilities Capital (excluding DNNP Facilities) FTEs - Ref 2 table Line No. 12	324.3	517.3	**59.51%**

Question(s):

a) Please confirm that the values in Table 1 are correct. If not confirmed, please provide corrected values.

b) Please provide 2025 actual Project OM&A as presented in the Reference 1 table if available.

c) Please explain why the Project OM&A costs trend down from 2024 to 2025 by 29.94% while the OPG Nuclear Facilities Capital FTEs sees an increase from 2024

to 2025 of 59.51%. To what extent is the difference in trends due to more project costs being capitalized rather than being expensed as OM&A?

d) Please clarify if OPG's capitalization policy on project costs has changed in the 2024-2025 period.

Response

a) Confirmed.

b) Refer to Ex. L-A1-CCC-001, which includes Ex. F2-3-1, Table 1 updated with 2025 year-end actual numbers.

c) The OPG Nuclear Facilities Project OM&A costs trending down from 2024 actual to 2025 budget by $32.3M is due primarily to Project #87908 Darlington Unit 1 Steam Generator Primary Side Clean, which incurred nearly all of its project spend in 2024 (Ex. F2-3-3, p. 3, lines 1-11). Other drivers for 2024 expenditures are noted in Ex. F2-3-2, Section 5.0. These drivers are not due to increased capitalization of costs.

The actual OPG Nuclear Facilities Project OM&A costs for 2025 were $63.1M, which is $12.5M below the 2025 budget and $44.8M lower than the 2024 actual. The 2025 actual costs were lower than budget primarily due to lower removal costs associated with capital projects and shifts in project schedules and associated expenses.

Actual 2025 OPG Nuclear Facilities Capital FTEs was 384.9, which represents an 18.7% increase from 2024 (Ex. L-A1-CCC-001). The increase in Capital FTEs from 2024 to 2025 is unrelated to Project OM&A costs decreasing from 2024 to 2025 and is instead tied to the increase in capital project expenditures in 2025 and the ramp up to support the 2026 capital portfolio. The increase in capital investment in 2025 is not due to more project costs being capitalized rather than being expensed as OM&A and OPG's capitalization policy has stayed constant between 2024 and 2025, as discussed in part d).

d) OPG's capitalization policy has not changed in the 2024-2025 period.

Board Staff Interrogatory #203

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 3 / Schedule 2 / Table 1
Ref 2: Exhibit F2 / Tab 3 / Schedule 2 / page 3

Preamble:

At Reference 1, the Comparison of Project OM&A - OPG Nuclear Facilities ($M) table lays out the 2020-2026 Project OM&A Actual/Budget vs. OEB-Approved difference.

At Reference 2, OPG states that planned project OM&A costs for 2027-2031 are $410.6 million. This value is $76.9 million (16%) lower than the actual expenditure amount of $487.4 million in the 2022-2026 term (2025 and 2026 being forecast). This decrease is primarily driven by decreased planned expenditures in Project OM&A (Portfolio) of $11.7 million and Non-Portfolio Projects of $65.2 million.

OEB staff created the following table showing Project OM&A year over year trends.

Table 1 – Project OM&A Year over Year

	2022	**2023**	**2024**	**2025**	**2026**	**2022-2026 term**
Total Project OM&A Including Adjustments ($ millions) - Actual - Ref 1 table Line No. 18, Actual columns	89.5	141.1	107.9	75.6	73.3	487.4
Total Project OM&A Including Adjustments ($ millions) - OEB-Approved - Ref 1 table Line No. 18, OEB-Approved columns	86.4	82.5	76.6	72.8	60.1	378.4
Project OM&A Actual over OEB-Approved ($ millions)	3.1	58.6	31.3	2.8	13.2	**109.0**

Question(s):

a) Please confirm that the values in Table 1 are correct. If not confirmed, please provide the corrected values.

b) Given the forecasted decrease in project OM&A in 2027-2031 term compared to 2022-2026 actual, please explain if the $109 million over OEB-Approved spending on project OM&A in 2022-2026 is due to pacing of 2022-2026 projects going ahead of original schedule, project OM&A scope change, or neither. If neither, please explain.

c) Please provide the estimated costs and in-service dates of each of the projects in Reference 3. If the sum of those projects' estimated costs differs from the $152.6 million 2027-2031 Plan for Portfolio Project (Unallocated) at Reference 1, please explain

Response

a) Confirmed.

b) The 2022-2026 Actuals / Budget variance to 2022-2026 OEB-Approved for Project OM&A cost is not due to pacing of 2022-2026 projects going ahead of original schedule or project OM&A scope changes. The primary drivers of the variance are the following new projects that were not in EB-2020-0290, which account for $75.3M (69%) of the variance:

Portfolio Projects (Allocated):

- #87908 Darlington Unit 1 Steam Generator Primary Side Clean (+$20.5M) (Ex. F2-3-3, p. 3, lines 1-11)

Non-Portfolio Projects:

- Fuel Channel Life Management Phase V Project (+$13.3M)
- FCLE Related Ongoing Costs[1] (+$26.8M) (Ex. F2-3-3, p. 2, lines 16-27)
- Darlington Steam Generator Primary Moisture Separators Replacement Projects (+$14.7M) (Ex. D2-1-3, p. 13, line 22 to p. 15, line 15)

For further information on variance drivers to OEB-Approved spend, refer to Ex. F2-3-2, Sections 4.0 and 5.0.

c) Following clarification sought from OEB staff, OPG understand that this question was provided in error and no response is required.

[1] Represents the Pickering Unit 8 Boiler Secondary Side Advancement Scale Conditioning.

Board Staff Interrogatory #204

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 3 / Schedule 2 / Table 1
Ref 2: Exhibit F2 / Tab 3 / Schedule 2 / p. 1
Ref 3: Exhibit F2 / Tab 3 / Schedule 3 / Table 4

Preamble:

Reference 1 states at line 24 that the 2027-2031 Plan for Portfolio Projects (Unallocated) is $152.6 million.

Reference 2 states that Portfolio Projects (Unallocated) is "the remaining budget available to cover the cost of projects that are progressing through the review and approval process but do not have a PMOC-approved budget or an approved BCS."

References 3 lists unallocated OM&A projects.

Question(s):

a) Please provide the estimated costs and in-service dates of each of the projects in Reference 3. If the sum of those projects' estimated costs differs from the $152.6 million 2027-2031 Plan for Portfolio Project (Unallocated) at Reference 1, please explain.

b) For the projects at Reference 3, are there business cases or similar documentation that supports the project need and cost estimates? If so, please provide them for those projects greater than $20 million. If not available, please describe the information provided to the business unit asset management governing body.

Response

a) Refer to Ex. L-F2-CCC-075, Attachment 1 for estimated costs of unallocated OM&A candidate projects. In-service dates are not applicable to OM&A projects and only applicable to capital projects. Potential project end dates have been provided in Attachment 1 (confidential) but, as noted in Ex. L-F2-CCC-075, cost and schedule information for unallocated projects are preliminary, high-level estimates and are subject to change through the annual business planning process.

   Ex. F2-3-3, Table 4 contains only Tier 1 (Projects >$20M) and Tier 2 (Projects >$5M and <$20M) OM&A candidate projects, which add up to $99.2M in the 2027-2031

IR term, and does not reconcile to $152.6M as the table does not include potential Tier 3 (Projects <$5M) OM&A projects and other unallocated funds. The other unallocated funds are, in part, included in recognition of the anticipated additional investments expected to be identified in support of Pickering second life operations as well as emergent projects. In later years of the business plan, in recognition of emerging work issues that require timely resolution, Darlington has other unallocated funds to support anticipated inspections that require project management oversight.

b) For projects greater than $20 million listed in Reference 3, the only project with a BCS is for Project 89223 – DN U2 Primary Heat Transport Pump Motors Oil Leak Repairs, which is provided at Attachment 1. For the remaining unallocated projects listed in Reference 3, refer to Ex. L-D2-SEC-056 Attachment 4.

ONTARIO POWER GENERATION

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Business Case Summary

Project #	89223	**BCS Document Number**	D-BCS-33130-10008
Project Title	89223 - DN UNIT 2 PHT-PM OIL LEAK REPAIRS		
Facility	D - DARLINGTON NGD	**Investment Classification**	Sustaining
Project Level (Scalability)	B	**Financial Classification**	62030 - OM&A - PROJECT
Release: Gate and Project Phase	G3 - Execution - (Full)	**Target Project Completion Date**	2030-May-31
Estimate Class (Current Request)	Class 3	**Estimate Class (Overall Project)**	Class 3

Recommendation

We recommend release of$34,643k, including [redacted] of contingency.

The Total Project Cost is estimated to be $34,643k, including [redacted] of total contingency.

This project will address and mitigate the risks associated with the 2-33130-PM1/2/3/4 DE bearing oil leaks, thereby relieving the on-going Operations/Maintenance burdens, eliminating the potential safety hazards, and ensuring the long-term motor reliability.

This release is to repair four (4) leaking Primary Heat Transport (PHT) Pump Motors (PM) in U2 during the D2721 outage. In order to accomplish this objective, four (4) available spare motors are required. Three (3) pump motors to be installed will be delivered from Project# 84415. One (1) remaining spare motor (R06) will be repaired and returned as a spare under this project, prior to the start of the outage in 2026.

Investment Cash Flows

Project Number	89223 - DN UNIT 2 PHT-PM OIL LEAK REPAIRS					**FAC**	62030 - OM&A - PROJECT		
$K	**LT YE last year**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**Future**	**Total**
Previous releases	0								0
Currently Requested	0	81	5,729	8,569	13,768	6,457	39		34,643
Total released to date	0	81	5,729	8,569	13,768	6,457	39		34,643
Future required	0								0
Total Project Cost	0	81	5,729	8,569	13,768	6,457	39		34,643
Ongoing Costs	0								0

Total OAR Approval	34,643.0

Approvals	**Signatures**	**Date**
The recommendation, including the identified ongoing costs, if any, represents the best option to meet the validated business need.		
Recommended by: Direct Report of Line Approver : Hassan Qadri Director Station Engineering Dir DN Station Eng	Hassan Qadri	2025-11-18
I concur with the business decision as documented in this BCS.		
Finance Approval : Maha Tam VP Ops & Projects Controllership	Maha Tam	2025-11-26

*Associated with OPG-STD-0076, Developing And Documenting Business Cases

ONTARIO POWER GENERATION

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Business Case Summary

I confirm that this investment/project, including the identified ongoing costs, if any, will address the business need, is of sufficient priority to proceed, and provides value for money.		
Line Approval per OAR : **OAR Element : 1.1** **Allan Grace** **SVP Darlington**	Allan Grace	2025-11-26

EXECUTIVE SUMMARY – Project Overview

PHT motors perform the critical function of transferring heat from the fuel to the boilers for power generation or to a heat sink to provide cooling of the fuel. Oil seal leaks were identified on new Unit 1, 2 and 3 PHT Pump Motors during the first routine inspection after their return to service. Oil was observed leaking and pooling on stator windings, rotor, stator coolers and motor bus bars. Cleanup and repair cannot be performed in situ or at site as it requires full motor disassembly.

A risk assessment of the seal leak issue by OPG (NK38-CORR-33130-0794084) recommends that the problem be corrected early to preserve the life of the motors, before cumulative motor damage occurs. Oil leakage will degrade the motor stator winding insulation and increase motor operating temperatures resulting in premature motor failure, potentially leading to a forced Unit shutdown to replace the motor.

This project is to repair four (4) oil leaking motors in Unit 2 during the Darlington Nuclear Station U2 outage (D2721), as well as the repair of one (1) additional motor (R06) to support the execution of this work during outage. One of the spare motors intended for U2 outage (D2127) was installed in U4 to replace a motor (R06) having Resistance Temperature Detector (RTD) related issues. Therefore, there are only three (3) spares currently available for Unit 2. To support the outage and the replacement of the four (4) leaking motors in U2, the additional motor will be repaired for the RTD related issues in 2026 bringing the spare motor inventory to four (4).

While the project estimate includes costs related to the oil leak repairs, OPG is pursuing cost recovery through warranty claim with the manufacturer.

This project is proceeding directly to a full Execution Phase (Gate 3) release. This project has a similar scope as project# 84415, PHT motor oil leak repairs for Units 1 and 3. Project# 84415 is on track and has successfully completed 50% of the scope of work.

This release will fund the following scope of work:
1. Repair of one (1) PHT pump motor (R06).
2. Removal of the four (4) leaking PHT pump motors from U2 (M7, M8, M9 and M10).
3. Installation of pump motors. One (1) motor (R06) from 89223 and three (3) from 84415 (M6, M1, M2).
4. Completion of oil leak repair of the four (4) removed motors from U2.
5. Return four (4) repaired motors to the station as spares.

The key risks involved, and the mitigations applied with this project are:
1. OEM Support/ Long Lead/ Alternative Materials availability.
Mitigation: Work with legal and supply change for early resolution on warranty claims.

2. Discover issues during inspection assessments during repair which may result increase in cost and/or delay to schedule.
Mitigation: Work with the vendor to inspect the bearing pads at the early stage of the component inspection.

Business Need

For Project Level A or B

There are twenty-one (21) PHT Pump Motors at Darlington site. Sixteen (16) are needed for normal operations (4 per unit) and five (5) spares are to remain on site. Ten (10) of the PHT Pump Motors were replaced with redesigns and installed in Unit 1, 2 and 3.

Oil leaks from the drive-end (DE) bearing seals were discovered during the first internal inspections of the new motors. Oil is leaking and pooling on the inside of the motor shroud covering the motors internal components, including the stator windings, rotor, stator coolers, bus bars, air baffles, auxiliary junction box and associated wiring. Additional issues include oil foaming in the non-drive end (NDE) oil reservoir (oil level not visible) and oil leakage at the NDE of the motor (oil on top of motor).

One of the spare motors intended for U2 was installed in U4 to replace a motor having RTD related issues and, another motor (R01) can no longer be used as it is too old. Thus, there are now only three (3) spares instead of five (5). To support the outage and the replacement of the four (4) oil leaking motors in U2, the additional motor (R06) will be repaired for RTD related issues in 2026, bringing the spare motor inventory to four (4).

This project is to repair four (4) oil leaking motors in Unit 2 during the Darlington Nuclear Station U2 outage (D2721), as well as the repair of one (1) additional motor (R06) to support the execution of this work during outage.

Business Case Summary

Preferred Alternative:	Replace and Repair PHT Motors	For Project Level A, B or C

Description of Preferred Alternative

Replace four (4) oil leaking PHT pump motors in Unit 2, during D2721 outage. To support this, one (1) additional motor (R06) will be repaired for RTD related issues in 2026.

Scope of Work includes:
1. Repair of one (1) PHT pump motor (R06).
2. Removal of the four (4) leaking PHT pump motors from U2 (M7, M8, M9 and M10).
3. Installation of pump motors. One (1) motor (R06) from 89223 and three (3) from 84415 (M6, M1, M2).
4. Completion of oil leak repair of the four (4) removed motors from U2.
5. Return four (4) repaired motors to the station as spares.

Key Assumptions:
1. OEM support (technical, parts, etc.) will be available to support motor repairs/replacements, as well as spare parts.
2. OEM or equivalent parts will be available on time to support the motor repairs schedule.

Deliverables:

Previous Release: N/A

Current Release:

Deliverable Type	*Milestones*	*Associated Milestones (if any):*	*Target Date*
Procurement Process of Motor R06	Procurement Contracts Awarded/PO Issued	89223M1340	2026-03-26
Repair and return of a spare motor (R06) to support D2721 scope.	LLM_Long Lead Manufacturing Complete	89223M1580	2026-12-21
Replace 2-33130-PM1/2/3/4 with spares during D2721.	Available for Service and/or Ready For Service Completed	89223M1750	2027-11-30
Repair and return of removed/defective motors from U2 as spares.	Material / Equipment Available	89223M1551	2029-05-14
Project Closeout	Project Close Out Completed	89223M9998	2030-05-31

Future Release: N/A

Alternative 2:	**Base Case - No Project**	For Project Level A, B or Value-Enhancing

Not recommended as current PHT motor oil seal leakage issue will not be resolved. Continued operation with the oil leaks will not support safe and reliable continued operations of Darlington. This will pose production and safety risks going forward and will also expose the PHT pumps to the high risk of failure as a result of the degradation due to oil leakages.

Pros:
1. None.

Cons:
1. Failure of motors will lead to forced outage.
2. A catastrophically failed motor may not be repairable (additional new motors may have to be procured).

Alternative 3:	**Delay Work**	For Project Level A, B or Value-Enhancing

This alternative is not recommended. Defer PHT motor replacement and repair to scheduled upcoming outages. A delay will mean missing the next planned opportunity for repair and extending the project completion date.

Risks of delay:
1. Increased and more frequent maintenance to remove oil from inside the motor
2. DNGS has a limited ability to remove oil from an installed motor
3. Increased oil viscosity may clog stator vents and coolers, increasing motor operating temperatures
4. Oil contamination on windings may lead to degraded rotor/ stator insulation and premature winding failure
5. Cumulative damage / fouling of internal parts such as (coolers, rotor, stator windings, bearing oil passages, etc.)
6. Risk of premature motor failure and forced outage(s)
7. Work delayed until the next planned U2 outage, the year 2030

Pros:
1. Delay in Cost Spend.

Cons:
1. High Risk of motor failure leading to a forced outage.
2. Extended burden on Operations and Maintenance to operate the plant with defective motors.

Alternative 4:	**Procure New Motors for Replacement**	For Project Level A, B

Replace deficient motors with new motors with the upgraded design. The alternative is not recommended due to the longer lead time and higher costs.

Pros:
1. New Motors may have a longer operating life.

Cons:
1. Long lead time to procure new motors
2. Significantly higher cost of new motors (approx. $8.5M new vs $3.5M each to repair; replacement costs are similar)
3. Additional outages required.

Key Risk Assessment — For Project Level A, B or C

Risk Class	Description of Risk	Response Type / Actions / Final TCD	Residual Ranking
Quality	Discovery of QA non-compliance items.	Mitigate 75942 - Work closely with repair vendor to provide adequate oversight. 11/30/2029	Medium
Technical	Repair vendor not able to complete all 4 repairs in time for outage.	Mitigate 75944 - Keep the schedule align with vendor capabilities (2 motors repair at a time) 8/31/2028	Medium
Technical	Failures of one or more PHT motors during operation and unavailability of spares.	Mitigate 76096 - Keep a viable spare at site in case any operating motor fails. 11/28/2029	Low
Procurement - Materials	Discovery of damaged bearing pads in one of the 5 motors.	Mitigate 75601 - Discovery of damage bearing pads Work with the vendor to inspect the bearing pads at the early stage of the component inspection. 8/25/2029	Medium

ONTARIO POWER GENERATION

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Business Case Summary

Financial Evaluation		For Project Level A, B (with multiple feasible alternatives) or Value-Enhancing			
$K	**Alternative**	**Base Case (No Project)**	**Delay Work**	**Alternative 4**	**Alternative 5**
N/A					

Analysis of Financial Evaluation – Key Assumptions and Key Results:

A financial evaluation is not required for sustaining projects.

Qualitative Factors — For Project Level A or B

Completion of this project will positively impact the business drivers of the nuclear safety and financial performance by improving reliability, reducing maintenance burden, and supporting the long-term operation of DNGS.

Post Implementation Review (PIR) Plan (refer to OPG-GUID-00120-0007)

Is PIR Required?	Yes	**PIR Completion Date**	2031-05-31

PIR KPI's	Current Baseline	Target Result	How to Measure?	Who will measure?
Condition of Motors	There are four (4) PHT motors considered to be at moderate risk of failure in mid-term operation due to oil leakages (M07-M10).	Seal leaks are repaired and risk to continuous operation is low.	Scheduled routine online inspections of motors to ensure oil leaks have been mitigated.	Components Engineering

Definitions and Acronyms

BCS	Business Case Summary
PHT	Primary Heat Transport
PMP	Project Management Plan
PM	Pump Motor
DNGS	Darlington Nuclear Generating Station
OPEX	Operating Experience
OEM	Original Equipment Manufacturers
OAR	Organizational Authority Register
FAT	Factory Acceptance Tests
SAT	Site Acceptance Test
CCF	Change Control Form
NICR	Non-Identical Component Replacement

Business Case Summary

APPENDICES

Appendix A1: Summary of Estimate

Project Number	89223 - DN UNIT 2 PHT-PM OIL LEAK REPAIRS						FAC	62030 - OM&A - PROJECT		
$K	LT YE last year	2025	2026	2027	2028	2029	2030	Future	Total	%
0 - Cost Management		19	135	136	142	61			493	1
1 - Project Management	[redacted]									
2 - Inspection										
3 - Engineering										
4 - Procurement										
5 - Construction										
6 - Commissioning										
Closeout										
Subtotal										
Outside WBS										
Contingency										
Subtotal w/ Contingency										
Interest										
Other										
Total		81	5,729	8,569	13,768	6,457	39		34,643	100
Removal Costs (incl. above)										0

Appendix A2: Summary of Estimate – Notes

Escalation Rate	4.14	Interest Rate (going-forward)	

Appendix A3: Summary of Estimate - In-Service Estimates

$K	Only applicable to capital projects. In-Service amount shall include interest but exclude removal costs.			
Project#	**Date**	**Description**	**Amount**	**%**
N/A				
		Total:		

Prepared by		Reviewed and Endorsed by (Execution Authority)	
Renee Tipler Corpuz Assistant Project Leader DN Projects 1.2	2025-11-07	Perrik Le Dreff VP Major Projects Darlington Nuclear Projects	2025-11-17

Board Staff Interrogatory #205

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 4 / Schedule 1 / p. 1
Ref 2: Exhibit F2 / Tab 4 / Schedule 1 / Table 1

Preamble:

At Reference 1, OPG states that Darlington station has a 36-month planned "cyclical outage" schedule. OPG states that non-refurbishment work conducting on units during their refurbishment "effectively replaces" cyclical outages that would have otherwise been undertaken.

Reference 2 shows Outage OM&A for 2020-2031.

Question(s):

a) Please confirm that, for 2022-2026, the Darlington non-refurbishment "cyclical outage" OM&A is included under the "Darlington Outages" in Reference 2.

Response

a) Confirmed.

Board Staff Interrogatory #206

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 4 / Schedule 1 / pp. 1-2

Preamble:

At Reference 1, OPG states that Darlington New Nuclear Program (DNNP) facilities' refueling outages will initially be performed on a 12-month cycle followed by 24-month cycles. Pickering station has a 30-month planned outage schedule. Darlington station has a 36-month planned outage schedule.

Question(s):

a) Please clarify if the 24-month outage cycle cadence for DNNP is expected for the duration of the facility's life.

b) Please explain how OPG plans outage schedules efficiently to maximize utilization of outage OM&A resources.

Response

a) Following the initial 12-month outage for each unit, a 24-month outage interval for DNNP, required for fueling, is expected for the duration of the facility's life.

b) Refer to Ex. F2-4-1, Section 4.3.

In addition, nuclear outages are planned and executed using a Planned Outage Management (N-PROC-MA-0013) procedure, which provides a systematic approach for guiding an outage through its life cycle. This procedure includes resource management milestones to ensure adequate resources are available to plan and execute outages efficiently.

Board Staff Interrogatory #207

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 4 / Schedule 1 / p. 4

Preamble:

At Reference 1, OPG states that the Pickering Cyclical Maintenance program will primarily be executed by existing OPG operational staff.

Question(s):

a) Given that the Pickering Cyclical Maintenance is a new category in OPG's 2026-2031 OM&A budget, please provide the number of existing FTEs and any new hire FTEs whose costs will be accounted in Pickering Cyclical Maintenance OM&A in 2026-2031.

Response

a) See Chart 1 below for the FTE forecast associated with the Pickering Cyclical Maintenance OM&A budget. The FTE forecast is based on the workforce demand to execute the program, reflecting existing operational staffing levels for the equivalent work prior to Units 5-8 coming offline for refurbishment. New hires would be used to manage attrition of existing employees in the normal course as part of overall workforce management, where applicable, and are not separately forecast.

Chart 1 – Pickering Cyclical Maintenance – Annual FTEs

Year	2026	2027	2028	2029	2030	2031
Annual FTE	75	431	422	422	423	260

Board Staff Interrogatory #208

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 4 / Schedule 1 / pp. 4-5
Ref 2: Exhibit F2 / Tab 4 / Schedule 1 / Table 1

Preamble:

At Reference 1, OPG states that both Base OM&A and Pickering Cyclical Maintenance OM&A resources are required to carry out the ongoing inspection, maintenance and regulatory compliance activities at Pickering during the four-unit refurbishment outage.

At Reference 2, the Outage OM&A table (line 1 and 2) shows that Darlington recorded Outage OM&A during its refurbishment years (2020-2026). The table (line 4 and 5) also shows that Pickering will have zero Outage OM&A planned during its refurbishment years (2027-2030).

Question(s):

a) Please clarify if the Pickering Cyclical Maintenance OM&A is a re-classification of costs that would otherwise be recorded under Base OM&A and Outage OM&A.

b) Please explain if and why Outage OM&A definition is applied differently for Darlington station and Pickering station during their respective refurbishment years.

Response

a) Yes, Pickering Cyclical Maintenance OM&A costs would otherwise be recorded under Base OM&A and Outage OM&A costs if the Pickering units were not in refurbishment during this period.

b) The Outage OM&A costs classification is applied differently for Darlington and Pickering during their respective refurbishment years. Darlington's Outage OM&A costs included certain non-refurbishment outage scope (referred to as Darlington Cyclical Outages) for various inspection, maintenance and related activities that are otherwise associated with a planned outage but which were undertaken on the units while they were under refurbishment. OPG recorded such costs as Outage OM&A costs because some Darlington units were not in refurbishment at that time and continued to take some planned outages.

In contrast, all four Pickering units will be in refurbishment during the 2027-2030 period and none will be taking planned outages during that time. As a result and given that the scope of Pickering's costs must also include what would otherwise have been online maintenance work funded by Base OM&A costs for an operating unit, like there was at Darlington, OPG is not applying an Outage OM&A cost classification for Pickering during the 2027-2030 period. Instead, the costs of the various inspection, maintenance and related activities during this period, whether they would have been online maintenance or planned outage scope, are classified as Pickering Cyclical Maintenance OM&A costs. Pickering Cyclical Maintenance OM&A costs are further discussed in Ex. F2-4-1, Section 3.0.

Board Staff Interrogatory #209

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 4 / Schedule 1 / p. 6

Preamble:

At Reference 1, OPG states that the completion of specific outages requires both base resources and incremental resources. Labour resources are captured in Base OM&A.

The incremental resource types associated with resources utilized during outages include:

- Non-Regular Labour: additional non-regular staff directly supervised by OPG staff (typically trade workers such as electricians).
- Overtime: regular and non-regular staff working on overtime in support of outage execution.
- Augmented Staff: contractors directly supervised by OPG staff (typically engineers and assessors)

Question(s):

a) Does OPG pay Augmented Staff (contractors) overtime? In general, what is the labour cost differential between utilizing OPG staff to work overtime during outages vs. using contractors?

Response

a) OPG does not pay overtime to Augmented Staff because they are employed by another company and OPG pays the vendor a single contract rate. Generally, Augmented Staff are brought in for specialized expertise on a fixed-term basis and/or to help manage peak workload periods (discussed in Ex. F2-4-1, p.7, lines 13-23). When overtime is assigned during outages, it is assigned to meet the needs of the outage scope and schedule. The nature or scope of the work determines the labour jurisdiction and how the work is to be assigned. Augmented Staff and internal labour resources cannot readily be substituted for one another as this will also depend on skill specialization.

When comparing wage rates in general, the cost differential for work assigned to the PWU labour jurisdiction is approximately [redacted] for regular time and approximately [redacted] if there is a need for overtime work, compared to

Augmented Staff. The cost differential for Society labour jurisdiction work compared to Augmented Staff is approximately [redacted] for regular time and approximately [redacted] if there is a need for overtime work.

Board Staff Interrogatory #210

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 4 / Schedule 1 / p. 11

Preamble:

At Reference 1, OPG states that the actual outage OM&A costs also include unbudgeted planned outages.

Question(s):

a) Please clarify if "unbudgeted planned outages" includes planned but under-budgeted outages.

Response

a) As defined in Ex. E2-1-1, Attachment 1, p. 3, an "unbudgeted planned outage" refers to an emergent outage that was not included in the approved nuclear outage and generation plan that underpins the business plan, but for which OPG had sufficient time to notify the IESO at least 28 days prior to the start date. It does not include regular planned outages that were under-budgeted.

Board Staff Interrogatory #211

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 5 / Schedule 2 / Table 1a and 1b
Ref 2: Exhibit F2 / Tab 5 / Schedule 1 / p. 1

Preamble:

At Reference 1, the Comparison of OPG Nuclear Facilities Fuel Costs ($M) tables provide the OEB approved, Actual and Budget fuel costs in 2022-2026.

At Reference 2, OPG states that its average price of manufactured nuclear fuel bundles loaded into a CANDU reactor has increased since EB-2020-0290 and this trend is expected to continue over the IR term.

OEB staff created the following table showing the trends in fuel costs:

Table 1 – Fuel Costs ($ millions)

	2022	2023	2024	2025	2026
OPG Nuclear Facilities Fuel Costs - Ref 1 table Line No. 8 and 15/16, Actual / Budget columns	222.5	218.4	211.8	255.1	239.2
OPG Nuclear Facilities Fuel Costs - Ref 1 table Line No. 8 and 15/16, OEB-Approved columns	177.3	181.3	209.5	189.9	148.0
Fuel costs variance to OEB-Approved	45.3	37.1	2.3	65.2	91.2

Question(s):

a) Please confirm that the values in Table 1 are correct. If not confirmed, please provide the corrected values.

b) Please clarify if the price of manufactured nuclear fuel bundles is hedged for the near term or not.

c) As shown in Table 1, the 2025 and 2026 budgeted fuel costs are higher than the OEB-Approved amounts. Please explain the degree to which the difference is due to fuel price increases, higher energy production, or other factors.

d) Please provide the 2025 actual fuel costs, if available.

Response

a) Confirmed.

b) OPG assumes "near term" to mean the period up to the end of 2028.

OPG has already taken delivery of all planned uranium concentrates deliveries for the 2026 calendar year. OPG is fully contracted for 2027 uranium requirements and is 83% contracted for 2028 uranium requirements.

The prices that will be paid for uranium deliveries in 2027 and 2028 are subject to USD foreign exchange rates, and partial volumes are subject to uranium spot market price volatility while other partial volumes are subject to the rate of increase of an inflation-related index (refer to Ex. L-F2-CCC-077, part e)).

OPG has a contract in place for uranium dioxide conversion and CANDU fuel fabrication services that cover the 2026, 2027 and 2028 delivery years and hedge the costs of these services in those years, subject to a price adjustment mechanism that accounts for inflation and the rate of change of input costs.

Refer to Ex. F2-5-1, Sections 4.2, 4.3, and 4.4 for further discussion of OPG's CANDU nuclear fuel supply chain procurements.

c) As shown at Ex. F2-5-2, Table 1b, the 2025 and 2026 budgeted fuel costs are higher than the OEB-Approved amounts, predominantly due to higher nuclear fuel bundle consumption costs. Further explanations of these variances can be found at Ex. F2-5-2, p. 3, lines 16-22 and lines 3-8, respectively.

Additionally, there is an increase in used fuel storage and disposal variable expenses in the 2025 budget to reflect the Darlington Unit 4 new fuel load, relative to such new fuel assumed to be loaded in 2026 in the OEB approved amounts, due to Unit 4's earlier than expected in-service date; as well as higher production at Darlington in the 2025 budget as discussed in Ex. E1-2-1, Section 2.3. For the 2026 budget, the decrease in used fuel variable expenses due to the Darlington Unit 4 new fuel load being advanced to 2025 is largely offset by the higher expenses associated with the production from Pickering Units 5-8, which were assumed to

permanently cease operation at the end of 2025 in the OEB-Approved amounts. The higher discount rate of 3.93% used to calculate the used fuel variable expenses, associated with the asset retirement obligation adjustment recorded as at December 31, 2023, compared to 2.94% for the OEB-Approved amounts, partially offsets the increase in 2025 and contributes to the decrease in 2026. The year-end 2023 asset retirement obligation adjustment is discussed in Ex. C2-1-1, Section 5.2.

d) Refer to Ex. L-A1-CCC-001, Attachment 1, Table 44.

Board Staff Interrogatory #212

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 5 / Schedule 1 / p. 7

Preamble:

At Reference 1, OPG states that since EB-2020-0290, OPG has increased the fuel procurement planning timeframe from five years to 15 years, due in part to market drivers such as increasing nuclear power demand, and supply and demand dynamics expected in the global uranium market.

Question(s):

a) Please provide the increased annual working capital amount arising from the extension of the fuel procurement planning timeframe from five years to fifteen years.

Response

Extending the procurement planning horizon from 5 to 15 years allows OPG to secure supply capacity for a longer period without increasing annual nuclear fuel inventory demand. Consequently, no additional working capital is required.

Board Staff Interrogatory #213

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 5 / Schedule 1 / pp. 12-13

Preamble:

At Reference 1, OPG states that given the observed increase in uranium price volatility and the elevated risk of continued cost increases during this IR term, OPG has relied on UxC's High-Price Midpoint curve instead of the Mid-Price Midpoint curve used in EB-2020-0290.

Question(s):

a) Please provide the forecasted fuel costs in 2027-2031 using UxC's High-Price Midpoint curve and using the Mid-Price Midpoint curve.

Response

a) Refer to Ex. L-F2-SEC-171.

Board Staff Interrogatory #214

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 5 / Schedule 1 / p. 16

Preamble:

At Reference 1, OPG describes the Darlington New Nuclear Program (DNNP) facilities' nuclear fuel procurement supply chain and some procurements done in 2023-2025.

Question(s):

a) Please clarify where these 2023-2025 procured costs for DNNP facilities are being recorded.

Response

a) The DNNP nuclear fuel procurements undertaken in 2023-2025 were for deliveries beginning in 2026 onwards (the first of which are uranium hexafluoride deliveries in 2026). No fuel costs under these contracts were incurred in the 2023-2025 period.

Board Staff Interrogatory #215

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 6 / Schedule 1 / p. 1

Preamble:

At Reference 1, the Applicants state that they present "the purchases of OM&A expense services for OPG's nuclear operations (excluding Darlington Refurbishment, Pickering Refurbishment, Pickering Feasibility and Darlington New Nuclear Program) that meet the threshold of $20 million in total OM&A expense, consistent with the OEB filing requirements".

Question(s):

a) Please clarify where in the Applicants' evidence equivalent information on OM&A purchased services for Darlington Refurbishment, Pickering Refurbishment, Pickering Feasibility and Darlington New Nuclear Program can be found. If not provided, please provide the information.

Response

a) The OM&A purchased services for the Darlington Refurbishment Program that meet the criteria threshold of $20 million in total OM&A expense as set out in Ex. F2-6-1 are set out below. OPG will file an associated correction to Ex. F2-6-1.

Vendor Name	Description/Nature of Activities	Request for Proposal (RFP) Process		Justification, if not Competitive
		Competitive	Single Source	
SLN-AECON JOINT VENTURE	Provider of general construction and Engineering-Procurement-Construction ("EPC") services.	x		N/A

There were no corresponding Darlington New Nuclear Program, Pickering Refurbishment, or Pickering Feasibility costs over the 2020-2024 period.

Witness Panel: Nuclear Operations and Nuclear Projects

Board Staff Interrogatory #216

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 6 / Schedule 1 / p. 1
Ref 2: Exhibit F2 / Tab 2 / Schedule 1 / Table 2a
Ref 3: Exhibit F2 / Tab 4 / Schedule 1 / Table 2

Preamble:

At Reference 1, OPG states that the total OM&A purchase services expenditures for all contractors for the historical period (2020-2024) was $247.6 million in 2020, $300.5 million in 2021, $255.5 million in 2022, $287.4 million in 2023, and $275.6 million in 2024.

At Reference 2, Other Purchased Services actual amounts for 2020-2024 are included under Base OM&A.

At Reference 3, Other Purchased Services actual amounts for 2020-2024 are included under Outage OM&A.

OEB staff produced the following table showing other purchased services.

Table 1 – Other Purchased Services ($ millions)

	2020	**2021**	**2022**	**2023**	**2024**
Other Purchased Services - Base OM&A - Ref 2 table, Line 7	130.16	151.14	159.58	143.42	164.91
Other Purchased Services - Outage OM&A - Ref 3 table, Line 6	135.22	188.12	128.03	157.28	169.61
Total of Other Purchased Services, Ref 2 and Ref 3	**265.37**	**339.26**	**287.61**	**300.70**	**334.52**
Total OM&A purchase services expenditures, Ref 1	**247.6**	**300.5**	**255.5**	**287.4**	**275.6**

Question(s):

Witness Panel: Nuclear Operations and Nuclear Projects

a) Please confirm that the values in Table 1 are correct. If not confirmed, please provide the corrected values.

b) Please explain why the values in the two “Total” rows in Table 1 are different.

Response

a) Confirmed.

b) The values in the Total of Other Purchase Services, Reference 2 and Reference 3 row reflects Base and Outage OM&A purchase services only and excludes Project OM&A purchase services expenditures. The Total OM&A purchase services expenditures at Reference 1 reflects Base OM&A, Outage OM&A and Project OM&A expenditures for those vendors whose total expenditures over the 2020-2024 (5 year) period exceed $20M, as per Section 8.2 of the Filing Requirements for Ontario Power Generation Inc. Therefore, the two “Total” row values in Table 1 are different.

Board Staff Interrogatory #322

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Attachment 2 / pp. 37-44

Preamble:

At Reference 1, OPG states:

> 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.

Question(s):

a) For each year from 2021-2023, please provide a table showing the adjustment made to each affected cost category.

b) Aside from the Darlington site, please provide a list of all plant refurbishments affecting the 57 nuclear sites studied by ScottMadden from 2006 to 2023.

c) Aside from the Darlington site, please confirm that no refurbishment normalizations have been applied to the costs of any other site.

Response

a) Chart 1 below shows the adjustments made to each Total Generating Costs cost category for Darlington's Refurbishment normalization methodology for the years 2021-2023.

Chart 1: Refurbishment Normalization Methodology – Darlington

2024 Benchmarking Report ($K)	Annual			3-Year
	2021	2022	2023	2023
OM&A	1,066,820	902,440	982,563	2,951,823
Capital	326,294	454,447	547,277	1,328,018
Non-Normalized (Sub-Total)	1,467,101	1,409,975	1,593,117	4,470,192
Refurbishment Adjustment - OM&A	(191,488)	(325,926)	(370,301)	(887,715)
Refurbishment Adjustment - Capital	(87,868)	(259,891)	(313,576)	(661,335)
Refurbishment Adjustment (Sub-Total)	(279,356)	(585,817)	(683,877)	(1,549,050)
Normalized – OM&A	875,331	576,514	612,262	2,064,108
Normalized - Capital	238,426	194,556	233,701	666,683
Total Normalized OM&A & Capital	1,113,758	771,069	845,963	2,730,790

b) Refer to Ex. L-F2-Staff-328, part b).

c) Confirmed.

Board Staff Interrogatory #323

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / p. 9
Ref 2: Exhibit F2 / Tab 1 / Schedule 1 / Attachment 4 / p. 7

Preamble:

At Reference 1, OPG states that ScottMadden analyzed eighteen years of Electric Utility Cost Group (EUCG) data (from 2006-2023) for OPG and it indicated that Canada Deuterium Uranium (CANDU) technology increases predicted Total Generating Cost (TGC) by over $539 million 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.

At Reference 2, it illustrates the calculation of Darlington TGC adjustments based on econometric analysis and refurbishment costs.

Question(s):

a) Please clarify if the above updated study and normalization methodology applies to both Darlington's and Pickering's normalized TGC calculation in 2023 and their annual target calculation in 2026-2031.

b) Given the differences between the reactor design of the units at Pickering and Darlington, please clarify if there is any difference to account for the CANDU technology costs impact in the TGC normalization calculations between the two stations.

c) Given that Pickering will start refurbishment in late 2026, please clarify if any normalization is developed and applicable to Pickering's refurbishment project and its annual normalized TGC calculation in 2027-2031. If so, please provide calculation details similar to the calculation of Darlington TGC adjustments based on econometric analysis and refurbishment costs.

Response

a) ScottMadden's updated study and normalization methodology applies to both Darlington and Pickering's normalized TGC/MWh calculations in 2023, as shown in Ex. F2-1-1, p. 11, Darlington's annual target calculations for 2026-2031 and to

Pickering's 2026 target calculations. Pickering does not have annual Value for Money targets during the IR term, including for normalized TGC/MWh, as discussed in Ex. L-F2-Staff-183.

b) No, there is no difference for the technology normalization adjustment between Pickering and Darlington, as both stations use CANDU technology.

c) No, normalizing TGC/MWh is not applicable to Pickering during refurbishment over the IR term, as discussed in Ex. L-F2-Staff-183. As noted in part a), Pickering does not have Value for Money targets for 2027-2031.

Board Staff Interrogatory #324

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / pp. 8-9
Ref 2: Exhibit F2 / Tab 1 / Schedule 1 / Attachment 4 / pp. 6-7

Preamble:

In Reference 1, OPG explains that ScottMadden conducted econometric analyses of Electric Utility Cost Group (EUCG) data for OPG and its industry peers to assess whether and to what extent site characteristics influence total generating cost (TGC) over time, and to normalize observed costs for those characteristics. In an earlier analysis using nine years of EUCG data (2009–2017), ScottMadden found 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". In the current study, an expanded eighteen-year dataset (2006–2023) is used. ScottMadden reported "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." In both cases, ScottMadden then adjusted the EUCG data to normalize these factors.

At Reference 2, ScottMadden notes in footnote 3 that the prior study's Canada Deuterium Uranium (CANDU) adjustment was $283.9 million in 2017 dollars, which inflation-adjusted to 2023 dollars would be ~$343.3 million — still substantially below the current $539 million figure. The document does not explain the factors driving this ~57% real increase in the CANDU technology cost penalty. Reference 2 also notes that there are only three CANDU plants in the 57-site EUCG dataset.

Question(s):

a) Please explain why a different data period is used in the current study.

b) Please confirm if the same set of "industry peers" is used in both analyses.

c) Regarding Reference 3, please explain step by step how ScottMadden arrived at the Plant Weighted Age variable found in the Weighted Performance Calcs tab.

d) Please explain the driving factors of the differences in the effect of average unit age on predicted TGC in the 2018 study and the 2025 study.

Witness Panel: Nuclear Operations and Nuclear Projects

e) Please identify and quantify the factors that account for the increase in the CANDU technology adjustment from ~$343 million (2018 study, inflation-adjusted to 2023 dollars) to ~$539 million (2025 study, 2023 dollars), distinguishing between the effect of: (a) the expanded dataset period (9 years vs. 18 years), (b) changes in the composition of the EUCG peer panel, (c) actual cost increases at CANDU plants relative to Pressurized Water Reactor/Boiling Water Reactor peers, and (d) any other contributing factors.

f) Given that there are only three CANDU generating stations in the 57-site EUCG dataset, please discuss how ScottMadden assessed the statistical reliability of a coefficient derived from three generating stations within a dataset of 57 sites.

Response

The following responses (a-f) were prepared by ScottMadden Management Consultants:

a) ScottMadden included 18 years of data, compared to nine years of data used previously, because increasing the amount of data improves the accuracy, stability, and predictiveness of the model derived from that data.

b) While the peer panels are similar in both analyses, they are not the same. The 2018 study used a 63-site EUCG panel consisting of 37 PWR sites, 23 BWR sites, and 3 CANDU sites. The 2025 study used a 57-site EUCG panel consisting of 34 PWR sites, 20 BWR sites, and 3 CANDU sites. The variance of six is due to plant closures.

c) The Plant Weighted Age variable is calculated as a capacity-weighted average unit age at the plant-year level.

The steps are:

1. For each unit and year in the “IAEA Unit Data and Weighting” tab, determine the unit’s Commercial Start date and the applicable Aging End Date for that year.
2. Calculate Unit Age (Months) as the number of months between Commercial Start and Aging End Date for that unit-year.
3. For each unit-year, multiply Unit Age (Months) by Rated Unit Power (RUP) to create Weighted Age. This is shown as:
   Weighted Age = Unit Age (Months) × RUP
4. Aggregate those unit-level weighted ages to the plant-year level by summing Weighted Age across all units at the plant. In the workbook, this is on the ‘Weighted Performance Calcs” tab in the ‘Sum of Weighted Age” field.

5. Sum RUP across all units at the plant for the same year. In the workbook, this is on the 'Weighted Performance Calcs" tab in the 'Sum of RUP" field.
6. Compute Plant Weighted Age as:

$$Plant\ Weighted\ Age = \frac{\Sigma(Unit\ Age\ in\ Months\ \times\ RUP)}{\Sigma \mathrm{RUP}}$$

7. That plant-year result is then brought into the "Master Compilation" tab as Plant Weighted Age, and the R script uses that field directly in the regression model. The script then estimates TGC as a function of Plant_Weighted_Age, site capacity, and reactor type.

d) The main driving factor of the difference in the effect of average unit age on predicted TGC between the current study and the 2018 study is due to changes in the underlying dataset and the statistical relationships within that dataset. When the dataset was expanded from 2009–2017 to 2006–2023 and the peer panel changed, these relationships changed. In particular:

- If age becomes more correlated with other variables in the model (e.g., capacity or reactor type), the regression will attribute less independent effect to age
- If the marginal relationship between age and TGC weakens in the expanded dataset, the estimated coefficient on age will decrease.

Consistent with this, the current model results show that the age coefficient is substantially smaller and is less statistically significant, indicating that once capacity and reactor type are controlled for, age explains less incremental variation in TGC in the updated model. Accordingly, the reduction in the age adjustment reflects a reallocation of explanatory power within the regression model, rather than a change in methodology.

e) To assess the drivers of the increase, ScottMadden performed additional sensitivity analysis using consistent model specifications across different time periods. The results are summarized below (all values in thousands of Canadian dollars):

Study	Period	Basis	CANDU Coefficient
Prior Study	2009-2017	2017$Ck	283,946
Prior Study (with Infl'n Adj)	2009-2017	2023$Ck	343,291
Current Study	2006–2023	2023$Ck	539,468
Current Study (same starting point)	2009–2023	2023$Ck	555,768

These results indicate the following:

(a) & (c) Expanded dataset period & CANDU relative to PWR/BWR (primary driver)

The increase in the CANDU technology adjustment reflects the re-estimation of the regression model using more recent data. As the CANDU adjustment is the estimated coefficient on the CANDU indicator variable, changes in this value arise from changes in the underlying dataset and the statistical relationships within that dataset.

From a regression perspective, this is captured through:

- Changes in the relative costs between CANDU and PWR/BWR plants, and
- How those differences interact with other variables in the model (e.g., capacity and age).

(b) Changes in EUCG peer panel composition (limited impact)

The only change in the peer panel was to remove plants that are no longer in commercial operation. The 57 plants in the current peer panel were also present in the prior peer panel. Six plants ended commercial operation between this report and the prior report.

f) Although there are only three CANDU sites, it reflects three quarters of the CANDU plants in North America and the regression is estimated on 54 CANDU site-year observations over 2006-2023, within a total sample of 1,026 plant-year observations.

The statistical reliability of the CANDU coefficient in the current regression is supported by the regression output itself:

Estimated CANDU coefficient: C$539.5 million
Standard error: C$32.1 million
t-statistic: 16.8
p-value: $< 2e^{-16}$
Approximate 95% confidence interval: C$476 million to C$603 million

So, while the number of distinct CANDU stations is small, the coefficient is estimated very precisely in the plant-year panel actually used in the model. However, because the CANDU coefficient is identified from only three sites, it necessarily captures not only reactor-technology differences, but also any persistent CANDU-site characteristics that are not separately controlled for and that are common to those Canadian stations, such as regulatory environment, operating context, and other structural differences. The 2025 report notes that CANDU plants differ from PWR/BWR plants in several relevant ways, including unit configuration, outage/maintenance requirements, and operation in Canada under a different regulatory and market environment.

Board Staff Interrogatory #325

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Attachment 4 / p. 6 / footnote 2

Preamble:

At Reference 1, ScottMadden states "[w]e 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."

Question(s):

a) Please explain why MW capacity was included in the econometric model if no adjustment to total generating cost (TGC) was made.

Response

The following response was prepared by ScottMadden Management Consultants:

a) Larger plants generally have higher total costs. By including capacity in the model, ScottMadden was able to account for this relationship and more accurately isolate the impact of other factors, such as reactor type and unit age.

   However, ScottMadden did not adjust TGC for capacity in the benchmarking results because doing so would also require adjusting generation (MWh) in a consistent way. Specifically, adjusting TGC for capacity without making a consistent adjustment to generation would distort the TGC/MWh metric, as capacity directly influences both the numerator (cost) and denominator (generation).

   So, capacity was included in the model to improve its explanatory power but not used as a normalization factor in order to keep the benchmarking approach straightforward and transparent.

Board Staff Interrogatory #326

Interrogatory

Reference:
Ref 1: Cost Model - With Formulas - BWR Base v4 (For OEB).xlsx
Ref 2: Exhibit F2 / Tab 1 / Schedule 1 / Attachment 4

Preamble:

Reference 1 forms part of the confidential working papers that support ScottMadden's Nuclear Cost Performance Benchmarking study, Reference 2.

Question(s):

a) In the calculation of TGCperMWhOutageAdjusted within the "Cost per MWh Calcs" tab, please confirm whether or not Total_Generating_Costs is adjusted for inflation.

Response

The following response was prepared by ScottMadden Management Consultants:

a) Confirmed. Total_Generating_Costs is adjusted for inflation.

As described in the ScottMadden report at Ex. F2-1-1, Attachment 4, p. 8, all Total Generating Cost (TGC) values are converted to a common dollar basis (2023 dollars) prior to performing the econometric analysis and related calculations.

Board Staff Interrogatory #327

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Attachment 4 / p. 11
Ref 2: Master Data Adjusted For 0 Generation - ORIGINAL.xlsx
Ref 3: OPG Regression Analysis v0.07 (For OEB).R

Preamble:

At Reference 1, ScottMadden states:

> 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.

Question(s):

a) Please explain why OPG Regression Analysis v0.07 (For OEB).R defines Planned_Outage_PCT using Outage_Hours rather than Planned_Outage_Hrs.

b) Please explain the difference between Outage Hours and Total Outage Hrs in Master Data Adjusted For 0 Generation - ORIGINAL.xlsx, tab “Master Compilation.” Please confirm that ScottMadden is using Outage Hours in its Nuclear Outages Analysis.

c) Using the sourcedataoutage data frame in OPG Regression Analysis v0.07 (For OEB).R, CAEC calculated the average share from 2006 to 2023 of planned outage hours (Planned_Outage_PCT) and the average age (Plant_Weighted_Age) for the three CANDU sites. To the extent that planned maintenance outages for CANDU reactors occur on a fixed schedule as described above, please explain the variation in average Planned_Outage_PCT across these three sites. In particular, despite

having similar plant ages, explain why plant 967 and the Pickering plant have significantly different planned plant outage percentages.

d) Regarding Reference 3 and the Darlington plant capacity and planned outage percent from 2006 to 2023.
   i. Please explain how Planned_Outage_PCT is related to the mid-life refurbishment projects at the Darlington plant.
   ii. Please confirm that such projects affect reported capacity and MWh.

Response

The following responses (a-d) were prepared by ScottMadden Management Consultants:

a) 'Planned Outage Hrs', 'Unplanned Outage Hrs', 'External Outage Hrs', and 'Total Outage Hours' were derived from International Atomic Energy Agency ("IAEA") data. Whereas Outage_Hours reflects the outage hours as reported in Electric Utility Cost Group ("EUCG").

   For consistency, EUCG data was the data source used throughout this analysis.

b) Outage_Hours reflects actual hours incurred for planned refueling/maintenance outages reported through EUCG; and 'Total Outage Hrs' is a calculated value derived from a separate data source (IAEA-based unit-level data).

   Confirmed, Outage_Hours from EUCG data was the data source used throughout this analysis.

c) While CANDU reactors follow planned maintenance outage cycles, the outage percentages used in the analysis are based on actual reported planned (not forced) outage hours in the EUCG dataset, rather than a standardized or assumed outage schedule (e.g., 24-,30-, or 36-month intervals).

   In the prior study, ScottMadden relied on survey responses from operators to estimate planned outage durations by reactor type and maintenance (or refueling) cycle. In contrast, the current analysis used actual reported planned outage hours over the 2006–2023 period. The methodology then normalized plants to the level of the best-performing (i.e., lowest percentage of actual planned outage hours) plant rather than using assumed values based on survey responses.

   As a result, the calculated Planned_Outage_PCT reflects observed plant performance over time, which can vary across sites for several reasons, including:

- Differences in outage scope and execution from one cycle to the next
- Differences in plant configuration (e.g., number of units and unit size)
- Differences in operating practices and site-specific conditions across plants

Accordingly, even where plants have similar average unit ages and follow broadly similar outage cycles, it is expected that their observed outage percentages will differ when measured using actual historical outage hours over a long period.

In this context, the variation observed between plant 967 and Pickering reflects differences in their actual outage experience over the 2006–2023 period, rather than a difference in the underlying outage cycle framework.

d)

i. Planned_Outage_PCT is calculated using reported outage hours related to the units in service. For the Darlington mid-life refurbishment, individual units were taken offline for extended periods. This time is not reported in the outage figures. To account for the offline units in refurbishment, the number of units associated with the plant were reduced proportionately in the affected years. In other words, if one unit was offline for the whole year, the units figure was reduced from ‘4’ to ‘3’.

ii. Confirmed, these projects reduced the plant capacity and MWh reported in the EUCG data.

Board Staff Interrogatory #328

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Attachment 4 / p. 12

Preamble:

At Reference 1, ScottMadden states:

> 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.

Question(s):

a) Please explain what is meant by "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."

b) Did ScottMadden consider whether or not such capacity adjustments were needed for other sites in the sample in addition to the Darlington site? If not, please explain.

Response

The following responses (a-b) were prepared by ScottMadden Management Consultants:

a) This statement means that the impact of the Darlington refurbishment was already reflected in the data used for the analysis.

During refurbishment, one or more units at Darlington were offline for extended periods. In the dataset, this was captured through reduced reported capacity (i.e., fewer operating units or lower available MW) in those years. As a result, both the reported generation (MWh) and the effective capacity of the plant already reflect the refurbishment outages.

Because the outage impact was already embedded in the reported capacity and generation data, ScottMadden did not need to make an additional, separate adjustment to capacity for those refurbishment periods. Doing so would have risked double-counting the effect.

b) ScottMadden did not apply similar MW capacity-related adjustments for other sites in the sample. While other plants in the EUCG dataset have undertaken life-extension activities during the data window, these activities were not treated in the same manner. We did not have detailed cost data associated with these life extension projects at other plants and thus did not and could not remove these costs from their TGC as we did for Darlington. Furthermore, when applying model-derived downward adjustments for these plants, we did not reduce the size of these downward adjustments based on the associated costs for life-extension work. This combination of factors (i.e., higher TGC as a result of not removing life extension costs and additional reduction in TGC from full application of model-derived adjustments) made us comfortable that the comparison was still appropriate.

Society Interrogatory #010

Interrogatory

Reference:
OEB staff interrogatory F2-Staff-180

Preamble:

OEB staff have requested the external purchased services FTE number that otherwise would be included in the Indeavor Nuclear Staffing Benchmarking Study for 2024.

Question(s):

a) Please provide the estimated total cost for these external purchased services FTE's. This should be the total billed cost, not the sum of an estimated labour rate for such.

Response

a) The estimated total cost for the requested external purchased services FTEs, provided at Ex. L-F2-Staff-180, is $88.8M, based on actual amounts paid.

Society Interrogatory #011

Interrogatory

Reference:
(1) OEB staff interrogatory F2-Staff-181
(2) Exhibit F4-3-1, Attachment 1, "Appendix 2K"

Preamble:

OEB staff have requested that OPG reconcile the difference in inferred total OPG Nuclear staff numbers both included and excluded from the Indeavor Nuclear Staffing Benchmarking Study for 2024 and reference (2) above.

Question(s):

a) If the interrogatory response to F2-Staff-181 concludes that there is an error in reference (2), please update this reference.

Response

a) Not applicable, as there was no error in Reference 2 per Ex. L-F2-Staff-181, and therefore no update is required.

Society Interrogatory #012

Interrogatory

Reference:
Exhibit F2-1-1, Attachment 5, OPG Nuclear Staff Benchmarking by Indeavor dated November 2025.

Preamble:

"OPG's 2024 staffing headcount is 4,458, which is 9.3% below the benchmark of 4,913." [Executive Summary p4]

Question(s):

a) Please breakdown both this OPG staffing headcount of 4458 and the variance of 455 (9.3%) by representation jurisdiction i.e. Management, SUP represented and PWU represented.

b) Does this staffing headcount underage indicate that OPG is understaffed as compared to this peer group?

c) What are the health and safety consequences of such understaffing in OPG as compared to this peer group?

Response

a) The OPG nuclear staffing benchmarking headcount of 4,458 has been broken down in Chart 1 below by represented group. OPG and Indeavor are not privy to the peer group information at this level of detail and therefore cannot provide the breakdown of the variance to benchmark by represented group.

Chart 1: OPG Nuclear Staffing Benchmarking Headcount Breakdown

	Total
Management	424
Society Represented	1,511
Power Workers Union (PWU) Represented	2,446
Augmented Staff	44
EPSCA	33
Total	**4,458**

Witness Panel: Nuclear Operations and Nuclear Projects.

b) The Nuclear Staffing Benchmarking Report, which has been revised as discussed in Ex. L-F2-SEC-164, part d), shows that OPG's nuclear staffing headcount variance is 44, or 1.0%, below benchmark.

OPG is not understaffed. Rather, based on the 2025 Indeavor nuclear staffing analysis, OPG has been able to maintain safe, reliable operations with 1.0% less staff compared to the benchmark. OPG's Building Talent for Today & Tomorrow initiative focuses on ensuring work programs are resourced appropriately in accordance with the 2025-2031 Business Plan while minimizing the organizational impacts associated with transition to the Pickering Refurbishment Program and Pickering and Darlington post-refurbishment operations (refer to Ex. F2-1-1, pp. 29-30).

c) As discussed in part b), OPG is not understaffed. Therefore, there are no health and safety consequences of being understaffed compared to the peer group. OPG's staffing levels are predicated on ensuring safe, reliable operations of the nuclear stations. Pickering and Darlington 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. (Ex. F2-1-1, p.15, lines 10-16).

AMPCO Interrogatory #105

Interrogatory

Reference:
F2-3-3 Table 1

Question(s):

a) Please provide the total project cost in EB-2020-0290 for: DN Primary Heat Transport Pump Motor Oil Leak Repair (Project #84415), Fuel Channel Life Extension Project (Project #80014) DN Irradiated Fuel Bay Stack Frames Project (Project #80067).

b) Please provide the final completion date in EB-2020-0290 for: DN Primary Heat Transport Pump Motor Oil Leak Repair (Project #84415), Fuel Channel Life Extension Project (Project #80014), DN Irradiated Fuel Bay Stack Frames Project (Project #80067), and DN U0 Switchgear Refurbishment (Project #84484).

c) Please confirm the Fuel Channel Life Extension Project (Project #80014) was completed in December 2025 at a cost of $63.6 million.

d) Please provide the actual completion date for PN U8 Boiler Secondary Side Advanced Scale Conditioning Project (Project #87117) and the original baseline total cost estimate. In the response, please indicate why a BCS is shown as n/a.

e) Please confirm DN U1 Steam Generator Primary Side Clean Project (Project #87908) was completed in December 2025 at a cost of $20.6 million.

f) Please provide the Project Over Variance Report for Project #84484.

Response

a) The requested total project costs as provided in EB-2020-0290 Ex. F2-3-3, Table 1 were:
- DN Primary Heat Transport Pump Motor Oil Leak Repair (Project #84415): $47.4M
- Fuel Channel Life Extension Project (Project #80014): $69.3M
- DN Irradiated Fuel Bay Stack Frames Project (Project #80067): $29.7M.

b) The requested final completion dates as provided in EB-2020-0290, Ex. F2-3-3, Table 1 were:

- DN Primary Heat Transport Pump Motor Oil Leak Repair (Project #84415): July 2025
- Fuel Channel Life Extension Project (Project #80014): December 2021
- DN Irradiated Fuel Bay Stack Frames Project (Project #80067): December 2022
- DN U0 Switchgear Refurbishment (Project #84484): December 2027.

c) Confirmed.

d) PN U8 Boiler Secondary Side Advanced Scale Conditioning Project (Project #87117) was completed June 2025.[1] The original cost estimate was $35.8M and the total project cost of the completed project was $26.8M. A standalone Business Case Summary ("BCS") for this project was not applicable, as this work was executed under the established Fuel Channel Life Extension Ongoing investment program, which covers expenditures for incremental work required to enable fuel channel and other major component (e.g., steam generators) operation to enable a nuclear station's beyond original design targets (refer to Ex. F2-3-3, p. 2).

e) Not confirmed. The field work for the DN U1 Steam Generator Primary Side Clean Project (Project #87908) was completed in May 2024. However, project closure report completion is ongoing, and the total project cost has not yet been finalized.

f) As required by OPG's governance, a Superseding BCS was prepared, which is provided at Ex. F2-3-3, Attachment 1, Tab 1, rather than a Project Over Variance Report. A project variance explanation for Project #84484 is provided at Ex. F2-3-3, pp. 3-6.

[1] In the course of preparing this response, OPG discovered an error in the date specified in Ex. F2-3-3, p. 2, line 23, which specified completion in December 2024.

AMPCO Interrogatory #106

Interrogatory

Reference:
F2-3-3 Table 2a, Table 2b, Table 2c

Question(s):

a) Please confirm all of the projects with a final completion date of 2025 to March 2026 have been completed.

b) Please provide the baseline approved cost and final completion date for each of the OM&A projects in Table 2a, Table 2b and Table 2c.

Response

a) Not confirmed. All projects with final completion dates of 2025 to March 2026 have been completed except for the following projects, which are all currently in close out:

Project # 84872 - DN PRECISE-D Scrape Tooling
Project # 87152 - PN Public Address System Core Upgrade
Project # 87187/87892 - PN Forebay Dredging

b) The total project cost and final completion date from the first Execution Business Case Summary is provided for each of the OM&A projects in Ex. F2-3-3 Table 2a, Table 2b and Table 2c in Attachment 1.

Line No.	Facility	Project Name	Project No.	1st Execution BCS Final Completion Date[1]	1st Execution BCS Total Project Cost ($M)[1]
		ONGOING PROJECTS FROM EB-2020-0290			
1	AIM	Inspection Qualification	66105	Dec-14	15.3
2	DN	DN Reduced HTS Pressure-Temperature Envelope Modifications	80016	Dec-19	11.7
3	DN	DN Aging Management Scope Defining Inspections	80110	Dec-18	9.9
4	PN	Pickering 58 Digital Control Computer Hardware Modernization	80135	n/a	n/a
5	DN	Darlington DCC/CP/SEM Computers Software Shipments	82825	Jun-27	8.6
6	DN	DN Fuel Handling Computer Software Release	82826	Jul-26	10.2
7	DN	DN Annunciation Modifications And Post-Accident Monitoring Configuration Management	83545	Dec-28	9.2
8	AIM	DN PRECISE-D Scrape Tooling	84872	Dec-21	5.3

		COMPLETED/DEFERRED/CANCELLED FROM EB-2020-0290			
9	DN	DN Boiler Blowdown Piping Replacement	31506	Jun-18	17.8
10	DN	DN GFP Sample Delay & Alternative PHT Sampling Point	31514	May-18	8.5
11	DN	DN PHT LRV Modifications (Waterhammer)	38933	Dec-25	21.6
12	PN	PN Instrumentation & Control Obsolescence	41024	Jun-16	5.6
13	PN	DCC Aging Management	62553	Dec-12	14.5
14	PN	PN Equipment Reliability Initiatives	80060	Dec-14	8.5
15	DN	DN New Primary Heat Transport Pump Seals	80071	Dec-17	16.6
16	DN	DN Aging Management	80079	Dec-16	8.2
17	DN	DN Annulus Spacer Life Management	83280	Dec-21	29.3
18	PN	Pickering Fuelling Machine Ram Seal Improvement	83302	Dec-19	14.6
19	DN	DN Civil Building Structure Repairs	83479	May-24	12.7
20	ENG	Asset Management Implementation	83824	Dec-19	9.4

21	DN	DN Resin Transfer Modification	84380	Dec-20	8.0
22	DN	DN Periodic Safety Review	84589	May-24	27.0
23	DN	DN PHT Pump Motor R01 Refurbishment	84766	Sep-23	8.7
24	DN	X-Lab Wireless Sensor Portfolio	84999	Mar-24	7.0
		PROJECTS NOT IN EB-2020-0290			
25	AIM	Matrix Inspection For Tubular Components	84850	n/a	n/a
26	AIM	Laser Induced Breakdown Spectroscopy Hydride Characterization Tool	86174	n/a	n/a
27	PN	Public Address System Core Upgrade	87152	Jan-25	6.9
28	DN	Fuel Channel Life Management Phase V Project	87175	Dec-27	14.6
29	PN	PN Forebay Dredging	87187/ 87892	Nov-24	20.2

Notes:

1 The designation of "n/a" means the project has not advanced to a First Execution BCS.

AMPCO Interrogatory #107

Interrogatory

Reference:
F2-3-3 Table 4

Question(s):

a) Please confirm all of the projects with a potential 2025 start date have started.

b) With respect to the DN U2 Primary Heat Transport Pump Motors Oil Leak Repairs Project (Project #89223), please provide:
   i. the potential expenditures in 2027
   ii. Please provide the forecast total cost of the project

c) With respect to the AIM End of Life Fuel Channel Component Retrieval Project (Project #89282), please provide:
   i. the potential expenditures in 2027
   ii. Please provide the forecast total cost of the project

Response

a) Not confirmed. Project #86299 has not started.[1]

b) Refer to Ex. L-F2-Staff-204, Attachment 2 for the Business Case Summary for Project #89223 - DN U2 Primary Heat Transport Pump Motors Oil Leak Repairs, which includes the following requested information for the project:
   i. Estimated expenditures for 2027 are $8.6M
   ii. Estimated total cost of the project is $34.6M.

c) Forecast total cost information is not yet defined and expenditures by year are not available for Project #89282 - AIM End of Life Fuel Channel Component Retrieval, as this is still an unallocated project. For estimated investment cost information, refer to Ex. L-F2-CCC-075, Attachment 1. As discussed in Ex. L-F2-CCC-075, the information provided is based on pre-Class 5 estimates that are subject to change.

[1] As noted in Ex. L-F2-3-Staff-204, Project# 89280 – DN Software Inventory Management 69000 was incorrectly included in Ex. F2-3-3, Table 4.

CCC Interrogatory #081

Interrogatory

Reference:
Exhibit F3, Tab 1, Schedule 1, Attachment 2, Table 1

Preamble:

The Hackett Group benchmarking study uses the categories of Finance, HR, ECS, IT, Procurement and Real Estate & Facilities Mgmt to benchmark OPG's corporate support costs.

Tables 1 presents OPG's corporate support costs using the categories Corporate & Technology Services, Real Estate, Supply Chain, Finance, Human Resources, and Corporate Centre.

Question(s):

a) Please recategorize Tables 1-4 so that they match the categories used by the Hackett Group in their benchmarking study, combining or disaggregating the categories in the Tables as necessary.

b) Please confirm that the benchmarking results do not account for the changes in support services costs from 2024 to 2031.

c) Please benchmark OPG's proposed 2031 corporate support costs, using forecast 2031 data as necessary.

Response

OPG assumes based on the question that the respective reference is intended to be Ex. F3-1-1, Table 1 and not Ex. F1-1-1, Attachment 2, Table 1.

a) OPG understands the question to be asking for a restatement of the historical and forecast cost information contained in Ex. F3-1-1 Table 1 in a manner that aligns to the taxonomy used by Hackett to perform the Corporate Support Benchmarking Study. OPG cannot provide this data as it has not conducted such an exercise and is unable to do so in the time available. This would require the same level of analysis of OPG's cost structure for each of the four additional historical years for nuclear and each of the eight additional historical years for regulated hydroelectric, and seven years of forecast information, as was necessary to develop the 2024

benchmarked costs, in line with Hackett's taxonomy. In addition, the benchmarking is performed by Hackett on a combined nuclear and regulated hydroelectric basis and as a result, the associated adjustments and recategorizations necessary to accord to Hackett's taxonomy have not been performed for each of the regulated businesses separately.

b) Confirmed.

c) Refer to part a).

In addition, the following response was prepared by The Hackett Group:

Hackett does not have the necessary data to provide an accurate benchmark comparison of OPG, or peers based on 2031 forecast data. That analysis was not included in the original scope of the OPG benchmark analysis and would be a departure from Hackett's benchmarking methodology. Hackett benchmarks are based on data collected from companies in the peer group based on current state performance. Developing a benchmark based on 2031 forecasts would require assumptions regarding future business drivers, potential organizational structures, technology adoption, and forward-looking macroeconomic changes. Hackett does not have the necessary data to do this comparison.

CCMBC Interrogatory #003

Interrogatory

Reference:
F3-1-1, page 48

Preamble:

"WTW undertook a comparison of OPG's wages to those provided by Bruce Power. 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."

Question(s):

a) How many employees have left OPG for jobs with Bruce Power over the past five years?

b) Is OPG concerned that it may be losing employees to Bruce Power?

c) Did WTW undertake a comparison of OPG's pensions, benefits and OPEB's to those provided by Bruce Power? If the answer is yes, please file it. If the answer is no, please explain why not.

Response

a) OPG does not comprehensively track the requested information specific to Bruce Power LP; however, it is known that there have been employees in various functions who have left OPG for jobs with Bruce Power LP over the past five years.

b) OPG actively manages risks related to staff retention and continues to monitor the ongoing demand for employees skilled and trained in the energy sector, particularly the nuclear industry. The success of the Darlington Refurbishment Program has created additional market interest in OPG's employees in certain roles, and more broadly, energy sector development is contributing to increased competition for talent. While OPG competes with Bruce Power LP for talent, they are not the exclusive contributor to the increased labour market risk. Refer to Ex. F4-3-1, pp. 13-17, which further describes talent retention considerations for OPG.

c) No. The analysis presented in Ex. F4-3-1, Attachment 4 was based on publicly available information. As noted in Ex. L-F4-CCMBC-004, part (b), the detailed information required to complete a pension and benefits analysis of Bruce Power LP's pension and benefits information is not publicly available.

Minogi Corp Interrogatory #009

Interrogatory

Reference:

- **Exhibit F3, Tab 3, Schedule 1**
- **Exhibit A1, Tab 3, Section 1.1**

Question(s):

a) Please confirm if OPG proposes procurement related reporting, scorecards, or record-keeping in this proceeding.

b) If yes to a), please describe.

c) If no to a), please confirm OPG's ability to report annually at facility/project level on spend with Ontario, Canadian, local or First Nation rightsholder suppliers and provide details.

d) Please confirm plans to implement such report for 2027-2031.

Response

a) - d) OPG is not proposing separate procurement related reporting to the OEB.

OPG already maintains multiple internal and external mechanisms to document, track, and report on procurement-related activities and outcomes, including corporate procurement records maintained in accordance with internal governance and financial control requirements. Publicly available reporting includes OPG's Annual Reports (refer to Ex. A2-1-1) and OPG's Corporate Balanced Scorecard (refer to Ex. L-F4-AMPCO-124 for the 2025 scorecard). In addition, OPG reports on procurement-related economic empowerment initiatives through the Reconciliation Action Plan ("RAP") Updates (refer to the 2022 RAP Report on opg.com), which includes information on procurement activities involving Indigenous and First Nations businesses.

OPG maintains procurement-related record-keeping, reporting, and scorecard practices. OPG's procurement process includes documented evaluation criteria, weightings, and an evaluation methodology used to assess and score supplier submissions, and OPG retains procurement records to support contract award and contract administration.

Minogi Corp Interrogatory #010

Interrogatory

Reference:

- **Exhibit F3, Tab 3, Schedule 1**
- **Exhibit F2, Schedule 5**

Question(s):

a) Please confirm if procurement for on-site storage, repackaging, monitoring, upgrades, or site waste management services at Pickering and Darlington follows standard OPG processes; describe any specific strategies for extended scenarios.

b) For each of the categories identified in a), please confirm and describe assessments of suitability for local or First Nation rightsholder businesses.

Response

a) Confirmed. OPG is unclear what “extended scenarios” refer to; OPG’s procurement process is described in Ex. F3-3-1.

b) Refer to Ex. L-D3-MC-012.

Minogi Corp Interrogatory #011

Interrogatory

Reference:

- **Exhibit F3, Tab 1, Schedule 1**
- **Exhibit F3, Tab 1, Schedule 1, Attachment 1**
- **Exhibit A2, Tab 1, Schedule 1, Attachment 4**

Question(s):

a) Please identify 2023–present OPG public statements, commitments, policies, or strategies on First Nation rightsholder economic inclusion, procurement, or partnerships.

b) Please describe the influence of the OPG public statements, commitments, policies, or strategies identified in a) on application assumptions, forecasts, and/or reporting.

c) Please describe any goals or tracking for local/First Nation rightsholder procurement in 2027-2031.

Response

a) and c)
OPG's focus is on advancing Indigenous economic inclusion through procurement and partnerships with local/First Nation rightsholders. Progress is tracked annually using contract award and spend data, with specific metrics to identify participation by community-owned and rightsholder-affiliated suppliers to support delivery and accountability. OPG has embedded Indigenous economic participation into its sourcing and supplier management processes. This includes hosting procurement information sessions for Indigenous businesses and OPG staff, requiring Indigenous engagement plans as part of RFP submissions, evaluating supplier performance against Indigenous engagement commitments, and delivering a structured mentorship program that pairs Indigenous business leaders with senior OPG leaders. Together, these programs provide a consistent framework to enable, support, and track local and First Nation rightsholders economic inclusion in OPG's procurement. Refer to https://www.opg.com/reporting/ for more information.

The Application reflects the assumptions made in OPG's 2025-2031 Business Plan.

Minogi Corp Interrogatory #012

Interrogatory

Reference:

- **Exhibit F3, Tab 1, Schedule 1**
- **Exhibit A2, Tab 1, Schedule 1, Attachment 4**
- **Exhibit D3, Tab 1, Schedule 1**
- **Exhibit D2, Tab 1, Schedule 1**

Question(s):

a) Please identify treaty lands relevant to Pickering, Darlington, and waste facilities for OPG's procurement/community purposes.

b) Please confirm use of location, proximity, treaty, or rightsholder criteria in identifying businesses for outreach/procurement.

c) Please provide total annual Pickering and Darlington procurement spending (2020–present) that OPG considers suitable for local or First Nation rightsholder sourcing.

d) Please describe the methodology for suitability determination pursuant to the response to c).

Response

a) The Pickering Nuclear Generating Station (PNGS), the Pickering Waste Management Facility (PWMF), the Darlington Nuclear Generating Station (DNGS) and the Darlington Waste Management Facility (DWMF) are located within the Williams Treaties (1923) including the Gunshot Treaty (1787–88). The Western Waste Management Facility (WWMF) is located within the area covered by Treaty 45 ½ (the Saugeen Tract Purchase), signed in 1836.

b) Refer to Ex. L-D3-MC-005.

c) and d) OPG does not categorize or track procurement spending as being specifically suitable for local or First Nation rightsholder sourcing. Refer to Ex. L-F3-MC-009 and Ex. L-F3-MC-011 for information on OPG's procurement reporting and Indigenous economic inclusion. Further, Ex. L-D3-MC-005 describes OPG's procurement evaluation process and assessment of suppliers.

Minogi Corp Interrogatory #013

Interrogatory

Reference:

- **Exhibit F3, Tab 1, Schedule 1**
- **Exhibit F3, Tab 1, Schedule 1, Attachment 1**
- **Exhibit A2, Tab 2, Schedule 1**
- **Exhibit D3, Tab 1, Schedule 1**

Question(s):

a) Please confirm consideration of a procurement framework by 2026/2027-2031 for First Nation rightsholder participation near nuclear facilities.

b) If yes to a), please describe:

(i) the status of that consideration;
(ii) any proposed timeline;
(iii) any internal approvals required; and
(iv) any reporting or tracking metrics.

c) If no to a), please describe OPG's rationale for not considering such a procurement framework.

d) Please identify any legal, operational, and/or safety considerations for such a framework.

Response

a)-d) Refer to Ex. L-D3-MC-006, parts (a)-(c). OPG's procurement process is described in Ex. F3-3-1, including Section 7.0 entitled "Social License and Procurement".

Pinto Interrogatory #001

Interrogatory

Reference:
Internal Controls and Maintenance Information
Corporate Real Estate (CRE) Asset and Work Management Systems

Preamble:

Context: Order of Magnitude

OPG's Corporate Real Estate (CRE) function manages a large complex portfolio of properties and facilities, including assets located on or directly supporting nuclear generating sites. Based on OPG's formal reporting, this portfolio comprises hundreds of buildings and supporting structures distributed across thousands of hectares and entails >$100 million annually in combined capital and operating expenditures. In recognized facilities management practice, corporate real estate and facilities costs are commonly among the largest categories of enterprise expenditure, often second to labour. While the relative proportion may differ in a regulated utility environment, the scale of CRE investment and its role in supporting safe, reliable, and continuous operations make the effectiveness of CRE maintenance systems, internal controls, and oversight a matter of material importance.

Purpose and Scope

This interrogatory is narrowly tailored to establish the existence, content, and reliability of system-level information used by Ontario Power Generation Inc. ("OPG") to manage, monitor, and report on Corporate Real Estate ("CRE") maintenance activities, including maintenance backlog and exceptions, during the period January 1, 2020 to December 31, 2025.

The information required is required to assess OPG's evidence under the approved Issues List, including Issues 11-16 (Operations, Maintenance and Asset Management) and Issue 37 (Internal Controls and Oversight).

This interrogatory is structured to establish the factual maintenance and backlog information generated by OPG's internal systems and to confirm whether those systems were subject to appropriate post-implementation validation, effectiveness review, and ongoing control.

The Intervenor is prepared to execute the OEB Declaration and Undertaking with respect to any confidential information.

Definitions

"CRE System" means Archibus, Passport/AssetSuite, and/or any successor, parallel, or integrated system used to manage CRE maintenance, work orders, asset condition, backlog, or exception reporting.

"Maintenance Backlog" means deferred, overdue, or uncompleted corrective, preventive, or regulatory maintenance work orders.

"Exception" means any system-generated or management-defined indicator identifying overdue work, non-compliance, or elevated risk.

"Safety-critical assets" means CRE assets whose failure could reasonably result in safety, regulatory, environmental, or significant operational risk.

Nuclear-critical assets" means CRE assets, including storage facilities, warehouses, or support infrastructure, whose failure or loss could reasonably impair the availability of materials, equipment, or services essential to continued nuclear operations.

Question(s):

A. System Outputs and Maintenance Backlog

For the period 2020-2025, produce standard or routinely available CRE System reports or exports showing:

- Total maintenance backlog by year;
- Backlog by asset category and by facility;
- Identification of safety-critical and nuclear-critical assets within the backlog;
- Aging of backlog items.

If backlog data were not consistently captured or reported for any portion of this period, state:

- The years of facilities affected; and
- What alternative tracking methods, if any, were used.

B. Exception and Risk Visibility

Produce all exception reports, dashboards, or summaries generated by or derived from the CRE System during the same period that identified:

- Overdue or deferred maintenance; and
- Safety-critical, nuclear-critical, or regulatory-related exceptions.
- Identify whether such exception information was:
- Automatically generated by the system; or
- Manually compiled, supplemented, or overridden.

C. System Configuration, Data Integrity, and Effectiveness Review

Produce documentation sufficient to show:

- The approved CRE system configuration used to support maintenance, backlog, and exception reporting; and
- Any material configuration changes between 2020 and 2025 that affected backlog tracking, exception identification, or reporting.
- Identify the role(s) or function(s) responsible for:
- CRE System data integrity; and
- Accuracy and completeness of CRE maintenance reporting.

With respect to the CRE system as a capital project:

- Produce any Post-Implementation Review (PIR), benefits-realization review, or equivalent assessment prepared to evaluation system effectiveness following implementation; or
- If no such review was completed, state this explicitly.
- If a PIR or equivalent review was completed, produce records identifying:

Any material findings, recommendations, or identified gaps; and Corrective actions or follow-up measures taken in response.

Privilege and Non-Existence

If any responsive record is withheld on the basis of privilege, produce a privilege log identifying the document, date, author, recipient, and basis of the claim, together with a non-confidential description of its subject matter.

If any requested information does not exist, state this explicitly.

Response

In accordance with the Applicants' letter filed on May 4, 2026 and the OEB's Motions decision dated May 15, 2026, OPG has revised this interrogatory response.

a) to c)

This interrogatory seeks extensive details and documentation pertaining to facilities maintenance covering a six-year period. The request is overly broad, lacks clarity and is unreasonably onerous to respond to. The information sought is not material, lacks relevance, and/or offers minimal, if any, probative value in deciding the OEB-approved issues in this proceeding.

Notwithstanding the foregoing, in an effort to be helpful, OPG initially responded on April 24, 2026 by providing various information on topics that are the subject of this

interrogatory. Furthermore, in the letter filed by the Applicants on May 4, 2026 in respect of Mr. Pinto's motions and certain other interrogatory responses (in which he narrowed his requests), OPG proposed to provide or refer to certain additional documents or information. Specifically, Mr. Pinto's motion # 1 related to Ex. L-F3-Pinto-001 and Ex. L-F3-Pinto-002 sought a narrower scope of information (as described in the motion) regarding five "nuclear support" facilities, for the period 2023-2025, in respect of certain types of maintenance issues or deferrals (regarding "life safety" or "code critical" facilities systems) with accompanying "triggering criteria" defined in his motion material.

In accordance with the OEB Decision and Order on Motions and Intervenor Evidence EB-2025-0297 dated May 15, 2026 that directed OPG to provide the information proposed in its May 4, 2026 letter (and otherwise denied Mr. Pinto's motions seeking other information), OPG has revised this interrogatory response to provide the following information, in addition to the information provided initially on April 24, 2026:

- summary information or a table with additional information regarding open maintenance items or work orders for the facilities listed in this motion (including information regarding duration of any deficiencies meeting the described criteria, and whether a deficiency was classified by OPG as safety-related or not);
- a description of the organizational role(s) responsible for maintaining, reviewing, and escalating this information;
- inspection reports that Fire Safety Solutions ("FSS") performed for the identified buildings, which lists any deficiencies and the work orders from when the deficiencies were cleared with FSS – and while OPG does not have a definition for "prolonged", it reviews examples to identify any such deficiencies that are currently open;
- information regarding the Whitby Forbes warehouse fire-protection system sprinkler issue raised by Mr. Pinto, including a summary of that issue and how it was addressed; on this topic, OPG has provided certain documentation, including work orders, confirmation from the Ontario Ministry of Labour, and minutes from the municipal Fire Department inspection;
- the 2025 building condition assessment report for the Whitby warehouse ; and
- confirmation regarding formal assessments or audits related to facilities maintenance or supporting systems.

For added context, as stated in OPG's May 4, 2026 letter, OPG notes that of the five facilities identified by Mr. Pinto, there are no amounts sought for recovery in the proposed 2027-2031 revenue requirements for the Wesleyville property[1], and there are no amounts sought for recovery in the proposed revenue requirements in respect of the Whitby Forbes warehouse after it is planned to be vacated during 2027[2].

[1] Refer to Ex. F3-2-1, p. 2, lines 11-13.
[2] Refer to Ex. D3-1-1 p.15, lines 24-30.

OPG's Real Estate & Facilities ("RE") department manages properties in the Greater Toronto Area, including support buildings and infrastructure outside of the nuclear protected area and select support facilities inside the protected area (such as administration buildings and vehicle maintenance garages) at the Pickering and Darlington nuclear stations. RE monitors and manages maintenance activities using preventative and corrective maintenance systems and field oversight activities. Information is extracted from the systems daily to prioritize and action work activities.

The RE department does not use the definition of "nuclear critical" or similar categorization in the RE scope of responsibility or system database and therefore cannot provide data by this category.

Safety-related maintenance requisitions and work orders include electrical safety hazards, tripping hazards, spills, and leaks. Where there is a risk to life, health, or plant operations resulting from these issues, the area(s) is placed in a safe state (ex. restrict access, de-energize, procedural changes/controls) until corrective actions can be completed.

OPG interprets the term "maintenance backlog" to mean all open RE maintenance requisitions, ranging from office moves, meeting room set ups, custodial, plumbing, electrical, heating, ventilation and cooling, roof leaks and window replacements, among other things. Consistent with this interpretation, Chart 1 below shows the total of all open and closed corrective maintenance requisitions in respect of (and as of the end of) the time period being requested. The number of days to close maintenance requisitions and work orders depends on factors such as materials availability, resource availability, training lead times and coordination with third parties including landlords, regulators or OPG work teams. In addition, there were 26,619 preventative maintenance work orders at the Pickering and Darlington sites, of which approximately 87% were closed in this same period.

Chart 1 - Corrective Maintenance Requisitions by Facility as of December 31, 2025 (2020-2025)

Location	Closed	Closed Safety	Open	Open Safety	% Closed
1 HOLT*	24,565	639	469	24	98.1
1675 MONTGOMERY**	18,696	426	119	3	99.4
800 KIPLING	6,073	542	7	0	99.9
700 UNIVERSITY	3,954	75	4	1	99.9
889 BROCK	3,855	280	53	2	98.6
1855 ENERGY	3,191	101	20	1	99.4
675 SANDY BEACH	3,024	199	21	2	99.3
777 BROCK	1,420	89	49	4	96.7
1549 VICTORIA	1,240	124	18	2	98.6

230 WESTNEY	1,056	79	0	0	100.0
177 TIE	846	26	4	1	99.5
2255 FORBES	697	57	8	0	98.9
2655 LAKESHORE	600	22	9	1	98.5
1600 STELLAR	423	36	0	0	100
1910 CLEMENTS	306	24	3	0	99.0
78 RICHMOND	222	41	2	0	99.1
1340 PICKERING P	177	23	0	0	100
1600 CHAMPLAIN	63	5	0	0	100
890 BROCK	43	21	0	0	100
1908 COLONEL	30	0	0	0	100
1915 CLEMENTS	23	1	2	1	92.0
Grand Total	**70,504**	**2,810**	**788**	**42**	**98.9**

*1 Holt includes all buildings and infrastructure maintained by RE on the Darlington site.
**1675 Montgomery includes all buildings and infrastructure maintained by RE on the Pickering nuclear site.

Corrective and preventative maintenance reporting is managed through several systems and tools. No material changes occurred between 2020 and 2025 that would have affected the tracking, identification, or reporting of corrective or preventative maintenance for RE. System data integrity, accuracy, and completeness are monitored by RE.

Based on Mr. Pinto's motion description and requests, OPG is providing the additional information below regarding the Darlington Learning Center ("DLC"), the Pickering Learning Center ("PLC"), the Darlington Energy Complex ("DEC"), the Wesleyville property (which Mr. Pinto describes as the Wesleyville Generating Station[3]) and the Whitby Forbes Warehouse (which Mr. Pinto describes as the Whitby Warehouse) for 2023-2025.

Among the buildings identified in Mr. Pinto's motion, there are no open OPG safety requisitions from 2023 and there is one open safety requisition from each of 2024 and 2025. The open work order from 2024 originated in December 2024 from a Joint Health and Safety Committee ("JHSC") inspection and identifies the need to update the Fire Safety Plan and Emergency Response Plan at the Wesleyville property. Upon further review, OPG validated that the safety plan has been updated and fire drills were completed in 2025 and this ticket should have been closed at that time. No further corrective action is required.

The open work order from 2025 which was initiated in June 2025, originated from a JHSC inspection, and identifies a stairwell light that needs replacement or repair. The lighting in the area was reviewed and deemed adequate for safety. Lighting

[3] The Wesleyville property is not an operating generating station.

replacement in this area requires scaffolding and this ticket will be closed after the work can be scheduled and completed safely.

Responsibility for maintaining, reviewing, and escalating maintenance work orders falls within the responsibilities of the First Line Manager ("FLM"), Facility Services. Open work orders are reviewed daily by the FLM, and there is a continuous opportunity for escalation of work orders with the Manager and Senior Manager, Facilities and Projects when additional support is required.

Fire Safety Solutions ("FSS") is contracted with OPG to support operational fire safety services. The type of services may include site inspections, recommendations, and fire safety expertise. FSS prepared inspection reports for four of the five identified locations. OPG performs inspections for the DLC location as it is located within the Darlington site. Refer to Attachment 1 for a report containing a summary of all work orders from FSS for the described locations for the time period 2023-2025 and Attachment 2 for the FSS currently open work orders from these locations for this time period. Refer to Attachment 3 (confidential) for the completed fire safety inspections for all five noted locations for the period of 2023-2025. Fire safety inspections are completed annually for each component.

In regard to the Whitby Forbes warehouse fire-protection system issue raised by Mr. Pinto, OPG disagrees with the assertion that there was a fire-protection system impairment at this location in 2025. The Whitby Fire Department and the Ministry of Labour (MoL) each separately visited the Whitby Forbes Warehouse on October 8, 2025 and October 14, 2025, respectively, to investigate separate anonymous complaints regarding an alleged fire protection impairment. No orders were issued as a result of either visit. The Fire Chief and MoL Inspector were satisfied that the fire-protection system complied with the Ontario Fire Code, and no further action was necessary. Minutes from the meeting with the Whitby Fire Department are provided in Attachment 4.

Furthermore, the MoL Inspector met with representatives from OPG and worker representatives from the JHSC. The Inspector was informed that the fire suppression system was inspected regularly and that the fire sprinkler heads were scheduled to be replaced by year-end 2025. The replacement of the sprinkler heads has been completed. Refer to Attachment 5 for the October 14, 2025 Ministry of Labour Anonymous Complaint Investigation at 2255 Forbes (Whitby Forbes Warehouse).

OPG confirms that for the period requested, there are no formal assessments or audits related to facilities maintenance or supporting systems. For a summary of all internal audits conducted at OPG since 2020, refer to Ex. A1-4-1, Attachment 4.

RE continually assesses the condition of assets through monthly facility risk and safety tours, monthly JHSC inspections and third-party building condition assessments, most recently completed in 2025. Findings from site tours and JHSC inspections are recorded in RE's corrective maintenance system as described above. Refer to Attachment 6 (confidential) for the 2025 Building Condition Assessment Report for 2255 Forbes (Whitby Forbes Warehouse).

Fire Safety Solutions Work Order Summary 2023-2025

Job Name	WO#	Job Type	Job Status	Create Date	Completed Date	Job Description
1855 Energy Dr. (Darlington)	7755	Deficiency	Completed	6/9/2023	7/14/2023	Sprinkler: Dry system compressor tank drain is damaged. - Replace bleeder valve with 1/4:" ball valve with nipples - 90's and plug
1855 Energy Dr. (Darlington)	7915	Deficiency	Completed	7/7/2023	8/10/2023	Sprinkler: SV-5 fire pump suction valve tamper switch not operational. Potter OSYSU-2 switch requires replacement Sprinkler: Time and Material - Jockey pump did appear to be operational during testing. Possible transducer issue recommend investigating
1855 Energy Dr. (Darlington)	8305	Deficiency	Completed	9/15/2023	4/4/2024	2022 annual deficiency repairs
1855 Energy Dr. (Darlington)	8376	Service Call	Completed	9/28/2023	10/5/2023	Training - L2 WP in class training
1855 Energy Dr. (Darlington)	9385	Service Call	Completed	3/18/2024	4/3/2024	Need new pressure switch and brass fitting
1855 Energy Dr. (Darlington)	9420	Deficiency	Completed	3/22/2024	5/4/2024	Sprinkler: Standpipe FDC failed testing and needs repairs. Pressurized up to 150 psi but stopped there as the brass 4x6 reducer in the wall was leaking. Had to cut a hole in drywall pipe shaft to investigate the leak. The hole will have to be enlarged for repair work and covered with access door once complete. Dismantling connection, cleaning joints and retightening should be sufficient. Replace 6" grooved couplings with (2) new slip on Victaulic.
1855 Energy Dr. (Darlington)	10043	Service Call	Completed	7/8/2024	7/10/2024	Service Call - getting a false alarm for the generator runnings. Alarm on panel but nothing running.
1855 Energy Dr. (Darlington)	10191	Service Call	Completed	7/31/2024	8/1/2024	Service Call - site walk through Zn83 generator running m3-136 Supervisory monitor - open ckt trouble' Kept coming in and out and would clear within a second. Investigated Main Elec. Room generator module (Simplex 0519-237 F) Got a reading of 13.23 k ohms, should be a reading around 6.8 which is why the open keeps coming in and out. Recommend replacing module and EOL. Will need generator tech to provide safe access and to test generator once repairs are completed. Generator is Outside South West corner of the building.
1855 Energy Dr. (Darlington)	10043A	Service Call	Completed	8/7/2024	1/8/2025	
1855 Energy Dr. (Darlington)	10484	Deficiency	Completed	9/9/2024	11/29/2024	Deficiency - Fire Alarm: - Trouble on FACP - 'Clean Room Strobe Panel - Signal Circuit - (M3-92) no answer'. - Booster requires replacement Model - Simplex 4009 IDNet NAC extender panel and (2) Simplex IM module required - OPG electrician required to assist with breaker shutdown
1855 Energy Dr. (Darlington)	10993	Service Call	Completed	12/3/2024	12/3/2024	Service Call - Panel Trouble - Disable generator running point on fire panel. Stephen called in service
1855 Energy Dr. (Darlington)	11121	Service Call	Completed	1/6/2025	1/29/2025	Service Call - Learning Centre - Node 2, an annunciator has reportedly been going into trouble periodically for months. Panel reports a brown out and reboots. Further investigation required with Programmer and FSS fire alarm technician
1855 Energy Dr. (Darlington)	11145	Service Call	Completed	1/9/2025	1/9/2025	Service call - shift sp line and move sp head
1855 Energy Dr. (Darlington)	11374	Service Call	Completed	2/21/2025	2/24/2025	Service Call - Bypassed pull (M2-203)(M2-53)(M2-52) for renovations second floor. 3 troubles will remain in panel. Took down all 3 pulls for demo. (M2-203) Will have to be re-enabled once relocated. Other two will require programmer to delete.
1855 Energy Dr. (Darlington)	11503	Service Call	Completed	3/14/2025	3/18/2025	Service Call - Cap our sprinkler system for the north side of the second floor.
1855 Energy Dr. (Darlington)	11548	Service Call	Completed	3/25/2025	3/27/2025	Service Call - We need to isolate another section of the sprinkler system on the 2nd floor at the DEC Service Call - Return trip required to reconnect piping once alterations complete.
1855 Energy Dr. (Darlington)	11548A	Service Call	Completed	3/28/2025	4/14/2025	90 and coupling left on fire pump controller in mock up area.
1855 Energy Dr. (Darlington)	11639	Reno	Completed	4/10/2025	5/26/2025	Reno - Fire Alarm Modifications: - Includes deprograming of one pullstation deleted from fire alarm system - Includes bypassing of system while work is being completed - Pullstation to be physically removed by others
1855 Energy Dr. (Darlington)	11956	Service Call	Completed	6/10/2025	6/17/2025	Training - L2 WP in class training next Tuesday. This is in Darlington nuclear station at holt rd.
1855 Energy Dr. (Darlington)	12153	Deficiency	Completed	7/15/2025	11/16/2025	Deficiency - Perform Retrofit: - 12 Year Maintenance of the existing Ansul Fire System
1855 Energy Dr. (Darlington)	12180	Service Call	Completed	7/18/2025	4/24/2025	CAPPING SPRINKLER ZONES
1855 Energy Dr. (Darlington)	12215	Service Call	Completed	7/24/2025	7/24/2025	Generator trouble.
1855 Energy Dr. (Darlington)	12432	Service Call	Completed	9/2/2025	9/3/2025	Power down.
1855 Energy Dr. (Darlington)	12442	Service Call	Completed	9/4/2025	9/8/2025	Activate alarm and check if Chubb is receiving signal - at all OPG buildings
1855 Energy Dr. (Darlington)	12554	Service Call	Completed	9/24/2025	9/25/2025	Getting trouble in frequently (Gen A running) and would like to have this point disabled temporarily till can schedule to resolve with FSS and Total Power.
1855 Energy Dr. (Darlington)	12566	Service Call	Completed	9/25/2025	9/29/2025	Isolating the construction floor for Classic to make a repiar, then refilling system once completed

Job Name	WO#	Job Type	Job Status	Create Date	Completed Date	Job Description
1855 Energy Dr. (Darlington)	12854	Service Call	Completed	11/18/2025	11/19/2025	Replacing IAM for clean room - Generator running point Extinguishers: - A total of (12) 5LB ABC extinguishers are due for service and require replacement - A total of (1) 10LB ABC extinguishers are due for service and require replacement Please see report for locations - The following extinguisher requires remounting with new hook INSIDE ELECTRICAL ROOM 230 – 5LB Fire Alarm – Priority Urgent:
1855 Energy Dr. (Darlington)	13181	Deficiency	Completed	1/20/2026	2/11/2026	- Def#1 – Warehouse West Wall Centre pull station is broken and require replacement. Model: 4099-9055CA
1855 Energy Dr. (Darlington)	13190	Service Call	Completed	1/22/2026	1/26/2026	To isolate some devices
1855 Energy Dr. (Darlington)	13228	Service Call	Completed	1/27/2026	1/27/2026	detected trouble on panel, elevator machine room Sprinkler - Priority Urgent: Def #2 - New Wiock up - Riser 1-1/4" angle test drain valve leaks during test and requires replacement Victaulic Testmaster style 720 Threaded, Def #3 – Warehouse South LP does not reset – Potter PS120 switch requires replacement, Def #7 – Loaded/Dirty sprinkler heads require cleaning in the following areas 3rd Floor – Lunchroom (2x) loaded heads Sprinkler - Maintenance: - Rdef #7 – Water motor gong in sprinkler room did not operate – Further investigation required - Rdef#10 & #12 – (3) roll up doors in ground floor require head guards (2) loading dock –(1) garbage room - Def #1,5,6,8,11- A total of (6) chrome 2piece escutcheon plates are missing and require replacement Calibration shop room 173 Penthouse Boiler Room Penthouse Elevator Machine Room Ground Floor – North centre office area near washroom 3rd Floor elevator machine room #1&#2 - Def #9 - Water motor gong did not operate -Model;Reliable C – Further investigation required Sprinkler – Priority: Time and Materials - Rdef #2 – 3 year Air Leak test required on 3 systems – (1 Dry and 2 pre-action) - Rdef #3 - 5 Year internal Obstruction investigation is due – 7 risers and 2 pre-action - Rdef#4 – 5 Year alarm valve internal inspection is due – 6 valves - Rdef #5 - All system risers, strainers and orifices are due for cleaning/flushing - 65 FOOT ELECTRIC BOOM RENTAL FOR OBSTRUCTION TESTING - Def #10- Require a low point drain on the 8" test header to drain trap water after pump test - Rdef#13 – (2x) 12" QR 155F dry heads are over 10 years old and require replacement Sprinkler: Time and Materials - Rdef #1 - Suggest installing isolating control valve on 2x pre-action systems above the DPV to allow proper testing and tripping of alarm valves without flooding piping of system that protects sensitive areas - Rdef #9 - Clean room wet zone, drain requires to be piped to drain in order to properly test "clean room" flow switch. -1" pipe &
1855 Energy Dr. (Darlington)	13181A	Deficiency	Completed	1/27/2026	4/24/2026	fittings required, must core thru block wall to floor drain in mech. Room. Will require scanning of wall
1855 Energy Dr. (Darlington)	13346	Service Call	Completed	2/11/2026	2/12/2026	replace simplex XPS 4100-5103
1855 Energy Dr. (Darlington)	13368	Service Call	Completed	2/17/2026	2/20/2026	Investigate AMP loading across system to determine if better loading balance can be achieved. The ground fault on the fire panel at the DEC is in solid now. We'd like to have a tech dispatched to have a look.
1855 Energy Dr. (Darlington)	13388	Service Call	Completed	2/20/2026	2/20/2026	The fault appeared after we replaced the power supply and an amplifier.
1855 Energy Dr. (Darlington)	13440	Deficiency	Completed	3/3/2026	3/6/2026	Sprinkler: 4" Liquid filled gauge (0-300psi) recommended on the discharge side of the pump, requested by OPG personnel
1855 Energy Dr. (Darlington)	13463	Service Call	Completed	3/9/2026	3/9/2026	Ground fault on the fire alarm panel
1855 Energy Dr. (Darlington)	13639	Service Call	Completed	3/30/2026	3/31/2026	Replace module & resistor, Generator tech onsite to isolate and replace it at site.
1855 Energy Dr. (Darlington)	13725	Service Call	Completed	4/13/2026	4/15/2026	Investigate Ground fault at site.
1855 Energy Dr. (Darlington)	10948	Service Call	Completed	11/26/2024	5/6/2026	Service Call - There are intermittent troubles on the fire alarm panel. Require Total power on site to get safe access to generator A controller to replace resistor. As per Jaso I have disable "M3-136 " point for now to avoid coming and going trouble.
1855 Energy Dr. (Darlington)	12215A	Service Call	Completed	7/25/2025	5/4/2026	access and work protection required.

Job Name	WO#	Job Type	Job Status	Create Date	Completed Date	Job Description
1855 Energy Dr. (Darlington)	13181B	Deficiency	Completed	4/14/2026	5/4/2026	Sprinkler: - During the 5 year obstruction investigation the fitters found that the dry system has some sludge build up in the 2 ½" main and the alarm check. - Recommend a flushing of the dry system - Quote Includes for boom lift rental - Scheduled regular business hours Monday -Friday 7am – 4:00pm
2255 Forbes Street	8558	Deficiency	Completed	10/25/2023	2/26/2024	Sprinkler: - A total of (9) Gauges are expired and require to be replaced - Systems orifices & strainers are due for flushing/cleaning - Quick response Pendent Sprinkler Heads & ESFR Sprinkler Heads are 20 years old & are Fire Extinguishers: - A total of (1) 10LB CO2 extinguisher needs service and requires to be replaced - A total of (6) 100' Hoses are due for testing and require to be replaced - (1) 10LB ABC extinguisher requires hook to be re-mounted
2255 Forbes Street	2285S	Deficiency	Completed	1/29/2024	2/10/2024	Extinguishers: A total of (3) 10LB ABC extinguishers are damaged and require replacement, (1) 20LB ABC extinguisher located in Server Room requires a hook and remount into drywall
2255 Forbes Street	8558A	Service Call	Completed	2/5/2024	2/20/2024	Replace additional head
2255 Forbes Street	9333	Deficiency	Completed	3/7/2024	4/2/2024	Deficiency Combo
2255 Forbes Street	2287A	Service Call	Completed	3/25/2024	6/10/2024	test 9 sprinkler heads
2255 Forbes Street	9830	Service Call	Completed	6/4/2024	6/11/2024	Flow test in Hose cabinets
2255 Forbes Street	11627	Deficiency	Completed	4/9/2025	5/14/2025	Combo deficiencies - SP , EXT & E&L
2255 Forbes Street	12551	Deficiency	Completed	9/24/2025	2/13/2026	Sprinkler: The ESFR (C9226) sprinkler heads were sent for ULC testing and the test results were 2 of the 9 heads failed testing. As per the 2023 Edition of NFPA 25 all ESFR C9226 heads in the warehouse will require replacement to meet standard requirements
2255 Forbes Street	13007	Service Call	Completed	12/18/2025	12/19/2025	ran fire drill, no auditbles
2255 Forbes Street	13237	Deficiency	Completed	1/27/2026	3/10/2026	Fire Alarm: A total of (2) Edwards pull stations are missing glass rods in the following locations Extinguishers: A total of (1) 15.5LB Halotron extinguisher is due for service and requires replacement. Replace with (1) 13LB Clean Agent Cleanguard+ Extinguisher Front by Copier Sprinkler: Class 2- 1 ½" hose valves are due for operation testing Sprinkler: 1" check valves on common drains pass while flowing water. Sometimes multiple alarms come in at the same time due to this. Recommend replacing with spring check valve * need OPG permit* Not done - Large work protection required. All systems and points out of servuie for work protection. The following sprinkler escutcheon plates are missing and require replacement - this is complete as of 5/14/2026 Front Entrance Vestibule (1x) plate missing Lunch room in warehouse (1x) plate missing First Aid room (1x) plate missing Break Office by Sprinkler Header (5x) plates missing *Plates were installed in most places, tiles need to be supplied by OPG for (3) that were not installed*HVAC STRAPPED TO FRAMING - SHAKES CEILING NOT FIXABLE BY FSS *3 fell off after installed and maybe need some tape to hold in place* * They rattle loose from HVAC mounted to ceiling above*
2255 Forbes Street	11627A	Deficiency	Active	7/29/2025	Open	Scheduled for completion 6/30/2026
2655 Lakeshore (Wesleyville)	7827	Deficiency	Completed	6/23/2023	6/12/2024	Combo Deficiency Repairs
2655 Lakeshore (Wesleyville)	7905	Service Call	Completed	7/7/2023	7/7/2023	As per call to answering service the site would like a tech to come by and bypass a Beam Detector false alarming due to high humidity.
2655 Lakeshore (Wesleyville)	8405	Service Call	Completed	10/3/2023	10/3/2023	Check panels & pumps for pressure fluctuation
2655 Lakeshore (Wesleyville)	8786	Deficiency	Completed	11/29/2023	10/6/2023	Sprinkler Deficiencies
2655 Lakeshore (Wesleyville)	9252	Deficiency	Completed	2/23/2024	10/21/2024	Sprinkler Deficiencies
2655 Lakeshore (Wesleyville)	9449	Deficiency	Completed	3/27/2024	4/9/2024	Extinguisher Deficiencies
2655 Lakeshore (Wesleyville)	9543	Service Call	Completed	4/12/2024	4/12/2024	after hours Fire Alarm activated in building 9. Dry system activated
2655 Lakeshore (Wesleyville)	9776	Deficiency	Completed	5/24/2024	6/3/2024	Change the current OS& Y valve to a butterfly valve
2655 Lakeshore (Wesleyville)	9252S	Deficiency	Completed	7/24/2024	10/19/2024	Sprinkler Deficiencies

Job Name	WO#	Job Type	Job Status	Create Date	Completed Date	Job Description
2655 Lakeshore (Wesleyville)	10244	Service Call	Completed	8/9/2024	8/9/2024	After hours leak on pipe
2655 Lakeshore (Wesleyville)	10244A	Service Call	Completed	8/9/2024	8/15/2024	Replace full length pipe
2655 Lakeshore (Wesleyville)	10276	Service Call	Completed	8/15/2024	8/15/2024	Supervisory low-pressure alarm for bldg.. 3, dive shop
2655 Lakeshore (Wesleyville)	9252SA	Service Call	Completed	10/21/2024	7/21/2025	Sprinkler Deficiencies
2655 Lakeshore (Wesleyville)	11147	Service Call	Completed	1/9/2025	1/13/2025	Hydrant is passsing water has ice on cap, fitter to contact Jason on site
2655 Lakeshore (Wesleyville)	11295	Service Call	Completed	2/5/2025	2/11/2025	brace the standpipe system against water hammer
2655 Lakeshore (Wesleyville)	11660	Service Call	Completed	4/15/2025	4/15/2025	TRAINING YARD PUMP PIPE REPLACEMENT
2655 Lakeshore (Wesleyville)	11760	Service Call	Completed	5/5/2025	5/7/2025	SWAP JOCKEY PUMPS IN PUMP HOUSE
2655 Lakeshore (Wesleyville)	11786	Service Call	Completed	5/8/2025	5/9/2025	Fire Training Yard Pump investigation – determine if pressure loss auto start is needed.
2655 Lakeshore (Wesleyville)	11819	Service Call	Completed	5/14/2025	5/20/2025	Panel 3 Replacement
2655 Lakeshore (Wesleyville)	12015	Service Call	Completed	6/20/2025	6/20/2025	building 6 standpipe system leak
2655 Lakeshore (Wesleyville)	12433	Deficiency	Completed	9/3/2025	12/15/2025	Supply and install (1) new Kunckle 6” Fire Pump valve Model 228H-P01AM6” 125# inlet x 6” 125# outlet UL and FM approved Extinguishers: Building 6- Fire Training Facility: Building 1- Pipe Fabrication Facility: Building 3- IRI Diving Operations: Building 5 – Warehouse/Shop: Building 7 – Fire Pump House: Building 9 – Warehouse/Shop: Building G1 & G2- West Garages: Bldg. G1 West Garage – Garage Rear Fire Alarm: Building 7 – Fire Pump House: - The FACP batteries are due for service. Require replacement of (2x) 12V7AH batteries Building 9 – Warehouse/Shop:
2655 Lakeshore (Wesleyville)	13196	Deficiency	Completed	1/22/2026	2/26/2026	- Level 140 in Staor F smoke detector is missing cover and requires replacement (1) Simplex 4098-9714 - 6’to 8’ ladder required
2655 Lakeshore (Wesleyville)	13367	Service Call	Completed	2/17/2026	2/18/2026	Bldg 9, dry system trip. 4" pipe needs to be replaced. OPG to supply lift. Replace pipe and drain low points and return system to normal.
2655 Lakeshore (Wesleyville)	13452	Service Call	Completed	3/4/2026	3/13/2026	Kuncle Relief Valve BLD7
2655 Lakeshore (Wesleyville)	13516	Service Call	Completed	3/16/2026	3/16/2026	low pressure Sprinkler: Building 7 – Fire Pump House: Done - Bldg. 7- Spare head box requires minimum (6) sprinkler heads. Head box requires (3x) ½” SR 286F K5.6 Brass uprights needed to meet requirement Building 9 – Warehouse/Shop:rolled into 2026 annual - Bldg.9 - Hose valve 140 level is passing and requires replacement. 1.5” ball valve in place to restore system without having to isolate hose valve (SW of people elevator 3rd Floor)
2655 Lakeshore (Wesleyville)	11631	Deficiency	Active	4/10/2025	Open	- Bldg.9 - 3 year Full trip test is due – suggest to schedule in spring (warmer temperatures) - rolled into 2026 annual Stand pipe leaking inside block wall in training building Will have to replace 1.5" pipe from above ceiling down to FHC. It appears to be leaking from a fitting inside the wall that feeds the hose valve Will have to remove FHC from wall and investigate inside of block. May require chipping of block to access piping as it swings 90s through the block cavity. Easy access from above as block wall only goes just above the ceiling tiles. Piping needs to be replaced & 1.5"
2655 Lakeshore (Wesleyville)	12015A	Service Call	Active	6/26/2025	Open	hose valve requires reinstall - scheduled for completion 6/30/2026
2655 Lakeshore (Wesleyville)	13620	Service Call	Completed	3/26/2026	5/7/2026	Install 2 Valmatic air release valves on jockey pumps at building 7.
2655 Lakeshore (Wesleyville)	13452A	Part Supply	Active	4/20/2026	Open	Parts supply - Valve rebuilt by TVS-VALVE AT FSS DELIVERY REQUIRED, ARRIVED 5/12/26; sheduled for completion 6/30/2026
2655 Lakeshore (Wesleyville)	13794	Deficiency	Active	4/23/2026	Open	Fire Alarm: Time and materials - Bell did not operate in the following location- 6"-24VDC, 0.028A Building 6 by Women’s Change Room Will require OPG electrician to assist with bell replacement - (2) existing Supervisory’s and (7) disable on system related to beam detectors – further investigation required BELL COMPLETE, BEAM DETECTORS DISABLED- REMAIN LIKE THAT UNTIL BUILDING IS TORN DOWN - NO ACCESS. IN SAFE STATE UINTIL BUILDING DEMOLITION.

Job Name	WO#	Job Type	Job Status	Create Date	Completed Date	Job Description
						Switch is sticking and pump would not shut off. Auto. Pressure switch requires replacement.
675 Sandy Beach	7744	Service Call	Completed	6/7/2023	6/12/2023	(1) Potter PCS 300 -auto pressure switch
675 Sandy Beach	7927	Service Call	Completed	7/10/2023	7/11/2023	The WMG is missing the bolt & cover and would like to have it replaced while on site for the monthly inspection
						Water Motor Gong is currently damaged and requires replacement. - (1) Reliable model water motor gong required
675 Sandy Beach	7933	Deficiency	Completed	7/11/2023	9/12/2023	- Materials and labour to supply and install
675 Sandy Beach	8759	Service Call	Completed	11/27/2023	12/2/2023	As per Afshin we are to arrange load testing/signal testing and "Simulator B" access for a weekend to complete annual inspection.
675 Sandy Beach	8890	Service Call	Completed	12/18/2023	12/20/2023	compressor running on
675 Sandy Beach	9311	Part Supply	Completed	3/4/2024	3/12/2024	As per Afshin we are to supply 5 x 4098-9714C smoke heads to be dropped off to Dave Menzies when available.
675 Sandy Beach	9340	Part Supply	Completed	3/8/2024	3/12/2024	Afshin has requested 15 plastic pull stsation rods for pull stations to be supplied.
675 Sandy Beach	10396	Service Call	Completed	8/28/2024	8/29/2204	Project groups is looking some assistant to remove some the duct heater detector (3 of them) and reconfigure the new duct heater detector which is a part of new RTUs being installed and project or their vendors will give you a new PO for this work. Please work with Muhammad on this.
						Air handling units 6,7 & 8 do not have any duct smoke attached to units. The relay associated with them shuts down on any alarm. Tested the shutdown while all 3 units were running and all units shutdown on alarm. Unable to locate the relay for the units so I was unable to open and ground the relay.
675 Sandy Beach	10396A	Service Call	Completed	8/30/2024	9/17/2024	Will need to locate the relay in order to complete the verification.
675 Sandy Beach	10949	Service Call	Completed	11/26/2024	12/10/2024	Replace ps 120
675 Sandy Beach	11009	Service Call	Completed	12/9/2024	12/10/2024	leak on the excess pressure pump
						Weekend After Hours Request
675 Sandy Beach	11035	Service Call	Completed	12/11/2024	12/23/2024	bypass the system for their contractor doing hot work on the 3rd floor ceiling columns.
675 Sandy Beach	11054	Service Call	Completed	12/16/2024	12/23/2024	verify RTU 5
675 Sandy Beach	11854	Part Supply	Completed	5/22/2025	6/10/2025	Take 20 smoke detectors for next monthly.
675 Sandy Beach	11871	Service Call	Completed	5/26/2025	5/26/2025	Panel fault
675 Sandy Beach	12014	Service Call	Completed	6/20/2025	6/19/2025	fire alarm went off, they are unable to bypass the system.
675 Sandy Beach	12085	Service Call	Completed	6/30/2025	7/3/2025	leak on pump supply line
675 Sandy Beach	12660	Service Call	Completed	10/14/2025	10/17/2025	FSS tech to re-test PLC FDC and have camera available in case the pressure is not holding.
675 Sandy Beach	12873	Service Call	Completed	11/21/2025	11/25/2025	We have issue with two sprinkler heads in PLC (room1309 and one in hallway). It looks like that they are obstructed and we may need to lower the piping. I need a sprinkler fitter to come for assessment (require material, isolation/ work protection,…)
675 Sandy Beach	13024	Service Call	Completed	12/19/2025	12/23/2025	Assist with Elevator Testing
675 Sandy Beach	13115	Deficiency	Completed	1/12/2026	1/30/2026	Deficiency Combo
675 Sandy Beach	13567	Deficiency	Completed	3/24/2026	4/28/2026	Water motor gong was ringing inconsistently when tested and requires further investigation or replacement

Exhibit L-F3-Pinto-001, Attachment 2

Fire Safety Solutions Work Orders

This Attachment was filed as confidential information in its entirety.

Exhibit L-F3-Pinto-001, Attachment 3

Fire Safety Solutions and OPG Fire Safety Inspection Reports

This Attachment was filed as confidential information in its entirety.

October 8, 2025 Meeting Minutes – Fire Department Anonymous Complaint Investigation at 255 Forbes Warehouse

Meeting Minutes
Date: October 8, 2025
Meeting: OPG and Fire Department Meeting
Location: 255 Forbes

Attendees:

- Alex Freeman (Fire Department, Whitby)
- Marcel Moniz (Facilities, OPG)
- Tami Boulton (Facilities, OPG)
- Steve Williams (Facilities, OPG)
- Roman Mityayev (Facilities, OPG)

Detailed Discussion:

1. Fire Department Complaint and Validation Process
Alex Freeman from the Whitby Fire Department initiated the meeting by outlining the receipt of an anonymous complaint regarding several ongoing deficiencies at the 255 Forbes facility. The most significant concern highlighted in the complaint was related to the placement and condition of sprinkler heads within the building. Alex clarified that, as part of the Fire Department's mandate, every complaint—regardless of source—must be formally investigated and validated. This process ensures transparency and accountability, and it is standard procedure to follow up on all reported issues.

2. Open Communication and Proactive Engagement
Alex emphasized the value the Fire Department places on its relationship with OPG, noting that OPG is regarded as a key and responsible member of the local community. Prior to this meeting, Alex had already spoken with Marcel Moniz and was reassured to learn that Marcel was not only aware of the concerns but had already begun taking steps to address them. This proactive approach was commended by the Fire Department.

3. Nature of the Complaint and Contractor Findings
The complaint, though anonymous (with the Fire Department unable to disclose any identifying information), referenced a set of deficiencies identified by a contractor and

submitted to OPG. While most of the items listed were considered minor, the issue of sprinkler head replacement stood out as a potential concern. The contractor's report indicated that out of a sample of 9 sprinkler heads tested, 2 failed to meet the required standards. The Fire Department stressed that, in the absence of a full replacement program, further investigation and sampling would be warranted to determine if these failures were isolated or indicative of a broader issue, given that there are approximately 1,000 sprinkler heads in the building.

4. Code Compliance and Exceeding Standards

Marcel Moniz provided a detailed update on OPG's maintenance practices, specifically regarding the sprinkler system. He confirmed that OPG's current protocols fully satisfy the requirements set out in the Ontario Fire Code. Alex Freeman reiterated the distinction between the enforceable minimum standards of the Ontario Fire Code and the best practices recommended by the National Fire Protection Association (NFPA 25), which speaks more directly to sprinkler head replacement. While the Fire Department always encourages property owners to exceed the minimum code requirements, enforcement is limited to what is explicitly stated in the Ontario Fire Code.

It was unequivocally stated by Alex Freeman, that OPG is, at present, fully compliant with all relevant fire code regulations. It was also noted by Marcel that OPG's approach often goes beyond what is legally required, as demonstrated by their routine monthly and annual inspections, and their willingness to address deficiencies proactively. The Fire Department acknowledged and praised OPG's commitment to maintaining a high standard of fire safety, noting that this far exceeds the practices observed at many other facilities.

5. Responsibility and Accountability

It was clarified that, under the terms of the lease agreement, OPG is responsible for all aspects of fire suppression within the building. The Fire Department's primary concern is ensuring code compliance, and they confirmed that OPG currently meets or exceeds all regulatory obligations. However, both parties agreed that pursuing the planned sprinkler head replacement and other improvements would further enhance safety and demonstrate OPG's ongoing commitment to best practices.

6. Deficiency Tracking and Continuous Improvement

Marcel noted that while OPG is diligent in identifying and addressing deficiencies—such as issues with emergency lighting—there is room for improvement in formally closing out these items. The current process sometimes results in repairs being completed without official closure of the deficiency record. OPG is committed to refining its procedures to ensure that all identified issues are not only addressed but also properly documented and closed out, further reinforcing their high standards of accountability.

Action Items:

- OPG to proceed with the planned replacement of sprinkler heads and other identified improvements.
- The Fire Department will schedule a follow-up inspection upon completion of the work, recognizing that these actions go above and beyond the minimum requirements of the Ontario Fire Code. OPG to provide associated documentation that the deficiency work has been completed so that they can close this item.
- January 2026 is the approximated inspection of the building.
- OPG to enhance internal processes for tracking and closing out all fire safety-related deficiencies.

Ministry of Labour, Immigration, Training and Skills Development

Occupational Health and Safety

Ontario

Field Visit Report

OHS Case ID: **8919DSKVTSL**
Field Visit no: **8919DSKVTSL-8919-FV001** Visit Date: **2025-OCT-14** Field Visit Type: **INITIAL**

Workplace Identification: **ONTARIO POWER GENERATION**
2255 FORBES STREET, WHITBY, ON CA L1N 9X1
Notice ID:

Telephone:	JHSC Status:	Work Force #:	Completed %:
-	**Active**	**40**	

Persons Contacted: **SHELBY BELL (FIRST LINE MANAGER/ JHSC MANAGEMENT MEMBER), CHRIS MCCONNELL (DIRECTOR OF SUPPLY CHAIN AND OPERATIONS), MARCEL MONIZ (SENIOR MANAGER FACILITIES), BEN HERR (JHSC WORKER MEMBER)**

Visit Purpose: **TO AUDIT COMPLIANCE WITH THE OHSA AND ITS ASSOCIATED REGULATIONS**

Visit Location: **OFFICE AREA**

Visit Summary: **NO ORDERS ISSUED. SEE DETAILED NARRATIVE**

Detailed Narrative:

Attended the workplace to respond to an anonymous complaint reported to the Ministry of Labour, Immigration, Training, and Skills Development (MLITSD).

The complainant alleges the following:

- Fire suppression equipment is not maintained.

Inspector Findings:

The employer stated fire suppression system inspections are carried out regularly every month, along with annual checks, all conducted by a third party contractor. The employer is in the process of replacing the fire sprinkler heads and the project is expected to be completed by the end of October. Employer also stated Whitby Fire Department was on site and verified the system was in good working order.

Discussed the details of the complaint with the Joint Health and Safety Committee (JHSC) members. The JHSC members were unaware of concerns or complaints regarding fire suppression system in the workplace.

Employer is reminded no employer or person acting on behalf of an employer shall,

(a) dismiss or threaten to dismiss a worker;

(b) discipline or suspend or threaten to discipline or suspend a worker;

(c) impose any penalty upon a worker; or

(d) intimidate or coerce a worker,

because the worker has acted in compliance with this Occupational Health and Safety Act (the Act) or the regulations or an order made thereunder, has sought the enforcement of the Act or the regulations.

No further MLITSD action necessary at this time.

END OF DETAILED NARRATIVE

Recipient	Inspector Data	Worker Representative
Name Shelby Bell	**Guler Arasan** O.H.S.A. & B.O.S.T.A INSPECTOR PROVINCIAL OFFENCES OFFICER 1-2275 Midland Ave, Scarborough ON M1P 3E7 MOLCOMPLIANCEIHSTORE@ontario.ca **Tel: (437) 218-4523** **Fax: (416) 314-5405**	Name Ben Herr
Title Firmwarehouse		Title Receipt. Inspector
Signature SBell	Signature GA	Signature

You are required under the Occupational Health and Safety Act to post a copy of this report in a conspicuous place at the workplace and provide a copy to the health and safety representative or the joint health and safety committee if any. Failure to comply with an order, decision or requirement of an inspector is an offence under Section 66 of the Occupational Health and Safety Act.You have the right to appeal any order or decision within 30 days of the date of the order issued and to request suspension of the order or decision by filing your appeal and request in writing on the appropriate forms with the Ontario Labour Relations Board, 505 University Ave., 2nd Floor, Toronto, Ontario M5G 2P1.You may also contact the Board by phone at (416) 326-7500 or 1-877-339-3335 (toll free), mail or by website at http://www.olrb.gov.on.ca/ for more information.

The Government of Ontario wants to hear from you. You can provide feedback on this visit at 1-888-745-8888

Exhibit L-F3-Pinto-001, Attachment 6

Forbes Warehouse Condition Assessment

This Attachment was filed as confidential information in its entirety.

Pinto Interrogatory #002

Interrogatory

Reference:
Oversight, Risk Management, Accountability and Strategic Practices
CRE Maintenance Backlog, Condition Assessments, Risk Treatment, Corrective Actions, and Strategic Planning

Preamble:

Purpose and Scope

This interrogatory builds on IR-1 and seeks information necessary to assess how CRE maintenance information, backlog, and exceptions were evaluated, escalated, and acted upon; the adequacy of OPG's risk management, governance, and internal controls; and the degree to which OPG implemented recognized facilities and maintenance best practices and its own stated Facilities & Projects (F&P) strategic objectives during the period January 1, 2022 to December 31, 2025.

This interrogatory relates to Issues 11-16, 23-26, 37, and 38-40 of the approved Issues List.

Unless otherwise indicated, terms have the same meaning as in IR-1.

Question(s):

A. Condition Assessments and Investigations

For safety-critical or nuclear-critical CRE assets with deferred or overdue maintenance during 2022-2025, produce:

- Routine condition assessments, inspection reports, or investigative findings; and
- Records of recommended or completed follow-up actions.
- Produce any annual Building Condition Assessment reports, trend analyses, or comparable facility condition studies prepared by or for the Facilities & Projects organization during 2022-2025.
- Identify instances where no formal condition assessment (including annual condition assessments) was conducted despite known backlog, deferrals, or exceptions.

B. Risk Assessment and Acceptance

Produce any risk registers, risk summaries, or impact analyses in effect during 2022-2025 that incorporated CRE maintenance backlog, deferred work, or CRE-related exceptions.

For material CRE maintenance deferrals, produce records showing:

- The assessed risk (qualitative or quantitative); and
- Whether the risk was mitigated, deferred, or accepted.
- Where risks were formally or informally accepted, identify:
- The approving authority; and
- The duration or period of acceptance.

C. Oversight and Decision-Making

Produce records evidencing management-level or executive-level of CRE maintenance backlog or risk during 2022-2025, including:

- Briefing materials;
- Decision notes; and
- Direction provided to management.
- Identify instances where CRE maintenance deferrals were linked to:
- Capital planning assumptions; or
- Anticipated facility replacement, refurbishment, or redevelopment.

D. Corrective Actions and Organizational Controls

Produce records of corrective actions taken during 2022-2025 in response to:

- Identified deficiencies in CRE maintenance systems, tools, or processes; and
- Repeated maintenance exceptions or sustained backlog growth.
- Produce any internal audits, reviews, or assessments conducted during 2022-2025 that evaluated:
- Effectiveness of CRE maintenance delivery; and
- Adequacy of systems, internal controls, or governance arrangements.

E. Specific Work Orders and Prior Raised Concerns

With respect to work orders previously raised regarding CRE maintenance concerns that remained open, were revisited, or were otherwise active during 2022-2025 (including those identified in FOI files 26-001 and 26-002), identify:

- The current status of each work order;
- The last substantive action taken;
- The responsible role or function; and
- Any associated invoices, purchase orders, or contracts.
- Produce internal correspondence or records from 2022-2025 that document:
- Concerns raised regarding these work orders; and
- Decisions to defer, modify, or close them without completion.

F. Strategic Planning and Best-Practices Implementation

Produce any Strategic Facilities Plan, Facilities & Projects strategy, Facilities Master Plan, or comparable document that was in effect, updated, relied upon, or referenced by OPG during 2022-2025.

For each such plan or strategy, produce records showing how it was implemented during this period, including:

- Trend analyses or environmental scans used to inform decision-making;
- Alignment with OPG's mission, strategic imperatives, and values;
- Short- and long-range facility plans;
- Project plans tied to stated objectives;
- Evaluation mechanisms, metrics, or follow-up reports;
- Benchmarking studies and actions taken in response;
- Business continuity, facilities reliability, preventive maintenance, or risk-management initiatives referenced in the plan;
- Staffing, resourcing, or organizational design changes implemented or maintained to support the plan; and
- Stated goals or targets and progress against them.

Identify any instances during 2022-2025 where OPG's actual CRE or Facilities & Projects practices materially diverged from its stated strategic objectives or best-practice commitments.

G. Insurance and Third-Party Risk Oversight

Produce records sufficient to demonstrate compliance during 2022-2025 with applicable insurance policy requirements and third-party risk-control obligations relevant to CRE properties, including records of inspections, risk surveys, recommendations, and follow-up actions by insurers or insurer-appointed risk engineers.

H. Cross-Jurisdictional Coordination and Resource Competition

Describe the governance, monitoring, and escalation mechanisms used by OPG to manage jurisdictional overlap and resource competition between the central CRE organization and Nuclear Operations & Maintenance, including:

- How prioritization decisions affecting CRE assets on nuclear sites are made and reviewed;
- How work protection, lockout-target, or similar requirements affecting CRE maintenance are coordinated and monitored;
- How known organizational or process weaknesses identified in strategic planning exercises (including the Strategic Plan) were tracked and addressed; and

Any corrective actions or control enhancements implemented to mitigate operational, safety, or continuity risks arising from such cross-jurisdictional challenges.

Privilege and Non-Existence
If any responsive record is withheld on the basis of privilege, produce a privilege log and non-confidential description as set out in IR-1.

If any requested information does not exist, state this explicitly.

Response

In accordance with the Motions Resolutions letter filed on May 4, 2026, the Applicants have revised this interrogatory response.

a) to h)

This interrogatory seeks extensive details and documentation pertaining to facilities maintenance covering a four-year time period. The request is overly broad, lacks clarity, and is unreasonably onerous to respond to. The information sought is not material, lacks relevance, and/or offers minimal, if any, probative value in deciding the OEB-approved issues in this proceeding.

Notwithstanding the foregoing, in an effort to be helpful, OPG initially responded on April 24, 2026 by providing additional information on topics that are the subject of this interrogatory. Furthermore, in the letter filed by the Applicants on May 4, 2026 in respect of Mr. Pinto's motions and certain other interrogatory responses (in which he narrowed his requests), OPG proposed to provide or refer to certain documents or information.

In accordance with the OEB Decision and Order on Motions and Intervenor Evidence EB-2025-0297 dated May 15, 2026 that directed OPG to provide the information proposed in its May 4, 2026 letter, OPG has revised its response in Ex. L-F3-Pinto-001 to provide additional responsive information and documents.

As discussed in Ex. L-F3-Pinto-001, OPG does not have a specific definition for "nuclear critical" or similar categorization in the Real Estate & Facilities ("RE") department scope of responsibility or system database and therefore cannot provide data by his category. Similarly, "backlog" is not a term or status used in RE maintenance reporting; OPG tracks open corrective maintenance requisitions and open preventative maintenance work orders.

RE continually assesses the condition of assets through monthly facility risk and safety tours, monthly Joint Health and Safety ("JHSC") inspections and third-party building condition assessments, most recently completed in 2025. There are thousands of pages of records relating to these assessments during the time period Mr. Pinto requests. Findings from site tours and JHSC inspections are recorded in RE's corrective maintenance system as described in Ex. L-F3-Pinto-001.

Work protection follows applicable health and safety legislation, including O. Reg. 851 (Industrial Establishments) and O. Reg. 231/91 (Construction), which are outside the scope of this proceeding.

OPG declines to provide further requested information in this interrogatory for the reasons noted above.

Pinto Interrogatory #003

Interrogatory

Reference:
Governance, Independence, and Conflict-Management Controls
Affiliated-Entity Oversight, Cross-Appointments, and Coordinated Practices

Preamble:

Context

During the period under review, Ontario Power Generation Inc. ("OPG") conducted material activities through multiple affiliated entities, including subsidiaries and related entities operating in different jurisdictions and under varying regulatory and commercial frameworks. Such structures are commonly associated with heightened governance, independence, and conflict-management risks, particularly where leadership roles, decision-making authority, or operational practices overlap. This interrogatory seeks to understand how OPG identified, managed, and mitigated those risks at a design and control level.

Purpose and Scope

This interrogatory seeks information necessary to assess the adequacy of OPG's governance framework, internal controls, and ethical safeguards in circumstances where OPG and its affiliated entities were represented as operating independently but may have been subject to shared leadership, coordinated practices, or cross-entity decision-making during the period January 1, 2000 to December 31, 2025.

The information requested relates to Issues 23-26 (Governance, Planning, and Cost Control), Issue 37 (Controls and Oversight), and Issues 38-40 (Risk Management and Compliance) of the approved Issues List.

This interrogatory is directed at institutional design and control effectiveness, not at individual conduct.

The Intervenor will execute the OEB Declaration and Undertaking with respect to any confidential material.

Definitions

"Affiliated Entity" means any subsidiary, joint venture, partnership, or related entity in which OPG held an ownership interest, governance role, or material influence.

"Cross-Appointment" means any instance where an individual simultaneously held executive, officer, or board-level roles across OPG and one or more Affiliated Entities.

"Coordinated Forum" means any recurring or ad-hoc meeting, committee, or working group involving representatives from OPG and one or more Affiliated Entities to discuss operational, strategic, human resources, contracting, or governance matters.

"Conflict Mitigation Measures" include disclosure requirements, recusals, independent approvals, secondary oversight, documentation requirements, or third-party review.

Question(s):

A. Representations of Independence and Governance Structure

For the period 2020-2025, identify how OPG described the operational and governance independence of each Affiliated Entity in public, regulatory, or internal materials.

Produce records sufficient to show:

- The formal governance structure for each Affiliated Entity; and
- Reserved authorities, approval thresholds, or escalation requirements involving OPG.

B. Cross-Appointments and Overlapping Authority

Identify all instances during 2020-2025 where individuals held concurrent executive or board-level roles across OPG and one or more Affiliated Entities.

For each instance, produce records sufficient to show:

- The roles held and duration of overlap;
- The scope of authority associated with each role; and
- Whether the roles involved influence over hiring, contracting, strategic partnerships, or capital or operating decisions.

C. Coordinated Forums and Information-Sharing Practices

Identify any Coordinated Forums involving OPG and Affiliated Entities during the period, including their:

- Purpose and mandate;
- Participant roles (by function, not by name); and
- Frequency and duration.
- Produce any policies, terms of reference, or guidance governing:
- Permissible topics of discussion;
- Information-sharing boundaries; and

- Safeguards intended to preserve decision-making independence.
- Identify whether such forums addressed matters including:
- Human resources or labour relations strategy;
- Workforce planning or movement across entities;
- Contracting practices or vendor engagement; or
- Sequencing or coordination of strategic initiatives.

D. Conflict Identification and Mitigation

Produce all policies, procedures, and Code of Business Conduct provisions in effect during 2020-2025 governing:

- Conflicts of interest;
- Cross-appointments; and
- Coordinated practices across Affiliated Entities.
- For each Cross-Appointment identified in Section B, identify:
- Whether a conflict assessment was conducted;
- What mitigation measures were applied; and
- The role or function responsible for oversight.

E. Escalation, Independence, and External Interface Controls

Produce records evidencing how OPG ensured that:

- Actual or perceived conflicts were escalated outside affected reporting lines; and
- Independent review or challenge was available where ordinary governance channels may themselves have been conflicted.

Produce policies or records governing communications between OPG and external public-sector bodies concerning matters involving Affiliated Entities, including:

- Documentation and record-keeping requirements; and
- Oversight or approval mechanisms intended to preserve independence.

F. Structural Conflicts of Interest and Delegated Authority Controls

Produce policies, procedures, or guidance in effect during 2020-2025 addressing structural or inherent conflicts of interest, including circumstances where:

- A single leadership role encompassed responsibility for functions with potentially competing control objects; or
- Segregation of duties ordinarily expected under governance best practices was not feasible.

For such circumstances, produce records sufficient to show:

- How the structural conflict was identified and assessed;
- What mitigation measures were required or recommended; and

- Whether the arrangement was treated as an acceptable risk, a transitional measure, or an approved exception.

Identify any instances during 2020-2025 where structural conflicts were acknowledged but permitted to continue, and the documented rationale for doing so.

Privilege and Non-Existence
If any responsive record is withheld on the basis of privilege, produce a privilege log identifying the document, date, author, recipient, and the basis of the claim, together with a non-confidential description of its subject matter.

If any requested record does not exist, state this explicitly.

Response

In accordance with the Applicants' letter filed on May 4, 2026 and the OEB Motions decision dated May 15, 2026, OPG has revised this interrogatory response.

This interrogatory seeks extensive details and documentation pertaining to the governance of affiliated and unregulated business activities. This request is overly broad and unreasonably onerous to respond to. The information sought is not material, lacks relevance, and/or offers minimal, if any, probative value in deciding the OEB-approved issues in this proceeding.

Notwithstanding the above, in an effort to be helpful, OPG initially responded on April 24, 2026 by noting that the topics raised in this interrogatory are addressed in the following pre-filed exhibits:

- Ex. A1-4-1 provides information about OPG's governance and organization;
- Ex. F3-1-4 provides details of affiliate relationships and associated cost allocation methodology; and
- Ex. F3-2-1 provides details of asset service fees charged by the regulated business to the unregulated businesses.

Furthermore, in the letter filed by the Applicants on May 4, 2026 in respect of Mr. Pinto's motions and certain other interrogatory responses (in which he narrowed his requests), OPG proposed to provide or refer to certain additional documents or information. In accordance with the OEB Decision and Order on Motions and Intervenor Evidence EB-2025-0297 dated May 15, 2026 that directed OPG to provide the information proposed in its May 4, 2026 letter (and otherwise denied Mr. Pinto's motions seeking other information), OPG has revised this interrogatory response to provide the following information:

- OPG's Code of Conduct (Attachment 1) and Code of Business Conduct Policy (Attachment 2), which apply to all OPG wholly-owned subsidiaries and describe accountability and responsibility for declarations of conflicts of interest;
- the Subsidiary and Joint Venture governance approved by OPG's Board of Directors (Attachment 3 – confidential);
- an overview of Laurentis Energy Partners ("Laurentis") and OPG's boards of directors and executive leadership (see below); and
- an explanation of how OPG's cost allocation methodology ensures appropriate attribution of applicable costs to unregulated affiliates, including executive leadership team time that is spent on unregulated business activities (see below); and
- the General Services Agreement between OPG and Laurentis which governs OPG provision to Laurentis of personnel and certain equipment or materials, access to OPG property and assets, and professional and corporate support services; and Laurentis' provision of services to OPG (refer to Ex. L-F3-SEC-179, Attachment 2).

Overview of OPG's Board of Directors and Executive Leadership

As a corporation, OPG has an independent Board of Directors ("BoD") with diverse backgrounds, comprised of ten directors. The President and Chief Executive Officer ("CEO") of OPG is the only employee of OPG who is also a member of the OPG BoD. Refer to OPG's website for a further description of the OPG BoD members: Who we are | Our Board of Directors – OPG.

OPG is led by an Enterprise Leadership Team ("ELT"), which is comprised of senior management employees from across the organization including the President and CEO. Members of the ELT include leaders of the major functions in the corporation, including Enterprise Operations, Enterprise Projects, Corporate Services and Finance, Commercial Operations and Regulatory Affairs, Enterprise Strategy, Corporate Affairs, and Law, Governance and ESG. Refer to OPG's website for a further description of OPG's ELT members: Who we are | Our executive team – OPG, and to Ex. A1-5-1 for a description of OPG's corporate organizational chart. Additional details on OPG's organizational functions can be found in Ex. F1-2-1, Attachment 1, Ex. F2-2-1, Attachment 1, and Ex. F3-1-1, Attachment 1.

Overview of Laurentis Energy Partners Board of Directors and Executive Leadership

As a corporation and a wholly owned subsidiary of OPG, the Laurentis BoD is comprised of three OPG ELT members. It does not include OPG's President and CEO. Refer to Laurentis' website for a further description of Laurentis BoD members: Board of Directors » Laurentis Energy Partners. As further described below, OPG's cost allocation methodology attributes a portion of the cost of OPG's ELT to OPG's unregulated business, including subsidiaries.

Laurentis is led by a senior leadership team, which is comprised of Laurentis senior management from across that organization and its President and CEO. Refer to Laurentis' website for a description of Laurentis' senior leadership team: Senior leadership team » Laurentis Energy Partners. Certain of these individuals, including the current President and CEO, are seconded from OPG on a full-time basis. While seconded, such individuals report into the Laurents organizational structure and do not hold an active position within OPG, and their costs are fully attributed to Laurentis and excluded from the regulated business. No members of OPG's BoD are on the Laurentis BoD and no members of the OPG BoD or OPG's ELT are on the Laurentis' senior leadership team.

Explanation of OPG's Cost Allocation Methodology

OPG's cost allocation methodology is detailed in Ex. F3-1-4 and associated Attachment 1, which is a report by Elenchus Research Associates ("Elenchus") reviewing the methodology as applied to OPG's 2025-2031 Business Plan that underpins this Application. For ease of reference, the discussion below provides an overview of the methodology, focusing on how it considers the attribution of OM&A costs between regulated and unregulated businesses, including affiliates.

OPG utilizes a cost allocation methodology to allocate the OM&A costs of its corporate Support Services and enterprise operations and project support functions and other common costs across its operations. The costs distributed using the cost allocation methodology include those of OPG's ELT and other senior management. The methodology attributes the costs to OPG's regulated and unregulated electricity generating businesses and facilities, as well as its subsidiaries, including Laurentis. The methodology attributes costs using specific identification or estimation of resources that are spent on a particular business, generating facility or subsidiary, where reasonably possible. Where specific identification or estimation is not reasonably possible, costs are allocated using formulaic cost drivers based on cost causation. Under the methodology, subsidiaries are treated consistently with OPG's other businesses.

The primary cost driver uses a blend of planned OM&A costs and capital expenditures ("OM&A/Capital"). Where a function using a cost driver such as OM&A/Capital performs an oversight function in respect of a subsidiary, such as in the case of OPG's ELT, the methodology factors in the respective inputs into the derivation of the driver, resulting in an allocation of such functional costs to the subsidiary (which in turn reduces the amount of costs allocated to the regulated business).

Among other findings, Elenchus' report at Ex. F3-1-4, Attachment 1 makes the following conclusions with respect to OPG's cost allocation methodology as it pertains to unregulated affiliates:

- "the allocation of OPG's oversight and ownership costs to the subsidiaries follows existing cost drivers for the applicable Central and Common Costs and is consistent with how these costs are allocated to OPG's other businesses" (p. 19);
- "Elenchus also agrees with OPG's approach to determining which departments within Central and Common Costs should be allocated to the unregulated subsidiaries, which is based on the nature of the departments' work" (p. 19);
- "Elenchus concludes that, between the use of corporate oversight allocations and an overhead allocation rate for transferred labour resources, OPG reflects the impact of the unregulated subsidiaries in the cost allocation methodology in a manner that appropriately separates costs between regulated and unregulated businesses" (p. 20).

As noted in Ex. F3-1-4 and associated Attachment 1, unregulated subsidiaries may purchase specific services or resources from OPG from time to time, on a cost basis. This includes OPG employees who may be seconded to the subsidiary. As noted in Ex. L-G2-SEC-202, when this occurs, OPG recovers the associated costs from Laurentis, including allocated support costs in accordance with OPG's cost allocation methodology. Such costs are not charged to OPG's regulated business, including within the proposed 2027-2031 revenue requirements in this Application. The allocated support costs are recovered through the use of a standard overhead allocation rate. In this regard, Elenchus confirmed that "a commensurate portion of Central and Common Costs, corresponding to an estimate of such costs for any transferred labour resources, is charged or otherwise attributed to the unregulated subsidiaries." (Ex. F3-1-4, Attachment 1, p. 20)

Code of Business Conduct

At Ontario Power Generation, we are working to electrify life in one generation. Employees, directors, officers, suppliers, consultants, contractors, subsidiaries, and business partners play a vital role in shaping our future by upholding all applicable laws and regulations, OPG policies, professional standards, and our Code of Business Conduct.

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A Message from Leadership

Nicolle Butcher
President &
Chief Executive Officer

Wendy Kei
Board Chair

At Ontario Power Generation (“OPG”), we hold ourselves to the highest standards of ethical conduct. We know this is fundamental in fulfilling our purpose to safely generate reliable low-carbon electricity for Ontario, our vision to electrify life in one generation, and our mission to build a sustainable future powered by our electricity, ideas and people.

Our business is complex and experiencing tremendous growth. Our longstanding reputation for ethical conduct is built on the choices we make, and is one of our most valuable assets. Each of us must continue to act with honesty, transparency, and respect in all our interactions – whether with business partners, contractors, communities, or each other.

Our OPG values and Code of Business Conduct (the “Code”) guide our actions and decisions. If OPG’s values of safety, integrity, excellence, inclusion and innovation are our ethical compass, the Code is our roadmap. We follow the Code to meet the highest standards of integrity in our business activities.

Our success depends on our shared commitment to ethical excellence. Together, we will continue to earn and maintain the trust of our stakeholders, protect our reputation, and serve as Ontario’s largest electricity generator.

Our Values

Our values are the foundation of everything we do – they guide our work, our behaviours, and our decisions. Our values shape how we show up and how we treat one another. Each of us should be committed to living and breathing our values each day, so that together, we can electrify life in one generation and change the world.

Safety
Commit to care

Be responsible for keeping yourself, each other, the public and the environment safe at all times. Embrace physical and psychological health and safety, and incorporate this into your day-to-day decision making.

Integrity
Commit to truth

Openness, honesty and transparency make us stronger, more effective partners, Indigenous allies and committed environmental stewards. Hold yourself and others to the highest standard of ethical conduct.

Excellence
Commit to better

Progress is a journey. Strive for excellence in everything you do. Work to deliver results in a reliable, efficient and cost-effective manner to support ongoing operations, development projects and maintain OPG's leadership position as a generator of choice.

Inclusion
Commit to us all

Prioritize equity, diversity and inclusion and treat everyone with dignity and respect. Build trust and support the social and cultural fabric of the communities where we live, work and serve.

Innovation
Commit to what could be

Embrace challenges as opportunities for innovation. Lead with curiosity and ingenuity in all that you do.

Our Behaviours

Through our culture and behaviours, we are building a sustainable future powered by our electricity, ideas and people. These behaviours reinforce OPG's values which are essential to our continued growth as an innovative, ethical and competitive provider of clean energy. Employees are expected to demonstrate the following behaviours:

Safety behaviours

- Protect ourselves and others
- Uphold the highest standards
- Learn from mistakes

Integrity behaviours

- Be open, honest and fair
- Stand up for what's right
- Take accountability

Excellence behaviours

- Work to deliver results
- Celebrate success but stay humble
- Set ambitious goals

Inclusion behaviours

- Be kind
- See diversity as a strength
- Be collaborative

Innovation behaviours

- Be curious and creative
- Seek alternative perspectives to improve ideas
- See failure as an opportunity to learn

For more information on OPG's values and behaviours, please visit the OPG Values PowerNet site.

Standards of Business Conduct

OPG expects the following high standards of business conduct from every OPG employee, director and officer, as well as agents, representatives, consultants, contractors and business partners. The Code applies to OPG's operations, including those carried out internationally. Standards of business conduct for OPG suppliers are outlined in OPG-STD-0141, Supplier Code of Conduct (the "Supplier Code").

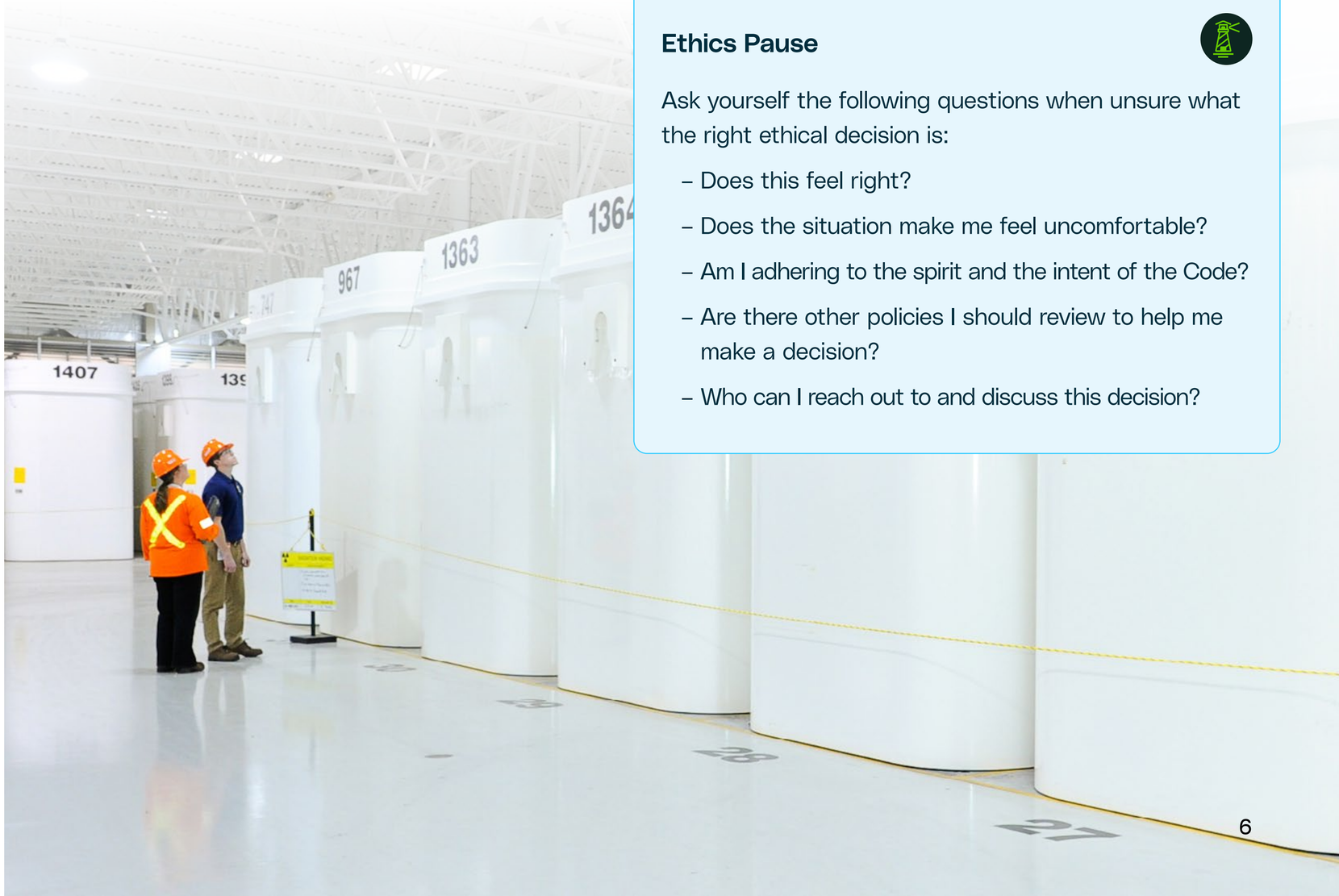
1.0 Reporting Code of Business Conduct Concerns

1.0 Reporting Code of Business Conduct Concerns

The Code may not always provide an answer to employees' ethical questions. It is not intended to cover every situation, so employees must comply with the spirit and intent of the Code, using judgment and acting with integrity, transparency, and respect for others.

Employees are required to report any known and suspected violations of the Code and Supplier Code. For questions, clarification, or to report possible breaches of the Code, contact:

- Your Line Manager
- Human Resources ("HR") contact
- Ethics Office through ServiceHub, or by emailing ethics@opg.com and humanrights@opg.com
- In circumstances that require immediate intervention such as workplace violence, theft and other security-related matters, contact Security & Emergency Services at 905-429-2551. At locations with site/plant security staff, employees must contact the local site/plant security group.



Ethics Pause

Ask yourself the following questions when unsure what the right ethical decision is:

- Does this feel right?
- Does the situation make me feel uncomfortable?
- Am I adhering to the spirit and the intent of the Code?
- Are there other policies I should review to help me make a decision?
- Who can I reach out to and discuss this decision?

1.1 Anonymous Reporting

Individuals may anonymously report known and suspected violations of the Code or Supplier Code through OPG's Anonymous Ethics Reporting Portal hosted by i-Sight. The Anonymous Ethics Reporting Portal provides a secure third-party reporting system and can be reached by calling 1-800-693-0278 or by accessing https://opg.i-sight.com/portal.

1.2 Retaliation and Reprisal

OPG maintains a strict policy prohibiting retaliation or reprisal, including threats against any employee for reporting in good faith or participating in a complaint process. Individuals found to have engaged in such conduct may face disciplinary measures, up to and including termination for cause in accordance with the *Employment Standards Act, 2000*.

Employees who believe they have experienced or witnessed retaliation or reprisal are encouraged to promptly report their concerns to their manager, HR contact, or the Ethics Office through ServiceHub, or ethics@opg.com.

Ethics Pause

Tips for submitting complaints anonymously:

- You have the choice to submit a complaint anonymously or provide your contact information
- If you want to remain anonymous, do not share information that reveals your identity when submitting a complaint
- Provide as much detail as possible including who was involved, witnesses, when it happened, where it happened, and details about the incident
- If you submit a complaint using the online portal, you will have the ability to engage in two-way anonymous communication, remember to write down your login information so you can re-visit the complaint

2.0

Safe, Respectful and Inclusive Workplaces

2.0 Safe, Respectful and Inclusive Workplaces

In accordance with OPG values, safety culture and legal obligations, OPG maintains safe, respectful, and inclusive workplaces. The following sections focus on behaviour expectations when working with other employees, contractors, vendor partners/suppliers and members of the public.

2.1 Harassment, Discrimination and Violence Free Workplaces

OPG is committed to maintaining workplaces free from harassment, discrimination, and violence. Employees are expected to:

- Promote healthy and safe workplaces that are free from harassment, discrimination and violence, including threats, attempts and/or actual violence
- Comply with legal obligations that promote employment equity and prohibit discrimination on the basis of race, ancestry, place of origin, colour, ethnic origin, citizenship, creed (religion), sex, sexual orientation, disability, age, marital status, family status, record of offences (pardoned), gender identity, gender expression and genetic characteristics
- Use bystander intervention techniques (distract, confront, support, report) in response to misconduct, including bullying, harassment and discrimination
- Comply with OPG-PROC-0099, Human Rights and Harassment Procedure, and report harassment and discrimination in a timely manner to managers, HR contacts, union representatives (if applicable), or the Ethics Office through ServiceHub or humanrights@opg.com
- Comply with OPG-PROC-0075, Violence Free Workplace Procedure and report any workplace violence issues immediately to management, Security & Emergency Services, either on site or at 905-429-2551

OPG does not tolerate harassment, violence or any behaviour that is physically and psychologically unsafe, including but not limited to:

- Behaviour that demeans, threatens or humiliates a person or group of people
- Comments, jokes or conduct of a sexual nature
- Abusive, threatening, intimidating or violent acts directed at anyone employees come in contact with in carrying out their responsibilities

Ethics Pause

Where can I find the definitions of harassment, discrimination and workplace violence?

Definitions related to harassment and discrimination are found in OPG-PROC-0099, Human Rights and Harassment Procedure.

Definitions related to workplace violence are found in OPG-PROC-0075, Violence Free Workplace Procedure.

2.2 Respectful and Inclusive Workplaces

OPG is committed to ensuring equal opportunity, and supporting respectful, equitable, diverse and inclusive workplaces. Employees are expected to:

- Treat everyone we do business with dignity and respect
- Respect individual differences and act professionally when conducting OPG business
- Lead by example and use bystander intervention to address inappropriate, disrespectful or rude behaviour
- Reflect and support the communities in which we operate
- Use and promote inclusive language (e.g. everyone and all vs. ladies and gentlemen)
- Be familiar with and support initiatives in the Reconciliation Action Plan (RAP) and the Equity, Diversity and Inclusion Strategy (ED&I Strategy)
- Take proactive measures to identify and address systemic barriers to equity, diversity and inclusion in OPG workplaces

OPG does not tolerate behaviours that undermines treating others with dignity, respect and inclusion, including but not limited to:

- Comments or conduct that demean, threaten or mock a person or group of people
- Engaging in disrespectful communications, or conduct that negatively impacts the workplace or OPG's reputation
- Targeting other employees for personal or political beliefs
- Using or displaying items (e.g. clothing, bags, stickers, etc.) that are disrespectful to others

Ethics Pause

What are some examples of disrespectful behaviour?

- Creating avoidable conflict that is not relevant or distracts from productive work
- Sabotaging someone or pulling pranks
- Belittling behaviours, rudeness or undermining others
- Interrupting others or using aggressive tones
- Calling someone a name or using inappropriate language

2.3 Online and Off Duty Conduct

OPG respects personal privacy. It is important to remember that online and off duty conduct can have consequences in the workplace, including situations where online or off duty conduct can negatively impact OPG's business, reputation, impacts the work environment or impacts the ability for employees to work with one another.

Employees must ensure online posts, emails or other forms of communication do not inadvertently link participation in political, commercial or other organizational interests with OPG.

Use online and social media within the guidelines and values of the Code and OPG's Social Media Policy (refer to the Ethics and Code of Business Conduct PowerNet) including internet, internal and external multimedia, and social networking sites and forums. Employees must ensure online conduct does not negatively impact OPG or its reputation. Any inappropriate behaviour that occurs online and may be connected to the workplace or working relationships will not be tolerated and may be subject to disciplinary action up to and including termination for cause in accordance with the *Employment Standards Act, 2000*.

Ethics Pause

Does posting a disclaimer online make a difference?

No, posting a disclaimer does not exempt you from responsibility for your online conduct. Employee online conduct must be consistent with the guidelines and values of the Code and OPG's Social Media Policy.

2.4 Media Communications

Only those identified as media spokespeople may speak to the media on behalf of OPG. Ask permission before speaking on behalf of OPG in any public forum including presentations to industry, community or business groups and/or media, including social media forums, or with a media representative.

When speaking to the media, employees must receive prior permission from their manager and Corporate Affairs Media Relations. Employees must not make remarks or comments on behalf of OPG. Refer all media inquiries and questions to the Corporate Affairs Media Relations Desk at 416-592-4008 or toll free 1-877-592-4008.

3.0 Transcription, Audio and Video Recordings

3.0 Transcription, Audio and Video Recordings

Employees are not permitted to record or transcribe conversations, phone calls, company meetings, or take photos/videos with any recording device except where prior consent of all parties has been obtained (consent may be verbal). When making recordings, the least intrusive recording method should be used (e.g. transcription or audio recording should be used when a video recording provides no additional benefit).

Recording devices include but are not limited to cell phones, digital recording devices, digital cameras and wearable technology. Workplace resources such as Teams or Artificial Intelligence ("AI") systems should not be set to automatically record or transcribe. Making transcriptions, audio, or video recordings without prior consent violates the Code, except as noted below.

Management may, from time to time, make recordings or transcribe work events, activities and/or announcements for reasonable business purposes including sharing information, in alignment with OPG's Electronic Monitoring Guide (refer to Cyber Security's PowerNet). In certain situations where recordings are made for reasonable business purposes (e.g. education/training, committee meetings, all-hands meetings, Town Hall meetings, announcements and OPG events) consent may not be required. In these situations, management should provide information where reasonable about the recordings, such as the purpose of the recording and how it can be accessed.

In situations where management records for the purpose of Code investigations, confidentiality will be maintained per section 16.0 Confidentiality.

Ethics Pause

What are the rules for accessibility related transcription?

Automated transcription functions on platforms such as Teams, etc. may be used for accessibility purposes, (i.e. to make information more accessible for employees with disabilities). Prior to use of the automated transcription function, meeting participants must be advised of the intent to transcribe and accessing the transcription of the meeting is for this specific purpose. In the absence of an accessibility requirement, transcriptions will be considered recording and must meet the consent criteria outlined above.

4.0 Environment

4.0 Environment

The following commitments support OPG's dedication to achieving the goal of net-zero emissions and protecting local communities in which OPG operates and the environment:

- Meet all legal requirements and OPG's environmental commitments, with the objective of exceeding legal requirements where it makes business sense to do so
- Continue to be a leader in climate change action and provide low-carbon electricity to Ontario today and in the future
- Strive to prevent or mitigate adverse environmental impacts with a long-term objective of continuous improvement
- Where it makes business sense, manage OPG sites in a manner that maintains or enhances significant natural areas and species of concern
- Work with Indigenous Rightsholders and community partners to support regional eco-systems and biodiversity through habitat stewardship considering western science and Indigenous perspectives

5.0 Conflict of Interest

5.0 Conflict of Interest

Employees must declare any actual, perceived, or potential conflict of interest to their manager and the Ethics Office using a Conflict of Interest request in ServiceHub, or using the OPG-FORM-0240, Actual, Potential or Perceived Conflict of Interest Declaration Form available on the Ethics and Code of Business Conduct PowerNet (collectively referred to as “COI Declaration”).

Employees can use OPG-GUID-08680-0002 Conflict of Interest Declaration Guideline when completing the COI Declaration process. Managers or supervisors who receive a COI Declaration from an employee may consult with the Ethics Office through ServiceHub or ethics@opg.com for assistance in determining next steps.

It is important to declare conflicts of interest to ensure personal interests do not conflict with OPG’s interests or business activities. Common examples where a COI Declaration needs to be submitted include but are not limited to outside business activities, relationships with employees or contractors, political participation, volunteering, and conflicts related to hiring and procurement activities.

If uncertain about a situation, employees should speak with their manager, HR contact or the Ethics Office through ServiceHub or ethics@opg.com for guidance.

Ethics Pause

What is a conflict of interest?

A conflict of interest is any situation where your personal interests (personal relationships, financial or social factors), present an actual, perceived or potential conflict with the interests of OPG. Conflicts of interest occur where personal interests could compromise judgement, decisions or actions in the workplace.

5.1 Outside Business Activities

With some exceptions, employees have the right to choose how to spend non-working hours. It is important to always make business decisions in the best interests of OPG. This includes ensuring OPG roles and duties come before interests related to outside business activities.

5.1.1 Working for Another Organization or Owning a Business

Secondary part-time employment or owning/operating a business must not impact employee's OPG duties, including job performance and availability. Employees are not permitted to use OPG resources or solicit business from colleagues, OPG, its subsidiaries, or OPG vendors/suppliers for secondary employment or personal business purposes. When engaging in other employment or running a business, employees are required to submit a COI Declaration to ensure appropriate mitigation measures are established.

Ethics Pause

When must I submit my COI Declaration when I am thinking of starting my own business?

Employees are required to submit COI Declarations promptly to ensure that their personal business activities do not conflict with OPG's interests. If you are unsure when to submit a COI Declaration when starting your own business, contact the Ethics Office through ServiceHub or ethics@opg.com.

Employees are required to obtain prior approval before working part-time for another organization or operating their own business outside of working hours, if such activities conflict, appear to conflict, or could potentially conflict with OPG's interests or with the employee's ability to perform their duties at OPG.

5.1.2 Serving as a Director or Officer of an Organization

Participation as a member of boards or organizations including non-profit organizations and charities, is encouraged. For individuals serving in director or officer capacities, submission of a Conflict of Interest (COI) Declaration is required.

Employees are not permitted to serve as a director or officer of organizations that provide goods or services to OPG, purchase goods or services from OPG, or compete with OPG.

5.1.3 Personal Investments

Employees must submit a COI Declaration for personal investments, including those made by a spouse, if they invest directly or indirectly in an entity that competes with or sells goods and/or services to OPG. This could include situations where employees may not directly hold the investment but control or direct the investment.

To ensure compliance with the Code, the following rules must be adhered to regarding investments with an entity that competes with or sells goods and/or services to OPG:

- Five Percent Limit: Generally, employees or their spouses are not permitted to own or control, either directly or indirectly, an ownership interest of five percent or more in an entity that competes with or sells goods and/or services to OPG. Employees are required to inform their manager and the Ethics Office in writing and seek approval prior to exceeding the five percent limit by submitting a COI Declaration. Notification to the manager and the Ethics Office is also necessary if the ownership interest is less than five percent but may create an actual, potential or perceived conflict of interest
- Insider Trading: Employees must comply with all applicable insider trading laws and regulations that govern use of sensitive information. Employees are not permitted to invest directly or indirectly based on sensitive OPG information gained through employment with OPG.

Ethics Pause

Do investments made on your behalf by an advisor need to follow the rules and guidance in section 5.1.3 Personal Investments?

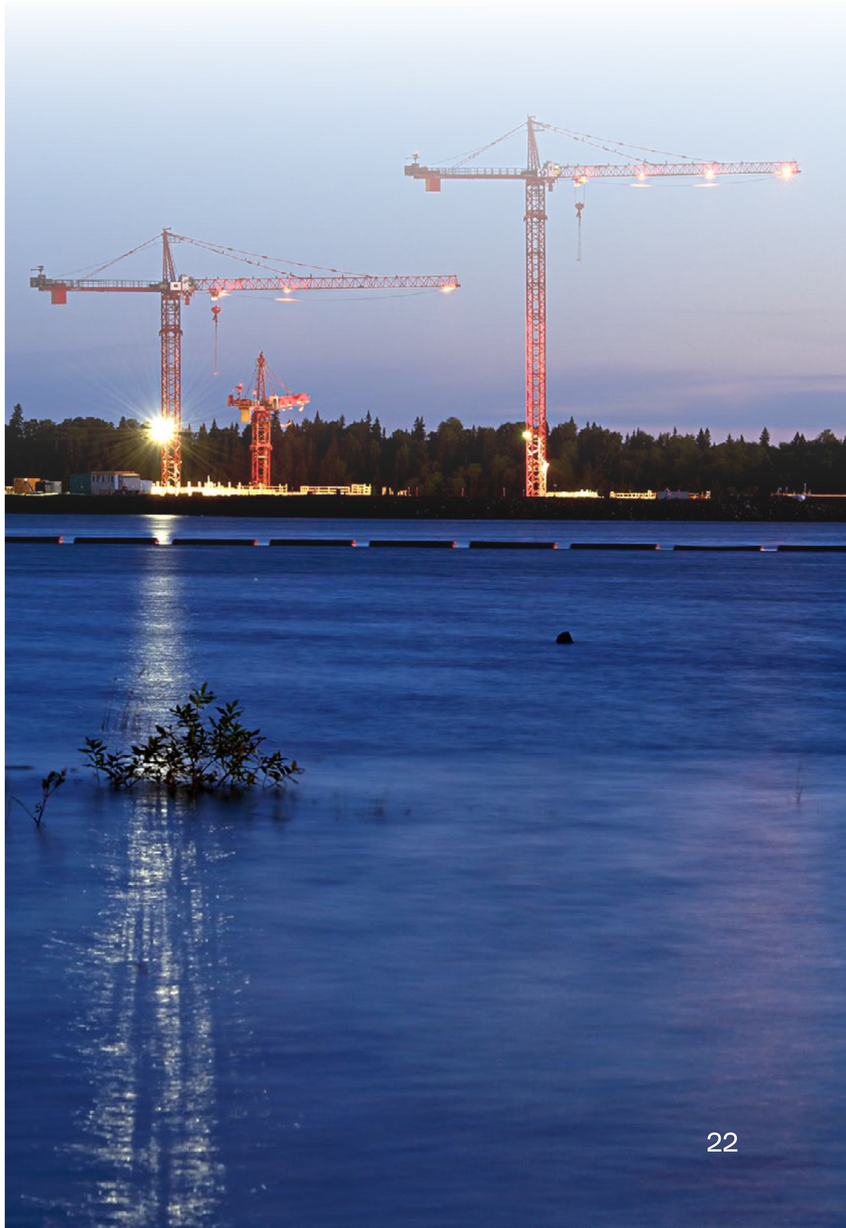
Yes, investments made by an advisor on your behalf need to abide by these personal investment requirements. Employees must submit a COI Declaration even if an advisor recommended or made the investment on your behalf, or if the investment is an entity that competes with or sells goods and/or services to OPG.

5.1.4 Prohibited Outside Business Activities

The outside business activities outlined below are prohibited:

- Using OPG's supplies, facilities, tools, IT infrastructure, personnel, or intellectual property while working for another organization
- Having colleagues or customers from other organizations use employee contact information at OPG
- Owning shares in a company that the employee is engaged with on behalf of OPG
- Participating in or in any way influencing OPG's purchasing or commercial decisions for projects, products and services that relate to a business interest or employment interest that could benefit the employee directly or indirectly, (e.g., a product or service from a company in which an employee, their spouse or other family member has an interest)
- Performing work:
  - For or owning/operating a company that competes with OPG
  - Or engaging in discussions about employment with a company competing with or doing work for OPG
  - That has the potential to assist a competitor of OPG in gaining competitive advantage (e.g., acting as a supplier to competitors)
  - For a supplier of OPG or selling products and/or services to OPG
  - Or owning/operating a business that offers products or services that could compete for business with OPG
  - Or promoting products or services for another organization during OPG working hours

In some circumstances, OPG approval may be considered upon submission of a COI Declaration set out in section 5.0 Conflict of Interest.



5.2 Personal Relationships

Personal relationships include family and close friends. There may be situations where employees develop close friendships in the workplace or have a family member that also works at OPG. Employees must avoid any situation where decision making or judgment could be influenced by personal relationships. This includes but is not limited to:

- Influencing, or attempting to influence the hiring, selection, referral or promotion of an individual with whom a personal relationship exists
- Having a direct or indirect reporting relationship with an individual with whom a personal relationship exists, including circumstances where responsibility for the individual's work and/or performance exists. An indirect reporting relationship involves someone who is responsible for an employee's work and/or performance even though they are not the direct manager.
- Making employment related decisions regarding an individual with whom a personal relationship exists (e.g. overtime, performance evaluations, compensation, discipline)
- Approving, reviewing, or otherwise evaluating work performed by an individual with whom a personal relationship exists (e.g. audits, quality checks, or other approvals)
- Participating in purchasing or procurement activities involving a company in which a family member, or an individual with whom a personal relationship exists, has an interest

Employees are required to submit a COI Declaration if they have personal relationships that could result in an actual, potential, or perceived conflict of interest. They must also take measures to prevent any conflict of interest with other employees, contractors, or vendor/supplier staff.

Ethics Pause

What is a close friendship?

A close friend is someone with whom an individual has an established, ongoing relationship that goes beyond a casual social acquaintance or normal collegial friendliness. When determining if someone is a close friend, the following questions should be considered:

- Have you known each other for a meaningful period of time (typically a year or more), with the relationship growing mainly through personal interaction outside typical work boundaries?
- Do you regularly share personal or family information not commonly discussed with coworkers or casual friends?
- Is or was the relationship romantic (this is always considered close)?
- Do you frequently spend time together outside of work (meals, events, hobbies, holidays)?
- Does the relationship involve significant personal support, such as advice or help during tough times?
- Would an outsider view this relationship as more than professional or casual?

5.3 Relationships with Non-Profit and Professional Organizations

Many of us have an interest in contributing to communities and professional organizations. However, this participation must not interfere with the performance of an employee's duties for OPG and/or the interests of OPG. Managers must approve any use of OPG time or assets to perform services for a community organization. If an employee acts as a spokesperson for an organization, they must make it clear that they are speaking on behalf of that organization, and not as a spokesperson or representative of OPG.

Employees must submit a COI Declaration if the non-profit or professional organization has a partnership with OPG or if their volunteering could create a conflict of interest with OPG.

5.4 Political Participation

As a private citizen, employees may participate in all levels of political activity during non-working hours, provided these activities do not interfere with or conflict with the employee's duties and obligations to OPG. Political activity includes but is not limited to running for political office and campaigning in public elections. Employees must submit a COI Declaration for all political participation.

Ethics Pause

If you choose to participate in political activity, remember:

- Your participation must be kept strictly separate from your association with OPG
- Employees must be on an approved leave of absence without pay to run as a candidate in a federal or provincial election
- Prior to running in municipal government elections, you must discuss your situation with your manager and the Ethics Office (ethics@opg.com). In some municipal election situations, employees may need to be on an approved leave of absence without pay
- OPG's supplies, facilities, tools and other business assets, including network assets, must not be used to support political activities
- Employees must not engage in solicitation for their political activities in the workplace
- Conversations in the workplace that promote political activities or platforms must be respectful

6.0 Purchasing and Hiring

6.0 Purchasing and Hiring

Ensure all purchasing and hiring policies, procedures and required processes are followed. Ensure all procurement and hiring processes are conducted in a fair, honest and transparent manner using such criteria as competitive pricing, quality, quantity, delivery and service. Ensure access for qualified vendors and applicants to compete for OPG business or employment opportunities.

OPG is guided by the ED&I Strategy and RAP; employees are expected to promote and pursue objectives set out in these documents, including hiring and procurement processes in accordance with Recruitment or Supply Chain protocols.

Employees must avoid actual, potential and perceived conflicts of interest during procurement and hiring processes. Ensure purchasing, hiring and selection processes do not involve favouritism, prejudice, preferential treatment or personal gain.

Employees who are involved in, or become aware of, purchasing, hiring, or selection decisions that may result in an actual, perceived, or potential conflict of interest are required to submit a COI Declaration as outlined in section 5.0 Conflict of Interest.

7.0 Business Gifts and Hospitality

7.0 Business Gifts and Hospitality

Never offer, ask for, give or receive any gift, hospitality or benefit that is intended to or could compromise or appear to compromise an employee's ability to make business decisions in the best interest of OPG.

Ethics Pause

What is hospitality?

Hospitality includes receiving meals, beverages, entertainment, accommodations and travel.

When providing meals, drinks, entertainment, and similar items on behalf of OPG, you must follow the guidelines set out in OPG-STD-0075, the Business Travel and Expense Standard.

7.1 Gifts

OPG employees are permitted to accept a gift of nominal value given as an expression of courtesy or hospitality if doing so is reasonable in the circumstances. Gifts with a value up to $50 are normally considered to be of nominal value.

From time to time, employees may wish to give each other small gifts to celebrate life events (e.g. retirement, birth of a child, etc.). This is permissible so long as the gift will not compromise or appear to compromise the employees' ability to make business decisions in the best interest of OPG.

There may be situations where employees are offered a gift from a supplier, potential supplier or another organization. Accepting nominal gifts of a promotional nature (e.g. mug, pen, lanyard, t-shirt, hat, etc.) or perishable items (fruit basket, chocolate, etc.) are acceptable as long as doing so is not prohibited per section 7.3 Prohibited Gifts and Hospitality.

These requirements do not change during traditional gift-giving seasons. Depending on the circumstances, gifts exceeding the nominal value should be returned with thanks and clarification of expectations under the Code or suitably distributed in the community. For instructions on how to handle gifts that do not meet these requirements, contact the Ethics Office through ServiceHub or ethics@opg.com.

7.2 Hospitality

Employees may be permitted to accept hospitality of paid meals.

In assessing whether a reasonable person might conclude that hospitality could influence the employee when performing their duties to OPG, at least the following shall be taken into consideration:

- Expected value
- Business or educational context
- Frequency
- Venue

7.3 Prohibited Gifts and Hospitality

The acceptance of the following gifts/hospitality is prohibited:

- Entertainment, travel or accommodation (except where directly related to OPG business, conferences or networking events)
- Gifts or benefits of any kind, including hospitality, from a vendor where employees are directly involved in the active procurement of goods or services involving that vendor
- Gifts or benefits of any kind, including hospitality, that were actively solicited by a representative of OPG

If uncertain about a situation, employees can speak with their manager, HR contact or the Ethics Office (ethics@opg.com).

Ethics Pause

Before you offer or accept anything, ask yourself:

- Is the value of the item nominal (e.g. a calendar or water bottle)?
- Is accepting this item in the best interests of OPG?
- What is the frequency the gift or hospitality is being offered?
- Is there a pre-existing business relationship?
- Is there an obligation to accept the gift for either party (i.e. cultural reasons)?
- Are the value and reason for the gift/hospitality appropriate considering the situation, people involved, and your role or function within OPG?
- Could accepting the gift/hospitality compromise or appear to compromise your ability to make a decision in OPG's best interest?
- Could giving a gift/hospitality influence or appear to influence any act or decision of the person receiving the gift/hospitality or secure any other improper advantage?
- How would this situation be perceived by others?
- Would you be uncomfortable discussing the gift/hospitality with your manager, peers or family?
- Is your behaviour compatible with ethical and accepted business practices?

8.0 Sensitive Information

8.0 Sensitive Information

Sensitive information includes information that is proprietary, technical, business, financial, personal or otherwise requires confidentiality. Sensitive information is owned by or has been entrusted to OPG and must be kept confidential to preserve OPG's competitive advantage or commercial interests.

When handling sensitive information, employees must comply with all legal, regulatory, or applicable contractual obligations. Sensitive information must be kept confidential to safeguard assets, employee and customer privacy, and preserve public safety.

Employee Responsibilities:

- Know what information must be kept confidential. Employees must ask their manager when in doubt. Refer to OPG-STD-0030, Protecting OPG's Information, and OPG-STD-0171, Intellectual Property that sets out the various security classifications applicable to sensitive information
- Except as required by law and only with prior written approval of the accountable manager, do not disclose sensitive information to anyone outside OPG. This applies even after employees have left OPG's employment
- Within OPG, do not disclose sensitive information to others, including colleagues or other employees, unless they need to know the information in order to carry out their OPG accountabilities
- Only use approved AI systems in accordance with the Code and OPG-STD-0030, Protecting OPG's Information
- Protect sensitive information against theft, loss, destruction, unauthorized access/ release, or misuse
- Do not use unauthorized sensitive information from other organizations for purposes related to OPG business
- Comply with any applicable insider trading laws and regulations that govern use of sensitive information
- Employees must advise their manager if they are aware of any inappropriate attempts to obtain or disclose sensitive information, or any misuse of such information
- Employees must advise their manager immediately if they, at any point, become aware of any inappropriate disclosure of sensitive information

9.0 Protection and Proper Use of Assets

9.0 Protection and Proper Use of Assets

While company systems such as email and internet access are primarily intended for business use, limited personal usage is permitted when conducted responsibly and within the boundaries of OPG's policies, standards, and procedures. Due to routine activities undertaken by the company for network management, security, investigations, and monitoring (as outlined in OPG's governing documents), users should be aware that privacy cannot be guaranteed.

Ethics Pause

What is limited personal use?

Limited personal use includes activity that is infrequent, reasonable, limited, and not related to outside business activities. It must occur outside of working hours (e.g. breaks) and must not interfere with productivity.

Some examples of prohibited personal use includes:

- Accessing inappropriate, offensive, harassing or discriminatory content
- Gambling or playing games
- Accessing prohibited social media sites or other prohibited websites
- Using OPG assets or systems for reasons related to outside business activities

All employees must take appropriate steps to:

- Ensure use of email and IT systems in accordance with the Cyber Security Policy, OPG-STD-0177, Acceptable Use Standard for Technology and other applicable standards and procedures (refer to Cyber Security's PowerNet)
- Protect OPG assets, including station, office and IT equipment from fraud, theft, damage, destruction and misuse (e.g. by vandalism or neglect), and use them only for OPG business
- Protect OPG's intellectual property, including copyrighted information, trademarks and logos, patents and trade secrets against loss or infringement, and use them only for OPG business
- Avoid misuse of other companies' property entrusted to OPG
- Only dispose of items having residual value according to OPG procedures that govern asset disposal
- Avoid use of removable media devices on OPG assets and do not bring electronic devices on site that could be used to record, replicate, or retrieve data and/or information, (e.g. AI devices/wearable technology). Acceptable personal devices such as medical devices, cell phones, and some smart watches can be used on site provided their use aligns with the requirements of the Code and OPG-STD-0177, Acceptable Use Standard for Technology

OPG does not tolerate fraud, theft, forgery, deceit and other dishonest behaviours.

9.1 Fraud & Theft

OPG has a zero-tolerance policy for fraud and theft. Fraud and theft are serious misconduct that can have a significant impact on OPG business including operational disruptions and reputational damage.

Employees found to have engaged in fraud or theft may be subject to discipline up to and including termination for cause in accordance with the *Employment Standards Act, 2000*.

There are many different types of fraud and theft that can occur including but not limited to:

- Health and Dental Benefits Fraud: An employee or dependent provides false or misleading information to an insurance provider with the intention of obtaining financial gain. For further details, refer to section 9.1.1 Benefits Fraud and Misuse.
- Sick-Time or Leave of Absence Abuse: An employee provides inaccurate information regarding their reason for taking sick leave and/or participates in activities inconsistent with the reported restrictions and/or limitations of their illness (e.g. calling in sick or requesting leave without legitimate medical justification).
- Time Theft: An employee fails to perform assigned job duties or participates in activities unrelated to their OPG position during scheduled working hours (e.g., submitting inaccurate or inflated time reports).
- Financial Fraud: An employee attempts to defraud OPG or its employees through fraudulent invoicing or payment activities. For additional details, refer to section 12.0 Accounting, Finance and Business Reporting.
- Expense Fraud: An employee submits reimbursement requests for expenses that are intentionally misrepresented as business-related, but are actually personal in nature (e.g. using an AMEX card or renting a vehicle for personal use while claiming these as business expenses).
- Asset Misuse: An employee takes OPG assets for personal purposes (e.g. taking tools home for personal tasks when these tools are owned by OPG).

Ethics Pause

What is fraud?

Fraud occurs when you intentionally provide misleading information for the purpose of obtaining a benefit or financial gain.

9.1.1 Benefits Fraud and Misuse

Benefits fraud and misuse occur when false or misleading information is submitted to insurance providers. This includes knowingly or negligently submitting a claim or permitting a service provider to submit a claim on an employee's behalf for items or services that are not covered under the applicable benefit plan. Employees have an obligation to review plan provisions before purchasing items and services to determine the level of coverage, if any. Employees are required to review all claims prior to submission.

Ethics Pause

What are some examples of benefits fraud and misuse?

Benefits fraud and misuse can take many forms, including:

- Employees knowingly or negligently submitting claims for services and/or products that were not provided or not covered by the plan (e.g. claims for treatments that the employee did not receive)
- Collusion by employees and providers to provide referral kickbacks or false receipts
- Misrepresenting dates, type or amount of service provided on receipts (e.g. designer sunglasses without prescription lenses, running shoes instead of orthotics, teeth whitening instead of dental cleaning)
- Employees transferring billing to other dependents under the plan to avoid coverage maximums (e.g. claims under a dependent's coverage to avoid coverage maximums)

Employees are accountable for any claims made to benefits insurance providers, even if a dependent submits a fraudulent claim under the employee's benefits plan.

10.0 Business Expenses

10.0 Business Expenses

Employees are expected to demonstrate integrity, prudence, and sound judgment when incurring or approving business expenses. All expenses must be reasonable and necessary, with clear business or commercial justification.

Employees who submit expenses for reimbursement, as well as managers who approve these expenses, are required to comply with OPG-STD-0075, Business Travel and Expenses Standard.

The corporate business expense card (AMEX) is to be used in accordance with OPG-INS-08700-0001 Corporate Business Expense Card Instructions for business purposes only.

11.0 Anti-Bribery and Corruption

11.0 Anti-Bribery and Corruption

Never offer, ask for, give or receive any form of bribe, kickback or any other type of improper payment, or attempt to gain influence or competitive advantage through improper means.

Ethics Pause

What is bribery?

Bribery is directly or indirectly giving or offering to give to an official a loan, reward, advantage or benefit of any kind as consideration for cooperation, assistance, exercise of influence, or an act or omission in connection with the transaction of business or any matter of business relating to the government or a claim against or any benefit that the government is authorized to bestow.

Employees must ensure that the requirements of all applicable anti-corruption laws are met, including, but not limited to the *Corruption of Foreign Public Officials Act*. Never offer or give facilitation payments, e.g. payments to foreign public officials to expedite or secure the performance of any act of a routine nature that is part of that official's duties or functions.

No payments, gifts or other benefits may be given, directly or indirectly, to public officials, political parties or political candidates for the purpose of influencing government decisions in OPG's favour or securing any other improper advantage.

Ensure that payments made to agents or other third parties are not used, in whole or in part, to influence government decisions or secure any other improper advantage. Do not engage in any form of corruption, extortion and/or embezzlement.

12.0 Accounting, Finance and Business Reporting

12.0 Accounting, Finance and Business Reporting

Aligned with OPG's core business imperatives–Operational Excellence, Project Excellence, Financial Strength, and Social License–all employees are required to:

- Use OPG funds only for lawful and proper purposes in accordance with approved authorities
- Never establish undisclosed funds or accounts
- Handle all cash and bank account transactions in a manner that avoids any question of fraud such as bribery, kickbacks, other illegal or improper payments, or any suspicion of impropriety whatsoever
- Ensure that all OPG documents accurately and clearly represent the relevant facts or true nature of a transaction, including but not limited to time reporting, sales reports, financial reports, and expense reports
- Individuals who are aware of conduct or practices that violate OPG financial accounting and reporting values or who have concerns regarding questionable accounting or auditing matters, are expected to report them to their manager, the Chief Ethics Officer, or VP Risk & Audit, Chief Audit Executive

13.0 Fair Competition

13.0 Fair Competition

All employees are required to follow applicable competition laws, such as the federal *Competition Act, Electricity Act* and *Ontario's Energy Board Act*. Additional information can be found in the Competition Legislation Compliance Guidelines for Preventing Anti-Competitive Behaviour, available from Law and Regulatory Affairs.

14.0 Suppliers

14.0 Suppliers

Employees must treat suppliers respectfully, fairly and in a professional manner. As required, employees must inform suppliers about the existence of the Code and the Supplier Code and provide access to the most recent versions of these documents.

When working with suppliers, remain mindful of the specific obligations and entitlements that are reflected in any contractual agreement between the supplier and OPG. Take reasonable steps to ensure that OPG's entitlements and obligations are properly maintained throughout the contractual relationship with the supplier.

Deal only with suppliers that act with integrity and adhere to high standards of ethical behaviour. Conduct sufficient due diligence and obtain contractual commitments from suppliers. This includes ensuring employees do not breach anti-corruption laws through the direct or indirect provision of payments, gifts or other benefits to public officials, political parties or political candidates for the purpose of influencing any act or decision or securing any other improper advantage. Take appropriate action to address concerns with problem suppliers. If appropriate and subject to contractual obligations, OPG may end its relationship with suppliers if conduct is unsatisfactory.

Avoid actual, perceived and potential conflict of interests in any interaction with vendors and suppliers. If a conflict of interest arises, employees must disclose concerns immediately to their line manager and submit a COI Declaration as appropriate.

Suppliers must comply with the Code and Supplier Code and must not engage in any conduct that would cause OPG or any of its employees to be in breach of any of the obligations set out in the Code.

Ethics Pause

Who can Suppliers contact to report employee conduct that does not adhere to the Code or Supplier Code?

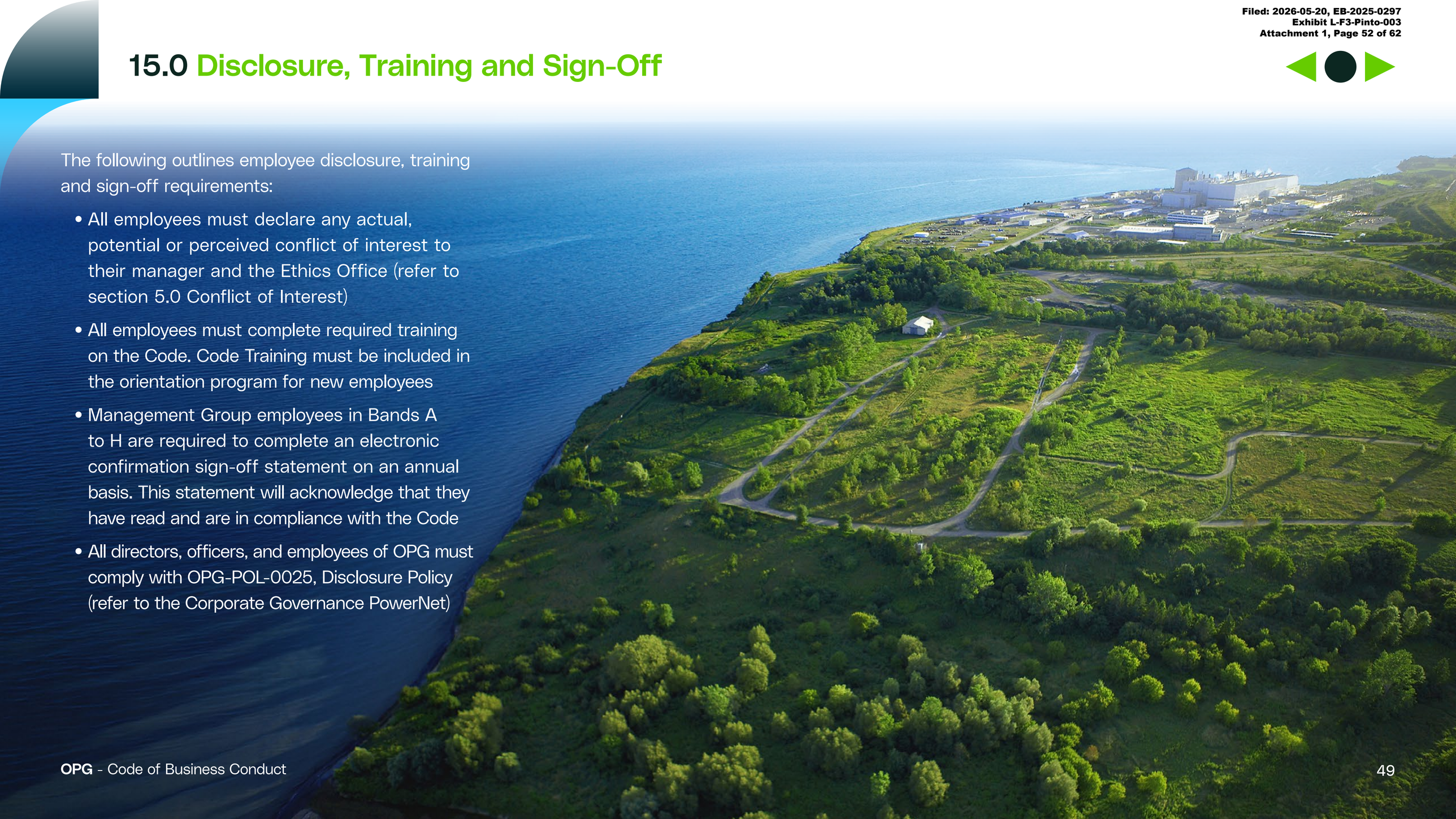
Suppliers can contact the Ethics Office (ethics@opg.com) and/or Security & Emergency Services (fraud, theft or workplace violence concerns) at 905-429-2551 if they have any concerns regarding potentially unethical conduct by OPG employees.

15.0 Disclosure, Training and Sign-Off

15.0 Disclosure, Training and Sign-Off

The following outlines employee disclosure, training and sign-off requirements:

- All employees must declare any actual, potential or perceived conflict of interest to their manager and the Ethics Office (refer to section 5.0 Conflict of Interest)
- All employees must complete required training on the Code. Code Training must be included in the orientation program for new employees
- Management Group employees in Bands A to H are required to complete an electronic confirmation sign-off statement on an annual basis. This statement will acknowledge that they have read and are in compliance with the Code
- All directors, officers, and employees of OPG must comply with OPG-POL-0025, Disclosure Policy (refer to the Corporate Governance PowerNet)



16.0 Confidentiality

16.0 Confidentiality

OPG will not disclose the identity of individuals who report known and suspected violations of the Code, including information that could identify employees involved, except as necessary to investigate, resolve, or otherwise address the issue. OPG will disclose information if it has a legal obligation to do so.

Those involved in a known and suspected Code violation, or are involved in or aware of a Code investigation, are required to keep all aspects confidential. Anyone who knowingly breaches confidentiality may be subject to disciplinary action up to and including termination for cause in accordance with the *Employment Standards Act, 2000*.

17.0 Consequences

17.0 Consequences

Those who do not comply with the Code including OPG's values and behaviours may be subject to disciplinary actions up to and including termination for cause in accordance with the *Employment Standards Act, 2000*. OPG reserves the right to discipline anyone who knowingly makes a false statement or provides false information. Further, employees may be subject to disciplinary action for failure to report information about known and suspected violations of the Code.

18.0 Accountabilities

18.0 Accountabilities

All employees at every level of the organization have accountabilities under the Code and OPG-POL-0013, Code of Business Conduct Policy (the “Code Policy”).

18.1 Employee Accountabilities

Employees at all levels in the organization are accountable for:

- Understanding their responsibilities under and complying with the Code
- Completing any required training on the Code
- Carrying out their responsibilities ethically and with integrity, and treating those with whom they do business with dignity and respect
- Seeking advice from their manager, HR contact or the Ethics Office if uncertain about the right ethical decision
- Declaring all actual, perceived or potential conflicts of interest, in writing, to their manager as soon as they are known
- Reporting conduct that violates or appears to violate the Code or Supplier Code to their manager, HR contact or the Ethics Office
- Maintaining confidentiality when engaged in a Code violation process, procedure or investigation

18.2 Manager Accountabilities

Managers at all levels in the organization are accountable for:

- Providing their employees with the necessary tools to understand and comply with their responsibilities under the Code
- Ensuring their employees complete any required training on the Code
- Ensuring their Bands A to H staff complete the required electronic confirmation sign-off statement on an annual basis
- Reporting known and suspected violations of the Code and the Supplier Code to their HR contact or the Ethics Office as soon as they are known
- Taking appropriate management action to address known and suspected violations of the Code in partnership with their HR contact. For clarity, managers must not permit or condone behaviours that they know or reasonably believe to be violations of the Code
- Ensuring their employees complete a COI Declaration for any actual, perceived or potential conflicts of interest, and addressing declarations from employees and suppliers in consultation with their manager, HR contact and the Ethics Office
- Being concerned, knowledgeable and reliable counsellors to whom employees can comfortably go for advice
- Maintaining confidentiality in complaint processes to the extent permitted by law and the company's ability to address the concern
- Creating a work environment based on respect that encourages ethical behaviour

18.3 Enterprise Leadership Team Accountabilities

Each Enterprise Leadership Team (ELT) member is accountable for:

- Monitoring compliance with the Code and Supplier Code within their organizations; and
- Submitting an annual due diligence report to the Chief Ethics Officer that confirms that their employees have completed all required training on the Code, Bands A to H staff have completed the annual electronic confirmation sign-off statement and all known and suspected violations of the Code have been reported to the Chief Ethics Officer

18.4 Vice President Risk & Audit, Chief Audit Executive Accountabilities

The Vice President Risk & Audit, Chief Audit Executive is accountable for:

- Providing independent assurance to the Board of Directors that the controls related to the Code and the Supplier Code are operating effectively

18.5 Chief Ethics Officer Accountabilities

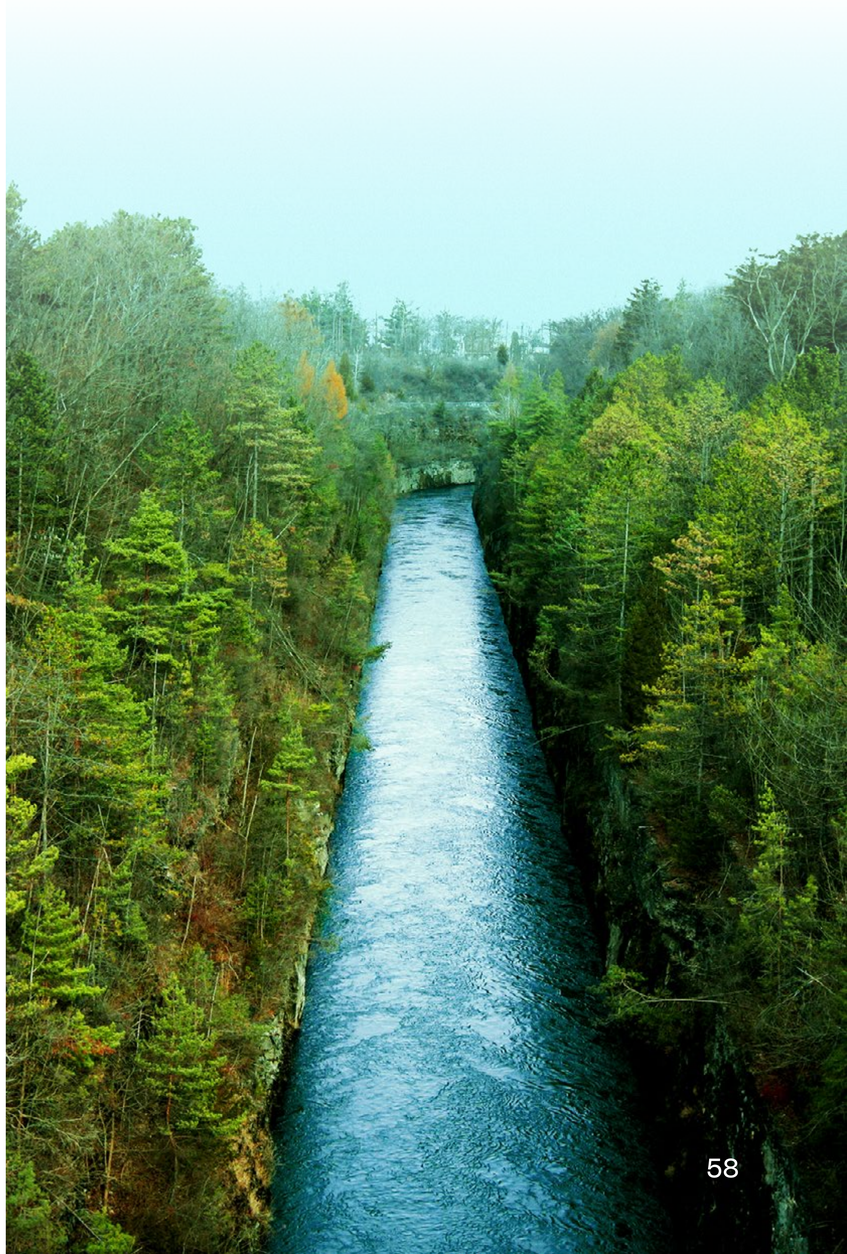
The Chief Ethics Officer is accountable, on behalf of the President and CEO, for:

- Ensuring that the Code Policy is implemented within OPG
- Preparing the Code and Supplier Code for approval by the Board of Directors
- Reviewing the Code and Supplier Code on a regular basis to ensure they continue to meet all relevant OPG standards and external business standards
- Tracking and reporting all known and suspected violations of the Code and the Supplier Code to the President and CEO, and OPG Board of Directors on an annual basis
- Providing advice and guidance with respect to the provisions of the Code and Supplier Code
- Ensuring that appropriate management action is taken to investigate and address known and suspected violations of the Code and the Supplier Code

The day-to-day monitoring of the Code is delegated to the Ethics Office. To contact the Chief Ethics Officer, email ethics@opg.com.

18.6 OPG Board of Directors

The OPG Board of Directors' mandate explicitly acknowledges its role in creating a culture of integrity throughout the organization. The Board has statutory obligations regarding conflicts of interest as well as a separate procedure for disclosure. The Board is required to follow provincial legislative requirements and guidance regarding specific types of conflicts and disclosure in their role as directors in the OPG Board of Directors' Conflict of Interest Policy and the Code Policy.



ONTARIO POWER GENERATION

OPG Proprietary		
Document Number: OPG-POL-0013		Revision R015
Usage Classification: Information	Sheet Number: N/A	Page: 1 of 3

Title: CODE OF BUSINESS CONDUCT POLICY

Policy Statements:

Ontario Power Generation (OPG) is committed to being an ethical company. It shall conduct its relationships with its employees, suppliers, customers, subsidiaries, stakeholders and the public in accordance with the values of safety, integrity, excellence, inclusion and innovation as outlined in the OPG Code of Business Conduct ("Code") and Supplier Code of Conduct ("Supplier Code").

Requirements:

OPG shall establish a Code and a Supplier Code that foster ethical behaviour in its business activities and, at a minimum, meet all external legal and regulatory requirements relating to employee and supplier conduct.

OPG shall not tolerate:

- Discrimination or harassment related to grounds protected by applicable human rights legislation
- Personal harassment including behaviour that demeans, threatens or humiliates a person or group of people
- Comments or conduct that demeans, threatens, ridicules or disparages a person or group of employees or people, even if they are not directed at a particular individual
- Comments, jokes or conduct that is sexual in nature
- Abusive, threatening, intimidating or violent acts directed at anyone employees come in contact with in carrying out their responsibilities
- Retaliation or reprisal, including threats against an employee for reporting in good faith or participation in a complaint process

OPG shall communicate to its employees, directors, officers, agents, representatives, consultants, business partners, contractors, subsidiaries and suppliers about their obligations under the Code and Supplier Code.

OPG shall monitor and enforce compliance with the Code and Supplier Code. OPG shall establish mechanisms where employees and suppliers can raise concerns and ensure that known and suspected violations of the Code and Supplier Code are appropriately investigated and addressed.

Accountabilities:

The Chief Ethics Officer is accountable, on behalf of the President & Chief Executive Officer for:

- Ensuring this policy is effectively implemented within OPG
- Preparing the Code and Supplier Code for approval by the Board of Directors Reviewing the Code and Supplier Code on a regular basis to ensure they continue to meet all relevant OPG standards and external business standards

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- Tracking and reporting all known and suspected violations of the Code and the Supplier Code to the President and CEO, and OPG Board of Directors on an annual basis
- Providing advice and guidance with respect to the provisions of the Code and Supplier Code
- Ensuring that appropriate management action is taken to investigate and address known and suspected violations of the Code and the Supplier Code

Each Enterprise Leadership Team (ELT) member is accountable for:

- Monitoring compliance with the Code and Supplier Code within their organizations
- Submitting an annual due diligence report to the Chief Ethics Officer that confirms that their employees have completed all required training on the Code, Bands A to H staff have completed the annual electronic confirmation sign-off statement and all known and suspected violations of the Code have been reported to the Chief Ethics Officer

The Vice President Risk & Audit, Chief Audit Executive is accountable for:

- Providing independent assurance to the Board of Directors that the controls related to the Code and Supplier Code are operating effectively

Managers at all levels in the organization are accountable for:

- Providing their employees with the necessary tools to understand and comply with their responsibilities under the Code
- Ensuring their employees complete any required training on the Code
- Ensuring their Bands A to H staff complete the required confirmation sign-off on an annual basis
- Reporting known and suspected violations of the Code and Supplier Code to their HR contact or the Ethics Office as soon as they are known
- Taking appropriate management action to address known and suspected violations of the Code in partnership with their HR contact. For clarity, managers must not permit or condone behaviours that they know or reasonably believe to be violations of the Code
- Ensuring their employees complete a written declaration of any actual, perceived or potential conflict of interest and addressing declarations from employees and suppliers in consultation with their manager, HR contact and the Ethics Office
- Being concerned, knowledgeable and reliable counsellors to whom employees can comfortably go for advice
- Maintaining confidentiality in complaint processes to the extent permitted by law and the company’s ability to address the concern
- Creating a work environment based on respect that encourages ethical behaviour

Employees at all levels in the organization are accountable for:

- Understanding Code responsibilities and complying with the Code
- Completing any required training on the Code
- Carrying out their responsibilities ethically and with integrity, and treating those with whom they do business with dignity and respect
- Seeking advice from their manager, HR contact or the Ethics Office if uncertain about the right ethical decision
- Declaring all actual, perceived or potential conflicts of interest, in writing, to their manager as soon as they are known
- Reporting conduct that violates or appears to violate the Code or Supplier Code to their manager, HR contact or the Ethics Office
- Maintaining confidentiality when engaged in a Code violation process, procedure or investigation

Attachments: Code of Business Conduct

Supplier Code of Conduct

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

Effective Date: May 11, 2026

Document requires CNSC Notification ☐

Exhibit L-F3-Pinto-003, Attachment 3

OPG Subsidiary and Joint Venture Governance

This Attachment was filed as confidential information in its entirety.

Pinto Interrogatory #004

Interrogatory

Reference:
Code of Business Conduct Controls and Senior-Level Oversight
External Business Relationships and Hiring-Related Governance

Preamble:

Purpose and Scope

This interrogatory seeks information necessary to assess whether OPG maintained and applied appropriate Code of Business Conduct ("CoBC") controls, conflict-management processes, and senior-level oversight mechanisms in connection with external business relationships involving other utilities and related hiring or engagement decisions, during a defined, event-specific period.

This interrogatory relates to Issue 37 (Internal Controls and Oversight) and Issues 38-40 (Risk Management, Compliance, and Ethical Conduct) of the approved Issues List.

The Intervenor will execute the OEB Declaration and Undertaking with respect to any confidential material.

Definitions

"External Utility" means any Canadian or provincial-scale electricity or energy utility operating outside Ontario and not part of OPG.

"Trigger Period" means the period beginning 30 days before and ending 6 months after any senior-level direction, request, or approval relating to the hiring, engagement, or placement of an individual associated with an External Utility.

"CoBC Controls" include disclosure requirements, conflict assessments, recusals, ethics reviews, approvals, or independent oversight required under OPG's Code of Business Conduct or related policies.

Question(s):

A. Code of Business Conduct Framework
Produce the Code of Business Conduct and any related policies, procedures, or guidance in effect during the Trigger Period governing:

- Conflicts of interest;

- External business relationships; and
- Use of senior executive authority in hiring or engagement decisions.
- Identify the roles or functions responsible during the Trigger Period for:
- Conducting conflict assessments; and
- Determining mitigation or recusal requirements.

B. Application of CoBC Controls During the Trigger Period

For the Trigger Period, identify whether any CoBC Controls were triggered in connection with:

- Business discussions or initiatives involving an External Utility; and
- Hiring, engagement, or placement decisions linked to such relationships.

For each instance, produce records sufficient to show:

- Whether a disclosure was made;
- Whether an assessment was conducted; and
- What mitigation measures, if any, were applied.

C. Hiring and Engagement Governance

Produce policies or guidance in effect during the Trigger Period governing:

- Creation of new positions or roles;
- Use of non-standard hiring pathways; and
- Approval requirements where no pre-approved position or headcount existed.

Identify whether any exceptions or non-standard practices were approved during the Trigger Period in connection with an External Utility relationship, and if so:

- The approving authority; and
- The documented rationale.

D. Oversight, Ethics Review, and Escalation

Identify whether any ethics review, screening, or determination was initiated or considered during the Trigger Period in relation to:

- External Utility relationships; or
- Related hiring or engagement decisions.

If so, produce records sufficient to show:

- The timing and scope of the review;
- Whether the review was internal or independent; and
- The outcome or disposition at a high level.

E. Restrictions on Future Employment, Re-engagement, and Access to Work

Produce policies or guidance in effect during the 2020-2025 Period governing restrictions on future employment, re-engagement, or access to work following

investigations or terminations, including any appeal or review mechanisms applicable to such restrictions.

Privilege and Non-Existence
If any responsive record is withheld on the basis of privilege, produce a privilege log identifying the document, date, author, recipient, and the basis of the claim, together with a non-confidential description of its subject matter.

If any requested record does not exist, state this explicitly.

Response

In accordance with the Motions Resolutions letter filed on May 4, 2026, the Applicants have revised this interrogatory response.

This interrogatory seeks extensive details and documentation pertaining to external business relationships involving other utilities and related hiring or engagement decisions. The request is overly broad, lacks clarity and is unreasonably onerous to respond to. The information sought is not material, lacks relevance, and/or offers minimal, if any, probative value in deciding the OEB-approved issues in this proceeding.

Notwithstanding the foregoing, in the letter filed by the Applicants on May 4, 2026 in respect of Mr. Pinto's motions and certain other interrogatory responses (in which he narrowed his requests), OPG proposed to provide or refer to certain documents or information. In accordance with OEB Decision and Order on Motions and Intervenor Evidence EB-2025-0297 dated May 15, 2026 that directed OPG to provide the information proposed in its May 4, 2026 letter, OPG has revised this interrogatory response to provide or refer to the following documents or information:

- OPG's Code of Business Conduct Policy, which describes accountability and responsibility for declaration of conflicts of interest at OPG, and confirmation that OPG wholly owned subsidiaries are also required to comply with this policy (refer to Ex. L-F3-Pinto-003);
- the General Services Agreement between OPG and Laurentis which governs OPG provision to Laurentis Energy Partners ("Laurentis") of personnel and certain equipment or materials, access to OPG property and assets, and professional and corporate support services, as well as Laurentis' provision of services to OPG (refer to Ex. L-F3-SEC-179, Attachment 2); and
- information listing any internal audits conducted at OPG (refer to Ex. A1-4-1 Attachment 4).

OPG declines to provide further requested information in this interrogatory for the reasons noted above.

Pinto Interrogatory #005

Interrogatory

Reference:
Subsidiary Contracting Governance, Cost Attribution, and Value-for-Money

Preamble:

Purpose and Scope

This interrogatory seeks information necessary to assess whether Ontario Power Generation Inc. ("OPG") maintains adequate governance, internal controls, and value-for-money discipline over the engagement and use of independent contractors by its subsidiaries, including Laurentis Energy Partners as a representative subsidiary, particularly where senior executives exercise influence across entities or where contractor services benefit more than one entity, during the period January 1, 2020 to December 31, 2025.

This interrogatory relates to Issues 23-26 (Governance, Planning, and Cost Control) and Issue 37 (Internal Controls and Oversight) of the approved Issues List.

The Intervenor will execute the OEB Declaration and Undertaking with respect to any confidential material.

Definitions

"Subsidiary" means any entity controlled by OPG, including Laurentis Energy Partners.

"Independent Contractor" means any person or entity through a professional services, staffing, or resourcing arrangement rater than as an employee.

"Cross-Entity Oversight" means circumstances where a senior executive exercises operational or financial oversight across OPG and one or more Subsidiaries.

Question(s):

A. Subsidiary Contractor Governance Framework
Produce policies, procedures, or guidance in effect during 2020-2025 governing:

- Engagement of Independent Contractors by Subsidiaries;
- Sole-source versus competitive selection
- Approval of contractor rates, scope, and duration; and

- Required value-for-money or alternatives assessments.

Identify how OPG ensures that contractor engagements by Subsidiaries are independently justified and subject to appropriate oversight.

B. Exercise Oversight and Conflict-Mitigation Controls

Produce policies or guidance governing Cross-Entity Oversight, including controls intended to mitigate conflicts of interest where senior executives influence:

- Demand for services at OPG; and
- Engagement or deployment of contractors at a Subsidiary.

Identify what controls were required or applied during 2020-2025 to prevent preferential sourcing or deployment of Subsidiary-engaged contractors due to cross-entity executive influence.

C. Cross-Entity Use of Subsidiary Contractors

Identify any instances during 2020-2025 where Independent Contractors engaged by a Subsidiary performed work that benefited:

- OPG; or
- Another Subsidiary.

For each instance, produce records sufficient to show:

- The nature of the work performed;
- Which entity engaged the contractor;
- Which entity benefited; and
- How the arrangement was approved.

D. Cost Attribution and Transparency

Produce policies or guidance governing:

- Time recording for contractors performing work across entities; and
- Cost attribution and charge-back between OPG and Subsidiaries.
- For the instances identified in Section C, produce records sufficient to show whether contractor time and costs were fully attributed to the benefiting entity.

If no format cost-tracking or attribution occurred, state this explicitly.

E. Value-for-Money and Alternatives Assessment

Identify whether value-for-money or alternatives assessments were undertaken before using Subsidiary-engaged contractors to support work benefiting OPG or another entity.

If no such assessments were undertaken, state this explicitly.

Privilege and Non-Existence
If any responsive record is withheld on the basis of privilege, produce a privilege log identifying the document, date, author, recipient, and the basis of the claim, together with a non-confidential description of its subject matter.

If any requested record does not exist, state this explicitly.

Response

In accordance with the Applicants' letter filed on May 4, 2026 and the OEB's Motions decision dated May 15, 2026, OPG has revised this interrogatory response.

This interrogatory seeks extensive details and documentation pertaining to the use of contractors by unregulated affiliates, which are outside the scope of, and not relevant to, this proceeding.

Notwithstanding the foregoing, in the letter filed by the Applicants on May 4, 2026 in respect of Mr. Pinto's motions and certain other interrogatory responses (in which he narrowed his requests), OPG proposed to provide or refer to certain documents or information. In accordance with the OEB Decision and Order on Motions and Intervenor Evidence EB-2025-0297 dated May 15, 2026 that directed OPG to provide the information it proposed in its May 4, 2026 letter (and otherwise denied Mr. Pinto's motions seeking other information), OPG has revised this interrogatory response to provide or refer to the following information or documents:

- an explanation of how OPG's cost allocation methodology ensures appropriate attribution of applicable costs to unregulated affiliates (refer to Ex. L-F3-Pinto-003);
- the General Services Agreement ("GSA") between OPG and Laurentis which governs OPG provision to Laurentis Energy Partners ("Laurentis") of personnel and certain equipment or materials, access to OPG property and assets, and professional and corporate support services, as well as Laurentis' provision of services to OPG (refer to Ex. L-F3-SEC-179, Attachment 2); and
- a summary description of OPG's use of contractor services from Laurentis, including an indication of the associated quantum of such services (see below).

<u>OPG's Use of Contractor Services from Laurentis</u>
OPG may engage contract personnel from Laurentis for defined scopes of work based on business need. During the period of January 1, 2023-December 31, 2025, there was a limited number of such contractor personnel engaged by OPG for work benefiting the regulated nuclear operations. These personnel provided specialized nuclear licensing, regulatory compliance support, engineering support and other services. The aggregate annual cost of these services as procured under the GSA

between OPG and Laurentis averaged $1.5 million over the period. For the 2027-2031 IR term, the average annual dollar value of such budgeted services that may form part of OPG's proposed 2027-2031 revenue requirements is less than $0.2 million. These budgeted services are in the areas of nuclear licensing and regulatory compliance support. OPG classifies the cost of such services as purchased services.

Pinto Interrogatory #006

Interrogatory

Reference:
HR and Labour Relations Governance, Termination Practices, and Leadership Oversight

Preamble:

Purpose and Scope

This interrogatory seeks information necessary to assess whether OPG and its Subsidiaries maintain adequate human resources and labour-relations governance, including leadership selection, evaluation, and termination controls, consistent with public-sector accountability and transparency expectations, during the period January 1, 2020 to December 31, 2025.

This interrogatory relates to Issues 23-26 (Governance, Planning, and Cost Control) and Issue 37 (Internal Controls and Oversight) of the approved Issues List.

The Intervenor will execute the OEB Declaration and Undertaking with respect to any confidential material.

Definitions

"Subsidiary" means any entity controlled by OPG, including Laurentis Energy Partners.

"Secondee means an OPG employee assigned to work at a Subsidiary.

"Senior Role" means Director, Vice-President, or equivalent.

"Termination" means separation from service, whether with or without cause, including the cessation of a contract.

Question(s):

A. Leadership Selection and Competency Framework
Produce policies, procedures, or guidance in effect during 2020-2025 governing:

- Selection, appointment, and evaluation of individuals into Senior Roles;
- Required competency, merit, or qualification frameworks; and

- Use of non-standard pathways (e.g., contractors, retirees, or secondees) for Senior Roles.

Identify any approved exceptions to standard selection or positing requirements during 2020-2025 and, for each:

- Describe the circumstances;
- Identify the approving authority; and
- Indicate how the exception was documented.

Identify Senior Role appointments during 2020-2025 where the incumbent had previously been a contractor, retiree, or secondee, and produce records sufficient to show:

- The criteria used to assess suitability;
- Any post-appointment evaluation conducted; and
- The circumstances of departure, if applicable.

B. Termination and Separation Governance

Produce policies or guidance in effect during 2020-2025 governing terminations and separations, including:

- With-cause versus without-cause determinations;
- Required approvals and due-process steps; and
- Allocation of termination costs between OPG and Subsidiaries.

Produce, in anonymized form where appropriate:

- A summary of termination events for Senior Roles during 2020-2025, including reason codes and approval levels; and
- Any internal reviews or analyses addressing elevated termination or turnover rates at a Subsidiary.

C. Oversight, Transparency, and Access Controls

Produce policies or guidance governing access to Senior Roles, including:

- Posting and competition requirements;
- Transparency of opportunities; and
- Interaction between temporary or contract pathways and permanent appointments.

Identify any instances during 2020-2025 where offers or appointments to Senior Roles were rescinded or materially altered, and produce records sufficient to show the rationale and approvals.

D. Public-Interest and Organizational-Stability Oversight

Produce any assessments, audits, or reviews conducted during 2020-2025 evaluating:

- Leadership stability and turnover risk at Subsidiaries; and

- Implications for workforce continuity, labour relations, or growth readiness.

Identify any parent-level interventions or escalations undertaken in response to leadership or HR/LR risk at a Subsidiary.

Privilege and Non-Existence
If any responsive record is withheld on the basis of privilege, produce a privilege log identifying the document, date, author, recipient, and the basis of the claim, together with a non-confidential description of its subject matter.

If any requested record does not exist, state this explicitly.

Response

In accordance with the Applicants' letter filed on May 42026 and the OEB Motions decision dated May 15, 2026, OPG has revised this interrogatory response.

This interrogatory seeks extensive details and documentation pertaining to OPG's unregulated affiliates' human resources and labour relations practices. The request is overly broad, lacks clarity and is unreasonably onerous to respond to. The information sought is not material, lacks relevance, and/or offers minimal, if any, probative value in deciding the OEB-approved issues in this proceeding.

Notwithstanding the foregoing, in the letter filed by the Applicants on May 4, 2026 in respect of Mr. Pinto's motions and certain other interrogatory responses (in which he narrowed his requests), OPG proposed to provide or refer to certain additional documents or information. In accordance with OEB Decision and Order on Motions and Intervenor Evidence EB-2025-0297 dated May 15, 2026, that directed OPG to provide the information proposed in its May 4, 2026 letter (and otherwise denied Mr. Pinto's motions seeking other information), OPG has revised this interrogatory response to provide or refer to the following documents or information:

- OPG's Code of Business Conduct Policy, which describes accountability and responsibility for declaration of conflicts of interest at OPG, and confirmation that OPG wholly owned subsidiaries are also required to comply with this policy (refer to Ex. L-F3-Pinto-003); and
- information listing any internal audits conducted at OPG (refer to Ex. A1-4-1, Attachment 4).

SEC Interrogatory #172

Interrogatory

Reference:
F3-1-1, p. 6-7

Preamble:

The evidence states "[s]ince 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."

Question(s):

For each of the implemented initiatives, please quantify the savings. In doing so, please provide the basis of the calculation including all assumptions.

Response

In this response, OPG identifies actions that Support Services have undertaken since EB-2020-0290 that have allowed the company to partly mitigate the growing demand for these services and increasing complexity of the context in which the company is operating.

As described in Ex. F3-1-1, pp. 4-5, OPG has worked to mitigate cost impacts and pressures associated with increased demand for Support Services and the complexity of such work since EB-2020-0290. Focus areas over the period included increased hiring pace and volume, intensified labour relations efforts and negotiations, increased supply chain pressures, ramping up procurement to secure contracts for major investments and ensuring continued access to cost-effective financing. OPG's focus over the 2027-2031 IR term will be on ensuring that operational, project, technology, workforce, and financial resources are sufficient to deliver planned projects and to reliably and efficiently operate the new and refurbished facilities.

Additionally, rapid advancements in cyber security threats and digital innovation required greater focus on the areas in OPG's digital strategy and IT operations. Despite this challenging operating context, OPG's IT function benchmarks in the second quartile, compared to the peer group, in the corporate cost study undertaken by The Hackett Group (refer to Ex. F3-1-1, Attachment 2, p.12). As noted in Ex. F3-1-1, p. 3, lines 11-13, "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" which is generally in line with inflation.

OPG is unable to attribute discrete cost savings to individual initiatives, as overall performance reflects the interacting effects of multiple initiatives, external conditions, and other operational factors that together drive the aggregate outcome.

Digital Strategy & IT Services

As described in Ex. D3-1-1 and in Ex. L-D3-SEC-122, Attachment 1, OPG's Digital Strategy is a foundational enabler to ongoing operational reliability and security, and through the IR term, various investments are necessary to address system obsolescence and business requirements. As new technology is adopted, the use of various technologies has provided varied and overlapping benefits such as through the use of Artificial Intelligence ("AI") and improved data analytics.

OPG has made further advancements in the utilization of technology to support operational work. Continuing to build on examples such as the use of drones for inspections, AI and data analytics tools are being leveraged to provide automation and performance benefits. In addition to OPG's in-house, secure generative AI (refer to Ex. F3-1-1, p.8), OPG has leveraged AI to develop tools to streamline the movement of spent nuclear fuel, improving workforce safety and operational planning efficiency. Generally, AI tools and its use are expected to continue to allow OPG to automate functions, over time, where it was previously not possible, and to make more informed decisions based on the extensive volumes of data created and gathered in the course of the company's operations.

As described in Ex. F3-1-1, 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 address anticipated cost increases, OPG will continue to adopt and consolidate new technologies when older legacy systems are decommissioned, as well as monitor software licensing contracts and cloud computing consumption by embedding more frequent reviews and controls into the project management process (refer to Ex. F3-1-1, p. 3).

Additionally, OPG has managed labour and contracted resources through a blended service delivery model as discussed in Ex. F3-1-1. The repatriation of the New Horizon System Solutions' ("NHSS") workforce, which brought certain IT services back in-house, considered the increasing contract costs while absorbing increasing demand for IT support, including an increase of about 30% in Help Desk tickets between 2022

and 2024 (refer to Ex. L-F3-SEC-175). OPG also experienced about 9% lower IT Support Services costs in 2023, the first full year following NHSS repatriation (refer to Ex. F3-1-1, Table 4). Notably, this strategy gave OPG greater control over cyber security investments and resourcing, which were becoming increasingly complex and costly since 2020.

Workplace Optimization

OPG's Corporate Headquarters project was completed on time and on budget in 2025, bringing together non-station support staff from across the Greater Toronto Area (refer to Ex. L-D3-SUP-009 and Ex. L-D3-SEC-123). Along with other workplace optimizations and transformations across various office buildings, the optimized design and layouts have enabled increased occupancy relative to prior workspace designs, with improved flexibility and opportunities for collaboration.

Despite the increasing number of staff requiring office space, the Corporate Headquarters project and workplace optimization and transformation projects will have resulted in the off-lease of five office buildings and spaces, contributing to an approximately 29% reduction in the square foot per FTE of OPG office space. This enables OPG to avoid net-new leases where possible (refer to Ex. D3-1-1, pp. 14).

Procurement & Vendor Programs

OPG has implemented vendor programs and procurement initiatives and practices to improve supplier performance, streamline nuclear supplier qualifications, and advance category management and strategic sourcing. These initiatives have allowed OPG to better adapt to changing market conditions and evolving business needs while mitigating supply chain risks that have intensified significantly since EB-2020-0290. For example, OPG streamlined the process for qualifying nuclear suppliers in response to the rapid expansion of the nuclear industry supply chain demand and to support the need for nuclear qualified vendors to execute its major nuclear projects such as the PRP and the DNNP. By proactively identifying risks and improving communication with vendors, there has been a 50% reduction in qualification timelines in recent pilot projects. OPG has also made significant advances in category management and strategic sourcing. For example, the Renewable Generation Programmatic Collaboration Agreements (refer to Ex. F3-3-1, p. 6) have contributed to secured capacity in a tight supply chain.

OPG has continued to mitigate inflationary, price and project schedule risk by aligning procurement timing for long-lead and cost-sensitive components to technical and operational needs, making early commitment decisions where appropriate to lock in pricing, secure manufacturing capacity, and/or limit exposure to future cost escalation. From a contracting perspective, inflation risk is managed through a mix of fixed-price, capped-price, and index-based escalation mechanisms tied to relevant indices to

ensure any adjustments reflect actual market movements (refer to Ex. L-D2-PWU-004). Together, these practices provide stronger cost control and improved project certainty by reducing exposure to inflationary pressures and procurement-related schedule risks.

Building the Workforce

Since EB-2020-0290, in order to address a complex labour environment, including the planned closure of Pickering, COVID-19 labour market pressures, the shift to Pickering refurbishment and a complex labour relations environment (refer to Ex. F4-3-1), OPG was able to partly mitigate the higher volume of work effort in recruitment and onboarding by stopping certain work, modernizing processes and, outside of compliance requirements, redistributing effort toward initiatives with the greatest business impact.

The peak in hiring and onboarding that occurred in 2023 and 2024 was an approximately 230% increase in the volume of recruitment and onboarding work since 2019. Actions to address this demand include the centralization of internal recruitment and the standardization of recruitment processes, including the use of automated assessment tools, key performance metrics to identify where processes could be streamlined, and investment in recruitment strategies such as increased outreach activities and expanded early careers programming. This contributed to an increase in qualified candidates, improved job offer acceptance rates and significantly reduced time to fill positions, securing the required workforce for OPG more quickly.

The inflow of new employees and internal movement of existing employees also increased the need for skills and leadership development. In response, OPG introduced a virtual platform allowing self-guided learning. This contributed to an avoidance in the cost of hiring additional leadership training staff, while ensuring efficient skills and leadership development for employees. Refer to Ex. L-F3-Staff-218 for a description of the increasing demand for Human Resources services and factors contributing to Human Resources costs and Ex. L-F3-SUP-013 for recruitment service level metrics from 2019-2024.

Within the Human Resources function, OPG has improved processes to shorten timelines and manage on-going demand for cases in ethics and labour relations functions. OPG implemented case management software, which combined with process improvements, has decreased ethics investigation timelines and contributed to corresponding cost control within the department.

Managing Financing Needs

OPG’s Finance function is focused on ensuring a cost effective and risk managed funding program to meet the Company's increasing borrowing requirements through a combination of robust treasury planning and management processes, maintaining relationships with a syndicate of banks and fixed income investors, and leveraging a strengthened internal treasury expertise. OPG’s debt management function is further discussed in Ex. L-C1-Staff-028, part c). OPG is also focused on implementing available credit support funding sources, as discussed in Ex. L-A2-SEC-024, which contribute to maintaining the Company's current investment grade credit ratings.

SEC Interrogatory #173

Interrogatory

Reference:
F3-1-1, p. 6-7

Question(s):

With respect to The Hackett Group, Benchmarking Study:

a) Please detail all methodological changes between the study filed in this application and that filed in EB-2020-0290.

b) [p.8] For each of the peer group companies, please provide the percentage of their revenue that comes from, a) nuclear generation, b) hydroelectric generation, c) other generation, d) transmission and distribution, and e) other.

Response

This response was prepared by The Hackett Group:

a) Hackett confirms that the methodology in the current study is consistent with the study filed under EB-2020-0290. There are no methodological changes.

b) Hackett's database does not include revenue segmented by nuclear generation, hydroelectric generation, other generation, transmission & distribution, and other. Additionally, the companies in the peer group do not disclose revenue in those segments, so the requested revenue segmentation is not publicly available.

The companies used in the peer group share similar demand drivers, industry complexities, and geographic coverage as OPG. The demand drivers evaluated include revenue, number of operating locations, and employee headcount. The geographic scope was limited to North America to help ensure that peer organizations operate under comparable market conditions and face similar regulatory and competitive challenges. The peer group is comprised of 14 North America–based companies, of which 43% have nuclear power generation assets. The median revenue for the peer group is approximately $7B, generally in line with OPG's annual 2024 revenue of approximately $5.6B.

SEC Interrogatory #174

Interrogatory

Reference:
F3-1-1, Table 1

Question(s):

Please provide the number of FTEs by corporate cost function.

Response

Attachment 1, 2 and 3 reflect the Allocation of Corporate Support & Administrative OM&A FTEs for the Regulated Hydroelectric, OPG Nuclear Facilities, and DNNP Facilities, respectively. For clarity, Ex. F3-1-1 Table 1 includes OPG's unregulated business activities, which is outside the scope of this Application.

Numbers may not add due to rounding.

Attachment #1

Corporate Support & Administrative Groups OM&A FTE's - OPG Regulated Hydroelectric[1]

Line No.	Corporate Costs	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Actual	2026 Budget	2027 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Base OM&A								
1	Corporate & Technology Services	26.2	26.0	37.5	43.4	45.3	44.8	49.6	45.9
2	Real Estate	1.1	2.1	3.3	3.2	4.4	3.1	4.0	3.7
3	Supply Chain	12.0	9.9	9.8	8.9	11.9	18.3	16.6	16.3
4	Finance	37.1	26.8	26.2	26.9	35.4	33.9	38.0	37.0
5	Human Resources	26.7	24.6	29.5	31.2	31.3	26.4	25.6	21.3
6	Corporate Centre	26.5	26.6	25.0	28.4	34.8	24.3	22.9	21.8
7	**Total Base OM&A**	129.5	115.9	131.2	142.1	163.1	150.8	156.8	146.1
8	**Project OM&A**	2.1	1.7	1.8	2.2	3.7	7.9	7.2	7.5
9	**Total OM&A**	131.6	117.6	133.0	144.3	166.8	158.7	164.0	153.6

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.

Numbers may not add due to rounding.

Attachment #2

Corporate Support & Administrative Groups OM&A FTE's - OPG Nuclear Facilities[1]

Line No.	Corporate Costs	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Actual	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	312.4	303.6	397.3	493.9	519.4	441.6	447.6	377.2	372.0	372.2	375.9	399.3
2	Real Estate	206.9	218.7	191.3	200.3	189.8	185.3	198.8	197.1	198.6	201.5	207.8	200.5
3	Supply Chain	228.4	209.6	213.3	234.2	221.1	180.0	172.3	146.2	141.9	140.6	140.3	169.5
4	Finance	117.7	120.6	122.2	134.0	137.1	152.8	155.4	147.5	145.6	147.0	146.8	146.8
5	Human Resources	120.0	109.7	124.5	153.4	148.5	130.0	118.8	93.8	92.6	90.3	86.4	98.9
6	Corporate Centre	79.2	75.9	80.5	78.4	84.0	98.9	91.3	84.8	84.1	85.0	86.9	88.4
7	**Total Base OM&A**	1,064.7	1,038.1	1,129.0	1,294.3	1,299.8	1,188.6	1,184.2	1,046.7	1,034.7	1,036.7	1,044.1	1,103.4
8	**Project OM&A**	19.2	18.5	21.0	24.8	45.5	38.2	27.6	29.9	36.9	35.6	36.9	36.8
9	**Total OM&A**	1,083.9	1,056.6	1,150.0	1,319.2	1,345.3	1,226.9	1,211.8	1,076.6	1,071.7	1,072.3	1,081.0	1,140.2

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.

Numbers may not add due to rounding.

Attachment #3

Corporate Support & Administrative Groups OM&A FTE's - DNNP Facilities

Line No.	Corporate Costs	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	21.4	24.3	26.5	23.0	20.5	17.9
2	Real Estate	7.0	10.1	10.3	10.2	6.8	10.2
3	Supply Chain	2.7	3.9	4.5	4.3	7.5	14.0
4	Finance	14.0	18.3	20.6	19.7	21.7	13.8
5	Human Resources	5.0	5.2	5.7	4.8	4.5	5.1
6	Corporate Centre	6.8	9.4	10.7	10.3	11.7	6.2
7	**Total Base OM&A**	56.9	71.2	78.3	72.4	72.8	67.2
8	**Project OM&A**	2.5	3.2	4.2	4.4	3.9	4.0
9	**Total OM&A**	59.3	74.4	82.5	76.9	76.7	71.2

Notes:

1 In preparing this interogatory response, the Applicants identified that approximately $1M in resources related to DNNP Factilities was inadvertently presented in respect of OPG Nuclear Facilities. This has no impact on the combined nuclear revenue requirements and is proposed to be corrected during the Payment Amounts Order process in this proceeding.

SEC Interrogatory #175

Interrogatory

Reference:
F3-1-1

Question(s):

With respect to Corporate & Technology Services:

a) [p.7] Please provide a copy of the analysis OPG used to determine it was better to repatriate 250 NHSS Staff as opposed to renewing its NHSS IT services agreement.

b) [Table 6] Please provide a breakdown of IT Support Costs.

Response

a) As discussed in Ex. F3-1-1, pp. 7-8, OPG concluded that outsourcing IT services was no longer cost-effective or flexible enough to meet rapidly evolving technology needs, particularly in areas such as AI, data analytics, and cyber security. The NHSS staff repatriation in 2022 contributed to overall improved IT resourcing flexibility and responsiveness to business needs. The financial analysis that was used to inform the decision identifies anticipated savings for each of three scenarios considered, including the preferred alternative (scenario 3). The financial analysis is provided in Attachment 1.

b) Refer to Attachment 2.

Filed: 2026-04-22
EB-2025-0297
Ex. L-F3-SEC-175
Attachment 1

Scenario Comparison (as of September 2021)

Status Quo Scenario: Do Nothing (Base Case) — Base Case

	2022 ($M)	2023 ($M)	2024 ($M)	Total ($M)
New Horizon Base Contract (estimate for 3 years) [1]	61.3	62.6	63.8	187.7
Total cost in Base OM&A	**61.3**	**62.6**	**63.8**	**187.7**

Scenario 1: PWU Repatriation with 3 year contract (2022-2024)

	2022 ($M)	2023 ($M)	2024 ($M)	Total ($M)
New Horizon Base Contract (estimate for 3 years) [1]	61.3	62.6	63.8	187.7
New ITSA contract with NHSS for 3 years	(33.8)	(33.8)	(33.8)	(101.4)
OPG PWU - IT Tech Staff - Base Labour (92 IT Tech @ approx. $139K/year/person)	(13.0)	(13.2)	(13.4)	(39.6)
OPG Management Hire to manage PWU staff (3 Senior Managers @ approx. $250k/year/person)	(0.7)	(0.8)	(0.8)	(2.3)
OPG Section Head Hire to supervise PWU staff (6 Section Heads @ approx. $200K/year/person)	(1.2)	(1.2)	(1.2)	(3.6)
Finance resource and non labour support (1 additional Finance HC to support CIO)	(0.2)	(0.2)	(0.2)	(0.7)
Estimated onboarding costs of NHSS staff (transition services costs from Capgemini and third party support)	(1.0)	-	-	(1.0)
Estimated software license costs for repatriated staff	(0.7)	(0.7)	(0.7)	(2.1)
Incremental savings to Base OM&A	**10.7**	**12.7**	**13.7**	**37.1**

Scenario 2: PWU Repatriation and Society Repatriation Feb 1, 2022 and Feb 1, 2024

	2022 ($M)	2023 ($M)	2024 ($M)	Total ($M)
New Horizon Base Contract (estimate for 3 years) [1]	61.3	62.6	63.8	187.7
New ITSA contract with NHSS (ending Feb. 1, 2024)	(33.8)	(33.8)	(2.8)	(70.4)
OPG PWU - IT Tech Staff - Base Labour (92 IT Tech @ approx. $139K/year/person)	(13.0)	(13.2)	(13.4)	(39.6)
OPG Management Hire to manage PWU staff (3 Senior Managers @ approx. $250k/year/person)	(0.7)	(0.8)	(0.8)	(2.3)
OPG Section Head Hire to supervise PWU staff (6 Section Heads @ approx. $200K/Year/person)	(1.2)	(1.2)	(1.2)	(3.6)
Finance resource and non labour support (1 additional Finance HC to support CIO)	(0.2)	(0.2)	(0.2)	(0.7)
Estimated onboarding costs of NHSS staff (transition services costs from Capgemini and third party support)	(1.0)	-	(0.5)	(1.5)
Society Base Labour (120 HC @ approx. $200k/year/person)	-	-	(24.3)	(24.3)
OPG Management Hire to manage Society IT staff (3 Senior Managers @ approx. $250K/year/person)	-	-	(0.8)	(0.8)
Estimated software license costs for repatriated staff	(0.7)	(0.7)	(0.7)	(2.1)
Early Retirement Allowance (potential negotiated labour costs, if required)	-	-	(5.9)	(5.9)
Incremental savings to Base OM&A	**10.7**	**12.7**	**13.2**	**36.6**

Scenario 3: PWU repatriation on Feb 1, 2022 and Society Early Repatriation Nov 1, 2022 (preferred scenario)

	2022 ($M)	2023 ($M)	2024 ($M)	Total ($M)
New Horizon Base Contract (estimate for 3 years) [1]	61.3	62.6	63.8	187.7
New ITSA contract with NHSS (ending Nov. 1, 2022)	(25.4)	-	-	(25.4)
OPG PWU - IT Tech Staff - Base Labour (92 IT Tech @ approx. $139K/year/person)	(13.0)	(13.2)	(13.4)	(39.6)
OPG Management Hire to manage PWU staff (3 Senior Managers @ approx. $250k/year/person)	(0.7)	(0.8)	(0.8)	(2.3)
OPG Section Head Hire to supervise PWU staff (6 Section Heads @ approx. $200K/Year/person)	(1.2)	(1.2)	(1.2)	(3.6)
Finance resource and non labour support (1 additional Finance HC to support CIO)	(0.2)	(0.2)	(0.2)	(0.7)
Estimated onboarding costs of NHSS staff (transition services costs from Capgemini and third party support)	(1.5)	-	-	(1.5)
Society Base Labour (92 HC for 2022 and 2023), 120 HC for 2024 onwards	(5.9)	(24.0)	(24.3)	(54.1)
OPG Management Hire to manage Society IT staff (3 Senior Managers @ approx. $250K/year/person)	(0.2)	(0.8)	(0.8)	(1.7)
Estimated software license costs for repatriated staff	(0.7)	(0.7)	(0.7)	(2.1)
Early Retirement Allowance (potential negotiated labour costs, if required)	(5.8)	-	-	(5.8)
Penalty (estimated early contract termination cost)	(4.6)	-	-	(4.6)
Incremental savings to Base OM&A	**2.2**	**21.7**	**22.5**	**46.4**

Notes:

1. Base contract cost estimate includes known requirements for enhancements, additional service requirements, application maintenance, and application removal costs. Under the assumption of historical costs plus inflation, scenario 3 is still the preferred option. No base contract costs are estimated after 2024.

Numbers may not add due to rounding.

Allocation of Corporate & Technology Services Base OM&A Costs - OPG Nuclear Facilities- Breakdown of IT Support Costs ($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:**												
4	Labour	18.0	19.9	32.9	57.7	61.0	58.4	58.7	56.5	57.5	60.6	62.0	66.6
5	Non-Regular Labour	0.4	0.6	1.6	1.1	0.7	1.0	0.6	0.3	0.3	0.3	0.3	0.3
6	Overtime	0.2	0.2	1.0	1.5	1.7	0.3	0.3	0.4	0.4	0.4	0.4	0.4
7	Augmented Staff	0.0	0.0	0.0	0.2	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.1
8	Materials	0.1	0.1	0.3	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Other Purchased Services	5.2	7.9	5.9	5.8	7.5	5.2	4.5	4.6	3.9	3.4	3.4	3.3
10	Other	0.9	0.1	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4
11	**Total NHSS and IT Support Costs**	74.3	77.3	72.2	67.0	72.5	65.2	64.4	62.1	62.5	65.1	66.6	71.3
12	**Shared Services**[1]	27.4	27.3	29.0	29.5	30.5	29.9	26.7	22.1	22.5	23.5	24.1	27.6
13	**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 Includes Shared Financial Services (formerly in Finance), HR Service Centre and Payroll Services (both formerly in People & Culture now known as Human Resources), and Business Infrastructure Services (formerly in Real Estate) as described in Ex. F3-1-1

SEC Interrogatory #176

Interrogatory

Reference:
F3-1-3

Question(s):

Please provide a breakdown of forecast/actual costs related to this application regardless of the year they are incurred by category (expert witness/consultants, external legal counsel, intervenor and OEB costs, and other). Please also provide actual costs incurred by category as of the date of the filing of this application, as well as actuals for the EB-2020-0290 application by category.

Response

The breakdown of actual costs by category related to this Application, EB-2025-0297, and EB-2020-0290 are provided in Chart 1 below.

Chart 1
Regulatory Proceeding Costs - Regulatory Affairs Department ($K)

Group	EB-2020-0290 Actual	EB-2025-0297 Actual[1]	EB-2025-0297 Budget
Regulatory Proceeding Costs:			
Expert Witnesses/Consultants	7,526.1	2,983.7	2,361.7
Intervenor Cost Awards	1,060.4	0.0	2,850.0
Other	334.7	275.0	167.7
Total Regulatory Proceeding Costs	8,921.2	3,258.7	5,379.4
External Legal Costs	1,750.8	1,382.1	2,827.5

Regulatory proceeding costs for EB-2025-0297 include certain 2026 Budget and 2027 Plan costs as applicable to this proceeding. In the course of preparing this response, OPG identified that in EB-2020-0290, Ex. F3-1-3, p.7, line 11, 2019 Actual,

[1] Up to and including December 31, 2025

erroneously categorized $75.8k of Expert Witnesses/Consultants costs in Intervenor cost awards. This correction has been reflected in Chart 1 under EB-2020-0290 Actual.

SEC Interrogatory #177

Interrogatory

Reference:
F3-1-1, Table 1-3c

Question(s):

With respect to Corporate Support & Administrative Groups OM&A Costs, is Table 1 (OPG) the costs of OPG regulated facilities or all OPG costs (regulated and unregulated)? If the latter, please explain why the totals in Table 1 (OPG) are not the sum of Tables 2 (Regulated Hydroelectric), Table 3 (OPG Nuclear Facilities) and Table 3c (DNNP Facilities).

Response

Exhibit F3-1-1, Table 1 represents total OPG Corporate Support & Administrative Services OM&A costs (regulated and unregulated) and therefore does not sum to such Table 2 (Regulated Hydroelectric), Table 3 (OPG Nuclear Facilities) and Table 3c (DNNP Facilities), which reflect only the regulated businesses.

SEC Interrogatory #178

Interrogatory

Reference:
F3-1-1
F3-1-2

Question(s):

With respect to support services and asset service fees, OPG has only provided the allocated amounts of the total OPG costs for hydroelectric to 2027.

a. [F3-1-1] Please expand Tables 2, 5, and 7b to include amounts allocated to regulated hydroelectric for each year between 2028 and 2031.

b. [F3-1-2] Please expand Table 1b to include amounts allocated to regulated hydroelectric for each year between 2028 and 2031.

Response

In accordance with the Motions Resolutions letter filed on May 4, 2026, OPG has revised this interrogatory response.

a) and b)

Refer to Attachment 1 and Ex. L-A1-SEC-012, Attachment 1, Tables 7 and 8, for the requested information.

Having provided this information in accordance with the Motions Resolutions letter filed on May 4, 2026, OPG maintains that the information for the outer years of the period (i.e., 2028-2031) is not relevant under the proposed regulated hydroelectric rate-setting methodology (Ex. A1-3-2, Section 2.0). Outside of the C-factor, OPG's proposed hydroelectric rate-setting methodology is based on a detailed review of the 2027 test-year (Ex. A1-3-2, Section 2.2). Beyond the 2027 test year, regulated hydroelectric revenue will be determined formulaically by the proposed annual adjustment mechanism outlined in Ex. A1-3-2, Section 2.3.

Numbers may not add due to rounding.

Table 1

Allocation of Corporate Support Staff Summary - Regular and Non-Regular (FTEs) - Regulated Hydroelectric - 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)
	Hydroelectric OM&A:												
1	**Regular Staff**	121.1	105.0	117.9	130.0	153.1	157.1	155.6	147.4	145.1	140.7	140.8	145.5
	Non-Regular Staff												
2	Temporary	10.5	12.7	15.1	14.2	13.7	12.8	8.4	6.2	5.7	5.4	5.9	6.0
3	**Subtotal Regulated Hydroelectric OM&A**	131.6	117.6	133.0	144.3	166.8	169.9	164.0	153.6	150.8	146.1	146.6	151.5
	Hydroelectric Capital:												
4	**Regular Staff**	6.3	7.6	10.0	10.0	11.5	27.5	29.9	36.4	37.3	37.7	36.9	33.6
	Non-Regular Staff												
5	Temporary	0.1	0.1	0.0	0.9	0.7	0.1	0.0	0.4	0.4	0.4	0.4	0.4
6	**Subtotal Regulated Hydroelectric Capital**	6.4	7.7	10.0	10.9	12.2	27.5	29.9	36.8	37.6	38.1	37.3	33.9
7	**Total Regulated Hydroelectric**	137.9	125.4	143.0	155.1	179.0	197.5	193.9	190.3	188.5	184.2	183.9	185.4

Numbers may not add due to rounding.

Table 2
Comparison of Allocation of Corporate Support & Administrative Costs ($M) 2026-2031
Regulated Hydroelectric

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)
	Base OM&A											
1	Corporate & Technology Services	17.3	0.7	18.0	0.9	18.9	0.6	19.4	1.0	20.4	0.8	21.2
2	Real Estate[1]	0.9	0.2	1.1	0.2	1.3	0.0	1.3	0.0	1.3	0.1	1.4
3	Supply Chain	4.0	0.1	4.1	0.0	4.1	(0.0)	4.1	0.2	4.3	0.3	4.6
4	Finance	9.2	0.1	9.3	(0.2)	9.2	0.1	9.3	(0.1)	9.2	0.7	9.9
5	Human Resources	6.5	(0.6)	5.8	0.1	6.0	0.3	6.3	0.2	6.4	0.6	7.0
6	Corporate Centre	9.9	0.2	10.1	(0.9)	9.2	0.4	9.6	0.7	10.3	0.3	10.6
7	**Total Base OM&A**	47.7	0.7	48.5	0.2	48.6	1.3	50.0	1.9	51.9	2.9	54.7
8	**Lease/Utilities**	4.1	***(1.3)***	2.8	(0.2)	2.6	(0.3)	2.2	(0.0)	2.2	0.1	2.3
9	**Project OM&A**	2.2	***1.9***	4.1	0.0	4.1	(0.5)	3.7	(0.2)	3.5	(0.2)	3.3
10	**Total OM&A**	54.0	1.3	55.3	(0.0)	55.3	0.5	55.8	1.7	57.6	2.7	60.3

Line No.	Business Unit	2022-2026 Budget & Actuals	(c)-(a) Change	2027-2031 Plan
		(a)	(b)	(c)
11	**Project OM&A**	11.1	***7.5***	18.6

Notes:
1 Excludes amounts captured in the Asset Service Fee (Ex. F3-2-1).

SEC Interrogatory #179

Interrogatory

Reference:
F3-1-4

Question(s):

Please provide a copy of all shared services or similar agreements between OPG's affiliates and OPG.

Response

The requested OPG service agreements with Atura Power, Laurentis Energy Partners (confidential), PowerOn Energy Solutions (confidential), and Origin Nuclear are provided in Attachments 1, 2, 3, and 4, respectively. Refer to Ex. L-A1-CCC-010 for such agreements with DNNP LP.

SECOND AMENDED AND RESTATED GENERAL SERVICES AGREEMENT

Among

NV LP

and

PORTLANDS ENERGY CENTRE L.P.

and

BRIGHTON BEACH POWER L.P.

and

ONTARIO POWER GENERATION INC.

Effective Date: April 29, 2020
Dated as of May 11, 2021

THIS SECOND AMENDED AND RESTATED GENERAL SERVICES AGREEMENT (this "**Agreement**") is entered into as of the 11th day of May, 2021, with an effective date of April 29, 2020

AMONG:

NV LP, a limited partnership formed under
the laws of the Province of Ontario **("NV LP")**

and

PORTLANDS ENERGY CENTRE L.P., a limited partnership formed under
the laws of the Province of Ontario **("PEC LP")**

and

BRIGHTON BEACH POWER L.P., a limited partnership formed under
the laws of the Province of Ontario **("BB LP")**

and

ONTARIO POWER GENERATION INC., a corporation
incorporated under the laws of the Province of Ontario **("OPG")**

WHEREAS PEC LP and OPG entered into a general services agreement made effective as of March 1, 2009 (the "**Original General Services Agreement**");

AND WHEREAS PEC LP and OPG entered into an amended and restated general services agreement dated April 29, 2020 ("**A&R GSA**"), to amend the Original General Services Agreement to include services provided in respect of Halton Hills Generating Station and Napanee Generating Station, in addition to Portlands Energy Centre;

AND WHEREAS the Parties now wish to further amend the A&R GSA in order to include services provided to NV LP and BB LP and wish to retain April 29, 2020 as the effective date of this Agreement;

AND WHEREAS PEC LP operates the PEC Facilities, BB LP operates Brighton Beach Generating Station, and NV LP is the common shareholder of the general partner of each of PEC LP and BB LP;

AND WHEREAS PEC LP and BB LP are each registered to do business as Atura Power;

AND WHEREAS NV LP, PEC LP and BB LP each require services to be provided by OPG from time to time, and NV LP, PEC LP and BB LP and OPG desire to enter into this Agreement to set out the general terms and conditions that will apply to provision of such services, with an effective date as of April 29, 2020.

NOW THEREFORE, in consideration of the mutual covenants and undertakings contained herein, and subject to and on the terms and conditions herein set forth, the Parties hereto agree as follows:

ARTICLE 1
DEFINITIONS

1.1 Specific Definitions

As used in this Agreement, the following terms shall have the meaning set forth or as referenced below:

(a) "**Actual Labour Costs**" means OPG's hourly standard labour rates (calculated to include salary, direct and indirect benefits) together with related long-term incentive and corporate overhead costs, with no mark-up for profit;

(b) "**Applicable Laws**" in respect of any Person, property, transaction or event, means all present and future laws, statutes, regulations, treaties, judgements and decrees applicable to that Person, property, transaction or event and, whether or not having the force of law, all applicable requirements, requests, official directives, rules, consents, approvals, authorizations, guidelines, orders and policies of any Governmental Authority having or purporting to have authority over that Person, property, transaction or event;

(c) "**Atura Group**" shall mean NV LP, its general partner, PEC LP, PEC Inc., BB LP, BB Ltd., and each of their respective directors, officers, employees, contractors, subcontractors, agents or representatives;

(d) "**BB Ltd.**" shall mean Brighton Beach Power Ltd., a corporation incorporated under the laws of the Province of Ontario, and the sole general partner of BB LP, and wholly-owned by NV LP;

(e) "**Claims**" shall mean all claims, demands, losses, costs, penalties, damages, injuries, expenses, liabilities, suits or proceedings, including reasonable legal fees;

(f) **"Confidential Information**" means all information, written or oral, furnished by a Party, directly or indirectly, to the receiving Party, including but not limited to all contracts, financial information, engineering reports, environmental reports, technical and economic data, marketing terms and arrangements, knowledge, know-how and related information such as plans, maps, drawings, field notes, sketches, photographs, computer records or software, specifications, models, or other information which is or may be either applicable to or related in any way to the assets, business or affairs of the disclosing Party or the Facilities. Confidential Information shall include the Intellectual Property and the Materials. Confidential Information shall not include information that is already known to the receiving Party on a non-confidential basis from a source that is entitled to disclose the information, or that is or becomes generally available to the public other than as a result of any act or omission of the receiving Party or its officers, employees or advisers, or that is received by the receiving Party from a third party which is not prohibited from disclosing it;

(g) "**Facilities**" means the PEC Facilities, Brighton Beach Generating Station and any other generation facilities that may be acquired in the future directly or indirectly by NV LP;

(h) "**General Services**" shall have the meaning as set out in Article 3.1;

(i) "**Governmental Authority**" shall mean any federal, provincial, local, municipal or other governmental, administrative, judicial, regulatory agency or entity having or asserting valid jurisdiction over a Party, the Facilities or this Agreement, including the Independent Electricity System Operator (IESO) and its successors;

(j) "**Intellectual Property**" shall have the meaning as set out in Article 7.1;

(k) "**Materials**" shall have the meaning as set out in Article 7.1;

(l) "**Party**" means a party to this Agreement and "**Parties**" means all of them, as the context requires;

(m) "**PEC Facilities**" means Halton Hills Generating Station, Napanee Generating Station, Portlands Energy Centre and any other generation facilities that may be acquired in the future by PEC LP;

(n) "**PEC Inc.**" shall mean Portlands Energy Centre Inc., a corporation incorporated under the laws of the Province of Ontario, and the sole general partner of PEC LP and owned 50/50 by NV LP and OPG;

(o) "**Person**" shall mean any individual, sole proprietorship, partnership, corporation or company, with or without share capital, trust, foundation, joint venture, Governmental Authority or any other incorporated or unincorporated entity or association of any nature;

(p) "**Work Estimate and Approval Form**" shall mean the document issued by OPG in substantially the form attached as Exhibit "B" to this Agreement; and

(q) "**Work Request Form**" shall mean the request for services issued by NV LP, PEC LP or BB LP in substantially the form attached as Exhibit "A" to this Agreement.

1.2 Interpretation

(a) The singular imports the plural, the masculine, the feminine, and vice versa and words importing persons shall include a natural person, firm, trust, partnership, association, corporation, joint venture or government (including any governmental agency);

(b) references to "this Agreement", "hereof", "herein" and similar expressions refer to the Agreement (including the recitals) and any appendices or schedules hereto, and to no other documents; and

(c) the division of this Agreement into parts, Articles, sub-articles and paragraphs and the insertion of headings are for convenience of reference only and shall not affect in any way the meaning or interpretation of this Agreement.

1.3 Currency

Unless otherwise indicated, all dollar amounts referred to in this Agreement are in lawful money of Canada.

1.4 Exhibits

The following are the Exhibits attached to and incorporated by reference in this Agreement, which are deemed to be a part hereof:

Exhibit A - Work Request Form
Exhibit B - Work Estimate and Approval Form

ARTICLE 2
TERM

2.1 Term

The term of this Agreement shall commence on April 29, 2020 and continue for four years until and including April 28, 2024 (the "**Term**"). The Parties may extend the Term by mutual agreement on mutually agreeable terms in writing. This Agreement may also be terminated earlier by either Party with ninety (90) days' prior written notice to the other Party, or at any time upon mutual consent of the Parties in writing.

ARTICLE 3
GENERAL SERVICES

3.1 General Services

This Agreement shall apply to all technical and other services provided by OPG, either directly or through its subcontractors, to NV LP, PEC LP or BB LP, pursuant to the terms of this Agreement (the "**General Services**").

3.2 Scope

Except with the prior consent of the Parties, as evidenced by the issuance of an approved Work Estimate and Approval Form, this Agreement shall not apply to, and General Services shall not include, technical or other services estimated to cost in excess of $200,000. General Services shall also not include any market related services from, or the sharing of any related information technology systems with, OPG or its affiliates (excluding NV LP and its subsidiaries).

3.3 Standard of Care

In the provision of the General Services to NV LP, PEC LP or BB LP by OPG hereunder, OPG shall exercise the degree of care, diligence and skill as would a reasonably prudent Person having responsibility for the provision of services of the nature of the General Services to a generating facility similar to the Facilities in comparable circumstances.

In the event of any breach of this Article 3.3 of this Agreement, provided none of NV LP, PEC LP or BB LP has delivered to OPG a timely notice as required herein, OPG shall at its own expense, re-perform the non conforming General Services. The remedy set forth in this Article 3.3 is the sole and exclusive remedy for such a breach.

ARTICLE 4
PROCESS

4.1 Request for General Services

General Services which are required by NV LP, PEC LP or BB LP and which can be provided by OPG shall be initially identified through verbal discussions. To formally request such General Services, any of NV LP, PEC LP or BB LP shall complete a Work Request Form indicating the project name, a brief description of the services required, and any timeline or other limitations or applicable conditions, including special terms and conditions. The Work Request Form shall then be forwarded to OPG's contact as set out on the form.

4.2 Definition and Estimation

Upon receipt of a Work Request Form from any of NV LP, PEC LP or BB LP, OPG will determine if it will provide an estimate in response. If so, it shall complete a Work Estimate and Approval Form confirming the work to be carried out and estimating the schedule, resources and total costs and price. The Work Estimate and Approval Form shall then be forwarded to NV LP, PEC LP or BB LP's contact as set out on the form.

4.3 Authorization

In response to a Work Estimate and Approval Form, NV LP, PEC LP or BB LP shall then indicate its approval to its terms and conditions by executing the form. The Work Estimate and Approval Form, when executed by both Parties and delivered to OPG, will serve as authorization for OPG to commence and carry out the General Services as specified therein.

4.4 Applicable Terms and Conditions

The General Services shall be performed in accordance with the terms and conditions of this Agreement. To the extent the Parties may mutually agree, the General Services may be subject to any additional or special terms and conditions as provided in the Work Estimate and Approval Form. Without limiting the generality of the foregoing, and for clarity, a Work Estimate and Approval Form may contain special terms and conditions applicable to the General Services described therein. To the extent such special terms and conditions are inconsistent or conflict with the terms and conditions in this Agreement, such special terms and conditions shall govern.

4.5 Price for Services

NV LP, PEC LP or BB LP agrees to pay, and OPG hereby agrees to accept as full payment for the General Services, the compensation and fees as set forth in the applicable Work Estimate and Approval Form.

The price for General Services may be fixed price or time and materials, as agreed in the applicable Work Estimate and Approval Form. In the case of General Services performed on a fixed price basis, subject to Article 5.2 below, the price includes all activities and materials required to perform the services, and the price will not be subject to adjustments for changes in any cost of the services to OPG without the written consent of NV LP, PEC LP or BB LP, as applicable.

Where the price for General Services is on a time and materials basis, the applicable labour or unit rates for the individuals providing the services shall be equal to OPG's Actual Labour Costs. In addition, and where applicable to General Services provided on a time and materials basis, NV LP, PEC LP or BB LP shall pay for all third party expenses incurred by OPG in providing those services together with the direct cost of any materials, equipment or other deliverables thereunder, all without mark-up for profit or otherwise.

4.6 Facility Policies and Procedures

If OPG provides General Services at the Facilities, OPG shall do so in accordance with the applicable party's policies and procedures, including security checks, that have been provided to OPG.

ARTICLE 5
PAYMENT

5.1 Invoices

Notwithstanding anything else in this Agreement, OPG shall invoice PEC LP for all General Services performed for any of NV LP, PEC LP and BB LP and invoices will indicate the price, labour-hours and fees or other compensation payable for provision of the services as provided in Article 4.5 above. OPG will provide invoices to PEC LP on a monthly basis, or as agreed from time to time, for all General Services provided.

5.2 Taxes

Any federal goods and services tax/harmonized sales tax which is payable in respect of the General Services shall be added to the invoices and each such invoice shall state separately the amount of such tax payable together with OPG's goods and services tax/harmonized sales tax registration number.

5.3 Payment of Invoices

PEC LP shall pay all invoices within thirty (30) days of receipt of the invoice.

ARTICLE 6
LIABILITY AND INDEMNIFICATION

6.1 Indemnity by PEC

PEC LP shall indemnify, defend and hold harmless OPG and its directors, officers, employees, subcontractors and agents from and against all Claims imposed upon or incurred by

OPG with respect to any personal injury or death of any individuals performing General Services pursuant to this Agreement, arising out of the gross negligence or willful misconduct of PEC LP during the Term of this Agreement.

6.2 Liability of OPG

OPG shall indemnify, defend and hold harmless the Atura Group from and against all Claims imposed upon or incurred by any member of the Atura Group by or in favour of a third party (including, without limitation, those Claims arising in favour of or brought by or on behalf of any of NV LP, PEC LP, BB LP, employees, agents, contractors, subcontractors or representatives), based upon, in connection with, relating to or arising out of the provision of the General Services, where and to the extent that any such Claim results from, arises out of or is attributable to the gross negligence or willful misconduct of OPG in the provision of the General Services.

6.3 Limitation of Liability

Subject to Article 6.5, the liability of OPG for all Claims by NV LP, PEC LP and BB LP against OPG arising in respect of this Agreement will not exceed:

(a) an amount equal to the cumulative amount of all amounts paid or payable under this Agreement by NV LP, PEC LP or BB LP, as applicable, to OPG, exclusive of any goods and services tax/harmonized sales tax; and

(b) the amount of insurance recoverable under this Agreement.

6.4 No Liability

Notwithstanding anything in this Agreement, OPG shall not be responsible to the Atura Group for any losses, damages, costs, expenses and injury of every kind and character:

(a) to the property, facilities, equipment or materials (including, the Facilities) of any member of the Atura Group; or

(b) except for third party Claims under Articles 6.2 and Claims under Article 7.3, resulting from Atura Group’s access to or use of the Materials or the Intellectual Property.

6.5 Exceptions to Limitation

The limitation of liability set out in Article 6.3 will not apply, however, to:

(a) third party Claims under Article 6.2; or

(b) Claims suffered or incurred by a member of the Atura Group or any Claims made against any member of the Atura Group by any Person, to the extent arising in respect of the deliberate or willful breach of this Agreement by OPG.

6.6 Consequential Damages

Except for any third party Claims, and except to the extent recoverable under insurance required by this Agreement, no Party will be liable to another Party for any indirect or consequential damages.

6.7 Duty to Mitigate

Each Party has a duty to mitigate damages and shall use all commercially reasonable efforts to minimize any losses, costs, expenses, damages or other liabilities it may incur as a result of the other Party's performance or non-performance of this Agreement.

ARTICLE 7
INTELLECTUAL PROPERTY

7.1 Ownership of Materials

The Parties acknowledge that OPG owns and possesses significant intellectual property, which may have applicability to the development, implementation and operation of NV LP, PEC LP and BB LP. All of the materials, literary works, and other works of authorship that are prepared for or delivered to NV LP, PEC LP or BB LP by OPG under this Agreement (such as test results, data, documentation, reports, drawings, programs, programming tools, presentation materials and summarized information) (the "**Materials**") shall be owned exclusively by OPG.

Furthermore, the Parties agree that OPG (either independently or jointly with other third parties) has all right, title and interest in Materials, including but not limited to:

(i) any copyright;
(ii) any idea, design, process, database, data, testing procedure, models, concept, technique, invention, discovery or improvement, whether or not patentable; and
(iii) any other intellectual or proprietary right, that is inherent in the Materials (the "**Intellectual Property**").

7.2 Use of Materials

OPG retains the right to use the Materials and the Intellectual Property developed or owned by OPG and provided to NV LP, PEC LP or BB LP pursuant to this Agreement, and subject to applicable patents and copyrights, the Materials and Intellectual Property may be used freely by OPG.

Notwithstanding the above, OPG hereby grants to each of NV LP, PEC LP and BB LP, a limited licence during the Term of this Agreement and for as long as (as applicable) PEC LP operates the PEC Facilities or BB LP operates Brighton Beach Generating Station to use, execute, perform and display the Materials and the Intellectual Property, provided that such actions are for the sole purpose of operating and decommissioning the Facilities. Any other use of the Materials, including sublicence, transfer, copying or reproducing to any other third party, shall only be in accordance with terms to be negotiated by the Parties.

Should any of NV LP, PEC LP or BB LP wish to acquire any other rights of usage to the Materials or Intellectual Property, it may issue a notice to OPG pursuant to Article 8 of this Agreement and OPG may agree to enter into negotiation for such acquisition. Any such acquisition of rights shall be subject to terms to be negotiated on a case by case basis.

7.3 Warranty and Indemnity

OPG will pay all royalties, licence fees and other monetary amounts required in respect of the Materials and the Intellectual Property associated with the General Services.

OPG confirms that it owns or has obtained from third parties, duly authorised grants of all right, title and interest necessary to provide to NV LP, PEC LP or BB LP a licence regarding the Intellectual Property associated with the General Services in the manner set out in Article 7.2 of this Agreement.

OPG will, at its expense defend all claims, actions or proceedings against NV LP, PEC LP or BB LP based on any allegation that the Intellectual Property, or any part of the Intellectual Property, constitutes an infringement upon, or a misappropriation of any Intellectual Property and will pay to NV LP, PEC LP or BB LP, as applicable, all resulting costs, damages, charges and expenses incurred. NV LP, PEC LP or BB LP, as applicable, will give OPG written notice of any such claim, action or proceeding and at the request and expense of OPG, NV LP, PEC LP or BB LP, as applicable, will provide all available information, assistance and authority required to conduct its defence.

If all or any part of the Intellectual Property is finally determined to constitute an infringement or misappropriation of intellectual property rights, or if NV LP, PEC LP or BB LP, as applicable, is enjoined from using any of the Intellectual Property as a result of an infringement or misappropriation claim, OPG will at its expense promptly obtain for NV LP, PEC LP or BB LP, as applicable, the right to continue using the Intellectual Property or promptly modify or replace the noncompliant elements of the Intellectual Property to the extent necessary to render the Intellectual Property compliant, without adversely affecting the functional or performance capabilities of the Materials.

ARTICLE 8
ADDITIONAL TERMS

8.1 Termination

From and after the effective date of termination of this Agreement, OPG shall not be entitled to any further payments under Article 5 for the periods subsequent to the effective date of termination but shall be paid all fees accrued to the effective date of termination. OPG shall submit a final statement of fees to PEC LP within ninety (90) days of the effective date of termination and such fees shall be paid to OPG within thirty (30) days of receipt by PEC LP of such statement. All rights accruing prior to the effective date of termination and all indemnity rights and the provisions of Article 6 and Article 8.11 shall survive the effective date of termination.

8.2 Transfers on Termination

On termination, OPG shall co-operate to ensure an orderly and smooth transition of the provision of all General Services to NV LP, PEC LP or BB LP, as applicable, or to such party as

NV LP, PEC LP or BB LP may direct so as to ensure that any disruptions to the Facilities caused by the termination are minimized. Within thirty (30) days of the effective date of termination, OPG shall, to the extent that it is able, subject to legislative and contractual restrictions, deliver to and, where applicable, transfer into the name of NV LP, PEC LP or BB LP, as applicable, or as NV LP, PEC LP or BB LP may in writing direct, all property and documents of NV LP, PEC LP or BB LP then in the custody of OPG.

8.3 Confirmation of Records

During the term of the Agreement, and only in respect of General Services invoiced on a time and materials basis, PEC LP shall have the right to reasonable access to the books, records and accounts maintained by OPG related to provision of the General Services to verify the accuracy of the hours and expenses as invoiced by OPG. PEC LP will provide OPG with thirty (30) days notice of any such request to verify the records.

8.4 Subcontracting

NV LP, PEC LP and BB LP acknowledge OPG's requirement to subcontract certain of the General Services to meet its obligations under this Agreement. OPG shall, in entering into any such contractual agreement with a subcontractor, ensure that such subcontractor is subject to the applicable terms and conditions of this Agreement including but not limited to all confidentiality requirements.

8.5 Assignment

This Agreement shall not be assigned by any Party without consent of the other Parties, which consent shall not be unreasonably withheld, provided that no Party may assign its interest in this Agreement to an affiliate.

8.6 Counterparts and Entire Agreement

(a) This Agreement and any amendments hereto may be executed in one or more counterparts, each of which shall be deemed to be an original by the Parties, but all of which shall be considered one and the same instrument. Any counterpart signature transmitted by sending a scanned copy by electronic mail or similar electronic transmission will be deemed to be an original signature; and

(b) This Agreement contains the entire agreement between the Parties hereto with respect to the subject matter hereof and supersedes all prior agreements and understandings, oral or written, with respect to such matters.

8.7 Notices

All notices hereunder shall be deemed given if in writing and delivered personally or sent by email, courier or by registered or certified mail (return receipt requested) to the Parties at the following addresses (or at such other address as shall be specified by like notice):

(a) if to OPG, to:
Ontario Power Generation Inc.
700 University Avenue

Toronto, Ontario M5G 1X6

Attention: Senior Vice President, Renewable Generation
Email: nicolle.butcher@opg.com

(b) if to NV LP, PEC LP or BB LP to:
Atura Power
1415 Joshuas Creek Drive, Unit #101
Oakville, ON L6H 7G4

Attention: President
Email: Chris.Fralick@aturapower.com

Any notice given by mail, email or other electronic means shall be effective when received. Each Party may, by giving notice thereof to the other Party, change its address for notice, or designate to which notices must be directed, at any time.

8.8 Governing Law and Disputes

(a) This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario.

(b) If there is a dispute between the Parties in connection with this Agreement, the Parties will, acting reasonably and in good faith, use all reasonable efforts to resolve the dispute as soon as possible by negotiation.

8.9 Severability

The provisions of this Agreement shall be deemed severable and the invalidity or unenforceability of any provision shall not affect the validity or enforceability of the other provisions hereof. If any provision of this Agreement, or the application thereof to any person or entity or any circumstance, is invalid or unenforceable, (a) suitable and equitable provisions shall be substituted therefor in order to carry out, so far as may be valid and enforceable, the intent and purpose of such invalid or unenforceable provision, and (b) the remainder of this Agreement and the application of such provision to other persons, entities or circumstances shall not be affected by such invalidity or unenforceability, nor shall such invalidity or unenforceability affect the validity or enforceability of such provision, or the application thereof, in any other jurisdiction.

8.10 Amendment, Modification and Waiver

Any amendments, modifications and waivers of this Agreement shall be done in writing and executed by all Parties.

8.11 Confidential Information

This Agreement and any Materials created hereunder shall be deemed to be Confidential Information and, for the term of this Agreement and a period of one (1) year after termination of this Agreement, none of NV LP, PEC LP and BB LP, without the consent of OPG, and vice versa, will divulge or communicate to any person or entity or exploit for any purpose whatsoever any

Confidential Information disclosed to it by the other Party or any Confidential Information obtained or produced in relation to the Agreement. Such prohibition does not prevent the disclosure of Confidential Information:

(a) to officers, employees, advisers or contractors engaged by any of the Parties in connection with the Agreement, or to the partners of NV LP, PEC LP or BB LP, and who are made aware of the confidential nature of the Confidential Information; or

(b) which is ordered or required by any Applicable Law or Governmental Authority or in accordance with the requirements of any recognized stock exchange.

Each of OPG (excluding, for greater clarity, NV LP and its subsidiaries), on one hand, and NV LP and its subsidiaries, on the other, will not disclose to the other any competitively sensitive information including information regarding electricity bid and offer strategies, electricity offer prices and quantities, gas procurement strategies and outage plans, unless such information is shared in accordance with the ring-fence conditions in its respective OEB licence and/or the applicable ring-fencing plan.

For greater clarity, OPG will not use any Confidential Information obtained under this Agreement to, what could reasonably be, the detriment of NV LP, PEC LP and BB LP.

8.12 OPG's Insurance

During the term of this Agreement, OPG shall, at its sole expense, maintain in full force and effect at all times during the performance of the General Services insurance coverages with terms, conditions and limits as set forth below, with insurers and under forms of policies reasonably satisfactory to PEC LP and BB LP:

(a) Commercial General Liability Insurance having an inclusive limit of five million dollars ($5,000,000) per occurrence, including personal injury and property damages for activities not related to the General Services;

(b) Automobile Liability Insurance on all vehicles used in connection with the General Services, whether owned, leased or rented by OPG, which insurance shall have a limit of five million dollars ($5,000,000) in respect of bodily injury (including passenger hazard) and property damage resulting from any one accident; and

(c) Workers' Compensation insurance according to the jurisdiction in which the General Services are being performed.

At the request of PEC LP or BB LP, OPG shall deliver to PEC LP certificates evidencing the aforementioned policies. Insurance described under clause (a) above shall include PEC LP, BB LP, their employees and subcontractors as additional insureds.

In addition to the above, each policy shall include a clause specifying that the insurer(s) shall endeavour to provide not less than thirty (30) days advance notice in writing to PEC LP and BB LP prior to cancellation, termination or material alteration of said policy of insurance.

The requirements contained herein as to policy types, limits, terms and conditions as well as PEC LP's or BB LP's approval of insurance coverage to be maintained by OPG are not intended to and shall not in any manner limit or qualify the liabilities and obligation assumed by OPG elsewhere under this Agreement.

Regardless of OPG's requirements as to insurance set out in this Article 8.12, insolvency, bankruptcy or failure of any insurer to pay any claim that may arise shall not constitute a waiver by PEC LP or BB LP of any of the provisions of this Agreement.

OPG is responsible for any and all deductibles from the above insurance policies.

8.13 PEC LP's and BB LP's Insurance

During the Term of this Agreement, PEC LP and BB LP shall, at its sole expense, maintain in full force and effect at all times during the performance of the General Services insurance coverages with terms, conditions and limits as set forth below, with insurers and under forms of policies reasonably satisfactory to OPG.

(a) Commercial General Liability insurance having a minimum inclusive limit, for personal injury and property damage, of at least ten million dollars ($10,000,000) per occurrence. This insurance shall be on a broad Canadian manuscript policy form which shall include but not be limited to the following:

(i) Contractual Liability;
(ii) Products/Completed Operations Liability;
(iii) Employers Liability;
(iv) a Cross Liability and Severability of Interests clause; and
(v) that it is primary insurance for all insureds without any pro-rata consideration from any other similar insurance carried by OPG or any of the other insureds.

This policy will be primary and include OPG as an additional named insured.

(b) Property "All Risks" physical damage insurance, covering, without limitation, breakdown of electrical and mechanical systems, all materials, supplies, equipment, machinery, pipe, appurtenances and other similar property. This policy will be primary and include OPG as an additional insured as its interest may appear with a waiver of subrogation against all insured Parties hereunder.

(c) Environment/Pollution Liability Insurance, providing coverage for first party property damage and site clean-up and any third party claims for bodily injury, property damage and clean-up for pollution and environmental incidents arising out of the operation of the Facilities, with a limit of not less than five million dollars ($5,000,000) per occurrence and in the aggregate. The policy will be primary and include OPG as an additional insured.

At the request of OPG, PEC LP shall deliver to OPG a non-priced certified copy of said Property All Risk Insurance policy and said Commercial General Liability insurance policy, both of which shall contain an article specifying that the insurer(s) shall endeavour to provide not less than thirty (30) days advance notice in writing to OPG prior to cancellation, termination, or material alteration of said policies of insurance.

In the event of a loss under the above described policies, PEC LP or BB LP, as applicable. shall give immediate notice to OPG, and shall assist and cooperate in the timely settlement of any claim hereunder. PEC LP and BB LP are responsible for any and all deductibles from the above insurance policies.

8.14 No Joint Venture, Partnership, etc.

Nothing contained herein shall be construed as creating any joint venture, partnership, agency or joint and several liability among the Parties.

[*signature page follows*]

IN WITNESS WHEREOF, this Agreement has been signed by duly authorized representatives on behalf of each of the Parties hereto as of the date first written above.

PORTLANDS ENERGY CENTRE L.P., by its general partner, **PORTLANDS ENERGY CENTRE INC.**

Per: _____
Name: Chris Fralick
Title: President

BRIGHTON BEACH POWER L.P., by its general partner, **BRIGHTON BEACH POWER LTD.**

Per: _____
Name: Chris Fralick
Title: President

NV LP, by its general partner, **2685277 ONTARIO INC.**

Per: _____
Name: Chris Fralick
Title: President

ONTARIO POWER GENERATION INC.

Per: _____
Name: Nicolle Butcher
Title: SVP - Renewable Generation & Power Marketing

Exhibit A - Work Request Form

General Service Agreement – Services Request Form

GSA Tracking Number: ……

Description/Scope of Work (Requestor to complete)

(What, When, Where, Purpose, etc.)

☐ PEC ☐ BBP ☐ HHGS ☐ NGS ☐ All Atura / Common Support

……..

Start of Work

Does the Work need to be completed as soon as possible: YES ☐ NO ☐

☐ Regulatory ☐ Business ☐ Loss of Production

Please explain urgency: ……..

Positions Who Would Perform Work and Numbers Required (identify trades / specialty skills to complete)

……

Is it possible for this work to be completed by?

Regular Staff ☐ If no, explain: ……..

Temporary Staff ☐ If no, explain: ……..

Recommendation & Rationale:

…....

Complete the following estimates for this work (assuming proceeding to an external company):

Cost of Work: Labour $.... Non-Labour $.....

Number of Field Hours ……

Informed PWU local steward (if applicable): ☐ Date: DD/MMM/YY

Prepared by: **Reviewed by:**

Requestor Human Resources Manager

Forward completed form to Integration Manager and HR Manager, to be filled in HR LOF.

Exhibit B - Work Estimate and Approval Form

The attached form is used to define work scope and labour details and to estimate schedule and costs in response to a Work Request under the terms of the General Services Agreement. Once approved, the Parties will execute the form. The executed form will be the approval to OPG to commence the work.

WORK ESTIMATE AND APPROVAL FORM

General Information	
Date:	**Work Order Number:**
OPG Contact:	**Atura Contact:**
OPG WO Manager:	**Atura WO Manager:**

Contract Type

☐ **Fixed Price** ☐ **Time & Material** ☐ **3rd Level Support "Technical Support"** ☐ **T&M Supplementary Staff**
☐ **Other, please specify:**

Contract Period:	**Start Date:**	**End Date:**

Work Description Summary:

Signatures of Agreement

[to be filled in, depending on which entity requesting services] (Atura):

_____
Date
MM-DD-YYYY

Ontario Power Generation Inc (OPG):

_____
Date
MM-DD-YYYY

Detailed Work Description
☐ **Refer to Work Request Form** **SCOPE OF WORK** •

Other Supporting Documentation
☐ Additional relevant PEC project information, policies, procedures, standards that OPG requires to complete the Work Estimate and Approval Form. **SAFETY** ○

Pricing Detail

Specific Terms & Conditions

AMENDING AGREEMENT

This "**Amending Agreement**" is entered into as of **November 19, 2024** and is effective as of **April 29, 2024** (the "**Effective Date**") between

ONTARIO POWER GENERATION INC. ("**OPG**")

and

NV LP ("**NV L.P.**")

and

PORTLANDS ENERGY CENTRE L.P. ("**PEC L.P.**")

and

BRIGHTON BEACH POWER LP ("**BB L.P.**" and, together with OPG, NV L.P., and PEC LP, the "**Initial Parties**")

and

ATURA H2 L.P. ("**AH2 L.P.**" and, together with the Initial Parties, "**All Parties**")

Recitals

A. The Initial Parties entered into the Second Amended and Restated General Services Agreement, dated May 11, 2021 and effective April 29, 2020 (the "**Agreement**"), whereby OPG may, from time to time, provide services to NV L.P., PEC L.P., and BB L.P.

B. The Agreement expired on April 28, 2024, and, in accordance with Section 2.1 of the Agreement, the Initial Parties wish to amend the Agreement to extend the Term for an additional four (4) years with successive automatic extensions.

C. AH2 L.P. wishes to become a Party to the Agreement and the Initial Parties agree to add AH2 L.P. as a Party to the Agreement.

D. By executing this Amending Agreement, All Parties will extend the Term of the Agreement and AH2 L.P. will become a Party to the Agreement, on the terms and conditions set out in this Amending Agreement.

Therefore, in consideration of the mutual covenants and agreements herein contained and other good and valuable consideration (the receipt, adequacy and sufficiency of which is hereby acknowledged), All Parties agree as follows:

1. Interpretation

Capitalized terms used but not defined herein have the meanings assigned to them in the Agreement.

2. Article 2 – Term

Section 2.1 of the Agreement is deleted in its entirety and replaced with the following:

> "The term of this Agreement shall commence on April 29, 2024 and continue for four years until and including April 28, 2028 (the "**Term**"). The Term will continue to automatically extend for successive four (4) year terms unless terminated earlier by a Party with ninety (90) days' prior written notice to the other Party, or at any time upon mutual consent of the Parties in writing."

3. Additional Party to the Agreement

All Parties hereto confirm and agree that, upon execution and delivery of this Amending Agreement, AH2 L.P. is hereby added as a "Party" to the Agreement, as fully and with the same force and effect as if AH2 L.P. had originally executed and delivered a counterpart thereof, and that the defined term "Parties" shall be deemed to include AH2 L.P.

4. Services continued under the Agreement

The provisions of this Amending Agreement are effective as of the Effective Date. For the avoidance of doubt, All Parties agree that any services provided by OPG to NV L.P., PEC L.P., or BB L.P., in the period between the expiry of the Agreement and the execution of this Amending Agreement, shall be deemed to have occurred under the Agreement.

5. General

(a) Except as herein provided, the terms and conditions of the Agreement shall continue in full force and effect, unamended.

(b) This Amending Agreement may be executed in one or more counterparts and may be delivered by electronic means, each of which shall be deemed an original and all of which when, taken together, shall constitute one and the same instrument.

(c) This Amending Agreement is governed by and is to be construed and interpreted in accordance with the laws of the Province of Ontario and the federal laws of Canada applicable in the Province of Ontario.

**[REMAINDER OF THIS PAGE INTENTIONALLY LEFT BLANK;
SIGNATURE PAGE FOLLOWS]**

IN WITNESS WHEREOF All Parties have executed this Amending Agreement made as of the date first written above.

ONTARIO POWER GENERATION INC.

Per:_____
Name: Nicolle Butcher
Title: Chief Operations Officer
I have authority to bind the Corporation

NV L.P., by its general partner, **2685277 ONTARIO INC.**

Per:_____
Name: Shelley Babin
Title: President and CEO
I have authority to bind the Corporation

PORTLANDS ENERGY CENTRE L.P., by its general partner, **PORTLANDS ENERGY CENTRE INC.**

Per:_____
Name: Shelley Babin
Title: President and CEO
I have authority to bind the Corporation

BRIGHTON BEACH POWER L.P., by its general partner, **BRIGHTON BEACH POWER LTD.**

Per:_____
Name: Shelley Babin
Title: President and CEO
I have authority to bind the Corporation

ATURA H2 L.P., by its general partner, **ATURA HYDROGEN INC.**

Per:_____
Name: Shelley Babin
Title: President and CEO
I have authority to bind the Corporation

Signature page – Amending Agreement

IN WITNESS WHEREOF All Parties have executed this Amending Agreement made as of the date first written above.

ONTARIO POWER GENERATION INC.

Per:_____
Name: Nicolle Butcher
Title: Chief Operations Officer
I have authority to bind the Corporation

NV L.P., by its general partner, **2685277 ONTARIO INC.**

Per:_____
Name: Shelley Babin
Title: President and CEO
I have authority to bind the Corporation

PORTLANDS ENERGY CENTRE L.P., by its general partner, **PORTLANDS ENERGY CENTRE INC.**

Per:_____
Name: Shelley Babin
Title: President and CEO
I have authority to bind the Corporation

BRIGHTON BEACH POWER L.P., by its general partner, **BRIGHTON BEACH POWER LTD.**

Per:_____
Name: Shelley Babin
Title: President and CEO
I have authority to bind the Corporation

ATURA H2 L.P., by its general partner, **ATURA HYDROGEN INC.**

Per:_____
Name: Shelley Babin
Title: President and CEO
I have authority to bind the Corporation

Signature page – Amending Agreement

AMENDED AND RESTATED BUSINESS AND SERVICES AGREEMENT (the "Agreement")

THIS AGREEMENT made as of the 31 day of July, 2020.

BETWEEN:

ONTARIO POWER GENERATION INC., a Corporation incorporated under the laws of the Province of Ontario, Canada

(hereinafter called "**OPG**")

- and -

LAURENTIS ENERGY PARTNERS INC., a Corporation incorporated under the laws of the Province of Ontario, Canada
(hereinafter called "**LEP**").

WHEREAS

1. OPG is a power generating company having personnel with experience in the nuclear, hydroelectric and thermal industry and associated support infrastructure.

2. LEP, a wholly owned subsidiary of OPG, is a company organized to provide operation, management, emergency planning, construction, development, operation, maintenance, inspection and technical services to the nuclear, hydroelectric and thermal industry.

3. To perform these services, LEP wishes to have access to personnel and certain equipment or materials and procure a range of professional and corporate support services from OPG.

4. OPG agrees to provide personnel and certain equipment or materials and supply these professional and corporate support services to LEP, if and when available.

5. OPG also wishes to retain LEP from time to time to provide, and LEP agrees to supply to OPG, LEP Services (as defined below) in accordance with this Agreement.

6. The parties entered into an agreement to set out the terms and conditions upon which OPG would provide such personnel, certain equipment or materials and services to LEP dated as of May 28, 2012 (the "Original Agreement").

7. The Original Agreement was amended and restated by agreement dated as of December 23, 2015 and was amended by Amendment 2 dated as of December 30, 2017 and Amendment 3 dated as of July 22, 2020 (the "Amended Agreement").

8. OPG and LEP now wish to amend and restate the Amended Agreement as set out herein in this Agreement.

NOW THEREFORE, in consideration of the mutual covenants and agreements hereinafter contained and for other good and valuable consideration (the receipt and sufficiency of which is acknowledged by each of the parties hereto) the parties covenant and agree each with the other as follows:

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ARTICLE 0.1
APPLICATION

0.1.1 This Agreement governs:

0.1.2.1 OPG's provision to LEP of personnel and certain equipment or materials, access to OPG property and assets, and professional and corporate support services; and

0.1.2.2 LEP's provision of LEP Services to OPG.

0.1.2 The process for requesting, releasing and recording services to be provided under this Agreement is set out in Appendix A.

ARTICLE 1
PROVISION OF PERSONNEL

1.1 LEP Support Employees. Subject to the terms and conditions herein, OPG will provide or arrange for the provision of existing OPG employees or other OPG labour resources to LEP, as may be requested by LEP. Existing OPG employees may provide support in executing and managing LEP's operations on a full-time basis ("Secondments") or perform discrete work characterized by tasks, activities, or duties for or on behalf of LEP, including to parties with whom LEP has a commercial relationship for the provision of services ("Operational Resources"). Collectively, Secondments and Operational Resources represent "**LEP Support Employees**".

1.2 OPG Support Employees. Subject to the terms and conditions herein, LEP will provide or arrange for, from time to time, the provision of existing LEP employees or other LEP labour resources to OPG, as requested by OPG (collectively, "OPG Support Employees") to perform duties for or on behalf of OPG, including to parties with whom OPG has a commercial relationship for the provision of services. In doing so, LEP will also provide OPG with an estimate of costs OPG, can expect to incur in procuring this service.

1.3 Annual Employee Plan. LEP shall deliver to OPG an annual employee resourcing plan setting out expected Secondments requirements for internal business support and Operational Resources requirements, including for commercial or technical support needs arising from possible commercial opportunities for the upcoming year. Upon receipt of the LEP employee plan, OPG shall review and notify LEP of any anticipated resourcing constraints. For clarity, the employee plan is expected to be provided as part of the annual business planning process completed by LEP in accordance with timelines as set out by OPG, and may be revised and updated throughout the year. LEP and OPG shall coordinate throughout the term of this Agreement to ensure that LEP has continuous access to OPG's employee resources subject to the qualifications set out in Section 1.3.

1.4 LEP Support Employee Assignment Requests. LEP shall make all LEP Support Employee requests to OPG as promptly as possible. Such request shall specify the number of LEP Support Employees needed, the expected duration of such requested services and the type of services that will be performed by the requested LEP Support Employees. The parties agree that the choice of which employee and how many employees are made available as LEP Support Employees is subject to the mutual approval of both parties. Notwithstanding the foregoing, OPG is under no obligation to provide any employees to LEP if such resource allocation would result in an impact to the current service standard levels provided at OPG's facilities, or would represent a reasonable risk to the safe operations of OPG's facilities.

1.5 LEP Support Assignment Agreement. OPG will enter into a subcontract agreement, secondment agreement, work assignment or such other form of agreement or document agreed to between LEP and OPG (a "**LEP Support Assignment Agreement**") to document the terms of any LEP Support Employee assignment. LEP Support Assignment Agreements will be among LEP and OPG, and if necessary, the applicable LEP Support Employee, and will specify that the LEP Support Employee will be working on behalf of LEP, identifying the work locations designated by LEP, and other terms of the assignment agreeable to OPG, LEP and the LEP Support Employee, if applicable. Each LEP Support Assignment Agreement shall ensure that LEP's confidentiality obligations to third party clients will be adhered to by such LEP Support Employee. All LEP Support Employees will remain employees of OPG and not become employees, servants or agents (except to the extent expressly specified in the applicable LEP Support Assignment Agreement) of LEP. All pay and benefits of the LEP Support Employees will continue to be the responsibility of OPG.

1.6 Invoices and Expenses. OPG will, in accordance with Article 7 or as otherwise agreed to between LEP and OPG, invoice LEP at the greater of:

1.6.1 the market price for providing those services as appropriate, and
1.6.2 all costs incurred by OPG in providing the services including:
1.6.2.1 OPG's applicable employee costs including salary, incentive compensation, standard OPG allocations for benefits and pension and any applicable overhead or administrative costs incurred by OPG with respect to the administration of the employees incurred by OPG for each LEP Support Employee and any additional costs paid by OPG in accordance with the LEP Support Assignment Agreements for those LEP Support Employees;
1.6.2.2 all third party expenses incurred by OPG in providing those services; and
1.6.2.3 the direct cost of certain equipment or materials, or other deliverables used to provide the services.

1.7 Incurred Expenses. In the event that OPG reimburses the expenses incurred by LEP Support Employees while working for LEP, in accordance with the terms of the LEP Support Assignment Agreement, LEP will reimburse OPG for such expenses in accordance with the terms of the Services Appendix (As defined under Article 4A).

1.8 Service Standards. LEP Support Employees will follow, at a minimum, the principles contained in OPG's Safe Operations Rules, OPG's Code of Business Conduct, LEP's Code of Business Conduct and all applicable quality assurance programs implemented by either OPG or LEP's clients. In addition, LEP will ensure that all LEP Support Employees comply with the safety programs of the applicable jurisdiction in which they are performing services on behalf of LEP.

1.9 The parties agree that the work and services provided by LEP Support Employees are separate and distinct from the Professional and Corporate Services provided by OPG to LEP in accordance with Section 3 and shall be invoiced by OPG separately from such Professional and Corporate Services.

1.10 OPG acknowledges and agrees that the Employee resources contemplated in this Agreement may be characterized by LEP to third party clients as a prime contractor subcontractor relationship. OPG will provide such further assurances of such arrangement, as may be reasonably requested by LEP.

ARTICLE 2
PROVISION OF CAPITAL EQUIPMENT

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2.1 Allocated Equipment. Subject to the terms and conditions herein, upon request from LEP, OPG will rent, lease or sell, as applicable, from time to time, certain equipment or materials ("**LEP Allocated Equipment**") to LEP so that it can provide services to third parties for the purposes of carrying on LEP's business activities. LEP Allocated Equipment shall include all necessary licenses, permits and approvals related to the transfer and use of such equipment, to the extent such licenses, permits and approvals can be transferred to, or otherwise relied on by, LEP.

2.2 Annual Equipment Plan. LEP shall deliver to OPG an annual equipment plan setting out potential equipment resource requirements for the upcoming year. Upon receipt of the LEP equipment plan, OPG shall review and notify LEP of any anticipated resourcing constraints and identify any potential contingency resources that may be available for such year. For clarity, the annual equipment plan is expected to be provided as part of the annual business planning process completed by LEP in accordance with timelines as set out by OPG, and may be revised and updated throughout the year. LEP and OPG shall coordinate throughout the term of this agreement to ensure that LEP has continuous access to OPG's equipment resources subject to the qualifications in Section 2.3.

2.3 Equipment Requests. LEP shall make all requests for certain equipment and material to OPG as promptly as possible. Such request shall specify the type of equipment or materials requested, the location such equipment or material will be used at, the expected duration such equipment or material will be needed and the preferred nature of the equipment or material agreement (i.e. rental or sale). OPG is under no obligation to provide any LEP Allocated Equipment if such resource allocation would result in an impact to the current service standard levels provided at OPG's facilities, would represent a reasonable risk to the safe operations of OPG's facilities.

2.4 Allocated Equipment Agreements. Upon receipt and approval of a request for LEP Allocated Equipment from LEP, OPG will document the terms and condition of the rental or sale agreement, as applicable, between LEP and OPG (a "**LEP Allocated Equipment Agreement**"). Any and all costs incurred by OPG to rent or sell LEP Allocated Equipment to LEP will be borne wholly by LEP, including, without limitation the cost of all activities· required to document, supply and deliver the LEP Allocated Equipment, all applicable freight, insurance, taxes and other charges incurred by OPG and reasonable wear and tear costs. Except as otherwise specified herein, LEP Allocated Equipment will be rented or sold, as applicable, at OPG's net book value by applying the remaining useful life to determine the calculated cost of such LEP Allocated Equipment, including a return on invested capital.

2.5 Ownership. Except as otherwise provided in a LEP Allocated Equipment Agreement, the LEP Allocated Equipment is, and shall at all times be and remain, solely and exclusively the property of OPG, and no right, title or interest in the LEP Allocated Equipment shall pass to LEP other than the right of LEP to possess and use the LEP Allocated Equipment for the term as provided in the LEP Allocated Equipment Agreement or as otherwise agreed to between OPG and LEP. The LEP Allocated Equipment shall remain personal property notwithstanding that the LEP Allocated Equipment or any part of the LEP Allocated Equipment may be affixed or attached to any other personal or real property.

2.6 Liability and Insurance. LEP shall be liable to OPG for all loss or damage (reasonable wear and tear excepted), cost, expense, charge, fine or penalty arising out of the LEP Allocated Equipment for the duration such LEP Allocated Equipment is in the custody and control of LEP. LEP shall give OPG notification of any loss or damage promptly upon LEP becoming aware of same. In the event of any such loss or damage, LEP shall pay to OPG the cost of either repairing or replacing the LEP Allocated Equipment or portion thereof that is subject to the loss or damage. LEP Allocated

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Equipment will be and remain at the risk of LEP until returned to OPG in accordance with the LEP Allocated Equipment Agreement. LEP will continue in full force and effect all insurance policies required in accordance with the LEP Allocated Equipment Agreement and give all notices and present all claims under all insurance policies in due and timely fashion.

ARTICLE 2.1
NUCLEAR LIABILITY PROTECTION FOR LEP AND ITS SUBCONTRACTORS OR SUPPLIERS

For purposes of this Article 2.1:

"**Losses**" means any and all losses of any kind or nature, including but not limited to economic loss, damage to property, personal injury, psychological damage, the cost of measures of reinstatement of impaired environment, cost of preventative measures and loss of income; provided, further, that nothing is excluded from the ambit of Losses, including heads of damage which are traditionally not recoverable at law. Losses includes but is not limited to damages, injuries, Claims (to include any costs incurred in respect thereof), demands, costs, adverse judgments, findings or rulings, penalties, expenses, payments, liabilities, whether personal, economic or preventative, direct or consequential, and whether incurred through settlement, in a court of law, in arbitration, in a regulatory proceeding or as a result of the directive, determination, finding, or order of a Governmental Authority or any obligation imposed by operation of any applicable law, or otherwise.

"**Nuclear Damage**" means any Losses, of any kind, to the extent that the Losses arise out of or result from a Nuclear Incident at an OPG facility.

"**Nuclear Incident**" means, in respect of the Nuclear Installation, any of the following, or any combination thereof:

a) a "nuclear incident" as defined under the Nuclear Liability and Compensation Act (Canada) or a nuclear liability convention; or

b) any emission of ionizing radiation from any source of radiation within, or released from, the Nuclear Installation; or

c) any occurrence involving Nuclear Material to the extent that such occurrence arises out of, or results from, or is connected with the radioactive properties, or a combination of the radioactive properties, and any toxic, explosive or other hazardous properties of, such Nuclear Material; or

d) any occurrence involving both non-nuclear material and, as described in (c) above, Nuclear Material, to the extent that it cannot be identified as having been caused only by the non-nuclear material; or

e) any occurrence elsewhere than on the site of the Nuclear Installation involving Nuclear Material which at the time of such occurrence:

    1) is being transported to or from such site;

    2) is being transported by or on behalf of any party, whether or not to or from

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such site;

3) is Nuclear Material that has been on such site, or has been transported to or from such site, or has been transported by or on behalf of any party, whether or not to or from such site,

in each case to the extent that such occurrence arises out of or results from or is connected with the radioactive properties, or a combination of the radioactive properties and any toxic, explosive or other hazardous properties of, such Nuclear Material.

"**Nuclear Installation**" means any of the following:

a) any Nuclear Reactor owned and operated by OPG;

b) any factory using Nuclear Fuel for the production of Nuclear Material, or any factory for the processing of Nuclear Material, including any factory for the re-processing of irradiated Nuclear Fuel owned and operated by OPG; and

c) any facility where Nuclear Material is stored owned and operated by OPG.

"**Nuclear Material**" means any of the following:

a) "nuclear material" as defined under the legislation of the Installation State;

b) nuclear Fuel, other than natural uranium or depleted uranium, that can produce energy by a self-sustaining nuclear fission chain reaction outside a nuclear reactor either alone or in combination with another material; and

c) radioactive products or waste.

"**Operator**" means, in relation to the Nuclear Installation, the person designated or recognized by the Installation State as the operator of that nuclear facility or who is otherwise the *de facto* operator of that nuclear facility.

2.1.1 The Parties expressly acknowledge and agree that in no event and under no circumstances shall LEP, irrespective of any of its activities, assume any role as Operator or be deemed to be an Operator of a Nuclear Installation.

2.1.2 The Parties acknowledge that OPG may, from time to time, allow LEP to access its Nuclear Installations and that Nuclear Damage may arise out of or relate to LEP's potential activities and uses permitted or contemplated under the Agreement. As between the Parties, OPG shall be exclusively and absolutely liable for all Nuclear Damage, wherever suffered or incurred and however caused, and OPG waives all rights (both present and future) to make any claim against LEP in respect thereof. OPG shall indemnify, defend and hold harmless LEP from and against all Nuclear Damage wherever suffered or incurred and however caused, without limitation, as a result of, in respect of, or in any way related to, connected to, or arising out of LEP's potential activities and uses permitted or contemplated under the Agreement.

2.1.3 LEP shall not have any liability for, and OPG shall waive all rights (both present and future) against LEP in respect of, loss of, or loss of use of, property at the Nuclear Installation, or to the means of transport, or to storage incidental to transport of Nuclear Material for which OPG is responsible at

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law.

2.1.4 The parties acknowledge that LEP may be asked by its contractual counterparties to obtain from OPG certain waivers or indemnities in respect of Nuclear Damage. Where it is necessary to LEP's business and appropriate in the opinion of OPG's Law Division, OPG authorizes LEP to flow down nuclear liability protection to its subcontractors or suppliers up to the full measure of protection afforded to LEP under this Agreement. However, the degree of nuclear liability protection that OPG authorizes LEP to flow down to its subcontractors or suppliers in a given circumstance is in accordance with the following terms:

2.1.4.1.1 in respect of subcontractors or suppliers who have recently entered into a direct contract with OPG containing nuclear liability terms, such protection is consistent with the terms that OPG has agreed to in such direct contracts with these suppliers or subcontractors; or

2.1.4.1.2 in respect of subcontractors or suppliers who have not recently entered into direct contracts with OPG containing nuclear liability terms, such protection is consistent with the terms that OPG recently has agreed to in a direct contract with a similarly situated subcontractor or supplier.

ARTICLE 3
PROFESSIONAL AND CORPORATE SERVICES

3.1 Professional and Corporate Services. OPG will provide or arrange for the provision of professional and corporate services required in connection with the operation of the business interests of LEP and as requested by LEP. The fees for Professional and Corporate Services will be based on the actual fully burdened OPG labour rates per hour, and will include OPG's applicable employee costs including salary, incentive compensation, standard OPG allocations for benefits and pension and any applicable overhead or administrative costs incurred by OPG with respect to the administration of the services and will be charged on a monthly basis. LEP will be consulted prior to external services being retained or consulted.

ARTICLE 4A
LEP PROVISION OF SERVICES AND GOODS

4A.1 In this Section 4A, the following terms have the respective meanings set out below:

4A.1.1 "**Applicable Laws**" in respect of any person, property, transaction or event, means: (1) all applicable laws, statutes, regulations, municipal by-laws and ordinances and treaties, including Environmental Laws; (2) any requirements under or prescribed by applicable common law, judgments, orders and decrees; (3) all Codes and Standards, applicable to that person, property, transaction or event at the applicable time and, whether or not having the force of law; and (4) all applicable Approvals.

4A.1.2 "**Approvals**" means any permits, licences, consents, approvals, clearances, orders, ordinances, registrations, filings or other authorizations respecting the Services as may be required by a Services Appendix, this Agreement or by any applicable governmental authorities having or purporting to have authority over

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the subject matter contemplated herein

4A.1.3 "**Codes and Standards**" means all requirements, licences, requests, directives, rules, guidelines, standards, specifications, codes, instructions, circulars, manuals and procedures as may be required by a Services Appendix, this Agreement or by any applicable governmental authorities having, or purporting to have, authority over the subject matter contemplated herein.

4A.1.4 "**Environmental Laws**" means any Applicable Laws relating to the protection of the natural environment (including any species that might make use of it) or human health or the import, use, storage, transportation or disposal of any hazardous materials.

4A.1.5 "**Goods**" means any goods, materials, instruments, devices, articles, supplies and equipment, or components of any of them, delivered or required to be delivered OPG under a Services Appendix.

4A.1.6 "**LEP Personnel**" means all personnel used by LEP or assisting LEP in the provision of the LEP Services including any personnel, staff, labour and other employees of LEP or a Subcontractor and any Subcontractor who is an individual.

4A.1.7 "**Losses**" means all claims, demands, costs, penalties, expenses, liabilities, injuries, losses and damages (including all reasonable fees and charges of engineers, architects, accountants, lawyers and other professionals and experts).

4A.1.8 "**Services**" means providing all labour, materials, services, Goods, data, consumables and acts required to be supplied or performed by LEP a Services Appendix and the delivery of any submittals required to supply the Goods and Services in the prescribed manner.

4A.1.9 "**Site**" means the land or actual place designated by OPG for the performance of LEP services.

4A.1.10 "**Subcontractor**" means a person (including the person's heirs, executors, administrators, personal and legal representatives, successors and permitted assigns) who supplies or performs any LEP Services under an agreement with LEP, another Subcontractor or a combination of LEP and another Subcontractor.

4A.2 For the purposes of this Agreement "**Service Appendix**" means an OPG generated electronic or paper form in the form of "**Appendix A"** issued to LEP as evidence of an order for LEP Services under this Agreement.

4A.3 During the term, LEP may, from time to time, be retained by OPG to provide Goods and Services as described in a Service Appendix (the "**LEP Services**").

4A.4 LEP will perform the LEP Services in accordance with the terms and conditions of this Agreement and any additional terms and conditions set out in the Service Appendix.

4A.5 **Change in the Services.** OPG may, without invalidating a Services Appendix, request LEP in writing to make changes in the Services. When a change causes an increase or decrease in the cost, scope or schedule, the Fees and schedule will be modified as agreed upon between LEP and OPG.

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4A.6 **Invoicing**

4A.6.1 **Original Invoice.** On a monthly basis or the frequency set out in the Service Appendix, LEP will electronically submit to OPG an invoice containing:

4A.6.1.1 the total amount owing by OPG in accordance with the Service Appendix (showing separately all amounts due as Canadian goods and services tax/harmonized sales tax levied under the *Excise Tax Act* (Canada) and expressly stating any amounts invoiced in a currency other than Canadian dollars);

4A.6.1.2 the OPG Service Appendix number and line number, if applicable;

4A.6.1.3 LEP's full name and address;

4A.6.1.4 the name of a contact individual at LEP, with a telephone number;

4A.6.1.5 electronic transfer instructions;

4A.6.1.6 LEP's invoice number (which must be unique for each invoice);

4A.6.1.7 the invoice date (which must be the date the invoice is delivered);

4A.6.1.8 the value of LEP Services provided in Canada and outside Canada, identified separately; and

4A.6.1.9 LEP's 15 digit registration number for the purposes of Part IX of the *Excise Tax Act* (Canada).

4A.6.2 **Payment Terms**. OPG will aggregate all outstanding invoices received and accepted by OPG for payment before the 25th day of each month. Subject to any Applicable Laws, OPG will pay LEP this aggregate amount electronically on the 25th day of the following month. All payments are conditional, however, on LEP fulfilling its obligations and making satisfactory progress in providing the LEP Services before the date payment is made. OPG's will determine whether or not such obligations have been fulfilled and progress is satisfactory.

4A.7 **Fees**. In consideration of the provision of the LEP Services, OPG agrees to pay to LEP the fees that are set out in the applicable Service Appendix (the "**Fees**"), which Fees (i) will not exceed the market price as appropriate and (ii) will include payment for the completion of the LEP Services under the applicable Service Appendix and the preparation and delivery to OPG of all deliverables to be provided by LEP in connection therewith.

4A.14.1 The Fees will include:

4A.7.1.1 LEP's applicable employee costs including salary, incentive compensation, standard LEP allocations for benefits and pension and any applicable overhead or administrative costs

incurred by LEP with respect to the administration of the employees incurred by LEP for each OPG Support Employee and any additional costs paid by LEP in accordance with the OPG Support Assignment Agreements for those OPG Support Employees;

4A.7.1.2 all third party expenses incurred by LEP in providing those services;

4A.7.1.3 the direct cost of certain equipment or materials, or other deliverables used to provide the services; and

4A.7.1.4 a return on invested capital as appropriate.

4A.14.2 Any and all costs incurred by LEP to rent or sell Goods to OPG will be borne wholly by OPG, including, without limitation the cost of all activities· required to document, supply and deliver the Goods, all applicable freight, insurance, taxes and other charges incurred by LEP and reasonable wear and tear costs. Except as otherwise specified herein, Goods will be rented or sold, as applicable, at LEP's net book value by applying the remaining useful life to determine the calculated cost of such Goods, including a return on invested capital.

4A.14.3 In the event that LEP reimburses the expenses incurred by OPG Support Employees while working for OPG, in accordance with the terms of the OPG Support Assignment Agreement, OPG will reimburse the expenses incurred by OPG Support Employees incurred while working for OPG, in accordance with the terms of the Services Appendix.

4A.8 **No OPG Control Over LEP Services.** OPG will not supervise, direct and have control or authority over:

4A.8.1 the means, methods, techniques, sequences or procedures respecting the performance of the LEP Services by LEP; and

4A.8.2 the safety programs and precautions used in respect of the LEP Services, subject to OPG's rights and obligations under the Occupational Health and Safety Act (Ontario).

OPG will not be responsible for any failure by LEP to comply with any applicable laws or this Agreement in providing the LEP Services.

4A.9 **Extension of Term.** If the end of the term of the Agreement does not coincide with the end of the term of any Service Appendix, then this Agreement will automatically renew with respect only to the LEP Services to be completed under each such Service Appendix until such Service Appendix is fully completed by LEP in accordance with the terms of such Service Appendix and this Agreement.

4A.10 **Codes of Conduct.** LEP will:

4A.10.1 not take any action that would cause OPG to breach an obligation set out in OPG's Code of Business Conduct ("Code"); and

4A.10.2 comply with all of the obligations set out in OPG's Supplier Code of Business

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Conduct ("**Supplier Code**").

A current copy of the Code and the Supplier Code is located at www.opg.com, and a copy of each has been reviewed by LEP.

4A.11 **Permits, Laws and Regulations.** LEP will (and will cause each Subcontractor to) comply with all Applicable Laws and all standards, specifications, manuals or codes of any technical organization or governmental authority. LEP will obtain, at its cost, all permits and other consents required in respect of the LEP Services.

4A.12 **Cyber Security.** LEP will, at all times, conduct the LEP Services in accordance with the cyber security requirements set out in Appendix B attached hereto.

4A.13 **Workplace Safety and Insurance Board.** LEP will provide its Workplace Safety and Insurance Board account number to OPG before commencing the LEP Services at the Site. LEP and each Subcontractor will be and remain at all times in good standing with the Workplace Safety and Insurance Board. Before initial arrival on the Site, and every 90 days thereafter, LEP will submit a clearance certificate from the Workplace Safety and Insurance Board as to LEP's status and that of all Subcontractors that will be providing LEP Services at the Site.

4A.14 **Health and Safety.** For all LEP Services provided by LEP on OPG premises, LEP will, at its expense: 4A.13.1 comply with all Applicable Laws and OPG's safety requirements applicable to the LEP Services as set out in the Services Appendix;

4A.14.1 comply with all Applicable Laws and OPG's safety requirements applicable to the LEP Services as set out in the Services Appendix;

4A.14.2 ensure that all of the Contractor's Personnel are equipped with all safeguards and personal protective equipment as may be necessary for the performance of the LEP Services;

4A.14.3 rectify any failures to comply with any Applicable Laws or OPG's safety requirements applicable to the LEP Services immediately when detected or directed by OPG;

4A.14.4 upon request by OPG, provide OPG with required safety reports or notices relating to the LEP Services;

4A.14.5 comply with any order to comply, stop work or any similar order or notice respecting the LEP Services issued by any governmental authority or by OPG;

4A.14.6 co-operate with OPG in reporting and investigating safety violations caused by any act or failure to act of the LEP or any of its Subcontractors; and

4A.14.7 to the extent that LEP or any of its Subcontractors were responsible for a safety violation, LEP will pay OPG for costs and expenses incurred to investigate, report and/or alleviate the safety violation.

4A.15 **Subcontractors and Contractor's Personnel.**

4A.15.1 LEP will be fully responsible for all acts and omissions of each Subcontractor and

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LEP Personnel and any such acts and omissions will be deemed to be those of LEP. Accordingly, respecting each obligation of the LEP under this Agreement or the Services Appendix, LEP will ensure that no LEP Personnel or Subcontractor will breach any such obligation.

4A.15.2 LEP will ensure that all of LEP Personnel engaged on the project will have the knowledge, abilities, experience and qualifications required for the Services and will be dedicated to the Services. LEP will provide such additional support as may be required from time to time for the LEP Services' proper performance.

4A.15.3 OPG may request, at its discretion, that LEP Personnel (including personnel of any Subcontractor) be changed. LEP will endeavor to accommodate such requests promptly.

4A.16 **Environment.** LEP will, at all times, perform the LEP Services in Accordance with Environmental Laws and any other environmental requirements as may be identified by OPG from time to time.

4A.17 **Foreign Nationals.** LEP will obtain at its cost all Approvals from all applicable governmental authorities respecting all foreign nationals who may be engaged in providing the LEP Services in Canada.

4A.18 **Intellectual Property.**

4A.18.1 Each party and Subcontractor retains all Intellectual Property Assets to methodology, knowledge and data brought to the Services and used therein. No Intellectual Property Rights existing before the start of the Services are passed hereunder other than licences and rights to use Intellectual Property Rights as set out in this Agreement and the applicable Services Appendix.

4A.18.2 All title and beneficial ownership interests to all Intellectual Property Rights which are created or otherwise arise in the provision or performance of the LEP Services will vest exclusively in, and remain with, LEP (the "**New Intellectual Property Rights**").

4A.18.3 LEP will not do any act which may compromise or diminish the licences referred to in Section 4A.18.4 and will perform any acts required to confirm or document the licences referred to in Section 4A.18.4.

4A.18.4 LEP represents and warrants that it owns or has obtained from third parties, duly authorized grants of all right, title and interest necessary to provide to OPG a licence regarding the Intellectual Property Rights associated with the Services in the manner set out in this Agreement and the applicable Services Appendix including waivers of moral rights for the benefit of OPG. LEP hereby grants to OPG a worldwide, non-exclusive, irrevocable, perpetual, royalty free and fully paid-up licence and uninterrupted right to use all such Intellectual Property Rights that are contained or embedded in, required for the use of, used in the production of, or required for the reproduction, modification, maintenance, servicing, improvement or continued operation of the Services. The rights granted under this paragraph include a right for OPG to: (i) make copies; and (ii) modify and create derivative works from the subject matter of the right. LEP will pay all royalties, licence fees and other monetary amounts required in respect of securing and

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licencing the Intellectual Property Rights referenced in this Section 4A.18.4 and any other Intellectual Property Rights associated with the LEP Services.

4A.18.5 LEP will, at its expense, defend all claims, actions or proceedings against OPG relating to or based on any allegation that the LEP Services, or any part of the LEP Services, constitutes an infringement upon, or a misappropriation of any Intellectual Property Rights and will pay to OPG all resulting Losses incurred by OPG in respect of such claims, actions or proceedings. OPG will give LEP written notice of any such claim, action or proceeding and, at the request and expense of LEP, provide all reasonably available information, assistance and authority required to conduct its defence.

4A.18.6 If all or any part of the LEP Services are finally determined by any court, arbitrator, or administrative body to constitute an infringement or misappropriation of Intellectual Property Rights of a third party, or if OPG is enjoined by any means from using the LEP Services, any part thereof, or any Intellectual Property Rights embodied therein as a result of any claim of infringement or misappropriation, LEP will at its expense promptly: (i) obtain for OPG the right to continue using the LEP Services; (ii) replace the infringing elements of the LEP Services with non-infringing elements, while maintaining the full functionality, integrity and performance capabilities of the Services; or (iii) modify the LEP Services so that it no longer infringes, while maintaining the full functionality, integrity and performance capabilities of the LEP Services.

4A.19 **Indemnity.** LEP will indemnify and hold harmless OPG, from and against:

4A.14.1 all Losses suffered or incurred by OPG arising in respect of the Services, to the extent that any such Losses are attributable to bodily injury, sickness, disease or death, or to damage to or destruction of tangible property, including any resulting loss of use thereof;

4A.14.2 all claims made against OPG by any person;

4A.14.3 all Losses suffered or incurred by OPG and all claims made against OPG by any person, to the extent arising in respect of a breach or threatened breach by LEP, any Subcontractor or any of LEP's Personnel, of Section 8 of the Agreement; and

4A.14.4 all Losses suffered or incurred by OPG and all claims made against OPG by any person to the extent arising in respect of any breach or threatened breach by LEP, Subcontractor or any of the LEP's Personnel, of Section 8 of this Agreement,

but only to the extent such Losses or claims are attributable to a material breach of a Services Appendix by LEP or by any negligent act, negligent omission, fraud or willful misconduct of LEP, Subcontractor or any of LEP's Personnel. The obligations of LEP under this Section 4A.19 will not be affected in any way by any certificate, acceptance, approval, payment or any other act, matter or thing done or omitted under this Agreement, including any act by OPG.

4A.20 **Limitation of Liability**. Subject to Section 4A.21 , the liability of either party respecting all claims arising in respect of a Services Appendix will not exceed an aggregate amount equal to the Fees payable under such Services Appendix.

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4A.21 **Exceptions.** LEP's limitation of liability set out in Section 9.1 will not apply to:

4A.21.1 LEP's indemnity obligations under Section 4A.19 with respect to third party claims;

4A.21.2 amounts recovered from insurance under this Agreement, with LEP acting diligently in pursuit of recovery from its insurers of indemnifiable claims arising under this Services Appendix, (or that would have been recovered had LEP complied with its obligations under Section 4A.22) to the extent of the limits specified in Section 4A.22; and

4A.21.3 Losses suffered or incurred by OPG or any claims made against OPG by any person, to the extent arising in respect of fraud, gross negligence, or willful misconduct by LEP or any of its Subcontractors.

4A.22 **Insurance.** LEP will maintain, or cause to be maintained, at its own expense, and shall cause its Subcontractors to maintain at all times during the term and any extension of this Agreement, the following insurance with reputable insurers whose policies are valid in the jurisdiction in which the Services are performed:

4A.22.1 commercial general liability insurance on an occurrence basis, with minimum limits of not less than $5,000,000 per occurrence, covering bodily and personal injury, including death, and property damage, including resulting loss of use. Such policy will contain severability of interests and cross liability clauses and will name OPG as an additional insured with respect only to liability arising from the operations of LEP; and

4A.22.2 if motor vehicles are used by LEP in the performance of this Services Appendix, automobile insurance covering all owned and non-owned vehicles with a limit of not less than $2,000,000.

Upon execution of this Agreement, and upon OPG's reasonable request thereafter, LEP will provide OPG with evidence of the required insurance in the form of certificates of insurance. LEP will ensure that all such policies will require that insurers endeavor to provide OPG with 30 days prior written notice of material change to or termination of any such policy

4A.23 **Consequential Damages Disclaimer**. Notwithstanding any other term in this Agreement or a Services Appendix, in no circumstances whatsoever will either party be liable to the other party for indirect, incidental or for consequential liabilities, damages, losses, costs or expenses, including loss of profit or revenues, loss of production, loss of use or any other similar damages or loss suffered or incurred by such other party, regardless of the legal theory upon which any such damages claim is based, even upon the fault, tort (including negligence), statute, regulation, or any other theory of law or strict liability.

4A.24 **Project Delivery.** LEP will diligent endeavor to complete the Services in accordance with the schedule set forth agreed to by the parties and, if necessary, will increase the level of effort/resources necessary to ensure the schedule is maintained. Any price or funding limitations, as outlined in a Services Appendix will not be exceeded without OPG's prior written authorization, notwithstanding any extra efforts required to maintain schedule. In the event of a delay or default in performance by LEP, OPG may, in its sole discretion, extent the time period for performance upon conditions satisfactory to OPG. Any extension granted by OPG will not prejudice its ability to exercise its termination rights in the event of further default or delay.

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4A.25 **Accounts and Rights to Audit.** LEP will keep proper accounts and records of the Services in form and detail satisfactory to OPG. Such accounts and records, including invoices, receipts, time cards and vouches will at all reasonable times be open to audit, inspection and copying by OPG. Accounts and records will be preserved and kept available for audit until the expiration of two years from the date of completion or termination of the Services.

4A.26 **Early Termination.** OPG may terminate the any Services Appendix ("**Terminated Services**") at any time before the end of a Services Appendix Term by giving notice of termination to LEP at least 30 days before the proposed early termination date. If OPG terminates the Services under this Section, OPG shall pay to LEP all Fees, Taxes and Late Payment Charges due for the Terminated Services up to the date of termination. OPG acknowledges that the Termination Fees are a reasonable estimate of LEP's damages and represent consideration for the deliverables, and are not a penalty.

4A.27 **Force Majeure**. Neither LEP nor OPG will be liable to the other for loss, damage or delay in the Services, or non-performance of any contractual obligation caused by war, riot, the act or order of any competent civil or military authority, fire, flood, pandemic, epidemic or by any other cause which is unavoidable and beyond the party's reasonable control. Both parties will be prompt in restoring normal conditions, re-establishing schedules, and resuming operations as soon as the interruptions have ceased. LEP will not be entitled to an extension of time for any delay covered in this Section 4A.27 unless notice of a claim thereof is given by LEP within 30 days after the commencement of the delay. The length of any such extension will be determined by OPG but will in no event be less than the length of such force majeure event.

4A.28 **Default by LEP.** Each of the following events and circumstances constitutes an event of default by LEP under the Services Appendix under which the event occurred (a "**LEP Event of Default**"):

4A.28.1 becoming subject to any act of insolvency or bankruptcy, dissolution or liquidation voluntary or otherwise;

4A.28.2 having a receiver, trustee, custodian or similar agent appointed on account of insolvency or in respect of any property;

4A.28.3 making a general assignment for the benefit of creditors;

4A.28.4 committing a breach of Anti-Corruption Laws;

4A.28.5 failing to comply with any reasonable request, instruction or order of OPG related to the Services;

4A.28.6 failing to pay accounts relating to the Services as they come due in accordance with the relevant contract;

4A.28.7 failing to comply with statutes, laws, regulations, bylaws or directives of competent authorities relating to the Services;

4A.28.8 failing to perform the Services with skill and diligence;

4A.28.9 any representation made by LEP herein that was intentionally false or misleading when made in any material respect;

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4A.28.10 failing, neglecting, refusing or being unable at any time during the term to provide reasonably adequate LEP Personnel to perform the Services; or

4A.28.11 being otherwise in default in carrying out any of its obligations under this Services Appendix, whether such default is similar or dissimilar in nature to the causes listed previously and failing to remedy the breach to the satisfaction of OPG within ten business days following receipt of notice from OPG specifying the breach, or if the breach cannot be cured within such ten business day period, after such longer period of time as is reasonably required to cure the breach (but no longer than 60 days in any circumstances), so long as LEP diligently and constantly endeavours to cure the breach during such extended period.

Notice that LEP is in default will not be required if the default relates to the bankruptcy, insolvency or financial instability of LEP. Other than defaults arising from Sections 4A.28.1, 4A.28.2 and 4A.28.3, OPG will provide the LEP with ten days written notice. Any action by OPG under this Section 4A.28 will be without prejudice to OPG's other rights or remedies under this Contract or law or under any security held by OPG for performance of this Contract by LEP

4A.29 **Recommendations.** If the Services include the provision of recommendations by LEP to OPG, OPG acknowledges and agrees that LEP does not warrant the completeness or exhaustiveness of its recommendations, nor shall LEP be liable for any omissions. OPG further acknowledges and agrees that it shall be solely responsible for deciding whether and how to implement those recommendations, and for any business risks associated with such implementation. LEP assumes no responsibility for on-going management decisions, whether with respect to the implementation of its recommendations or otherwise, or any other results of the Services provided. OPG agrees that it shall not share the results of such recommendations outside of its organization.

4A.30 **OPG Obligations**. LEP shall be excused from its inability to perform the Services or to provide any other deliverable, or for any delay in the performance of the Services or the provision of any deliverable to the extent of, the following: (a) non-performance of or any delay or deficiency in the performance by OPG of a OPG obligation under a Services Appendix; (b) where OPG directs LEP to provide the Services in accordance with a prioritization that OPG has been advised by LEP could reasonably be expected to have an adverse impact on the planned provision of the Services; (c) any delays, errors, defects or other problems contained in the information, materials and/or instructions provided to LEP by OPG; or (d) any OPG suspension, delay or cancellation of Services, including failure to deliver contracted volumes of waste to LEP.

ARTICLE 4.1
INTELLECTUAL PROPERTY

4.1.1 For purposes of this Section 4.1, "**Intellectual Property Assets**" means any and all rights that are or may be granted to, or recognized for the benefit of, any party under any legislation regarding patents, copyright and any copyrightable subject matter (including moral rights), trade-marks, trade names, service marks, confidential information or trade secrets, industrial or, as applicable, patent designs, integrated circuit topography rights and any other statutory provision or common or civil law principle regarding intellectual property, whether registered or unregistered, and including rights in any and all applications, registrations, re-issues, divisionals, continuations, continuations-in-part, renewals, re-examinations relating to the foregoing, and any and all rights in and to licenses and sub-licenses from third parties relating to the foregoing;

4.1.2 Recognizing that, from time to time, it may be desirable for LEP to sub-licence OPG Intellectual Property Assets to third parties, the parties hereto agree as follows:

4.1.2.1.1 Upon written authorization from the owner of the relevant Intellectual Property Assets, OPG hereby grants to LEP a perpetual, irrevocable, non-exclusive, royalty-free and fully paid up right and licence to use, sell, transmit or transfer the relevant Intellectual Property Assets and to sub-licence the right to use such Intellectual Property Assets to third Parties for such term as is suitable given LEP's commercial needs;

4.1.2.1.2 OPG and LEP hereby acknowledge and agree that OPG is and will remain the sole and exclusive owner of all right, title and interest in and to Intellectual Property Assets, subject only to the rights of third parties in any license agreement respecting the Intellectual Property Assets;

4.1.2.1.3 In consideration of OPG licensing the Intellectual Property Assets to LEP, LEP agrees to: (i) take all such steps as are reasonably required to safeguard the Intellectual Property Assets licensed to LEP from infringement, misappropriation, theft, misuse and unauthorized access; (ii) promptly notify OPG in writing if LEP becomes aware of any actual or suspected infringement, misappropriation or misuse of the Intellectual Property Assets; (iii) ensure that any agreement in which it sub-licenses OPG Intellectual Property Assets to third parties provides adequate protection for OPG's Intellectual Property Assets and such other protection from liability as is commercially reasonable; and (iv) pay to OPG at least 25% of the profits that LEP earns on the sub-licensing, sale, transmission or transfer of OPG Intellectual Property Assets.

4.1.2.1.4 Except for the limited rights and licences expressly granted under this Agreement, nothing in this Agreement grants, by implication, waiver, estoppel or otherwise, to Licensee or any third party any right, title or interest in or to the Intellectual Property Assets.

ARTICLE 5
TERM

This Agreement commenced on May 28, 2012 and shall terminate December 31, 2026, unless earlier terminated by the parties in writing, and subject to renewal with the mutual consent of the parties.

ARTICLE 6
TERMINATION

6.1 Notwithstanding Article 4, this Agreement may be terminated upon 30 days prior written notice by either party to the other party or upon the occurrence of the following events:

(a) in the event the parties fail to agree to a revised Appendix A in accordance with the terms of Section 3;

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(b) in the event of a material default in the performance of the Agreement by such other party; or

(c) by written notice effective immediately if the other party makes any extraordinary arrangement with its creditors generally, commits an act of bankruptcy, goes into liquidation or winding-up, has execution or distress levied upon any of its assets, or becomes unable to pay its debts, including its debts to the other party, as they fall due.

6.2 Upon termination of this Agreement pursuant to Section 6.1 ,

(a) the provisions of this Agreement which are expressed to survive this Agreement or to apply notwithstanding termination hereof shall be observed by both parties hereto; and

(b) neither party shall be liable to the other party, either for fees, expenses, other compensation, or damages of any kind or character whatsoever, whether on account of the loss by OPG or LEP of present or prospective profits or fees on sales or anticipated sales, or expenditures, investments, or commitments made in connection therewith, or in connection with the establishment, development, or maintenance of the business of any party, or on account of any other cause or thing whatsoever, provided that such termination shall not prejudice or otherwise affect the rights or liabilities of any party with respect to any indebtedness owing by either party to the other party at the time of termination.

ARTICLE 7
INVOICE AND PAYMENT

After the end of each month, OPG shall provide LEP with a notice (the "**Invoice**") setting forth the total amount owing to OPG in respect of the LEP Support Employee services, charges for certain equipment or materials used by LEP, and the professional and corporate services provided during such month. The Invoice will be delivered within the first 15 days of the following month and LEP shall be required to review and comment on such Invoice within 15 days following receipt thereof. LEP shall pay all undisputed amounts payable under such Invoice on the twenty fifth day of such following month (the "**Due Date**") (and if the Due Date is not a Business Day, the immediately following Business Day), and any disputed amounts shall be resolved in accordance with Article 10.Except as otherwise expressly provided herei "**Business Day**" means any day except a Saturday, Sunday, banking holiday or a statutory holiday in Toronto, Ontario and shall open at 8:00 a.m. and close at 5:00 p.m. local time. n, this is the only approved procedure by which LEP may compensate OPG under this Agreement. For clarity, OPG cannot charge costs to LEP by way of an accounting or book transfer.

ARTICLE 8
CONFIDENTIALITY

8.1 In the course of this Agre the OPG or LE (each a "**Disclosing Party**") will disclose to the other party (each a "**Receiving Party**") certain information (including applications of that information) which is confidential, a trade secret or otherwise proprietary to the Disclosing Party, including this Agreement (collectively, the "**Confidential Information**"). Confidential Information does not

include, however, information that the Receiving Party is able to demonstrate to the Disclosing Party's satisfaction, acting reasonably: (i) was or becomes generally known to the public through no fault of the Receiving Party or its respective shareholders, directors, officers, partners, members, representatives, agents, advisors or any of the Receiving Party's personnel or any other person for whom the Receiving Party is responsible at law; (ii) was specifically known by the Receiving Party before disclosure by the Disclosing Party and was not subject to any confidentiality obligation; (iii) was developed or ascertained independently without reference to the other party's Confidential Information; or (iv) was received from a third party without such third party being under a duty of confidentiality.

8.2 All Confidential Information remains, at all times, the exclusive property of the respective Disclosing Party. Except as expressly set out in this Agreement, a respective Receiving Party has no licence or other right to use or disclose any Confidential Information for any purpose whatsoever. Such Receiving Party may use Confidential Information only in respect of the preparation or provision of the goods, services and personnel as set out in this Agreement. Such Receiving Party will ensure that none of its current or former shareholders, directors, officers, partners, members, representatives, agents and advisors or any of its personnel or any other person for whom such Receiving Party is responsible at law will use any of the Confidential Information for any purposes other than those expressly set out in this Section 8.

8.3 At the Disclosing Party's request, the Receiving Party will promptly (and in any event, within ten business days of receipt of such request) return to the Disclosing Party or destroy, at the Disclosing Party's election, any and all Confidential Information belonging to the Disclosing Party, including all reproductions and any documents based on any of the Confidential Information, and will not retain any copies thereof provided that the Receiving Party may retain any copies of Confidential Information (a) required to comply with the requirements of any applicable legislation, other legal requirement, internal record retention policies or procedures or good governance, and (b) automatically created on the Receiving Party's computer systems by its normal back-up procedures for the period it normally archives backed-up computer records; however, such Confidential Information referred to in (a) and (b) remains confidential and subject to the terms of this Agreement. Promptly following delivery or destruction, as the case may be, on the request of the Disclosing Party, the Receiving Party will provide the Disclosing Party with written confirmation of completion.

ARTICLE 9
NOTICES

Unless otherwise provided herein, every notice provided for in this Agreement shall be in writing directed to the party to whom given, made or delivered at such party's address, by registered mail, by electronic mail or personally as follows:

If to OPG:
Ontario Power Generation Inc.
700 University Avenue, H19
Toronto, Ontario
M5G 1X6

Attention: Corporate Secretary
Email:

If to LEP:

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Laurentis Energy Partners Inc.
700 University Avenue, H19
Toronto, Ontario
M5G 1X6

Attention: Corporate Secretary
Email: laurentis@laurentisenergy.com

Either party may change its address from time to time by giving written notice of such change to the other party. If any such notice is delivered by hand to an officer of the addressee, it shall be deemed to have been received by the addressee as soon as such delivery or transmission has been made to said officer.

ARTICLE 10
DISPUTE RESOLUTION PROCEDURE

In the event that a dispute arises concerning any of the matters set forth herein, OPG and LEP shall cause the representatives designated by it to prepare and circulate promptly to the President of OPG and the President of LEP a written statement setting forth its position on the matter in dispute and its reasons for adopting such position. Each such office shall use their best efforts to resolve the matter in dispute within ten (10) business days following their receipt of such statement. If such officers agree upon a resolution of the matter, each of OPG and LEP shall take such action and necessary steps to ensure that such resolution is fully and promptly carried into effect.

ARTICLE 11
COMPLIANCE WITH ANTI-CORRUPTION LAWS

11.1 Each party will comply with, and will take all reasonable measures to ensure that its employees; subcontractors, agents or other third parties subject to its control or determining influence will comply with, all applicable anti-corruption laws and policies, including the *Foreign Corrupt Practices Act* (U.S.), the *Corruption of Foreign Public Officials Act* (Canada), the *Bribery Act* (U.K.) and any applicable laws of similar effect of any other jurisdiction (collectively "**Anti-Corruption Laws**"), in connection with the services supplied hereunder.

11.2 Each party represents, warrants and undertakes that it has instituted and maintains policies and procedures designed to ensure, and which are reasonably expected to continue to ensure, compliance with Anti-Corruption Laws, including policies and procedures designed to ensure that all agents, consultants or other persons employed or acting on its behalf or facilitating the conduct of its business comply with Anti-Corruption Laws.

ARTICLE 12
GENERAL

12.1 Entirety. This Agreement is intended by the parties as the final expression of their agreement and is intended also as a complete and exclusive statement of the terms of their agreement with respect to the matters herein. All prior written or oral understandings, offers or other communications of every kind pertaining to the matters herein are abrogated and withdrawn.

12.2 Relationship. This Agreement shall not be construed to constitute a joint venture, partnership or

agency between OPG and LEP. LEP acknowledges that it does not have, nor hold itself out to others as having, authority to bind OPG to contracts, agreements or other obligations.

12.3 Assignment. The provisions of this Agreement shall be binding upon and inure to the benefit of OPG, LEP and their respective successors and permitted assigns. Neither party may assign this Agreement without the prior written consent of the other party.

12.4 Headings. Headings provided in this Agreement shall have no meaning and are included only to facilitate reading of the Agreement.

12.5 Controlling Law. This Agreement is and shall be deemed to be a contract entered into pursuant to the laws of Ontario and shall in all respects be governed and enforced in accordance with the laws of Ontario.

12.6 Counterparts. This Agreement may be executed in one or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument. Any counterpart signature transmitted by sending a scanned copy by electronic mail or similar electronic transmission will be deemed an original signature.

12.7 Separability of Clauses. Any provision or provisions of this Agreement which in any way contravene the law of any province, state or country in which this Agreement is effective shall, in such province, state or country, to the extent of such contravention of law be deemed separable and shall not affect any other provision hereof or the validity hereof.

12.8 Waiver. Either party may waive any right, interest, or condition of this Agreement which is for its benefit without implying the waiver of any other right or interest, or subsequent waiver.

IN WITNESS WHEREOF, the parties have duly executed and delivered this Agreement as of the date first written above.

ONTARIO POWER GENERATION INC.

By: _____
Name: Sean Granville
Title: Chief Operations Officer & Chief Nuclear Officer

By: _____
Name:
Title:

LAURENTIS ENERGY PARTNERS INC.

By: _____
Name: Dominique Miniere
Title: Chief Executive Officer

By: _____
Name:
Title:

APPENDIX A

Process for Requesting, Releasing and Recording Agreed Upon Services

As referenced in Article 0.1 of the Agreement, services can be requested by either party from time to time. Sections 1-5 describe how to request services, obtain approval and appropriately file the release. This process is necessary to ensure that both OPG and LEP understand what has been agreed to, the duration of each release and to allow the businesses to maintain a controlled listing of work currently being executed and work that needs to be planned. Some services may require that the parties develop additional forms of documentation to appropriately describe those services and agree upon the terms and conditions that apply to those services. In such cases a Work Request Form need not be completed.

1. Request for Services

Services which are required and can be provided, shall be initially identified through verbal discussions during the business planning process or during the normal course of business. To finalize a services request, a Work Request Form (see sample below) will be completed and will indicate the project name or defined work package, a brief description of the services required, and any timeline, other limitation, or applicable conditions, including special terms and conditions.

Sample

Work Request Form	
Requesting Department and Organization	example - Enterprise Projects, OPG
Contact email	John.smith@opg.com
Start Date	January 1, 2021
End Date	December 31, 2021
Summary of Work	Summary of estimation requirements
Special Considerations - specialized requirements	Special qualifications, performance expectations, milestones,any other relevant information associated with the work
Submission Date	January 1, 2021
Required Response Required by	January 2, 2021

2. Definition and Estimation

Upon receipt of a Work Request Form, the responding organization will determine if it can provide an estimate in response. If the responding organization can, it shall complete a Work Estimate and Approval Form (see sample below), confirming the work to be carried out, the schedule, resources and total estimated cost. Before returning this estimation to the requesting party, the details will be approved by the appropriate OAR authority allowed to authorize contractual commitments for the organization. The form will then be routed to the requesting organization.

Work Estimate and Approval to Proceed Form

Release under the General Services Agreement between Laurentis Energy Partners and OPG

Revision #	Rev 0
Date	

The agreed upon, identified support is intended to capture total support requirements provided through SLA agreements are aligned with OPG's and LEP's approved Accounting Treatments.

For SLA purposes and BPC rollup, project #s have been simplified for SLA approvals/Bping.

Note: Please see attached SoW document for the services to be provided.

Bundle/ Function	Bundle/ Function	Service Provider
		OPG or LEP

				Annual Requirement						Total
Project #	**Description**	**Unit**	**Additional Information (JF2, etc)**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2021-2026**
		$k								0
		$k								0.0
		$k								0.0
		$k								0.0
		$k								0.0
		FTE								0.0
		FTE								0.0
	Total Labour $	$k	**Total Labour $**	0	0	0.0	0.0	0.0	0.0	0
		FTE								0.0
		$k								0.0
Subtotal, FTE		**FTE**		0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal Non-Labour, $		**$**		0	0	0	0	0	0	0

SLA Approvals:

Service Provider (OAR)
I have reviewed this estimation and agree that this service proposal can be delivered as submitted.

Name
Title
Organization

Signature

Date: _____

Acceptance Approval (OAR)
I accept this proposal and request that this service be executed.

Name
Title
Organization

Signature

Date: _____

Routing of completed SLA Releases:
cc: finance@laurentisenergy.com

LEP - Finance Use only

Sales order or Purchase order completed	☐
Alignment with Project completed	☐
Contractor Utilization updates completed	☐
Business Planning Schedule completed	☐

3. Review and Authorization

If the proposal is acceptable, the requesting party will approve the work to proceed through their respective OAR position holder(s). A copy will be routed back to the responding organization for confirmation to proceed and the services will be filed, transactional systems updated, and reports generated based on these commitments within both organizations. If OPG is the requesting party, OPG and LEP will also execute a Services Appendix to document the LEP Services.

4. Change Management – on released work

If aspects such as cost estimations, cancellations, terms or special conditions change, a change request be

circulated following a similar process as identified in step 2-3 to ensure all stakeholders are duly notified and are agreeable to such changes. The same form can be used and should be marked clearly as a CHANGE to any existing services.

5. Facility Policies and Procedures

If LEP Support Employees provide services at a LEP site, such employees shall do so in accordance with LEP policies and procedures, including security checks, that have been identified to OPG. LEP will provide to OPG a copy of such policies and procedures.

APPENDIX B
CYBER SECURITY

1.1 Certain Definitions. For the purposes of this Appendix B:

(a) "**Cyber Asset**" means:

(1) any asset designated by OPG as a Cyber Asset; or

(2) any computing hardware, software, firmware or other computing or information technology that:

(A) is transferred, licensed, made available, or otherwise provided by LEP to OPG under this Agreement or a Services Appendix, or is used exclusively by LEP for OPG under this Agreement or a Services Appendix, and

(B) has the ability to impact the availability, integrity or confidentiality of OPG Systems and Information,

unless OPG expressly specifies that such computing hardware, software, firmware or other computing or information technology is not considered a Cyber Asset under this Agreement.

(b) "**Cyber Equipment**" means any of LEP's computing hardware, software, firmware or other computing or information technology that is:

(1) not a Cyber Asset; and

(2) connected to any OPG Systems and Information or is used to access, create, modify, store, process or transmit OPG Data in the course of performing LEP's obligations under this Agreement or a Services Appendix.

(c) "**Cyber Services**" means any application, infrastructure or related service provided by LEP in relation to:

(1) any asset designated by OPG as a Cyber Asset; or

(2) any computing hardware, software, firmware or other computing or information technology that has the ability to impact the availability, integrity or confidentiality of OPG Systems and Information unless OPG expressly specifies that such application, infrastructure or related service is not considered Cyber Services under this Agreement or a Services Appendix.

(d) "**OPG Data**" means all information relating to OPG, its business, financial position, assets, technology, operations, activities or proposed activities and prospects, including any technical, commercial, legal, financial, strategic, tactical, regulatory or governmental information, reports, drawings, specifications, contracts, business plans, projections, forecasts or other documents or information, whether written or oral, and including such information that is provided to LEP by OPG or its representatives, or otherwise received or accessed by LEP, under this Agreement or a

Services Appendix, or created or provided to OPG by LEP under this Agreement or a Services Appendix.

(e) "**OPG Systems and Information**" means OPG's networks, information systems, industrial control systems, or any components thereof (including computing hardware, software, firmware or other computing or information technology), or any OPG Data.

(f) "**Priority One Cyber Asset**" means any Cyber Asset designated by OPG in the Services Appendix as a Priority One Cyber Asset; and

(g) "**Priority One Cyber Services**" means any Cyber Services designated by OPG in the Services Appendix as a Priority One Cyber Services.

1.2 Cyber Security Requirements. LEP:

(a) represents and warrants to OPG that: (i) LEP has a written and enforceable cyber security policy, and has established and maintains a cyber security program that is designed and implemented to prevent, detect and respond to cyber attacks that may impact OPG Systems and Information; and (ii) LEP Personnel (which, for the purposes of these requirements, includes any LEP Personnel having access to OPG Systems and Information) have completed position-appropriate cyber security training;

(b) will immediately revoke all access to OPG Systems and Information for any LEP Personnel who is terminated or no longer needs access to OPG Systems and Information;

(c) will notify OPG by sending an email to sccs@opg.com within 48 hours after discovering any security breach, incident or vulnerability impacting or otherwise involving OPG Systems and Information (including any Cyber Equipment if LEP, acting reasonably, believes any such security breach, incident or vulnerability may have impacted or may potentially impact OPG Systems and Information), and furthermore if such security breach, incident or vulnerability relates to any Cyber Asset, Cyber Equipment, or Cyber Services, LEP will also: (i) include in such written notification of any security breach, incident or vulnerability to OPG a description of the breach, incident or vulnerability, its potential security impact, its root cause, a remediation plan, and recommended mitigating or corrective actions; and (ii) promptly and continuously cooperate and coordinate with OPG to prevent, stop, contain, mitigate, resolve, recover from, respond to, and otherwise deal with any security breach, incident or vulnerability, including by providing OPG with ongoing status reports;

(d) will: (i) ensure that no contaminants, including viruses, worms, Trojan horses, adware, spyware, trackware, hack tools, dialers, joke programs, time locks or other software routines, codes or instructions of a similar nature are placed on, or allowed access to, any OPG Systems and Information; and (ii) perform patching and testing on any Cyber Equipment, including through the performance of anti-malware and vulnerability scans, in order to identify and correct or mitigate any cyber security weaknesses or vulnerabilities;

(e) if OPG provides specific LEP Personnel with a unique user identification (ID) to access OPG Systems and Information ("**Designated Named Account(s)**") will: (i) ensure only

LEP Personnel designated by name may use the Designated Named Account(s); (ii) ensure the Designated Named Account(s) are not shared with any individual or entity other than such LEP Personnel; and (iii) notify OPG immediately after becoming aware of a decision to terminate or re-assign any of LEP Personnel to whom OPG provided Designated Named Account(s), to allow OPG to revoke such LEP Personnel's access on a timely basis;

(f) if OPG provides LEP with a generic user identification (ID) to access OPG Systems and Information ("**Generic Account**"), will: (i) ensure only LEP Personnel authorized by OPG may use the Generic Account; (ii) ensure the Generic Account is not shared with any individual or entity other than such LEP Personnel; (iii) change the password for the Generic Account on a periodic basis in accordance with best practices; and (iv) notify OPG immediately after becoming aware of a decision to terminate or re-assign any of LEP Personnel authorized by OPG and change the password for the Generic Account immediately following such termination or re-assignment;

(g) if remote access (such as LEP-initiated interactive remote access or system-to-system remote access) is required to access OPG Systems and Information, will: (i) only use those internet protocol (IP) addresses, ports, and minimum privileges required for the remote access as mutually agreed by the parties; (ii) only use Designated Named Account(s); and (iii) in case of system-to-system connections that may limit OPG's capability to authenticate the personnel connecting from LEP's systems, maintain complete and accurate books, user logs, access credential data, records, and other information applicable to connection access activities for the entire term of this Agreement;

(h) will ensure that OPG Data is properly safeguarded; and

(i) if LEP is required by OPG to dispose of OPG Systems and Information, will ensure that: (i) the disposal is done securely and in a timely manner and in compliance with Applicable Laws; and (ii) if LEP retains any OPG Data created on LEP's Cyber Equipment by its normal back-up procedures, LEP: (a) has restricted access to any backed-up OPG Data; (b) does not intentionally attempt to recover such OPG Data, unless directed by OPG or required by Applicable Laws; and (c) if LEP does recover any such OPG Data (including as a result of a disaster recovery procedure), LEP will immediately dispose of such OPG Data, unless directed by OPG or required by Applicable Laws, provided that if LEP is required by Applicable Laws to recover or disclose any such OPG Data, LEP will: provide OPG prompt notice of such requirement and the details thereof so that OPG may challenge such requirement or seek an appropriate protective order; consult with OPG on the advisability of taking legally available steps to resist or narrow such requirement; disclose only such OPG Data as is required by Applicable Law; and use best efforts to obtain an order or other reliable assurance that confidential treatment will be accorded to such OPG Data.

1.3 Cyber Assets or Cyber Services. If LEP is providing any Cyber Asset or Cyber Service to OPG, in addition to the foregoing, LEP will:

(a) provide to OPG: (i) documentation that describes LEP's applicable aspects of its system development lifecycle and patch management program and update processes; (ii) documentation that describes the cyber security features and wireless or remote networking capabilities of the Cyber Asset; and (iii) cyber security-focused

instructions, including manuals, for the maintenance, support and reconfiguration of the Cyber Asset, and best practice recommendations for hardening of the Cyber Asset and, as applicable, OPG Systems and Information;

(b) provide to OPG the appropriate patches and/or updates to remediate any security vulnerabilities in the Cyber Asset within seven days after becoming aware of any vulnerabilities, disclose to OPG its mechanisms to deliver software, firmware and patches, including checksums, digital signatures or other means of identification for all software, patches and configuration files, and ensure its controls will enable OPG to verify the authenticity and integrity of the patches delivered through these mechanisms. If patches and/or updates cannot be made available by LEP within the specified period, LEP will provide mitigations and/or workarounds until the patches and/or updates are available and provided. This provision also applies to all third-party components used in the Cyber Asset;

(c) if applicable, use tamper-evident packaging when supplying to OPG any computing hardware and, at OPG's request, provide copies of any documentation to show the chain-of-custody for such hardware; and

(d) use information technology security best practices in the development of the Cyber Asset and will ensure that: (i) there are no hardcoded passwords utilized in the Cyber Asset; (ii) there are no accounts or known methods that are able to bypass authentication in the Cyber Asset, unless Contractor has made OPG aware of, and OPG has accepted in writing, such accounts or methods; and (iii) the most critical cyber security weaknesses are addressed in Contractor's system development life cycle (Contractor will refer to applicable standards, such as the SANS Top 25 Most Dangerous Software Errors, the OWASP Top 10, or their successors).

1.4 Priority One Cyber Assets or Priority One Cyber Services

Notwithstanding any other term in this Agreement, if the LEP is providing any Priority One Cyber Asset or Priority One Cyber Services, in addition to the foregoing, LEP:

(a) represents and warrants to OPG that no unsupported system components or binary or machine- executable codes from sources with limited or no warranty are used in the Priority One Cyber Asset;

(b) will comply with all of OPG's security policies, standards, and procedures as may be provided by OPG to LEP from time to time, unless OPG expressly specifies that a particular cyber security policy, standard, or procedure does not need to be adhered to under this Agreement or a Services Appendix;

(c) will comply with Applicable Laws, including the North American Electric Reliability Corporation's Critical Infrastructure Protection (NERC CIP) standards for Priority One Cyber Assets or Priority One Cyber Services relating to OPG renewable generation, the Canadian Standards Association (CSA) standard N290.7 for Priority One Cyber Assets or Priority One Cyber Services relating to OPG nuclear facilities;

(d) will identify in writing to OPG the individual(s) who will be accountable for the overall security of all aspects of the Work;

(e) will ensure that only LEP Personnel authorized by OPG are permitted to access, process, store or transfer OPG Systems and Information and only after verifying the implementation of required security controls as specified in this Agreement or a Services Appendix and OPG's security policies, standards, and procedures;

(f) will ensure that OPG Data is properly safeguarded using appropriate encryption at rest and in transit, and will use appropriate physical and logical boundary protection in case of processing, storing, or transmitting OPG Data;

(g) will: (i) work with OPG to identify and assess all critical components of the Priority One Cyber Asset in terms of the impact of the function or component failure on the availability, integrity or confidentiality of OPG Systems and Information; (ii) identify to OPG any open source, commercially licensed, or secondary market components of the Priority One Cyber Asset; (iii) for each critical component of the Priority One Cyber Asset, including third-party hardware, software, and firmware, provide to OPG all licensing information, version numbers, source of the critical component and, if applicable, the end-of-life of the critical components; (iv) provide to OPG the release schedule and availability of updates and patches for each critical component; and (v) disclose to OPG its mechanisms to deliver software, firmware and patches, such as checksums, digital signatures or other means of identification for all software, patches and configuration files, and ensure its controls will enable OPG to verify the authenticity and integrity of the patches delivered through these mechanisms;

(h) will complete the appropriate tests of the Priority One Cyber Asset and its critical components in order to provide assurance that all known vulnerabilities are identified and removed, and provide the results of such tests to OPG as part of its acceptance of such Priority One Cyber Asset. If OPG, in its sole discretion, decides to assess the appropriateness of the completed tests and acting reasonably determines that additional tests are required in order for OPG to accept the Priority One Cyber Asset, LEP will complete the additional tests of the Priority One Cyber Asset and its critical components and provide the results of such tests to OPG as part of its acceptance of such Priority One Cyber Asset;

(i) will identify all logical network-accessible ports and disable any unused or, as determined by OPG, any unnecessary physical and logical ports/protocols in the Priority One Cyber Asset;

(j) in collaboration and coordination with OPG in incident response activities, will ensure speed of communication, response times, corrective actions, and other related activities are in accordance with OPG's incident response standards provided by OPG to LEP from time to time. If OPG, in its sole discretion, determines that a security breach, incident or vulnerability relating to or potentially relating to a Priority One Cyber Asset or Priority One Cyber Services is having or may potentially have a high impact on OPG's ability to conduct business or creates a high risk to OPG, based on OPG's risk management policies and procedures, LEP will provide a remediation plan within one Business Day after receiving notice from OPG of such determination and will target the LEP within seven Business Days after receiving such notice. In all other cases, OPG and Contractor will mutually agree on a timely resolution that in no case will exceed the next scheduled maintenance release, unless OPG, in its sole discretion, accepts a later resolution;

(k) will maintain valid provenance with respect to any access, creation, modification, storage, or transfer of any Priority One Cyber Asset or related OPG Data; and

(l) will ensure it has effective audit and accountability policies and procedures in place that cover cyber security, and, upon request by OPG, LEP will share OPG-relevant cyber security audit information, such as OPG-related portions of a service organization control report, certifications and third-party assessments, with OPG.

OPG reserves the right to audit LEP in all aspects of cyber security, including (i) development processes, procedures, practices, and methodologies; and (ii) evidence from development and assessment activities providing grounds for confidence that (a) LEP has complied with all Applicable Laws, any applicable regulatory standards, and OPG's cyber security policies, standards, and procedures, (b) the required cyber security functionality has been implemented, and (c) the required cyber security strength has been achieved. OPG may use independent third-parties or OPG personnel to conduct assessments of systems, components, products, tools, and services to uncover vulnerabilities prior to accepting the Priority One Cyber Asset or Priority One Cyber Services. LEP will maintain records related to this Appendix for the period expiring the latest of: (i) three years; or (ii) such other period as set out under this Agreement or a Services Appendix. LEP will, at its expense, provide OPG or its auditors prompt access to LEP's premises, documents, records, and personnel as required for any such audit, and will ensure that OPG or its auditors may conduct similar audits of any of LEP's subcontractors. If any such audit reveals any breach of any of the foregoing cyber security requirements, LEP will correct the cause of the breach and reimburse OPG for all internal and external costs of such an audit, and OPG will be entitled to any other remedy available to it, whether under this Agreement or a Services Appendix or in accordance with Applicable Laws.

(Amending Agreement 3, Section 6)

ONTARIO POWER GENERATION

Records File Information **Internal Use Only**
Records 08133.3-P OPG-FORM-0073-R005*

Document Transmittal Record

Mail to:	**EXECUTED DOCUMENTS PROCESSING** **KD170**		
AUTHOR(S) (e.g., External Counterparties) **Ontario Power Generation Inc. and Laurentis Energy Partners Inc.**			
TITLE (e.g., Document or Contract Title) **Amended and Restated Business and Services Agreement**			DOCUMENT DATE (MM/DD/YYYY) **12/23/2015**
DOCUMENT IDENTIFIER			
General:	☐		Check "Amendment" and record the document number in the appropriate box ***if***: • The new document is associated with a previously registered document (e.g., the new document is an amendment, addendum, or sub-contract); and • It is to be filed with the previously registered document. If no document number is recorded, a new number will be assigned by the Executed Documents Processing Centre.
Amendment	☐ (provide G#)	G-14433-0001	
Commercial Operations:	☐		
Amendment	☐ (provide C#)	C-	
Real Estate (P# or X# assigned by Real Estate)		P- X-	
Supply Chain:	☐		
Amendment	☐ (provide S#)	S-14433-0001	

KEYWORDS (i.e., words not in document) **(a) Provisions of Capital Equipment** **(b) Provision of Personnel** **(c) Nicolle Butcher** Geographic Loc'n:	REFERENCE PO/Reference/External Document No. Effective Date (if applicable: MM/DD/YYYY) 12/23/2015 Expiry Date (if applicable: MM/DD/YYYY) 12/31/2017 Sender(s):

ORGANIZATION ☐ Energy Markets** ☐ Law*** ☐ Real Estate ☐ Supply Chain
** Due to CorDoc restrictions, Energy Markets cannot reflect the name change to Commercial Operations
***By default, law has access to all

SECURITY CLASSIFICATION ☐ OPG Confidential (default) ☐ OPG Confidential Exclusive
(For further information, refer to OPG-STD-0030, Classification, Protection, and Release of Information)

CUSTOM2 (OPG Commercial Operations only)
☐ D ☐ D-DSA ☐ D-0SA-A ☐ I ☐ I-BIO ☐ I-COAL ☐ I-EEI ☐ 1-EXCH ☐ I-URAN
☐ D-EA ☐ D-EA-A ☐ D-ISDA ☐ I-GAS ☐ I-ISDA ☐ I-LFC ☐ I-OIL ☐ I-TRANS

If applicable, select appropriate sub-folder below.

PERMISSION SUB-FOLDER – G, P, S OR X DOCUMENTS (REAL ESTATE, BUS. DEV., LAW/RISK, SUPPLY CHAIN)

☐ Business Development	☐ Credit Risk (Letters of Credit)	☐ Fund Management
☐ Niagara Plant Group	☐ Northeast Plant Group	☐ Northwest Plant Group

¨ Ottawa/St. Lawrence Plant Group	☐ Supply Chain
☐ Small Hydro	☐ Nuclear
☐ Dam Safety & Water Resources	☐ Hydro / Thermal
	☐ Indirect
	☐ Other:

PERMISSION SUB-FOLDER – C DOCUMENTS

☐ Confirmations	☐ Emission Reductions	☐ Interconnected & Transaction (I, I-EEI, I-EXCH, I-ISDA, I-LFC)
☐ Customer Collateral Documents	☐ Legacy (Generic)	
☐ Domestic (D, D-EA, D-EA-A, D-ISDA)	☐ Interconnected & Transaction (I-BIO, I-COAL, I-GAS, I-OIL, I-TRANS, I-URAN)	☐ Operating Committee Agreements
☐ Domestic (D-DSA, D-DSA-A)		☐ Verifications

The following information is required for information purposes only. It will not be added to CORDOC.

Contact Name: Glen Elliott	Location: H18	Tel: 416-592-5361

* Associated with OPG-PROC-0019, Records and Document Management

GENERAL SERVICES AGREEMENT

Between

POWERON ENERGY SOLUTIONS LP

- and -

ONTARIO POWER GENERATION INC.

Dated as of September 22, 2023

GENERAL SERVICES AGREEMENT

This General Services Agreement (this "**Agreement**") is entered into as of the 22nd day of September, 2023 (the "**Effective Date**")

BETWEEN:

POWERON ENERGY SOLUTIONS LP, a limited partnership formed under the laws of the Province of Ontario ("**PowerON**") by its general partner, **POWERON ENERGY SOLUTIONS INC.**, a corporation incorporated under the laws of the Province of Ontario,

and

ONTARIO POWER GENERATION INC., a corporation incorporated under the laws of the Province of Ontario ("**OPG**").

WHEREAS OPG is a power generating company having personnel with experience in the nuclear, hydroelectric and thermal industry and associated support infrastructure;

WHEREAS PowerON, a wholly owned subsidiary of OPG, is a company organized to provide services related to the charging of electric vehicles.

WHEREAS OPG requires services to be provided by PowerON from time to time;

AND WHEREAS PowerON and OPG hereby enter into this Agreement to set out the general terms and conditions under which OPG may, from time to time, retain PowerON to provide such services;

NOW THEREFORE, in consideration of the mutual covenants and undertakings contained herein, and subject to and on the terms and conditions herein set forth, the Parties hereto agree as follows:

ARTICLE 1
DEFINITIONS

1.1 Specific Definitions

As used in this Agreement, the following terms shall have the meaning set forth or as referenced below:

(a) "**Actual Labour Costs**" shall mean PowerON's hourly standard labour rates (calculated to include salary, direct and indirect benefits) together with related long-term incentive and corporate overhead costs;

(b) "**Anti-Corruption Laws**" shall have the meaning as set out in Article 8.2;

(c) "**Applicable Laws**", in respect of any Person, property, transaction or event, means: (1) all present and future laws, statutes, regulations, by-laws, ordinances and treaties applicable to that Person, property, transaction or event; (2) any requirements under or

prescribed by applicable common law, judgments, orders and decrees; (3) all Codes and Standards applicable to that Person, property, transaction or event at the applicable time and, whether or not having the force of law; and (4) all applicable Approvals;

(d) "**Approvals**" means any permits, licences, consents, approvals, clearances, orders, ordinances, registrations, filings or other authorizations respecting the General Services as may be required by a Work Estimate and Approval Form, this Agreement or by any applicable Governmental Authorities having or purporting to have authority over the subject matter contemplated herein;

(e) "**Claims**" shall mean all actual or threatened claims, demands, losses, costs, penalties, damages, injuries, expenses, liabilities, suits or proceedings, including reasonable legal fees;

(f) "**Codes and Standards**" means all requirements, licences, requests, directives, rules, guidelines, standards, specifications, codes, instructions, circulars, manuals and procedures as may be required by a Work Estimate and Approval Form, this Agreement or by any applicable Governmental Authorities having, or purporting to have, authority over the subject matter contemplated herein;

(g) **"Confidential Information**" shall mean all information, written or oral, disclosed by a Party, directly or indirectly, to the receiving Party, including but not limited to all contracts, financial information, engineering reports, environmental reports, technical and economic data, marketing terms and arrangements, knowledge, know-how and related information such as plans, maps, drawings, field notes, sketches, photographs, computer records or software, specifications, models, or other information which is or may be either applicable to or related in any way to the assets, business or affairs of the disclosing Party. For certainty, Confidential Information includes the terms of this Agreement. Confidential Information shall not include information that a receiving Party is able to demonstrate to the disclosing Party's satisfaction, acting reasonably: (1) was already known to the receiving Party on a non-confidential basis from a source that is entitled to disclose the information; (2) was or becomes generally available to the public through no fault of the receiving Party or its officers, employees or advisers; (3) was developed or ascertained independently without reference to the disclosing Party's information; or (4) was received by the receiving Party from a third party without such third party being under a duty of confidentiality;

(h) "**General Services**" shall have the meaning as set out in Article 3.1;

(i) "**Governmental Authority**" shall mean any federal, provincial, local, municipal or other governmental, administrative, judicial, regulatory agency or entity having or asserting valid jurisdiction over a Party or this Agreement;

(j) "**Intellectual Property Rights**" shall mean any rights, anywhere in the world, in or to patents, copyright and any copyrightable subject matter (including moral rights), trademarks, trade names, service marks, confidential information or trade secrets, industrial or, as applicable, patent designs, integrated circuit topography rights and any other statutory provision or common or civil law principle regarding intellectual property, whether registered or unregistered, and including rights in any and all applications, registrations, re-issues, divisionals, continuations, continuations-in-part, renewals, re-examinations relating to the foregoing, and any and all rights in and to licenses and sub-

licenses from third parties relating to the foregoing;

(k) **"New Intellectual Property"** shall have the meaning as set out in Article 7.1;

(l) "**Party**" shall mean a party to this Agreement and "**Parties**" means all of them, as the context requires;

(m) "**Person**" shall mean any individual, sole proprietorship, partnership, corporation or company, with or without share capital, trust, foundation, joint venture, Governmental Authority or any other incorporated or unincorporated entity or association of any nature;

(n) "**Work Estimate and Approval Form**" shall mean the document issued by PowerON in substantially the form attached as Exhibit "B" to this Agreement; and

1.2 Interpretation

(a) Unless otherwise specified, words importing the singular include the plural and vice versa, and words importing gender include all genders;

(b) references to "this Agreement", "hereof", "herein" and similar expressions refer to the Agreement (including the recitals) and any exhibits hereto, and to no other documents; and

(c) the division of this Agreement into Articles, sub-articles and paragraphs and the insertion of headings are for convenience of reference only and shall not affect in any way the meaning or interpretation of this Agreement.

1.3 Currency

Unless otherwise indicated, all dollar amounts referred to in this Agreement are in lawful money of Canada.

1.4 Exhibits

The following are the exhibits attached to and incorporated by reference in this Agreement, which are deemed to be a part hereof:

Exhibit "A" - Work Estimate and Approval Form
Exhibit "B" - Insurance
Exhibit "C" - Cyber Security

ARTICLE 2
TERM AND TERMINATION

2.1 Term

The term of this Agreement shall commence on the Effective Date and, unless terminated earlier as provided hereunder, shall remain in full force and effect for two years until and including September 22, 2025 (the "**Initial Term**"). The Initial Term thereafter may be renewed by OPG in its sole and absolute discretion for up to an additional two additional years (the Initial Term and any renewal thereof being collectively referred to herein as the "**Term**"). If the end of the Term does not coincide with the end of the term of any Work Estimate and Approval Form, then this

Agreement will automatically renew with respect only to the General Services to be performed under each such Work Estimate and Approval Form until such Work Estimate and Approval Form is fully completed in accordance with the terms of such Work Estimate and Approval Form and this Agreement.

2.2 Termination

Notwithstanding any term in this Agreement, either Party may, without cause, terminate this Agreement: (a) on six months prior written notice to the other Party, provided any General Services to be performed under any open Work Estimate and Approval Forms are fully completed or the Parties' provide mutual written consent to terminate such General Services; or (b) at any time upon mutual written consent of the Parties.

OPG may terminate an open Work Estimate and Approval Form at any time before the end of the term of such Work Estimate and Approval Form by giving notice of termination to PowerON at least 30 days before the proposed early termination date. If OPG terminates the General Services under this Section 2.2, OPG shall reimburse PowerON for: (a) all General Services completed and delivered; and (b) for the direct out-of-pocket costs to PowerON for General Services in progress directly incurred in the course of the General Services.

ARTICLE 3
GENERAL SERVICES

3.1 General Services

This Agreement shall apply to all technical and other services provided by PowerON, either directly or through its subcontractors, to OPG, including the provision of any deliverables, pursuant to the terms of this Agreement (the "**General Services**"). For clarity, the General Services do not include any construction related services.

3.2 Scope

Except with the prior consent of the Parties, as evidenced by the issuance of an approved Work Estimate and Approval Form, this Agreement shall not apply to, and General Services shall not include, technical or other services estimated to cost in excess of $5,000,000. General Services shall also not include any market related services from, or the sharing of any related information technology systems with PowerON.

3.3 Standard of Care

In the provision of the General Services to OPG by PowerON hereunder, PowerON shall exercise the degree of care, diligence and skill as would a reasonably prudent Person having responsibility for the provision of services of the nature of the General Services in comparable circumstances.

In the event of any breach of this Article 3.3 of this Agreement, PowerON shall, at its own expense, re-perform the non-conforming General Services. The remedy set forth in this Article 3.3 is the sole and exclusive remedy for such a breach.

ARTICLE 4
PROCESS

4.1 Request for General Services

OPG and PowerON shall verbally discuss the provision of General Services. To formally request such General Services, OPG shall complete a Work Estimate and Approval Form indicating the project name, a brief description of the services required, and any timeline or other limitations or applicable conditions, including special terms and conditions. The Work Estimate and Approval Form shall be forwarded to PowerON's contact.

4.2 Definition and Estimation

PowerON shall, in consultation with OPG, review and revise the Work Estimate and Approval Form. The Work Estimate and Approval Form shall then be forwarded to OPG's contact.

4.3 Authorization

If OPG approves the revised Work Estimate and Approval Form, OPG shall execute such form and deliver it to PowerON. An executed version of the Work Estimate and Approval Form will serve as authorization for PowerON to commence and carry out the General Services as specified therein.

4.4 Applicable Terms and Conditions

The General Services shall be performed in accordance with the terms and conditions of this Agreement. To the extent the Parties may mutually agree, the General Services may be subject to special terms and conditions as provided in the Work Estimate and Approval Form. To the extent such special terms and conditions are inconsistent or conflict with the terms and conditions in this Agreement, such special terms and conditions shall govern.

4.5 Price for Services

For each Work Estimate and Approval Form, OPG agrees to pay, and PowerON hereby agrees to accept as full payment for the General Services, the total sum for the General Services as set forth in the applicable Work Estimate and Approval Form, calculated in accordance with the pricing model outlined therein.

The price for General Services may be on a fixed price or time and materials basis, as agreed in the applicable Work Estimate and Approval Form. Where the price for General Services is on a fixed price basis, subject to Article 5.2 below, the price includes all activities and materials required to perform the General Services, and the price will not be subject to adjustments without the written consent of OPG.

Where the price for General Services is on a time and materials basis, the applicable labour or unit rates for the individuals providing such General Services shall be equal to PowerON's Actual Labour Costs. In addition, and where applicable to General Services provided on a time and materials basis, OPG shall pay for all third party expenses incurred by PowerON in providing those General Services together with the direct cost of any materials, equipment or other deliverables thereunder.

OPG and PowerON shall discuss mark-ups on a case-by-case basis. Any mark-ups, including mark-ups for profit, shall be indicated in the applicable Work Estimate and Approval Form.

4.6 Change in General Services

OPG may request PowerON in writing to make a change in the General Services. When a change causes an increase or decrease in the price, scope or schedule, the price and schedule shall be modified as agreed upon between PowerON and OPG.

4.7 Facility Policies and Procedures

If PowerON provides General Services on an OPG site, PowerON shall do so in accordance with the OPG's policies and procedures, including security checks, that will be provided to PowerON.

4.8 PowerON's Personnel

PowerON shall be fully responsible for all acts and omissions of each of its personnel, and any such acts and omissions will be deemed to be those of PowerON. PowerON shall ensure that all personnel engaged will have the knowledge, abilities, experience and qualifications required for the General Services. PowerON shall provide such additional support as may be required from time to time for the General Services' proper performance. OPG may reasonably request, at its discretion, that certain personnel (including personnel of any subcontractor) be changed. PowerON will endeavor to accommodate such requests promptly.

4.9 No OPG Control Over General Services

OPG shall not supervise, direct and have control or authority over:

(a) the means, methods, techniques, sequences or procedures respecting the performance of the General Services by PowerON; and

(b) the safety programs and precautions used in respect of the General Services, subject to OPG's rights and obligations under the *Occupational Health and Safety Act* (Ontario).

OPG shall not be responsible for any failure by PowerON to comply with any Applicable Laws or this Agreement in providing the General Services.

ARTICLE 5
PAYMENT

5.1 Invoices

Notwithstanding anything else in this Agreement, PowerON shall electronically invoice OPG for all General Services and invoices will indicate:

(a) the total amount owing by OPG in accordance with the Work Estimate and Approval Form (showing separately all amounts due as Canadian goods and services tax/harmonized sales tax levied under the *Excise Tax Act* (Canada) and expressly stating any amounts invoiced in a currency other than Canadian dollars);
(b) the Work Estimate and Approval Form number and line number, if applicable;
(c) PowerON's full name and address;
(d) the name of a contact individual at PowerON, with a telephone number;
(e) electronic transfer instructions;
(f) PowerON's invoice number (which must be unique for each invoice);
(g) the invoice date (which must be the date the invoice is delivered);

(h) the value of the General Services provided in Canada and outside Canada, identified separately; and
(i) PowerON's 15 digit registration number of the purposes of Part IX of the *Excise Tax Act* (Canada).

PowerON shall provide invoices to OPG on a monthly basis, or as agreed from time to time, for all General Services provided. On termination or expiry of this Agreement, PowerON shall submit a final invoice to OPG within ninety (90) days.

5.2 Taxes

Any federal goods and services tax/harmonized sales tax which is payable in respect of the General Services shall be added to the invoices and each such invoice shall state separately the amount of such tax payable together with PowerON's goods and services tax/harmonized sales tax registration number.

OPG will have no liability for any of PowerON's income or capital taxes imposed by any governmental authority respecting this Agreement. Unless otherwise stated in this Section 5.2, OPG will have no liability for any withholding, collection, payment, remitting or reporting of any taxes or statutory deductions paid or payable by PowerON or any of PowerON's subcontractors in respect of any subcontractor or any employee of PowerON or any subcontractor.

Notwithstanding any term in this Agreement, OPG may withhold any amount that is required to be withheld on payments made to non-residents of Canada in accordance with the *Income Tax Act* (Canada) and regulations thereto. OPG will have no obligation to gross up or otherwise increase payments made to PowerON or any of PowerON's subcontractors because OPG withheld any amount in respect of taxes. Where OPG so withholds any amount, OPG will remit such amount to the applicable Canadian tax authorities.

5.3 Payment of Invoices

OPG shall aggregate all outstanding invoices received and accepted by OPG for payment before the 25th day of each month. Subject to any Applicable Laws, OPG shall pay PowerON this aggregate amount electronically on the 25th day of the following month. All payments are conditional, however, on PowerON fulfilling its obligations and making satisfactory progress in providing the General Services before the date payment is made. OPG shall determine whether or not such obligations have been fulfilled and progress is satisfactory..

ARTICLE 6
LIABILITY AND INDEMNIFICATION

6.1 Indemnity by OPG

OPG shall indemnify, defend and hold harmless PowerON and its shareholder(s), directors, officers, employees, subcontractors, representatives and agents from and against all Claims imposed upon or incurred by PowerON with respect to any personal injury or death of any individuals performing General Services pursuant to this Agreement, arising out of the gross negligence or willful misconduct of OPG during the Term of this Agreement.

6.2 Indemnity by PowerON

PowerON shall indemnify, defend and hold harmless OPG and its shareholder(s), directors, officers, employees, subcontractors, representatives and agents from and against all

Claims imposed upon or incurred by OPG by or in favour of a third party (including, without limitation, those Claims arising in favour of or brought by or on behalf of any of PowerON, employees, agents, subcontractors or representatives), based upon, in connection with, relating to or arising out of the provision of the General Services, where and to the extent that any such Claim results from, arises out of or is attributable to the gross negligence or willful misconduct of PowerON in the provision of the General Services.

6.3 Limitation of Liability

Subject to Article 6.5, the liability of PowerON for all Claims by OPG against PowerON arising in respect of this Agreement will not exceed:

(a) an amount equal to the cumulative amount of all amounts paid or payable under this Agreement by OPG to PowerON, exclusive of any goods and services tax/harmonized sales tax; and

(b) the amount of insurance recoverable under this Agreement.

Subject to Article 6.5, the liability of OPG for all Claims by PowerON against OPG arising in respect of this Agreement will not exceed an amount equal to the cumulative amount of all amounts paid or payable under this Agreement by OPG to PowerON, exclusive of any goods and services tax/harmonized sales tax.

6.4 No Liability

Notwithstanding anything in this Agreement, PowerON shall not be responsible to OPG for any losses, damages, costs, expenses and injury of every kind and character:

(a) to the property, facilities, equipment or materials of OPG; or

(b) except for third party Claims under Articles 6.2 and Claims under Article 7.3, resulting from OPG's access to or use of the New Intellectual Property.

6.5 Exceptions to Limitation

PowerON's limitation of liability set out in Article 6.3 will not apply, however, to:

(a) third party Claims under Article 6.2; or

(b) Claims suffered or incurred by OPG or any Claims made against OPG by any Person, to the extent arising in respect of the deliberate or willful breach of this Agreement by PowerON.

OPG's limitation of liability set out in Article 6.3 will not apply, however, to Claims suffered or incurred by PowerON or any Claims made against PowerON by any Person, to the extent arising in respect of the deliberate or willful breach of this Agreement by OPG.

6.6 Consequential Damages

Except for any third party Claims, and except to the extent recoverable under insurance required by this Agreement, no Party will be liable to another Party for any indirect or consequential damages.

6.7 Duty to Mitigate

Each Party has a duty to mitigate damages and shall use all commercially reasonable efforts to minimize any losses, costs, expenses, damages or other liabilities it may incur as a result of the other Party's performance or non-performance of this Agreement.

ARTICLE 7
INTELLECTUAL PROPERTY

7.1 Ownership of Intellectual Property

Each Party and subcontractor retains all Intellectual Property Rights to methodology, knowledge and data brought to the General Services and used therein. No Intellectual Property Rights existing before the start of the General Services are passed hereunder other than licenses and rights to use Intellectual Property Rights as set out in this Agreement and the applicable Work Estimate and Approval Form.

All title and beneficial ownership interests to all Intellectual Property Rights which are created or otherwise arise in the provision or performance of the General Services will vest exclusively in, and remain with, OPG (the "**New Intellectual Property Rights**"). PowerON hereby assigns and shall cause each subcontractor to assign to OPG all rights, title and interest in and to the New Intellectual Property Rights. This assignment becomes effective in respect of each New Intellectual Property Right when such New Intellectual Property Right comes into existence, and in any event, no later than on the completion of the General Services.

7.2 Use of Intellectual Property

In respect of any Intellectual Property Rights not assigned to OPG under Section 7.1, PowerON hereby grants to OPG a worldwide, non-exclusive, irrevocable, perpetual, royalty free and fully paid-up licence and uninterrupted right to use all such Intellectual Property Rights that are contained or embedded in, required for the use of, used in the production of, or required for the reproduction, modification, maintenance, servicing, improvement or continued operation of the General Services.

OPG hereby grants to PowerON a limited license during the Term of this Agreement to use any New Intellectual Property created. Any such use of any New Intellectual Property, including sublicence, transfer, copying or reproducing to any other third party, shall only be in accordance with terms to be negotiated by the Parties associated with the applicable Work Estimate and Approval Form.

Should PowerON wish to acquire any other rights of usage to any New Intellectual Property created, it may issue a notice to OPG pursuant to Article 8 of this Agreement and OPG may agree to enter into negotiation for such acquisition. Any such acquisition of rights shall be subject to terms to be negotiated on a case-by-case basis.

7.3 Warranty and Indemnity

PowerON shall pay all royalties, license fees and other monetary amounts required in respect of securing and licencing the Intellectual Property Rights referenced in this Article 7 and any other Intellectual Property Rights associated with the General Services.

PowerON represents and warrants that it owns or has obtained from third parties, duly authorized grants of all right, title and interest necessary to provide to OPG a license regarding

the Intellectual Property Rights associated with the General Services in the manner set out in Article 7.2 of this Agreement.

PowerON shall, at its expense, defend all Claims against OPG relating to or based on any allegation that the General Services, or any part of the General Services, constitutes an infringement upon, or a misappropriation of any Intellectual Property Rights and shall pay to OPG all resulting costs, damages, charges and expenses incurred by OPG in respect of such Claims. OPG shall give PowerON written notice of any such Claim and at the request and expense of PowerON, OPG shall provide all available information, assistance and authority required to conduct its defense.

If all or any part of the General Services is finally determined to constitute an infringement or misappropriation of Intellectual Property Rights of a third party, or if OPG is enjoined from using the General Services, any part thereof, or any Intellectual Property Rights embodied therein as a result of an infringement or misappropriation claim, PowerON shall at its expense promptly: (a) obtain for OPG the right to continue using the General Services; (b) replace the infringing elements of the General Services with non-infringing elements, while maintaining the full functionality, integrity and performance capabilities of the General Services; or (c) modify the General Services so that it no longer infringes, while maintaining the full functionality, integrity and performance capabilities of the General Services.

ARTICLE 8
ADDITIONAL TERMS

8.1 Applicable Laws

(a) PowerON shall comply with all Applicable Laws and all standards, specifications, manuals or codes of any technical organization or governmental authority. PowerON shall obtain, at its cost, all permits and other consents required in respect of the General Services.

(b) PowerON shall comply with, and will take all reasonable measures to ensure that the parties subject to its control or determining influence will comply with, all applicable anti-corruption laws and policies, including the *Foreign Corrupt Practices Act* (U.S.), the *Corruption of Foreign Public Officials Act* (Canada), the *Bribery Act* (U.K.) and any Applicable Laws of similar effect of any other jurisdiction (collectively, "**Anti-Corruption Laws**"). PowerON represents, warrants and undertakes that it has instituted and maintains policies and procedures designed to ensure, and which are reasonably expected to continue to ensure, compliance with Anti-Corruption Laws, including policies and procedures designed to ensure that all Persons employed or acting on PowerON's behalf comply with Anti-Corruption Laws.

8.2 Confirmation of Records

PowerON shall keep proper accounts and records of the General Services. During the term of the Agreement, and only in respect of General Services invoiced on a time and materials basis, OPG shall have the right to reasonable access to the books, records and accounts maintained by PowerON related to provision of the General Services to verify the accuracy of the hours and expenses as invoiced by PowerON. OPG shall provide PowerON with thirty (30) days notice of any such request to verify the records. Accounts and records will be preserved and kept available for audit until the expiration of two years from the date of completion or termination of the applicable General Services.

8.3 Subcontracting

OPG acknowledge PowerON's ability to subcontract certain General Services to meet its obligations under this Agreement. PowerON shall, in entering into any such contractual agreement with a subcontractor, ensure that such subcontractor is subject to the applicable terms and conditions of this Agreement including but not limited to all confidentiality requirements. PowerON shall be fully responsible for all acts and omissions of each subcontractor, and any such acts and omissions will be deemed to be those of PowerON.

8.4 Assignment

This Agreement shall not be assigned by any Party without consent of the other Party, which consent shall not be unreasonably withheld, provided that any Party may assign its interest in this Agreement to a subsidiary without the consent of the other Party.

8.5 Counterparts and Entire Agreement

(a) This Agreement and any amendments hereto may be executed in one or more counterparts, each of which shall be deemed to be an original by the Parties, but all of which shall be considered one and the same instrument. Any counterpart signature transmitted by sending a scanned copy by electronic mail or similar electronic transmission will be deemed to be an original signature; and

(b) This Agreement contains the entire agreement between the Parties hereto with respect to the subject matter hereof and supersedes all prior agreements and understandings, oral or written, with respect to such matters.

8.6 Notices

All notices hereunder shall be deemed given if in writing and delivered personally or sent by email, courier or by registered or certified mail (return receipt requested) to the Parties at the following addresses (or at such other address as shall be specified by like notice):

(a) if to OPG, to:

Ontario Power Generation Inc.
700 University Avenue
Toronto, Ontario
M5G 1X6

Attention: Teri Lilley, Director, Supply Chain Plant Ops
Email: teri.lilley@opg.com

(b) if to PowerON, to:

PowerON Energy Solutions LP
2300 Yonge Street, Suite 2801
Toronto, Ontario
M4P 1E4

Attention: Managing Director
Email: keegan.tully@poweronenergy.ca

Any notice given by mail, email or other electronic means shall be effective when received. Each Party may, by giving notice thereof to the other Party, change its address for notice, or designate to which notices must be directed, at any time.

8.7 Governing Law and Disputes

(a) This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable in Ontario. The Parties irrevocably submit to the non-exclusive jurisdiction of the courts of Ontario and the Federal Court of Canada.

(b) If there is a dispute between the Parties in connection with this Agreement, the Parties shall, acting reasonably and in good faith, use all reasonable efforts to resolve the dispute as soon as possible by negotiation.

(c) The *United Nations Convention on Contracts for the International Sale of Goods* shall not apply to this Contract.

8.8 Severability

The provisions of this Agreement shall be deemed severable and the invalidity or unenforceability of any provision shall not affect the validity or enforceability of the other provisions hereof. If any provision of this Agreement, or the application thereof to any person or entity or any circumstance, is invalid or unenforceable, (a) suitable and equitable provisions shall be substituted therefor in order to carry out, so far as may be valid and enforceable, the intent and purpose of such invalid or unenforceable provision, and (b) the remainder of this Agreement and the application of such provision to other persons, entities or circumstances shall not be affected by such invalidity or unenforceability, nor shall such invalidity or unenforceability affect the validity or enforceability of such provision, or the application thereof, in any other jurisdiction.

8.9 Amendment, Modification and Waiver

Any amendments, modifications and waivers of this Agreement shall be done in writing and executed by all Parties.

8.10 Confidential Information

All Confidential Information remains, at all times, the exclusive property of the respective disclosing Party. Except as expressly set out in this Agreement, a receiving Party has no right to use or disclose any Confidential Information for any purpose whatsoever. A receiving Party may use Confidential Information only in respect of the preparation for, and the providing of, the General Services, including in negotiations with proposed subcontractors. Such receiving Party will ensure that none of its or its subcontractors' current or former shareholders, directors, officers, partners, members, representatives, agents and advisors or any of its personnel or any other person for whom such receiving Party or any subcontractor is responsible at law will use any of the Confidential Information for any purposes other than those expressly set out in this Section 8.11.

Each Party acknowledges and agrees that the other Party may be subject to the *Freedom of Information and Protection of Privacy Act* (Ontario), the *Ontario Energy Board Act* and the Ontario Energy Board Rules of Procedure (collectively, "**FIPPA and OEB Legislation**"). Each Party shall comply with its obligations under the FIPPA and OEB Legislation. Each Party is strongly advised to consult its own legal advisors as to the appropriate way in which confidential or proprietary business information should be marked as such in providing and receiving the General Services. Subject to the provisions of FIPPA and OEB Legislation, each Party shall use reasonable commercial efforts to safeguard the confidentiality of any information identified by the other Party as confidential but will not be liable in any way whatsoever to the other Party if such information is disclosed based on an order or decision of the Information and Privacy Commissioner of Ontario, Ontario Energy Board or otherwise as required by Applicable Law.

8.11 PowerON's Insurance

PowerON shall, at all times, maintain or cause to be maintained those insurance requirements as outlined in Exhibit "B".

8.12 Cyber Security

PowerON shall, at all times, conduct the General Services in accordance with the cyber security requirements set out in Exhibit "C".

8.13 Codes of Conduct

PowerON shall:

(a) not take any action that would cause OPG to breach an obligation set out in OPG's Code of Business Conduct ("**Code**"); and

(b) comply with all obligations set out in OPG's Supplier Code of Business Conduct ("**Supplier Code**"),

A current copy of the Code and the Supplier Code is located at www.opg.com and a copy of each has been reviewed by PowerON.

8.14 Force Majeure

Neither PowerON nor OPG shall be liable to the other for loss, damage or delay in the General Services, or non-performance of any contractual obligation, caused by war, riot, the act or order of any competent civil or military authority, fire, flood, pandemic, epidemic or by any other cause which is unavoidable and beyond the party's reasonable control. Both parties will be prompt in restoring normal conditions, re-establishing schedules, and resuming operations as soon as the interruptions have ceased. PowerON shall not be entitled to an extension of time for any delay covered in this Section 8.14 unless notice of a claim thereof is given by PowerON within 30 days after the commencement of the delay. The length of any such extension will be determined by OPG but will in no event be less than the length of such force majeure event.

8.15 Survival

All representations, warranties, guarantees and indemnities made in, required by or given under this Agreement, as well as all continuing obligations under this Agreement, will survive termination or expiry of this Agreement indefinitely.

8.16 No Joint Venture, Partnership, etc.

Nothing contained herein shall be construed as creating any joint venture, partnership, agency or joint and several liability among the Parties.

IN WITNESS WHEREOF, this Agreement has been signed by duly authorized representatives on behalf of each of the Parties hereto as of the date first written above.

POWERON ENERGY SOLUTIONS LP, by its general partner, **POWERON ENERGY SOLUTIONS INC.**

Keegan Tully

Name: Keegan Tully
Title: Managing Director

ONTARIO POWER GENERATION INC.

Name:
Title

8.16 No Joint Venture, Partnership, etc.

Nothing contained herein shall be construed as creating any joint venture, partnership, agency or joint and several liability among the Parties.

IN WITNESS WHEREOF, this Agreement has been signed by duly authorized representatives on behalf of each of the Parties hereto as of the date first written above.

POWERON ENERGY SOLUTIONS LP, by its general partner, **POWERON ENERGY SOLUTIONS INC.**

Name: Keegan Tully
Title: Managing Director

ONTARIO POWER GENERATION INC.

Paul Mascarin

Name: Paul Mascarin
Title: Director, Supply Chain

Exhibit "A" - Work Estimate and Approval Form

The attached form is used to define work scope and labour details and to estimate schedule and costs under the terms of the General Services Agreement. Once approved, the Parties shall execute the form. The executed form will be the approval from OPG to commence the General Services.

WORK ESTIMATE AND APPROVAL FORM

General Information		
Date:		**Work Order Number:**
OPG Contact:		**PowerON Contact:**
Contract Type		
Fixed Price **Time & Material** **Other, please specify:**		
Contract Period:	**Start Date:**	**End Date:**
Work Description Summary:		
Signatures of Agreement		
PowerON Energy Solutions LP, by its general partner, PowerON Energy Solutions Inc.:	_____ **Date** MM-DD-YYYY	***Ontario Power Generation Inc.:*** _____ **Date** MM-DD- YYYY

Detailed Work Description

☐

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Other Supporting Documentation

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SAFETY

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Pricing Detail

Specific Terms & Conditions

Exhibit "B" - Insurance

1. Insurance Policies

PowerON shall maintain in full force with financially responsible insurance carriers (with AM Best ratings of at least A- or a Standard & Poor's rating of at least BBB) of recognised standing acceptable to OPG, or with the appropriate governmental authorities, all coverages referred to in this this Exhibit "B". Each of these coverages is currently in full force and, except as provided below, PowerON shall ensure that all these coverages will be maintained in force continuously from the date of this Agreement until 60 days after the termination of this Agreement or such other date as OPG may designate in writing. PowerON shall ensure that all such coverages cover all subcontractors and that all insurance coverages applicable in Ontario will be obtained from insurance carriers that are duly licensed in Ontario to issue insurance policies for the limits and coverages required under this Exhibit "B".

(1) **Workers' Compensation.** PowerON shall maintain or cause to be maintained workers' compensation coverage as required by the *Workplace Safety and Insurance Act, 1997* (Ontario) or any other Applicable Laws respecting all of PowerON's personnel to the extent they are performing General Services on an OPG site.

(2) **Commercial General and Excess Umbrella Liability Insurance.** PowerON shall maintain commercial general liability and excess umbrella liability insurance, on an occurrence basis, in an amount not less than $5,000,000 inclusive for bodily injury, including death, personal injury and damage to property, including resulting loss of use thereof, for each occurrence. PowerON shall ensure that the excess umbrella liability insurance is in excess of the coverages under Sections 1 (to the extent the coverages under those sections include employer's liability) and Section 4. PowerON shall also ensure that the commercial general liability and excess umbrella liability coverage specifically includes the following:

(1) blanket contractual liability;

(2) damage to property of OPG, including resulting loss of use thereof;

(3) pollution liability coverage on at least a sudden and accidental basis;

(4) products and completed operations, including a term that such coverage will be maintained throughout the warranty period;

(5) cross liability;

(6) severability of interests;

(7) employer's liability;

(8) non-owned automobile liability; and

(9) broad form property damage

(3) **Errors & Omissions Insurance.** PowerON shall, at all times, maintain in full force and effect professional liability insurance in an amount not less than $2,000,000 per occurrence and in the aggregate, covering the period from start of conceptual design through to the termination of this Agreement and for a further discovery period of five years from the termination of this Agreement.

(4) **Motor Vehicle Liability Insurance.** PowerON shall maintain motor vehicle liability insurance, covering all licensed motor vehicles owned, rented or leased and used in respect of the General Services. PowerON shall ensure that this coverage will cover bodily injury and property damage liability to a combined inclusive minimum limit of $2,000,000 per occurrence and mandatory accident benefits.

(5) **Other.** PowerON shall maintain, at OPG's cost, any other form of insurance for such risks and in such amounts as OPG may require from time to time.

2. General Insurance Terms

(a) **Certificates of Insurance.** Both on the date of this Agreement and no more than 60 days and no fewer than 30 days before starting any General Services on an OPG Site, PowerON shall deliver to OPG certificates of insurance completed by a duly authorised representative of each of PowerON's insurers certifying that at least the minimum coverages required under this Exhibit "B" are in effect. PowerON shall ensure that each certificate will state that the coverages will not be cancelled, will not fail to be renewed and will not be materially changed by endorsement or through issuance of any other policy of insurance which restricts or reduces coverage, without 60 days advance written notice by courier given to OPG's Representative, with a copy delivered by email as follows:

[NOTICE]

To the extent that PowerON is required to maintain any coverages after final payment, PowerON shall deliver to OPG, at the time it approves the invoice, a certificate of insurance completed by a duly authorized representative of such Person's insurer certifying that such insurance will remain in force, subject to annual renewals, for the period of time required in this Exhibit "B".

(b) **Copies of Policies.** Promptly upon request by OPG, PowerON shall provide OPG with a certified copy of any insurance policy referred to in this Exhibit "B". OPG may only make a request following an occurrence where OPG may have coverage under the policy.

(c) **No Waiver by OPG.** If OPG fails to demand any certificate referred to in Section 2(a) or otherwise fails to demand other evidence of full compliance with Section 1 or fails to identify a defect from evidence provided, OPG has not waived, and OPG will not be deemed to have waived, any of PowerON's obligations. PowerON's obligation to purchase and maintain insurance under this Agreement, the bankruptcy or insolvency of any insurance company or the failure of any insurance company to pay any claim, will in no way limit or otherwise qualify the liabilities or obligations of PowerON under this Agreement.

(d) **No Approval by OPG.** If OPG receives and accepts any certificate or other evidence under this Section 2, OPG has not approved or agreed, and OPG will not be deemed to have approved or agreed, that PowerON has satisfied any of its obligations under Sections 1 or 2.

(e) **OPG May Purchase Insurance.** If PowerON fails to maintain any insurance required under Section 1 or any such insurance is inadequate in its scope, OPG may purchase any such insurance, at PowerON's sole expense. In the event OPG must purchase insurance under this Section 2(e), OPG may set off the costs thereof against any monies then or thereafter due, owing or payable to PowerON and may set off and retain, in addition, and in consideration for its work in procuring such insurance, an amount equal to the cost

thereof, in addition to the cost of such insurance.

(f) **Deductibles.** PowerON shall pay the amount of all deductibles under this Agreement and may not charge back any such amount to OPG.

(g) **Insurance Not Contributory.** With the exception of the insurance referred to in Section 1(4), PowerON shall ensure that all other insurance referred to in Section 1 will specify that such insurance is primary coverage and not contributory with, or in excess of, any insurance that may be maintained by OPG.

(h) **Subrogation.** PowerON shall ensure that each insurer which provides insurance under Section 1 will provide a waiver of subrogation to OPG, PowerON and all of PowerON's subcontractors.

(i) **OPG as Additional Insured.** PowerON shall ensure that each insurer that provides insurance under Section 1(2) will include OPG as an additional insured and, where applicable, as a loss payee, under such insurance.

(j) **No Invalidation by Others.** PowerON shall ensure that no insurance referred to in Section 1 will be invalidated or vitiated by any action or failure to act by OPG, any applicable subsidiary of OPG or by any breach by PowerON or any other Person of any declarations, warranties or other terms in such policies.

(k) **Notice of Claim.** PowerON shall deliver a Notice to OPG within three Business Days of asserting any claim under any insurance referred to in Section 1. PowerON shall include in the Notice the date of the events giving rise to the claim, a summary of the circumstances respecting the claim and the amount of the claim. PowerON shall provide OPG any additional information respecting the claim that OPG may request.

Exhibit "C" - Cyber Security

1.1 Certain Definitions. For the purposes of this Exhibit "C":

(a) **"Contractor**" means PowerON.

(b) "**Cyber Asset**" means:

(1) any asset designated by OPG as a Cyber Asset; or

(2) any computing hardware, software, firmware or other computing or information technology that:

(A) [redacted]

(B) [redacted],

[redacted].

(c) "**Cyber Equipment**" means any of Contractor's computing hardware, software, firmware or other computing or information technology that is:

(1) not a Cyber Asset; and

(2) [redacted].

(d) "**Cyber Services**" means any application, infrastructure or related service provided by Contractor in relation to:

(1) [redacted]

(2) [redacted].

(e) "**OPG Data**" means all information relating to OPG, its business, financial position, assets, technology, operations, activities or proposed activities and prospects, including any technical, commercial, legal, financial, strategic, tactical, regulatory or governmental information, reports, drawings, specifications, contracts, business plans, projections, forecasts or other documents or information, whether written or oral, and including such information that is provided to Contractor

by OPG or its representatives, or otherwise received or accessed by Contractor, under this Agreement, or created or provided to OPG by Contractor under this Agreement.

(f) "**OPG Systems and Information**" means OPG's networks, information systems, industrial control systems, or any components thereof (including computing hardware, software, firmware or other computing or information technology), or any OPG Data.

(g) "**Priority One Cyber Asset**" means any Cyber Asset designated by OPG as a Priority One Cyber Asset; and

(h) "**Priority One Cyber Services**" means any Cyber Services designated by OPG as a Priority One Cyber Services.

1.2 Cyber Security Requirements. Contractor:

(a) [redacted];

(b) [redacted];

(c) [redacted];

(d) [redacted];

(e) [redacted];

(f) [redacted]

[redacted];

(g) [redacted]

(h) [redacted]

(i) [redacted].

1.3 Cyber Assets or Cyber Services. [redacted]:

(a) [redacted]

(b) [redacted]

[redacted]

[redacted]

[redacted]

1.4 Priority One Cyber Assets or Priority One Cyber Services

Notwithstanding any other term in this Agreement, if the Contractor is providing any Priority One Cyber Asset or Priority One Cyber Services, in addition to the foregoing, Contractor:

(a) [redacted]

(b) [redacted]

(c) will comply with Applicable Laws, including the North American Electric Reliability Corporation's Critical Infrastructure Protection (NERC CIP) standards for Priority One Cyber Assets or Priority One Cyber Services relating to OPG renewable generation, the Canadian Standards Association (CSA) standard N290.7 for Priority One Cyber Assets or Priority One Cyber Services relating to OPG nuclear facilities;

(d) [redacted]

(e) [redacted]

(f) [redacted]

(g) [redacted]

[redacted]

(h) [redacted]

(i) [redacted]

(j) [redacted];

(k) [redacted]

(l) [redacted].

[redacted]

BUSINESS AND SERVICES AGREEMENT

BUSINESS AND SERVICES AGREEMENT (this "Agreement") is made effective as of the date of last execution hereto ("Effective Date"),

BETWEEN:

ONTARIO POWER GENERATION INC., a corporation existing under the laws of the Province of Ontario (Canada) ("**OPG**")

– and –

ORIGIN NUCLEAR INC., a corporation existing under the laws of Canada ("**ONI**")

WHEREAS

1. OPG is a power generating company having personnel with experience in the nuclear, hydroelectric and thermal industry and associated support infrastructure.

2. ONI, a wholly owned subsidiary of OPG, is a company organized to provide operation, management, emergency planning, construction, development, operation, maintenance, inspection and technical services to the nuclear industry.

3. To perform these services, ONI wishes to have access to personnel and certain equipment or materials and procure a range of professional and corporate support services from OPG.

4. OPG agrees to provide personnel and certain equipment or materials and supply these professional and corporate support services to ONI, if and when available.

5. OPG also wishes to retain ONI from time to time to provide, and ONI agrees to supply to OPG, certain services (the "ONI Services") in accordance with this Agreement.

6. The parties wish to enter into this Agreement to set out the terms and conditions upon which OPG would provide such personnel, certain equipment or materials and services to ONI, and upon which ONI may provide the ONI Services to OPG.

NOW THEREFORE, in consideration of the mutual covenants and agreements hereinafter contained and for other good and valuable consideration (the receipt and sufficiency of which is acknowledged by each of the parties hereto) the parties covenant and agree each with the other as follows:

SECTION 1 – APPLICATION AND PROCESS

1.1 APPLICABILITY

(a) This Agreement governs:
   (i) OPG's provision to ONI of personnel and certain equipment or materials, access to OPG property and assets, and professional and corporate support services; and

(ii) ONI's provision of ONI Services to OPG.

(b) The process for requesting releasing and recoding services to be provided under this Agreement is set out in Appendix A attached hereto.

1.2 PROVISION OF PERSONNEL

(a) ONI Support Employees. Subject to the terms and conditions herein, OPG will provide or arrange for the provision of existing OPG employees or other OPG labour resources to ONI, as may be requested by ONI. Existing OPG employees may provide support in executing and managing ONI's operations on a full-time basis ("**Secondments**") or perform discrete work characterized by tasks, activities, or duties for or on behalf of ONI, including to parties with whom ONI has a commercial relationship for the provision of services ("**Operational Resources**"). Collectively, Secondments and Operational Resources represent "**ONI Support Employees**".

(b) OPG Support Employees. Subject to the terms and conditions herein, ONI will provide or arrange for, from time to time, the provision of existing ONI employees or other ONI labour resources to OPG, as requested by OPG (collectively, "**OPG Support Employees**") to perform duties for or on behalf of OPG, including to parties with whom OPG has a commercial relationship for the provision of services. In doing so, ONI will also provide OPG with an estimate of costs OPG can expect to incur in procuring this service.

(c) Annual Employee Plan. ONI shall deliver to OPG an annual employee resourcing plan setting out expected Secondments requirements for internal business support and Operational Resources requirements, including for commercial or technical support needs arising from possible commercial opportunities for the upcoming year. Upon receipt of the ONI employee plan, OPG shall review and notify ONI of any anticipated resourcing constraints. For clarity, the employee plan is expected to be provided as part of the annual business planning process completed by ONI in accordance with timelines as set out by OPG, and may be revised and updated throughout the year. ONI and OPG shall coordinate throughout the term of this Agreement to ensure that ONI has continuous access to OPG's employee resources subject to the qualifications set out in this Section 1.2(c).

(d) ONI Support Employee Assignment Request. ONI shall make all ONI Support Employee requests to OPG as promptly as possible. Such request shall specify the number of ONI Support Employees needed, the expected duration of such requested services and the type of services that will be performed by the requested ONI Support Employees. The parties agree that the choice of which employee and how many employees are made available as ONI Support Employees is subject to the mutual approval of both parties. Notwithstanding the foregoing, OPG is under no obligation to provide any employees to ONI if such resource allocation would result in an impact to the current service standard levels provided at OPG's facilities, or would represent a reasonable risk to the safe operations of OPG's facilities.

(e) ONI Support Assignment Agreement. OPG will enter into a subcontract agreement, secondment agreement, work assignment or such other form of agreement or document agreed to between ONI and OPG (a "**ONI Support Assignment Agreement**") to document the terms of any ONI Support Employee assignment. ONI Support Assignment Agreements will be among ONI and OPG, and if necessary, the applicable ONI Support Employee, and will specify that the ONI Support Employee

will be working on behalf of ONI, identifying the work locations designated by ONI, and other terms of the assignment agreeable to OPG, ONI and, if applicable, the ONI Support Employee. Each ONI Support Assignment Agreement shall ensure that ONI's confidentiality obligations to third party clients will be adhered to by such ONI Support Employee. All ONI Support Employees will remain employees of OPG and not become employees, servants or agents (except to the extent expressly specified in the applicable ONI Support Assignment Agreement) of ONI. All pay and benefits of the ONI Support Employees will continue to be the responsibility of OPG.

(f) Invoices and Expenses. OPG will, in accordance with Section 7 or as otherwise agreed to between ONI and OPG, invoice ONI at the greater of:

(i) the market price for providing the applicable services as appropriate,
(ii) all costs incurred by OPG in providing such services including:
(A) OPG's applicable employee costs including salary, incentive compensation, standard OPG allocations for benefits and pension and any applicable overhead or administrative costs incurred by OPG with respect to the administration of the employees incurred by OPG for each ONI Support Employee and any additional costs paid by OPG in accordance with the ONI Support Assignment Agreements for those ONI Support Employees;
(B) all third party expenses incurred by OPG in providing such services; and
(C) the direct cost of certain equipment or materials, or other deliverables used to provide such services, and
(iii) all business expenses reasonably incurred by the ONI Support Employees in connection with the applicable services.

(g) Service Standard. ONI Support Employees will follow, at a minimum, the principles contained in OPG's Safe Operations Rules, OPG's Code of Business Conduct, ONI's Code of Business Conduct and all applicable quality assurance programs implemented by either OPG or ONI's clients. In addition, ONI will ensure that all ONI Support Employees comply with the safety programs of the applicable jurisdiction in which they are performing services on behalf of ONI.

(h) The parties agree that the work and services provided by ONI Support Employees are separate and distinct from the Professional and Corporate Services provided by OPG to ONI in accordance with Section 4 and shall be invoiced by OPG separately from such Professional and Corporate Services.

(i) OPG acknowledges and agrees that the ONI Support Employees resources contemplated in this Agreement may be characterized by ONI to third party clients as a prime contractor subcontractor relationship. OPG will provide such further assurances of such arrangement, as may be reasonably requested by ONI.

SECTION 2 – PROVISION OF CAPITAL EQUIPMENT

2.1 ALLOCATED EQUIPMENT

Subject to the terms and conditions herein, upon request from ONI, OPG may rent, lease or sell, as applicable, from time to time, certain equipment or materials ("**ONI Allocated Equipment**") to ONI so that ONI can provide services to third parties for the purposes of carrying on ONI's business activities. ONI Allocated Equipment shall include all necessary licenses, permits and approvals related to the transfer and

use of such equipment, to the extent such licenses, permits and approvals can be transferred to, or otherwise relied on by, ONI.

2.2 ANNUAL EQUIPMENT PLAN

ONI shall deliver to OPG an annual equipment plan setting out potential equipment resource requirements for the upcoming year. Upon receipt of the ONI equipment plan, OPG shall review and notify ONI of any anticipated resourcing constraints and identify any potential contingency resources that may be available for such year. For clarity, the annual equipment plan is expected to be provided as part of the annual business planning process completed by ONI in accordance with timelines as set out by OPG, and may be revised and updated throughout the year. ONI and OPG shall coordinate throughout the term of this agreement to ensure that ONI has continuous access to OPG's equipment resources subject to the qualifications in Section 2.3.

2.3 EQUIPMENT REQUESTS

ONI shall make all requests for certain equipment and material to OPG as promptly as possible. Such request shall specify the type of equipment or materials requested, the location such equipment or material will be used at, the expected duration such equipment or material will be needed and the preferred nature of the equipment or material agreement (i.e. rental or sale). OPG is under no obligation to provide any ONI Allocated Equipment if such resource allocation would result in an impact to the current service standard levels provided at OPG's facilities, would represent a reasonable risk to the safe operations of OPG's facilities.

2.4 ALLOCATED EQUIPMENT AGREEMENTS

Upon receipt and approval of a request for ONI Allocated Equipment from ONI, OPG will document the terms and condition of the rental or sale agreement, as applicable, between ONI and OPG (a "**ONI Allocated Equipment Agreement**"). Any and all costs incurred by OPG to rent or sell ONI Allocated Equipment to ONI will be borne wholly by ONI, including, without limitation the cost of all activities required to document, supply and deliver the ONI Allocated Equipment, all applicable freight, insurance, taxes and other charges incurred by OPG and reasonable wear and tear costs. Except as otherwise specified herein, ONI Allocated Equipment will be rented or sold, as applicable, at OPG's net book value by applying the remaining useful life to determine the calculated cost of such ONI Allocated Equipment, including a return on invested capital.

2.5 OWNERSHIP

Except as otherwise provided in a ONI Allocated Equipment Agreement, the ONI Allocated Equipment is, and shall at all times be and remain, solely and exclusively the property of OPG, and no right, title or interest in the ONI Allocated Equipment shall pass to ONI other than the right of ONI to possess and use the ONI Allocated Equipment for the term as provided in the ONI Allocated Equipment Agreement or as otherwise agreed to between OPG and ONI. The ONI Allocated Equipment shall remain personal property notwithstanding that the ONI Allocated Equipment or any part of the ONI Allocated Equipment may be affixed or attached to any other personal or real property.

2.6 LIABILITY AND INSURANCE

ONI shall be liable to OPG for all loss or damage (reasonable wear and tear excepted), cost, expense, charge, fine or penalty arising out of the ONI Allocated Equipment for the duration such ONI Allocated

Equipment is in the custody and control of ONI. ONI shall give OPG notification of any loss or damage promptly upon ONI becoming aware of same. In the event of any such loss or damage, ONI shall pay to OPG the cost of either repairing or replacing the ONI Allocated Equipment or portion thereof that is subject to the loss or damage. ONI Allocated Equipment will be and remain at the risk of ONI until returned to OPG in accordance with the ONI Allocated Equipment Agreement. ONI will continue in full force and effect all insurance policies required in accordance with the ONI Allocated Equipment Agreement and give all notices and present all claims under all insurance policies in due and timely fashion.

SECTION 3 – NUCLEAR LIABILITY PROTECTION FOR ONI AND ITS SUBCONTRACTORS OR SUPPLIERS

3.1 PARTICULAR DEFINITIONS FOR NUCLEAR LIABILITY

For the purposes of this Section 3,

"**Losses**" means any and all losses of any kind or nature, including but not limited to economic loss, damage to property, personal injury, psychological damage, the cost of measures of reinstatement of impaired environment, cost of preventative measures and loss of income; provided, further, that nothing is excluded from the ambit of Losses, including heads of damage which are traditionally not recoverable at law. Losses includes but is not limited to damages, injuries, claims (including any costs incurred in respect thereof), demands, costs, adverse judgments, findings or rulings, penalties, expenses, payments, liabilities, whether personal, economic or preventative, direct or consequential, and whether incurred through settlement, in a court of law, in arbitration, in a regulatory proceeding or as a result of the directive, determination, finding, or order of a governmental authority or any obligation imposed by operation of any applicable law, or otherwise.

"**Nuclear Damage**" means any Losses, of any kind, to the extent that the Losses arise out of or result from a Nuclear Incident at an OPG facility.

"**Nuclear Incident**" means, in respect of the Nuclear Installation, any of the following, or any combination thereof:

(a) a "nuclear incident" as defined under the *Nuclear Liability and Compensation Act* (Canada) or a nuclear liability convention; or
(b) any emission of ionizing radiation from any source of radiation within, or released from, the Nuclear Installation; or
(c) any occurrence involving Nuclear Material to the extent that such occurrence arises out of, or results from, or is connected with the radioactive properties, or a combination of the radioactive properties, and any toxic, explosive or other hazardous properties of, such Nuclear Material; or
(d) any occurrence involving both non-nuclear material and, as described in (c) above, Nuclear Material, to the extent that it cannot be identified as having been caused only by the non- nuclear material; or
(e) any occurrence elsewhere than on the site of the Nuclear Installation involving Nuclear Material which at the time of such occurrence:
    (i) is being transported to or from such site;
    (ii) is being transported by or on behalf of any party, whether or not to or from such site;
    (iii) is Nuclear Material that has been on such site, or has been transported to or from such site, or has been transported by or on behalf of any party, whether or not to or from such site,

in each case to the extent that such occurrence arises out of or results from or is connected with the radioactive properties, or a combination of the radioactive properties and any toxic, explosive or other hazardous properties of, such Nuclear Material.

"**Nuclear Installation**" means any of the following:

(a) any "nuclear reactor (as such term is defined in the *Nuclear Liability and Compensation Act* (Canada)) owned and operated by OPG;
(b) any factory using "nuclear fuel" (as such term is defined in the *Nuclear Liability and Compensation Act* (Canada)) for the production of Nuclear Material, or any factory for the processing of Nuclear Material, including any factory for the re-processing of irradiated Nuclear Fuel owned and operated by OPG; and
(c) any facility where Nuclear Material is stored owned and operated by OPG.

"**Nuclear Material**" means any of the following:

(a) "nuclear material" as defined under the legislation of the "installation state" (such term itself being defined under the *Nuclear Liability and Compensation Act* (Canada));
(b) nuclear fuel, other than natural uranium or depleted uranium, that can produce energy by a self-sustaining nuclear fission chain reaction outside a nuclear reactor either alone or in combination with another material; and
(c) radioactive products or waste.

"**Operator**" means, in relation to the Nuclear Installation, the person designated or recognized by the Installation State as the operator of that nuclear facility or who is otherwise the de facto operator of that nuclear facility.

3.2 NUCLEAR LIABILITY TERMS

(a) The parties expressly acknowledge and agree that in no event and under no circumstances shall ONI, irrespective of any of its activities, assume any role as Operator or be deemed to be an Operator of a Nuclear Installation.

(b) The parties acknowledge that OPG may, from time to time, allow ONI to access its Nuclear Installations and that Nuclear Damage may arise out of or relate to ONI's potential activities and uses permitted or contemplated under the Agreement. As between the parties, OPG shall be exclusively and absolutely liable for all Nuclear Damage, wherever suffered or incurred and however caused, and OPG waives all rights (both present and future) to make any claim against ONI in respect thereof. OPG shall indemnify, defend and hold harmless ONI from and against all Nuclear Damage wherever suffered or incurred and however caused, without limitation, as a result of, in respect of, or in any way related to, connected to, or arising out of ONI's potential activities and uses permitted or contemplated under the Agreement.

(c) ONI shall not have any liability for, and OPG shall waive all rights (both present and future) against ONI in respect of, loss of, or loss of use of, property at the Nuclear Installation, or to the means of transport, or to storage incidental to transport of Nuclear Material for which OPG is responsible at law.

(d) The parties acknowledge that ONI may be asked by its contractual counterparties to obtain from OPG certain waivers or indemnities in respect of Nuclear Damage. Where it is necessary to ONI's business and appropriate in the opinion of OPG's Law Division, OPG authorizes ONI to flow down

nuclear liability protection to its subcontractors or suppliers up to the full measure of protection afforded to ONI under this Agreement. However, the degree of nuclear liability protection that OPG authorizes ONI to flow down to its subcontractors or suppliers in a given circumstance is in accordance with the following terms:

(i) in respect of subcontractors or suppliers who have recently entered into a direct contract with OPG containing nuclear liability terms, such protection is consistent with the terms that OPG has agreed to in such direct contracts with these suppliers or subcontractors; or

(ii) in respect of subcontractors or suppliers who have not recently entered into direct contracts with OPG containing nuclear liability terms, such protection is consistent with the terms that OPG recently has agreed to in a direct contract with a similarly situated subcontractor or supplier.

SECTION 4 – PROFESSIONAL AND CORPORATE SERVICES

OPG will provide or arrange for the provision of professional and corporate services required in connection with the operation of the business interests of ONI and as requested by ONI. The fees for Professional and Corporate Services will be based on the actual fully burdened OPG labour rates per hour, and will include OPG's applicable employee costs including salary, incentive compensation, standard OPG allocations for benefits and pension and any applicable overhead or administrative costs, or third party costs (including, for certainty, legal and advisory services) incurred by OPG with respect to the administration of the services and will be charged on a monthly basis.

SECTION 5 – ONI POVISION OF GOODS AND SERVICES

(a) ONI Services shall be provided in accordance with (1) all applicable terms and conditions of this Agreement, and (2) those specific terms and conditions set out in the attached Appendix B.

(b) The parties agree to negotiate the terms and conditions of Appendix B no later than one (1) year after the Effective Date, and, upon successful completion of such negotiations, to incorporate such negotiated terms and conditions into Appendix B by execution of an amendment in accordance with Section 14(h).

(c) For the avoidance of doubt, no ONI Services shall be provide under this Agreement until the successful negotiation of Appendix B, in accordance with this Section 5(b), and the incorporation of Appendix B into this Agreement in accordance with Section 14(h).

SECTION 6 – INTELLECTUAL PROPRETY

(a) For the purposes of this Section 6, "**Intellectual Property Assets**" means any and all rights that are or may be granted to, or recognized for the benefit of, any party under any legislation regarding patents, copyright and any copyrightable subject matter (including moral rights), trade-marks, trade names, service marks, confidential information or trade secrets, industrial or, as applicable, patent designs, integrated circuit topography rights and any other statutory provision or common or civil law principle regarding intellectual property, whether registered or unregistered, and including rights in any and all applications, registrations, re-issues, divisionals, continuations, continuations-in-part, renewals, re-examinations relating to the foregoing, and any and all rights in and to licenses and sub-licenses from third parties relating to the foregoing.

(b) Each party will retain all of its Intellectual Property Assets to any information provided to the other party under this Agreement, and nothing in this Agreement grants, by implication, waiver, estoppel or otherwise, to a party or any third party any right, title or interest in or to the Intellectual Property Assets of the other party.

(c) Notwithstanding Section 6(b), the parties acknowledge and agree that the parties may negotiate different intellectual property rights to a party's Intellectual Property Assets in a future arrangement.

SECTION 7 – TERM

This Agreement commenced on the Effective Date and shall terminate December 31, 2030, unless earlier terminated by the parties in writing, and subject to renewal with the mutual consent of the parties.

SECTION 8 – TERMINATION

Notwithstanding Section 7, this Agreement may be terminated upon 30 days prior written notice by either party to the other party or upon the occurrence of the following events:

(a) in the event the parties fail to agree to a Work Request Form and/or a Work Estimate and Approval Form as set out in Appendix A;

(b) in the event of a material default in the performance of the Agreement by such other party; or

(c) by written notice effective immediately if the other party makes any extraordinary arrangement with its creditors generally, commits an act of bankruptcy, goes into liquidation or winding-up, has execution or distress levied upon any of its assets, or becomes unable to pay its debts, including its debts to the other party, as they fall due.

Upon termination of this Agreement pursuant to this Section 8,

(d) the provisions of this Agreement which are expressed to survive this Agreement or to apply notwithstanding termination hereof shall be observed by both parties hereto; and

(e) neither party shall be liable to the other party, either for fees, expenses, other compensation, or damages of any kind or character whatsoever, whether on account of the loss by OPG or ONI of present or prospective profits or fees on sales or anticipated sales, or expenditures, investments, or commitments made in connection therewith, or in connection with the establishment, development, or maintenance of the business of any party, or on account of any other cause or thing whatsoever, provided that such termination shall not prejudice or otherwise affect the rights or liabilities of any party with respect to any indebtedness owing by either party to the other party at the time of termination.

SECTION 9 – INVOICE AND PAYMENT

After the end of each month, OPG shall provide ONI with a notice (the "**Invoice**") setting forth the total amount owing to OPG in respect of the ONI Support Employee services, charges for certain equipment or materials used by ONI, and the professional and corporate services provided during such month. The Invoice will be delivered within the first 15 days of the following month and ONI shall be required to review and comment on such Invoice within 15 days following receipt thereof. ONI shall pay all undisputed

amounts payable under such Invoice on the twenty fifth day of such following month (the "**Due Date**") (and if the Due Date is not a Business Day, the immediately following Business Day), and any disputed amounts shall be resolved in accordance with Section 12. Except as otherwise expressly provided herein "**Business Day**" means any day except a Saturday, Sunday, banking holiday or a statutory holiday in Toronto, Ontario and shall open at 8:00 a.m. and close at 5:00 p.m. local time. The invoicing and procedure set out in this Section 9 is the only approved procedure by which ONI may compensate OPG under this Agreement. For clarity, OPG cannot charge costs to ONI by way of an accounting or book transfer.

SECTION 10 – CONFIDENTIALITY

(a) In the course of this Agreement, OPG or ONI (each a "**Disclosing Party**", as the context requires) will disclose to the other party (each a "**Receiving Party**", as the context requires) certain information (including applications of that information) which is confidential, a trade secret or otherwise proprietary to the Disclosing Party, including this Agreement (collectively, the "**Confidential Information**"). Confidential Information does not include, however, information that the Receiving Party is able to demonstrate to the Disclosing Party's satisfaction, acting reasonably: (i) was or becomes generally known to the public through no fault of the Receiving Party or its respective shareholders, directors, officers, partners, members, representatives, agents, advisors or any of the Receiving Party's personnel or any other person for whom the Receiving Party is responsible at law; (ii) was specifically known by the Receiving Party before disclosure by the Disclosing Party and was not subject to any confidentiality obligation; (iii) was developed or ascertained independently without reference to the other party's Confidential Information; or (iv) was received from a third party without such third party being under a duty of confidentiality.

(b) All Confidential Information remains, at all times, the exclusive property of the respective Disclosing Party. Except as expressly set out in this Agreement, a respective Receiving Party has no licence or other right to use or disclose any Confidential Information for any purpose whatsoever. Such Receiving Party may use Confidential Information only in respect of the preparation or provision of the goods, services and personnel as set out in this Agreement. Such Receiving Party will ensure that none of its current or former shareholders, directors, officers, partners, members, representatives, agents and advisors or any of its personnel or any other person for whom such Receiving Party is responsible at law will use any of the Confidential Information for any purposes other than those expressly set out in this Section 10.

(c) At the Disclosing Party's request, the Receiving Party will promptly (and in any event, within ten business days of receipt of such request) return to the Disclosing Party or destroy, at the Disclosing Party's election, any and all Confidential Information belonging to the Disclosing Party, including all reproductions and any documents based on any of the Confidential Information, and will not retain any copies thereof provided that the Receiving Party may retain any copies of Confidential Information (a) required to comply with the requirements of any applicable legislation, other legal requirement, internal record retention policies or procedures or good governance, and (b) automatically created on the Receiving Party's computer systems by its normal back-up procedures for the period it normally archives backed-up computer records; however, such Confidential Information referred to in (a) and (b) remains confidential and subject to the terms of this Agreement. Promptly following delivery or destruction, as the case may be, on the request of the Disclosing Party, the Receiving Party will provide the Disclosing Party with written confirmation of completion.

SECTION 11 – NOTICES

Unless otherwise provided herein, every notice provided for in this Agreement shall be in writing directed to the party to whom given, made or delivered at such party's address, by registered mail, by electronic mail or personally as follows:

If to OPG:

Ontario Power Generation Inc.
700 University Avenue, H18
Toronto, Ontario
M5G 1X6

Attention: Kim Lauritsen, SVP Enterprise Strategy & Growth

Email: kim.lauritsen@opg.com

If to ONI:

Origin Nuclear Inc.
700 University Avenue, H18
Toronto, Ontario
M5G 1X6

Attention: Jos Diening, President & CEO

Email: jos.diening@originnuclear.com

Either party may change its address from time to time by giving written notice of such change to the other party. If any such notice is delivered by hand to an officer of the addressee, it shall be deemed to have been received by the addressee as soon as such delivery or transmission has been made to said officer.

SECTION 12 – DISPUTE RESOLUTION PROCEDURE

In the event that a dispute arises concerning any of the matters set forth herein, OPG and ONI shall cause the representatives designated by it to prepare and circulate promptly to the President of OPG and the President of ONI a written statement setting forth its position on the matter in dispute and its reasons for adopting such position. Each such office shall use their best efforts to resolve the matter in dispute within ten (10) Business Days (as such term is defined in Section 9 of this Agreement) following their receipt of such statement. If such officers agree upon a resolution of the matter, each of OPG and ONI shall take such action and necessary steps to ensure that such resolution is fully and promptly carried into effect.

SECTION 13 – COMLIANCE WITH ANTI-CORRUPTION LAWS

(a) Each party will comply with, and will take all reasonable measures to ensure that its employees; subcontractors, agents or other third parties subject to its control or determining influence will comply with, all applicable anti-corruption laws and policies, including the *Foreign Corrupt Practices Act* (U.S.), the *Corruption of Foreign Public Officials Act* (Canada), the *Bribery Act* (U.K.) and any applicable laws of similar effect of any other jurisdiction (collectively "Anti-Corruption Laws"), in connection with the services supplied hereunder.

(b) Each party represents, warrants and undertakes that it has instituted and maintains policies and procedures designed to ensure, and which are reasonably expected to continue to ensure, compliance with Anti-Corruption Laws, including policies and procedures designed to ensure that all agents, consultants or other persons employed or acting on its behalf or facilitating the conduct of its business comply with Anti-Corruption Laws.

SECTION 14 – GENERAL

(a) Entirety. This Agreement is intended by the parties as the final expression of their agreement and is intended also as a complete and exclusive statement of the terms of their agreement with respect to the matters herein. All prior written or oral understandings, offers or other communications of every kind pertaining to the matters herein are abrogated and withdrawn.

(b) Relationship. This Agreement shall not be construed to constitute a joint venture, partnership or agency between OPG and ONI. ONI acknowledges that it does not have, nor hold itself out to others as having, authority to bind OPG to contracts, agreements or other obligations.

(c) Assignment. The provisions of this Agreement shall be binding upon and inure to the benefit of OPG, ONI and their respective successors and permitted assigns. Neither party may assign this Agreement without the prior written consent of the other party.

(d) Headings. Headings provided in this Agreement shall have no meaning and are included only to facilitate reading of the Agreement.

(e) Controlling Law. This Agreement is and shall be deemed to be a contract entered into pursuant to the laws of Ontario and shall in all respects be governed and enforced in accordance with the laws of Ontario.

(f) Counterparts. This Agreement may be executed in one or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument. Any counterpart signature transmitted by sending a scanned copy by electronic mail or similar electronic transmission will be deemed an original signature.

(g) Separability of Clauses. Any provision or provisions of this Agreement which in any way contravene the law of any province, state or country in which this Agreement is effective shall, in such province, state or country, to the extent of such contravention of law be deemed separable and shall not affect any other provision hereof or the validity hereof.

(h) Amendment. Except as expressly provided in this Agreement, no amendment of this Agreement in whole or in part is binding unless it is in writing and signed by each party.

(i) Waiver. Either party may waive any right, interest, or condition of this Agreement which is for its benefit without implying the waiver of any other right or interest, or subsequent waiver.

[***Remainder of this page intentionally left blank; signature page and appendices to follow.***]

IN WITNESS WHEREOF, the parties have duly executed and delivered this Agreement as of the Effective Date.

ONTARIO POWER GENERATION INC.

By:_____
Name: Kim Lauritsen
Title: SVP Enterprise Strategy & Growth
Date: 29 August 2025

ORIGIN NUCLEAR INC.

By:_____
Name: Jos Diening
Title: President & CEO
Date: 29 August 2025

By:_____
Name: Carlton Mathias
Title: Secretary
Date: 2 September 2025

[Signature Page – Business and Services Agreement]

APPENDIX A

PROCESS FOR REQUESTION, RELEASING, AND RECORDING AGREED UPON SERVICES

As referenced in Section 1 of the Agreement, services can be requested by either party from time to time. Sections 1-5 of this Appendix A describe how to request services, obtain approval and appropriately file the release. This process is necessary to ensure that both OPG and ONI understand what has been agreed to, the duration of each release and to allow the businesses to maintain a controlled listing of work currently being executed and work that needs to be planned. Some services may require that the parties develop additional forms of documentation to appropriately describe those services and agree upon the terms and conditions that apply to those services. In such cases a Work Request Form need not be completed.

1. Request for Services

Services which are required and can be provided, shall be initially identified through verbal discussions during the business planning process or during the normal course of business. To finalize a services request, a Work Request Form (see sample below) will be completed and will indicate the project name or defined work package, a brief description of the services required, and any timeline, other limitation, or applicable conditions, including special terms and conditions.

Sample

Work Request Form	
Requesting Department and Organization	example - Enterprise Projects, OPG
Contact email	john.smith@opg.com
Start Date	January 1, 2021
End Date	December 31, 2021
Summary of Work	Summary of estimation requirements
Special Considerations - specialized requirements	Special qualifications, performance expectations, milestones,any other relevant information associated with the work
Submission Date	January 1, 2021
Required Response Required by	January 2, 2021

2. Definition and Estimation

Upon receipt of a Work Request Form, the responding organization will determine if it can provide an estimate in response. If the responding organization can, it shall complete a Work Estimate and Approval Form (see sample below), confirming the work to be carried out, the schedule, resources and total estimated cost. Before returning this estimation to the requesting party, the details will be approved by the appropriate

OAR authority allowed to authorize contractual commitments for the organization. The form will then be routed to the requesting organization.

Work Estimate and Approval to Proceed Form

Release under the General Services Agreement between Laurentis Energy Partners and OPG

Revision #	Rev 0
Date	

The agreed upon, identified support is intended to capture total support requirements provided through SLA agreements are aligned with OPG's and ONI's approved Accounting Treatments. For SLA purposes and BPC rollup, project #s have been simplified for SLA approvals/Bping.

Note: Please see attached SoW document for the services to be provided.

Bundle/ Function	**Bundle/ Function**	**Service Provider**
		OPG or ONI

				Annual Requirement						**Total**
Project #	**Description**	**Unit**	**Additional Information (JF2, etc)**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2021-2026**
		$k								0
		$k								0.0
		$k								0.0
		$k								0.0
		$k								0.0
		FTE								0.0
		FTE								0.0
	Total Labour $	$k	**Total Labour $**	0	0	0.0	0.0	0.0	0.0	0
		FTE								0.0
		$k								0.0
Subtotal, FTE		**FTE**		0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal Non-Labour, $		**$**		0	0	0	0	0	0	0

SLA Approvals:

Service Provider (OAR)
I have reviewed this estimation and agree that this service proposal can be delivered as submitted.

Name
Title
Organization

Signature

Date: _____

Acceptance Approval (OAR)
I accept this proposal and request that this service be executed.

Name
Title
Organization

Signature

Date: _____

Routing of completed SLA Releases:
cc: finance@laurentisenergy.com

ONI - Finance Use only

Sales order or Purchase order completed	☐
Alignment with Project completed	☐
Contractor Utilization updates completed	☐
Business Planning Schedule completed	☐

3. Review and Authorization

If the proposal is acceptable, the requesting party will approve the work to proceed through their respective OAR position holder(s). A copy will be routed back to the responding organization for confirmation to proceed and the services will be filed, transactional systems updated, and reports generated based on these

commitments within both organizations. If OPG is the requesting party, OPG and ONI will also execute a Services Appendix to document the ONI Services.

4. Change Management – on released work

If aspects such as cost estimations, cancellations, terms or special conditions change, a change request be circulated following a similar process as identified in step 2-3 to ensure all stakeholders are duly notified and are agreeable to such changes. The same form can be used and should be marked clearly as a CHANGE to any existing services.

5. Facility Policies and Procedures

If ONI Support Employees provide services at a ONI site, such employees shall do so in accordance with ONI policies and procedures, including security checks, that have been identified to OPG. ONI will provide

APPENDIX B

TERMS FOR THE PROVISION OF GOODS AND SERVICES BY ONI TO OPG

SEC Interrogatory #180

Interrogatory

Reference:
F3-1-4, Attachment 1, p. 12

Question(s):

Please provide a live copy of the referenced OPG cost allocation model with all formulas intact.

Response

OPG does not maintain a separate "live" cost allocation model in the form of a standalone spreadsheet or similar file that can be produced with formulas intact. The cost allocation methodology and related computations are implemented and executed within OPG's SAP Business Warehouse ("BW") environment.

The BW environment is SAP's enterprise data warehousing and reporting platform that consolidates data from SAP and non-SAP source systems, applies data translations and business rules, and produces outputs based on defined logic and parameters through centrally managed data models and queries rather than spreadsheet-based formulas.

SEC Interrogatory #181

Interrogatory

Reference:
F3-2-1

Question(s):

With respect to Asset Service Fees ("ASF"):

a) [p.1] The evidence states, "[t]he ASF methodology considers that to the extent that 90% or more of the beneficial use of joint-use asset relates to a particular business, the related assets are fully attributed to that business." Does this mean that an asset is used 91% by the regulated business, and 9% by an unregulated business, therefore the unregulated business bears no cost of the asset? If, so please explain why that is appropriate.

b. [p.3-6] Please provide the underlying calculations used to determine the other costs, depreciation expense and tax-adjusted return for each of the Corporate Headquarters and Corporate IT ASF to each of the regulated segments (nuclear, DNNP, and hydroelectric)

Response

a) Confirmed.

If 90% or more of the beneficial use of a joint-use asset relates to the regulated hydroelectric business, the asset is included in the regulated hydroelectric rate base. This "dominant use" approach has been consistently applied in all OPG payments amounts proceeding beginning with EB-2013-0321, when 48 additional hydroelectric facilities were prescribed for regulation by the OEB under Ontario Regulation 53/05. These additional facilities and their associated supporting infrastructure such as controls dams and service centres had been in existence for many years prior to OPG's contracted hydroelectric facilities, which may share the use of these assets, being constructed in the province. The "dominant use" approach reflects the cost allocation principle of causation, given that the existence of an asset is effectively caused by the particular business that requires greater than 90% of the usage of that asset.

The treatment of OPG's joint-use assets, including hydroelectric joint-use assets, was reviewed by Elenchus Research Associates Inc. ("Elenchus") as part of their assessment of OPG's cost allocation methodology, filed at Ex. F3-1-4, Attachment 1, Section 3.5, where Elenchus found that this treatment "remains reasonable given the operation of OPG's business and is consistent with cost causality principles."[1]

b) The underlying calculations used to determine the Corporate IT ASF are provided for each of the regulated segments within the Ex. F3-2-1, Table 5. The underlying calculations used to determine the Corporate Headquarters ASF for each of the regulated segments can be found in Attachment 1.

[1] This treatment of joint-use assets was also reviewed by HSG Group Inc. in EB-2013-0321 (Ex. F5-5-1, p. 25).

Attachment 1

OPG Corporate Headquarters Asset Service Fee Calculation

			OPG Nuclear Facilities					DNNP Facilities					Regulated Hydroelectric
Line	**Component**	**Reference**	**2027**	**2028**	**2029**	**2030**	**2031**	**2027**	**2028**	**2029**	**2030**	**2031**	**2027**
1	Total Depreciation		5.0	5.4	5.8	6.0	6.2	5.0	5.4	5.8	6.0	6.2	5.0
2	% Allocated		71.4%	70.8%	71.0%	69.5%	71.2%	8.8%	10.1%	9.6%	10.2%	3.8%	13.4%
3	ASF Depreciation	Line 1 x Line 2	3.6	3.8	4.1	4.2	4.4	0.4	0.5	0.6	0.6	0.2	0.7
4	Total Property Tax		0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
5	ASF Property Tax	Line 4 x Line 2	0.2	0.2	0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0
	Cost of Capital												
6	Net Book Value		195.8	206.4	203.0	199.3	195.4	195.8	206.4	203.0	199.3	195.4	195.8
7	Cost of Debt	For OPG Nuclear and Reg. Hydro: Line 6 x Ex. C1-1-1 Tables 1-5, col. b), Line 4 x Ex. C1-1-1 Table 5, col. c), Line 4 For DNNP: Line 6 x Ex. C1-1-1 Tables 14 -18, col. (b), Line 3 x Ex. C1-1-1 Tables 14 -18, col. (c), Line 3	4.3	4.7	4.8	4.7	4.7	0.0	0.0	0.0	0.0	0.0	4.3
8	Return on Equity	For OPG Nuclear and Reg. Hydro: Line 6 x Ex. C1-1-1 Table 5, col. b), Line 5b x Ex. C1-1-1 Tables 1-5, col. c), Line 5a For DNNP: Line 6 x Ex. C1-1-1 Tables 14 -18, col. (b), Line 4 x Ex. C1-1-1 Tables 14 -18, col. (c), Line 4	9.3	9.8	9.6	9.4	9.3	17.8	18.8	18.5	18.2	17.8	9.3
9	Total Cost of Capial		13.6	14.5	14.4	14.2	13.9	17.8	18.8	18.5	18.2	17.8	13.6
10	ASF Cost of Capital	Line 9 x Line 2	9.7	10.3	10.2	9.9	9.9	1.6	1.9	1.8	1.9	0.7	1.8
11	Tax gross up	Line 8 * (25% / (1 -25%)) * Line 2	2.2	2.3	2.3	2.2	2.2	0.5	0.6	0.6	0.6	0.2	0.4
12	ASF Tax-Adjusted Cost of Capital	Line 10 + Line 11	11.9	12.6	12.5	12.0	12.1	2.1	2.5	2.4	2.5	0.9	2.2
13	Operating Costs		7.6	7.7	7.9	8.0	8.1	7.6	7.7	7.9	8.0	8.1	7.6
15	ASF Operating Costs	Line 13 x Line 2	5.4	5.5	5.6	5.6	5.8	0.7	0.8	0.8	0.8	0.3	1.0
16	Total OPG Corporate Headquarters ASF	Line 3 + Line 5 + Line 12 + Line 15	21.1	22.1	22.4	22.0	22.6	3.2	3.9	3.7	3.9	1.5	4.0

SEC Interrogatory #182

Interrogatory

Reference:
F3-2-1, Table 1

Question(s):

With respect to Asset Service Fees ("ASF"):

a) Please provide the number of IT-end users for nuclear, DNNP, and hydroelectric which are used to allocate IT related Support Services costs under OPG's cost allocation methodology.

b) Please explain the increase in Joint-use Renewable Generation Assets allocated to Regulated Hydroelectric in 2023.

Response

a) The number of IT-end users for OPG's nuclear facilities, the DNNP facilities and OPG's regulated hydroelectric facilities as used under OPG's cost allocation methodology in this Application is provided in Chart 1. As OPG does not forecast IT-end users, these figures are derived by using available actual IT-end users at a point in time, assigned by the applicable categories in Chart 1, and then extrapolating on a forecast basis by the change in FTEs in the respective categories. This approach has been found to be applied "in a consistent manner" by Elenchus Research Associates Inc. as part of their assessment of OPG's cost allocation methodology (Ex. F3-1-4, Attachment 1, p. 15).

Chart 1 – IT End-users Cost Driver

	2027	2028	2029	2030	2031
OPG Nuclear Facilities	10,017	9,790	9,874	9,857	10,404
DNNP Facilities	718	776	674	575	581
OPG Regulated Hydroelectric	1,164	1,164	1,139	1,139	1,126

b) The increase in the Joint-use Renewable Generation ("RG") ASF in 2023 is largely due to the in-service of the RG Monitoring and Diagnostic Centre used to monitor the performance of systems and components of the RG stations in support of shifting to more advanced condition-based maintenance strategies.

Witness Panel: Compensation and Corporate Costs

SEC Interrogatory #183

Interrogatory

Reference:
F3-2-1

Question(s):

With respect to the Nuclear Isotopes Usage Fee:

a) Please provide the full underlying calculations, and the basis for the inputs.

b) Does the fee include Laurentis Energy Partners plan to produce Lutetium-177 and Yttrium-90?

Response

a) The requested information is provided in Attachments 1 to 3. These calculations are performed for each of Darlington Unit 2 and Unit 3 with respect to the use of such reactors by OPG's unregulated subsidiary Laurentis Energy Partners to produce certain isotopes, and for Darlington station as a whole with respect to the use of all four reactors by OPG to produce Cobalt-60. Such fees are applied upon the commencement of commercial production of the isotopes at the corresponding unit or station and have been forecasted accordingly in this Application.[1]

b) Yes.

[1] As anticipated in EB-2020-0290, Laurentis Energy Partners undertook a project to construct modification at Darlington Unit 2 with the goal of producing Molybdenum-99. The project involved a capital investment in partnership with a third party and carried technical risk due to the complexity of the irradiation methods. At present, while the modification is operational, commercial production of Molybdenum-99 has not yet commenced pending the resolution of some of these risks.

Numbers may not add due to rounding.

Attachment 1
Nuclear Isotopes Asset Usage Fee- Darlington Unit 2- Laurentis Energy Partners

Line	Component	Reference	2027	2028	2029	2030	2031
1	Total Depreciation		198.2	208.4	214.2	224.4	237.4
2	% Allocated[1]		0.8%	0.8%	0.7%	0.7%	0.6%
3	Asset Usage Fee- Depreciation	Line 1 x Line 2	1.6	1.6	1.6	1.5	1.5
	Cost of Capital						
4	Net Book Value		4,648	4,693	4,597	4,622	4,690
5	Cost of Debt	Line 4 x Ex. C1-1-1 Tables 1-5, col. b), Line 4 x Ex. C1-1-1 Tables 1-5, col. c), Line 4	102.5	107.7	108.1	110.0	112.1
6	Return On Equity	Line 4 x Ex. C1-1-1 Tables 1-5, col. b), Line 5 x Ex. C1-1-1 Tables 1-5, col. c), Line 5	220.2	222.3	217.8	218.9	222.2
7	Total Cost of Capital	Line 5 + Line 6	322.7	330.0	325.9	328.9	334.3
8	Asset Usage Fee- Cost of Capital	Line 7 x Line 2	2.6	2.5	2.4	2.2	2.1
9	Tax gross up	Line 6 * Line 2 * (25% / (1 -25%))	0.6	0.6	0.5	0.5	0.5
10	Asset Usage Fee- Tax-Adjusted Return	Line 8 + Line 9	3.2	3.0	2.9	2.7	2.6
11	Other Costs		0.2	0.2	0.2	0.2	0.2
12	Asset Usage Fee- Darlington Unit 2- Laurentis	Line 3 + Line 10 + Line 12	5.0	4.8	4.7	4.5	4.3

Notes:

1 The relative undepreciated book value of investments into the Darlington Unit 2 generation assets and the respective modifications required to produce the isotopes is used to apportion the depreciation expense and return components between the Nuclear generation business and the unregulated business.

Numbers may not add due to rounding.

Attachment 2
Nuclear Isotopes Asset Usage Fee- Darlington Unit 3- Laurentis Energy Partners

Line	Component	Reference	2027	2028	2029	2030	2031
1	Total Depreciation		133.7	144.0	149.6	159.8	172.9
2	% Allocated[1]		4.0%	4.9%	4.7%	4.3%	3.9%
3	Asset Usage Fee- Depreciation	Line 1 x Line 2	5.4	7.0	7.0	6.9	6.8
	Cost of Capital						
4	Net Book Value		3,114	3,225	3,192	3,281	3,416
5	Cost of Debt	Line 4 x Ex. C1-1-1 Tables 1-5, col. b), Line 4 x Ex. C1-1-1 Tables 1-5, col. c), Line 4	68.7	74.0	75.1	78.1	81.6
6	Return On Equity	Line 4 x Ex. C1-1-1 Tables 1-5, col. b), Line 5 x Ex. C1-1-1 Tables 1-5, col. c), Line 5	147.5	152.8	151.2	155.4	161.8
7	Total Cost of Capital	Line 5 + Line 6	216.2	226.8	226.3	233.5	243.4
8	Asset Usage Fee- Cost of Capital	Line 7 x Line 2	8.8	11.1	10.6	10.1	9.5
9	Tax gross up	Line 6 * Line 2 * (25% / (1 -25%))	2.0	2.5	2.4	2.2	2.1
10	Asset Usage Fee- Tax-Adjusted Return	Line 8 + Line 9	10.7	13.6	13.0	12.3	11.6
11	Other Costs		0.2	0.2	0.2	0.2	0.2
12	Asset Usage Fee- Darlington Unit 3- Laurentis	Line 3 + Line 10 + Line 11	16.3	20.8	20.2	19.4	18.6

Notes:

1 The relative undepreciated book value of investments into the Darlington Unit 3 generation assets and the respective modifications required to produce the isotopes is used to apportion the depreciation expense and return components between the Nuclear generation business and the unregulated business.

Numbers may not add due to rounding.

Attachment 3
Nuclear Isotopes Asset Usage Fee- Darlington- OPG

Line	Component	Reference	2027	2028	2029	2030	2031
1	Total Depreciation	Ex. B3-4-1 Table 2, cols. (b) and (c), Lines 28, 40, 52, 64, and 76	589.1	630.1	653.0	693.7	746.0
2	% Allocated[1]		0.0%	0.4%	0.4%	0.3%	0.3%
3	Asset Usage Fee- Depreciation	Line 1 x Line 2	0.0	2.2	2.3	2.3	2.3
	Cost of Capital						
4	Net Book Value	Ex. B3-1-1 Table 2, cols. (c), (f) and (i), Lines 4 and 16	13,728.1	14,111.8	13,933.8	14,235.2	14,712.6
5	Cost of Debt	Line 4 x Ex. C1-1-1 Tables 1-5, col. b), Line 4 x Ex. C1-1-1 Tables 1-5, col. c), Line 4	302.8	323.9	327.7	338.7	351.6
6	Return On Equity	Line 4 x Ex. C1-1-1 Tables 1-5, col. b), Line 5 x Ex. C1-1-1 Tables 1-5, col. c), Line 5	650.3	668.5	660.1	674.3	697.0
7	Total Cost of Capital	Line 5 + Line 6	953.1	992.4	987.7	1013.0	1048.6
8	Asset Usage Fee- Cost of Capital	Line 7 x Line 2	0.0	3.5	3.5	3.4	3.2
9	Tax gross up	Line 6 * Line 2 * (25% / (1 -25%))	0.0	0.8	0.8	0.7	0.7
10	Asset Usage Fee- Tax-Adjusted Return	Line 8 + Line 9	0.0	4.3	4.3	4.1	3.9
11	Other Costs		0.6	2.3	3.8	2.3	2.4
12	Asset Usage Fee- Darlington - OPG	Line 3 + Line 10 + Line 11 + Line 12	0.6	8.9	10.4	8.7	8.6

Notes:

1 The relative undepreciated book value of investments into the Darlington generation assets and the respective modifications required to produce the isotopes is used to apportion the depreciation expense and return components between the Nuclear generation business and the unregulated business.

Board Staff Interrogatory #217

Interrogatory

Reference:
Ref 1: Exhibit F3 / Tab 1 / Schedule 4 / Attachment 1 / p. 17
Ref 2: Exhibit F3 / Tab 1 / Schedule 4 / Attachment 1 / p. 27

Preamble:

At Reference 1, Elenchus recommended that, for allocating the costs of the Energy Markets department, "OPG consider using a MCR cost driver rather than OM&A/Capital for allocating costs within Renewable Generation".

At Reference 2, Elenchus recommended that OPG enhance its internal written documentation of the cost allocation model and description of its allocation processes.

Question(s):

a) Is OPG planning to implement the Elenchus recommendation to use the Maximum Continuous Rating (MCR) cost driver discussed at Reference 1? If not, please explain OPG's rationale and provide any analysis conducted to support its decision.

b) Is OPG planning to implement the Elenchus recommendation made at Reference 2? If not, please explain OPG's rationale and provide any updated internal documentation.

Response

a) Yes.

b) Yes.

Board Staff Interrogatory #218

Interrogatory

Reference:
Ref 1: Exhibit F3 / Tab 1 / Schedule 1 / Attachment 2 / p. 13
Ref 2: Exhibit F3 / Tab 1 / Schedule 1 / p. 9

Preamble:

The Hackett Group (Hackett), which completed OPG's last two corporate support costs benchmarking studies, was retained by OPG again to carry out the study for this Application.

At Reference 1, Hackett identified that OPG's HR process costs increased from $3,806 per employee in 2019 to $4,742 per employee in 2024, while the peer group median is at $3,543 per employee in 2024.

At Reference 2, in discussing HR process costs remaining in the 3rd quartile, OPG refers to "intensified recruitment and onboarding efforts and other support required through a period of increased hiring and workforce transition".

Question(s):

a) Please provide a more detailed explanation regarding why OPG's HR process costs increased by almost $1,000 per employee since 2019 and why OPG is $1,200 per employee higher than the peer group median.

Response

a) Compared to 2019, HR process costs increased due to an increase in resources required to perform additional recruitment and onboarding work effort, and increased investment to automate the associated processes. These increases were necessary to meet elevated hiring requirements following a period of reducing hiring associated with the anticipated downsizing related to the end of Pickering commercial operations as planned in EB-2020-0290. As discussed at Ex. F4-3-1, pp. 11, 13-14 and Ex. F3-1-1, p. 4, the subsequent shift of the organization from downsizing to an expanded project mandate, including the refurbishment and continued operations of Pickering, resulted in a peak in hiring and onboarding needs, including an approximately 120% increase in the number of applications since 2022 and an approximately 199% increase in OPG onboarding since 2019 (refer to Ex. L-F3-SUP-013, Attachment 1).

In parallel, higher candidate decline rates (peaking at approximately 26% in 2022) required additional effort to fill positions, including expanded outreach and partnership activities aimed at improving acceptance outcomes, which resulted in an improvement of 33% in external offer decline rates by 2024. While these actions and related technology enhancements increased HR costs in the 2020-2024 period, the investments to automate and streamline recruitment and onboarding have delivered measurable efficiency gains, including a 34% reduction in the average time to fill positions (Ex. L-F3-SUP-013, Attachment 1).

The ongoing initiatives to automate and streamline the function and the expectation of a return to a comparatively lower volume of hiring between 2026-2030 contribute to the HR department's lower costs over the IR term. Based on Ex. F3-1-1, Table 1, the HR department's costs are forecast to decline from 2024 levels, in inflation adjusted terms, by approximately 13% by 2031, while absorbing the incremental needs associated with the operations of DNNP Unit 1 once it comes online (estimated using an illustrative 2.5% annual cost escalation assumption).

Society Interrogatory #013

Interrogatory

Reference:
OEB staff interrogatory F3-Staff-218

Preamble:

Hackett identified that OPG's HR process costs increased from $3,806 per employee in 2019 to $4,742 per employee in 2024, while the peer group median is at $3,543 per employee in 2024.

OEB staff have asked OPG to "provide a more detailed explanation regarding why OPG's HR process costs increased by almost $1,000 per employee since 2019 and why OPG is $1,200 per employee higher than the peer group median".

It is not clear from the submitted evidence as to whether OPG has maintained or improved or reduced its HR service levels to its internal client base of employees through the 2019 to 2024 period.

Question(s):

a) Please provide HR service level performance metrics actual annual values for its internal client base of employees for the period 2019 until 2024.

b) Please explain annual changes in these levels of +/- 5% or more as well as any changes between 2019 and 2024 of +/- 5% or more.

c) If OPG has no such performance metrics for its HR service levels to its internal client base of employees, please explain:
   i. Why there are no such performance metrics, and;
   ii. How and why notionally HR service levels to its internal client base of employees have changed between 2019 and 2024.

Response

a) Refer to Attachment 1.

   Certain metrics in Attachment 1 became available for reporting during the 2019-2024 period due to new data tracking capability. Information is provided for the years it is available.

b) The year over year changes in the metrics of +/- 5% or more as well as any changes between 2019 and 2024 of +/- 5% or more are driven by business needs as well as efforts to adopt technological advancements and to improve HR processes. The efforts resulted in an overall improvement of the metrics over the period. Refer to Ex. L-F3-SEC-172 and Ex. L-F4-Staff-218 for additional details regarding increased recruitment and employee support demand since EB-2020-0290.

c) Not applicable.

Attachment 1- Human Resources Service Metrics (2019-2024)

Line No.	Metric	2019	((c) - (a)) / (a)	2020	((e) - (c)) / (c)	2021	((g) - (e)) / (e)	2022	((i) - (g)) / (g)	2023	((k) - (i)) / (i)	2024	% Change over Period
		Actual	% Change	Actual	% Change	Actual	% Change	Actual	% Change	Actual	% Change	Actual	
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Recruitment - Avg Time to Fill (Days)							69	1%	70	-34%	46	-33%
2	Recruitment - External Offer Decline Rate							26%	-35%	17%	-47%	9%	-65%
3	Recruitment - Internal Movement	1,234	22%	1,504	1%	1,521	-3%	1,480	16%	1,723	1%	1,747	42%
4	Recruitment - External Hires	140	9%	153	46%	224	214%	704	78%	1,251	23%	1,539	999%
5	Recruitment - Trade Union Hall Requisitions	257	60%	410	-26%	304	5%	320	-10%	287	-8%	263	2%
6	Recruitment - OPG Onboarding Volume	762	31%	995	8%	1,079	86%	2,007	38%	2,777	-18%	2,279	199%
7	Recruitment - OPG Vendor Onboarding Volume	699	29%	904	70%	1,536	211%	4,782	-9%	4,349	6%	4,611	560%
8	Recruitment - Outreach Events	11	-100%	0	0%	0	0%	0	n/a	35	17%	41	273%
9	Recruitment - Equity Deserving Hire Ratio							31%	0%	31%	52%	47%	52%
10	Recruitment - ION Program Placements	12	67%	20	30%	26	8%	28	11%	31	77%	55	358%
11	Employee Turnover Rates	5.40%	12%	6.00%	-23%	4.70%	29%	6.00%	-40%	3.60%	5%	3.80%	-29%
12	HR - Case Volume			64,068	-6%	59,908	5%	63,059	3%	65,008	3%	66,997	5%
13	HRSC - Avg. Case Duration in Days			94	-21%	74	-92%	6	0%	6	-33%	4	-96%
14	Number of Employee Communications	917	15%	1,059	8%	1,147	5%	1,207	34%	1,620	6%	1,712	87%
15	Employee Training Hours (Non-Tech)	57,413	-38%	35,674	113%	75,901	29%	97,744	31%	128,002	34%	171,883	199%
16	Employee Self-Development Training Hours	N/A		1,053	39%	1,466	90%	2,785	90%	5,287	154%	13,449	1177%

VECC Interrogatory #012

Interrogatory

Reference:
Exhibit F3, Tab 2, Schedule 1, Table 1

Question(s):

a) Please update Table 1 -Corporate Asset Service Fees – Regulated Hydro Electric- to include 2025 actual results.

b) In 2023 actual costs for the Kipling Ave offices et al (line 2) and OPG Corporate Headquarters (Line 3) totaled $1.1 million. In 2027 the forecast is for no allocations from Kipling Ave et al. but $4.0 million in costs of CHQ. Please explain the change occurring between 2023 and 2027.

Response

a) Refer to Attachment 1.

b) As noted at Ex. F3-2-1, p. 2, lines 11-13 beginning in the IR term, asset service fees are no longer charged for the leasehold improvements at 700 University Avenue and the Wesleyville site. The asset service fee for the 800 Kipling Avenue site was discontinued following the site's sale in 2022. The increase in the asset service for the Corporate Headquarters (CHQ) since 2023 primarily corresponds to the associated in-service additions, discussed at Ex. D2-1-2, p. 4, line 15 to p. 5, line 2.

Attachment #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 Actual	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	0.7	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	1.6	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	9.7	9.6	12.7
5	**Total**	6.8	7.5	7.1	9.1	8.6	10.6	13.7	15.0	16.0	18.8	21.5	25.2

VECC Interrogatory #013

Interrogatory

Reference:
Exhibit F3-1-1 / Attachment 2 / Table 7b

Question(s):

a) Are the Hackett Group benchmark categories at page 2 of Attachment 2 (i.e. Finance/Procurement/Real Estate/Human Resources/ Information Technology/Executive) intended to match the similarly named six categories of corporate costs shown in the subsequent tables, e.g. Table 1-3b?

b) Please revise Table 7b to show 2025 actual results.

c) Please revise Table 7b to show the number of Staff in each of the six categories (as identified in response to a) above) for each year 2020 – 2027. For example, in 2020 allocating the 121.1 Regular Staff to each of the six categories.

Response

a) No. Refer to Ex. L-F3-CCC-081 for further details.

b) Refer to Attachment 1.

c) OPG is unable to provide the requested information for historical (2020-2023) and forecast years (2025-2031), by each of Nuclear and Regulated Hydroelectric, for the reasons provided in Ex. L-F3-CCC-081, part a).

OPG is able to provide the total regulated (Nuclear and Regulated Hydroelectric) FTEs in the categories that underlie the 2024 Hackett Corporate Benchmarking Study costs. Such total regulated FTEs by corporate group are set out in Chart 1 below.

1

Chart 1 – Total Regulated FTEs by Corporate Group in Corporate Cost Benchmarking Study, Shown by Hackett Grouping	
Corporate Group	**2024 Benchmarked FTEs**
Corporate & Technology Services (CTS) / Information Technology	333.4
Real Estate	28.8
Supply Chain / Procurement	135.0
Finance	147.5
Human Resources	237.7
Corporate Centre / Executive & Corporate Service (ECS)	125.5
Total Benchmarked FTEs	**1,007.9**

2

Attachment #1

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 Actual	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	146.7	155.6	147.4
	Non-Regular Staff								
2	Temporary	10.5	12.7	15.1	14.2	13.7	12.1	8.4	6.2
3	**Subtotal Regulated Hydroelectric OM&A**	131.6	117.6	133.0	144.3	166.8	158.7	164.0	153.6
	Hydroelectric Capital:								
4	**Regular Staff**	6.3	7.6	10.0	10.0	11.5	17.4	29.9	36.4
	Non-Regular Staff								
5	Temporary	0.1	0.1	0.0	0.9	0.7	0.4	0.0	0.4
6	**Subtotal Regulated Hydroelectric Capital**	6.4	7.7	10.0	10.9	12.2	17.9	29.9	36.8
7	**Total Regulated Hydroelectric**	137.9	125.4	143.0	155.1	179.0	176.6	193.9	190.3

VECC Interrogatory #014

Interrogatory

Reference:
Exhibit F3-1-1 Table 8

Question(s):

a) Please revise Table 8 to show 2025 actual results.

b) Please revise Table 8 in the same fashion as the previous question, showing the Staff allocated to each of the six categories. For this revision the years 2023 through 2027 are the only years we are requesting the revision to show.

Response

a) Refer to Attachment 1. Note certain amounts in this version of Ex. F3-1-1, Table 8 have been corrected in line with Ex. L-F2-Staff-199, Attachment 1.

b) Refer to Ex. L-F3-VECC-013.

Attachment #1

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 Actual	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	1,050.5	1,077.1	998.1	993.1	996.0	1,003.0	1,055.3
	Non-Regular Staff												
2	Term/ETE/PECO Temporary	57.4	76.1	79.2	61.9	53.0	39.9	33.3					
3	Temporary	146.9	156.0	168.5	186.2	152.1	118.1	73.4	55.4	55.5	53.2	54.9	58.0
4	EPSCA	24.6	25.3	22.1	21.6	15.7	18.4	28.1	23.1	23.1	23.1	23.0	26.9
5	**Total Non-Regular Staff**	229.0	257.3	269.8	269.7	220.8	176.4	134.7	78.5	78.5	76.2	78.0	85.0
6	**Subtotal Nuclear OM&A**	1,083.9	1,056.6	1,150.0	1,319.2	1,345.3	1,226.9	1,211.8	1,076.6	1,071.7	1,072.3	1,081.0	1,140.2
	Nuclear Capital:												
7	**Regular Staff**	14.7	14.2	21.5	42.5	45.5	65.4	116.3	155.7	153.1	156.0	152.0	144.5
	Non-Regular Staff												
8	Term/ETE/PECO Temporary	2.6	1.3	1.1	2.7	5.6	3.1	0.0	0.0	0.0	0.0	0.0	0.0
9	Temporary	1.0	0.0	0.0	10.8	11.1	0.0		3.2	3.2	3.2	3.2	3.2
10	EPSCA	10.7	10.2	1.0	2.8	1.7	1.4	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	4.5	0.9	4.1	4.1	4.1	4.1	4.2
12	**Subtotal Nuclear Capital**	29.0	25.7	23.6	58.8	63.9	69.9	117.2	159.8	157.2	160.1	156.1	148.6
	Darlington Refurbishment:												
13	**Regular Staff**	37.4	33.4	31.5	32.4	37.3	27.3	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	7.6	0.0	0.0	0.0	0.0	0.0	0.0
15	EPSCA	6.7	8.9	7.8	7.2	8.0	6.7	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	14.3	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	41.6	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	92.6	145.7	244.4	234.9	234.9	229.1	167.9
	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	8.3	1.0	3.0	1.0	1.0	1.0	1.0
21	EPSCA	0.0	0.0	0.0	0.0	4.5	2.9	8.0	13.0	13.0	13.0	13.0	10.3
22	**Total Non-Regular Staff**	0.0	0.0	0.0	0.0	11.0	11.2	9.0	16.0	14.0	14.0	14.0	11.3
23	**Subtotal Pickering Refurbishment**	0.0	0.0	0.0	0.9	40.7	103.9	154.7	260.4	248.9	248.9	243.1	179.2
	Darlington New Nuclear Program:												
24	**Regular Staff**	0.0	0.0	9.9	14.0	21.9	28.2	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	6.5	0.0	0.0	0.0	0.0	0.0	0.0
26	EPSCA	0.0	0.0	0.0	0.0	0.0	0.1	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	6.6	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	34.8	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	14.0	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	1.5	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	15.5	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	52.4	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	0.9	0.0	0.0	0.0	0.0	0.0	0.0
34	Temporary	1.5	0.5	2.0	2.4	2.5	1.2	1.0	1.0	1.0	1.0	1.0	1.0
35	EPSCA	0.0	0.0	0.0	0.0	0.9	0.4	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	2.5	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	54.9	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	1,547.4	1,603.6	1,555.9	1,535.2	1,531.3	1,531.5	1,519.4

AMPCO Interrogatory #108

Interrogatory

Reference:
F4-1-1 Table 1

Question(s):

Please provide the OEB-approved depreciation and amortization amounts for each of the years 2016 to 2024.

Response

Per the OEB's Filing Requirements, the phrase "OEB-approved" refers to the set of data used by the OEB as the basis for approving the payment amounts.[1] Because OPG has not rebased its regulated hydroelectric payment amounts since EB-2013-0321, there are no historical OEB-approved amounts for the years in question.

[1] Ontario Energy Board, *Filing Requirements for Ontario Power Generation Inc.*, September 17, 2024, p. 6.

AMPCO Interrogatory #109

Interrogatory

Reference:
F4-1-1 Table 2

Question(s):

Please provide the OEB-approved depreciation and amortization amounts for the Nuclear Facilities for each of the years 2020 to 2024.

Response

Chart 1 below provides the OEB-approved depreciation and amortization amounts for OPG's nuclear facilities for the years 2020 to 2024.

Chart 1 – OEB-Approved Depreciation and Amortization Amounts for OPG's Nuclear Facilities ($M)

	2020	2021	2022	2023	2024
OEB-approved Depreciation & Amortization[1]	575.1	286.0	547.2	462.9	567.4

[1] The 2020 and 2021 amounts are per EB-2016-0152 Payment Amounts Order, App. A, Table 10, col. (b), lines 40 and 50, respectively. The 2022-2024 amounts are per EB-2020-0290 Payment Amounts Order, App. A, Table 10, col. (b), lines 9, 18 and 27.

Witness Panel: Finance, D&V, Cost of Capital, Regulatory Constructs, Customer Impacts

AMPCO Interrogatory #110

Interrogatory

Reference:
F4-3-1 Attachment 1 p.1

Question(s):

a) Please define EPSCA and PECO.

b) Please breakdown the Management category in Appendix 2-K into Executive, Senior management, Managers/Supervisors and Individual Contributors.

c) Please breakdown the Society category in Appendix 2-K into Managers, Supervisors and Individual Contributors.

d) Please separate Salary and Incentive Pay costs.

e) Please explain and quantify “Fiscal Adjustment”.

f) Please provide an excel version of Attachment #1 that reflects part (b) to (d) and in the excel include the allocation of compensation between OM&A and Capital.

Response

a) Refer to Ex. L-F4-Staff-222, part c) for the definition of EPSCA. PECO refers to Pickering End of Commercial Operations. Refer to Ex. F4-3-1, pp 5-6, lines 24-2.

b) and c)

Refer to Attachment 1 for a breakdown of Management into Executive and Non-Executive Management, except for a breakdown of Managers/Supervisors and Individual Contributors. The Management category is reported at an aggregated level, and details are available to break down Executive and Non-Executive Management level; however, they are not available for the Manager/Supervisor versus Individual Contributor level. While a mathematical exercise could be undertaken to prorate the Non-Executive Management values into these two categories using FTEs as a basis, the results would not be representative given the variability in labour rates across Individual Contributors and Manager/Supervisory levels. For clarity, the Application presented a breakdown of the FTEs on this basis

with the available information in order to provide a broader perspective on the composition of OPG's workforce, in Ex. F4-3-1, Figures 4 (a) and 4 (b).

d) Refer to Attachment 1.

e) Refer to Ex. F4-4-1, p. 9, lines 17-23 for an explanation of the fiscal calendar adjustment. The amount of the fiscal adjustment for OPG's nuclear facilities is provided below.

Chart 1 - Fiscal Adjustment for OPG's Nuclear Facilities

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	Actual	Actual	Actual	Actual	Actual	Plan	Plan	Plan	Plan	Plan	Plan	Plan
OPG Nuclear Facilities	6.0	2.8	(0.2)	(0.0)	(8.2)	3.7	3.3	3.1	0.0	(13.9)	3.6	3.9

f) Refer to Attachment 1 for an excel version of Ex. F4-3-1, Attachment 1 and for a breakdown of compensation costs between OM&A and Capital.

AMPCO-110 Attachment 1

OM&A

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 Actual	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Staff (Regular and Non-Regular)	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**
	Nuclear - Direct													
1	Executive	26.4	21.8	22.8	25.1	27.8	26.2	27.1	24.4	20.8	20.7	20.7	19.9	24.1
2	Non-Executive Management	451.8	364.1	344.6	395.9	426.8	402.4	399.3	372.6	294.9	287.8	287.0	283.3	329.6
3	Management Subtotal	478.3	385.8	367.4	420.9	454.6	428.6	426.3	397.0	315.7	308.5	307.7	303.2	353.7
4	Society	1,736.5	1,607.1	1,446.5	1,540.5	1,607.9	1,477.5	1,546.9	1,453.1	985.7	965.2	970.4	967.8	1,155.3
5	PWU	3,092.3	2,925.9	2,470.0	2,474.5	2,644.2	2,507.1	2,650.4	2,570.5	2,041.9	2,035.1	2,102.8	2,063.1	2,441.6
6	Term/ETE/PECO Temporary	586.2	767.0	887.8	930.0	600.5	237.9	202.2	174.7	0.0	0.0	0.0	0.0	0.0
7	EPSCA	77.3	94.4	99.4	88.2	100.0	51.5	54.2	25.4	22.0	21.6	21.6	21.0	20.0
8	Subtotal	5,970.5	5,780.3	5,271.1	5,454.1	5,407.2	4,702.5	4,880.1	4,620.7	3,365.3	3,330.4	3,402.5	3,355.1	3,970.6
	Nuclear - Allocated													
9	Executive	23.7	21.1	22.8	24.1	22.7	24.0	25.7	26.7	23.9	23.7	23.9	23.4	22.8
10	Non-Executive Management	236.7	236.5	236.4	272.4	289.2	291.8	332.3	318.1	276.8	275.8	277.6	277.6	282.2
11	Management Subtotal	260.4	257.5	259.2	296.5	311.9	315.8	358.0	344.8	300.7	299.5	301.5	301.0	305.1
12	Society	349.1	344.6	364.5	485.5	527.7	497.4	544.0	497.9	431.4	431.1	429.5	434.6	456.0
13	PWU	409.6	381.0	426.3	458.6	444.9	370.9	393.4	350.6	321.5	318.0	318.2	322.4	352.3
14	Term/ETE/PECO Temporary	57.6	76.1	79.2	61.9	53.0	39.9	39.0	33.3	0.0	0.0	0.0	0.0	0.0
15	EPSCA	24.7	25.3	22.1	21.6	15.7	18.4	27.1	28.1	23.1	23.1	23.1	23.0	26.9
16	Subtotal	1,101.3	1,084.5	1,151.3	1,324.1	1,353.2	1,242.4	1,361.5	1,254.6	1,076.6	1,071.7	1,072.3	1,081.0	1,140.2
	Nuclear Facilities													
17	Executive	50.1	42.8	45.7	49.1	50.5	50.2	52.7	51.1	44.7	44.4	44.6	43.3	46.9
18	Non-Executive Management	688.5	600.5	580.9	668.3	716.0	694.2	731.6	690.7	571.7	563.6	564.6	560.9	611.8
19	Management Subtotal	738.6	643.4	626.6	717.4	766.5	744.4	784.3	741.8	616.4	608.0	609.2	604.2	658.8
20	Society	2,085.5	1,951.7	1,811.0	2,026.1	2,135.6	1,975.0	2,090.9	1,950.9	1,417.1	1,396.3	1,399.9	1,402.4	1,611.3
21	PWU	3,501.9	3,306.9	2,896.3	2,933.1	3,089.1	2,877.9	3,043.9	2,921.1	2,363.4	2,353.1	2,421.0	2,385.5	2,793.9
22	Term/ETE/PECO Temporary	643.9	843.1	967.1	991.9	653.4	277.8	241.2	208.0	0.0	0.0	0.0	0.0	0.0
23	EPSCA	102.0	119.7	121.5	109.8	115.7	69.9	81.3	53.5	45.1	44.7	44.7	44.1	46.9
24	Total	7,071.9	6,864.8	6,422.5	6,778.2	6,760.4	5,944.9	6,241.5	5,875.3	4,441.9	4,402.1	4,474.8	4,436.1	5,110.8
	Salary & Allowances (including Fiscal Adjustment)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
25	Executive	11.9	11.2	11.9	11.9	13.4	14.4	13.6	13.5	12.0	12.1	12.5	12.3	13.6
26	Non-Executive Management	98.8	88.2	91.8	101.3	110.3	116.9	118.2	116.1	100.3	101.0	104.2	106.7	120.4
27	Management Subtotal	110.6	99.4	103.7	113.1	123.7	131.4	131.9	129.5	112.3	113.1	116.7	119.0	133.9
28	Society	276.0	281.8	249.2	313.1	330.7	314.3	337.4	320.5	246.0	247.5	256.5	268.0	319.3
29	PWU[2]	410.2	417.9	351.0	418.6	487.1	411.2	403.8	404.3	339.7	347.8	374.4	381.0	462.3
30	Term[2]/ETE/PECO Temporary	69.3	95.0	114.9	130.9	84.3	37.2	26.8	24.3	0.0	0.0	0.0	0.0	0.0
31	EPSCA[2]	14.9	17.1	13.8	11.5	15.7	15.8	12.8	8.8	8.0	8.1	8.5	8.4	9.1
32	Unallocated[3]	(5.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33	Total	875.2	911.2	832.7	987.2	1,041.6	909.9	912.7	887.4	705.9	716.5	756.0	776.4	924.7
	Incentive Pay	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
34	Executive	6.9	6.1	6.2	7.8	6.6	8.4	7.7	6.7	6.8	7.3	7.5	7.5	7.9
35	Non-Executive Management	20.3	20.7	18.6	27.7	28.6	35.1	31.3	26.1	26.6	28.4	29.5	29.8	30.7
36	Management Subtotal	27.2	26.7	24.8	35.5	35.2	43.5	39.0	32.7	33.4	35.6	37.0	37.2	38.6
	Hydro One Shares	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
37	Society	4.8	4.6	4.9	5.0	5.4	5.8	2.8	2.4	2.4	2.3	1.8	1.8	1.6
38	PWU	10.6	12.2	12.2	12.7	12.8	15.5	7.2	6.4	6.1	5.9	5.2	4.8	1.2
	Total	15.5	16.8	17.1	17.6	18.2	21.3	10.0	8.8	8.5	8.2	7.1	6.6	2.8
	Overtime	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
39	Society	32.0	36.4	36.7	36.1	37.5	26.4	24.8	22.5	20.4	17.5	20.8	19.3	22.8
40	PWU	68.8	74.3	62.1	69.5	79.6	55.3	59.0	54.2	60.3	50.8	61.6	54.9	64.8
41	Term/ETE/PECO Temporary	8.7	11.3	15.6	19.9	11.2	3.9	3.1	2.5	0.0	0.0	0.0	0.0	0.0
42	EPSCA	1.5	2.8	3.8	3.7	5.0	1.9	0.9	0.6	1.0	0.8	0.9	0.8	0.7
43	Unallocated[3]													
44	Total	111.0	124.8	118.3	129.3	133.4	87.4	87.8	79.9	81.6	69.1	83.4	75.0	88.3
	Benefits (Current Benefits and Pension & OPEB)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
45	Executive	5.8	6.8	6.6	4.4	5.1	5.4	4.9	5.3	4.6	4.6	4.8	4.7	5.2
46	Non-Executive Management	50.1	51.9	50.3	27.6	45.3	44.6	40.5	43.9	36.9	37.0	38.8	39.4	44.8
47	Management Subtotal	55.9	58.7	56.9	31.9	50.5	50.0	45.4	49.2	41.5	41.6	43.6	44.0	50.0
48	Society	137.7	154.8	143.7	79.3	135.5	114.1	114.3	121.9	87.1	87.9	93.0	96.7	118.9
49	PWU	181.8	195.1	170.7	102.3	167.4	154.8	135.3	144.2	119.5	121.9	131.3	135.0	169.7
50	Term/ETE/PECO Temporary	5.0	5.8	8.0	8.8	7.1	2.8	1.7	1.5	0.0	0.0	0.0	0.0	0.0
51	EPSCA	1.0	0.2	0.3	(0.3)	(0.3)	1.3	0.6	0.4	0.4	0.4	0.4	0.4	0.4
52	Unallocated[3]	2.5												
53	Total	384.0	414.6	379.6	222.0	360.1	323.1	297.2	317.2	248.5	251.8	268.3	276.2	339.0
54	Current Benefits (Statutory)	56.1	54.7	55.4	59.5	65.9	59.6	65.0	62.3	50.2	50.4	54.7	54.4	65.1
55	Current Benefits (Non-Statutory)	32.5	40.8	39.0	40.5	38.9	46.9	44.5	42.8	35.0	36.1	38.3	38.9	46.9
56	Pension & OPEB (Current Service)[1]	295.4	319.1	285.1	122.0	255.3	216.5	187.8	212.1	163.2	165.3	175.4	182.9	227.0
	TOTAL COMPENSATION	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
57	Executive	24.6	24.1	24.7	24.0	25.2	28.3	26.2	25.4	23.4	24.0	24.8	24.4	26.7
58	Non-Executive Management	169.1	160.7	160.7	156.5	184.3	196.6	190.0	186.1	163.9	166.4	172.5	175.9	195.8
59	Management Subtotal	193.7	184.8	185.4	180.6	209.4	224.9	216.2	211.5	187.3	190.3	197.3	200.3	222.5
60	Society	450.6	477.7	434.5	433.6	509.1	460.6	479.3	467.3	355.8	355.2	372.2	385.8	462.6
61	PWU	671.5	699.5	596.1	603.0	746.9	636.8	605.3	609.1	525.6	526.4	572.5	575.7	698.0
62	Term/ETE/PECO Temporary	82.9	112.0	138.5	159.5	102.7	43.8	31.6	28.4	0.0	0.0	0.0	0.0	0.0
63	EPSCA	17.4	20.1	17.9	14.9	20.3	19.0	14.3	9.9	9.3	9.3	9.8	9.6	10.2
64	Unallocated[3]	(3.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
65	Total	1,412.8	1,494.2	1,372.4	1,391.6	1,588.5	1,385.1	1,346.7	1,326.1	1,077.9	1,081.3	1,151.8	1,171.4	1,393.3

[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)

Note: 2020 Actuals have been restated to more accurately reflect labour components, and by employee type and representation.

CAPITAL

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 Actual	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Staff (Regular and Non-Regular)	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**
	Nuclear - Direct													
1	Executive	6.9	7.2	6.4	6.2	10.2	13.1	16.0	10.4	9.4	9.4	9.4	9.4	9.3
2	Non-Executive Management	117.8	109.6	131.1	143.9	214.2	273.8	362.8	281.5	307.6	305.8	302.8	298.3	265.5
3	Management Subtotal	124.6	116.8	137.5	150.0	224.4	286.9	378.8	292.0	317.0	315.2	312.2	307.7	274.7
4	Society	392.9	402.8	423.8	495.1	650.0	851.2	1,234.9	1,042.9	1,323.9	1,304.4	1,298.9	1,280.0	1,069.8
5	PWU	180.8	168.9	200.8	202.3	255.1	332.2	430.0	583.0	1,174.9	1,191.8	1,207.6	1,207.9	812.0
6	Term/ETE/PECO Temporary	4.9	11.7	20.0	25.7	25.9	17.1	29.0	38.3	7.0	7.0	7.0	0.0	0.0
7	EPSCA	154.1	256.9	297.7	342.5	317.0	280.9	263.7	167.2	372.6	491.2	426.8	342.0	259.9
8	Subtotal	857.3	957.1	1,079.8	1,215.6	1,472.3	1,768.3	2,336.4	2,123.2	3,195.5	3,309.6	3,252.5	3,137.6	2,416.5
	Nuclear - Allocated													
9	Executive	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Non-Executive Management	7.3	8.2	11.0	14.6	25.1	37.3	37.4	34.3	39.1	37.0	36.3	34.8	25.0
11	Management Subtotal	7.3	8.2	11.0	14.6	25.1	37.3	37.4	34.3	39.1	37.0	36.3	34.8	25.0
12	Society	32.7	35.4	44.2	70.5	103.2	141.0	180.6	166.1	223.9	211.5	213.6	206.3	172.8
13	PWU	14.5	15.9	16.2	26.0	30.4	57.6	76.2	79.6	143.3	143.6	145.1	144.2	118.8
14	Term/ETE/PECO Temporary	2.4	1.3	1.1	2.7	7.7	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	EPSCA	17.4	19.1	8.9	10.0	14.3	11.1	9.9	8.9	13.9	13.9	13.9	13.9	11.2
16	Subtotal	74.4	79.9	81.4	123.7	180.6	250.1	304.2	288.9	420.2	406.1	408.9	399.3	327.8
	Nuclear Facilities													
17	Executive	6.9	7.3	6.4	6.2	10.2	13.1	16.0	10.4	9.4	9.4	9.4	9.4	9.3
18	Non-Executive Management	125.1	117.8	142.1	158.4	239.2	311.1	400.2	315.8	346.7	342.8	339.1	333.2	290.5
19	Management Subtotal	132.0	125.0	148.5	164.6	249.4	324.2	416.2	326.2	356.1	352.2	348.5	342.5	299.8
20	Society	425.6	438.2	468.0	565.6	753.2	992.2	1,415.5	1,209.0	1,547.8	1,516.0	1,512.5	1,486.3	1,242.6
21	PWU	195.3	184.8	217.0	228.3	285.5	389.8	506.2	662.6	1,318.3	1,335.4	1,352.7	1,352.1	930.8
22	Term/ETE/PECO Temporary	7.3	13.1	21.1	28.3	33.6	20.2	29.0	38.3	7.0	7.0	7.0	0.0	0.0
23	EPSCA	171.6	275.9	306.6	352.5	331.3	292.0	273.6	176.1	386.5	505.1	440.7	355.9	271.1
24	Total	931.7	1,037.0	1,161.2	1,339.4	1,652.9	2,018.4	2,640.5	2,412.1	3,615.7	3,715.7	3,661.4	3,536.8	2,744.3
	Salary & Allowances (including Fiscal Adjustment)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
25	Executive	2.2	1.9	1.5	1.6	2.6	3.2	3.9	2.7	2.5	2.5	2.6	2.6	2.7
26	Non-Executive Management	19.0	16.5	20.9	24.3	37.5	50.0	64.4	52.7	60.4	61.5	64.1	63.6	56.4
27	Management Subtotal	21.2	18.4	22.4	25.9	40.1	53.3	68.3	55.4	62.9	64.0	66.7	66.2	59.1
28	Society	53.2	58.7	64.9	84.1	111.7	150.9	208.9	182.9	252.7	257.4	271.5	271.7	234.1
29	PWU[2]	20.3	26.5	30.3	28.4	36.5	48.7	64.5	91.6	190.2	199.3	212.5	215.9	149.1
30	Term[2]/ETE/PECO Temporary	0.5	1.8	2.7	4.1	4.6	1.8	4.4	5.4	1.2	1.2	1.3	0.0	0.0
31	EPSCA[2]	25.9	47.0	55.3	68.7	66.3	51.7	45.2	29.9	71.5	93.7	86.0	71.3	56.1
32	Unallocated[3]	23.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33	Total	144.4	152.3	175.6	211.1	259.2	306.4	391.3	365.3	578.5	615.6	638.0	625.1	498.3
	Incentive Pay	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
34	Executive	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Non-Executive Management	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Management Subtotal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Hydro One Shares	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
37	Society	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
38	PWU	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Overtime	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
39	Society	5.6	6.0	7.4	11.0	14.6	16.4	17.6	14.4	21.2	21.2	22.0	21.8	16.9
40	PWU	3.3	2.7	4.3	4.8	6.5	8.2	8.0	9.5	31.1	31.6	34.9	35.9	21.3
41	Term/ETE/PECO Temporary	0.1	0.2	0.6	0.7	0.7	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
42	EPSCA	3.2	9.3	15.3	18.2	18.5	8.9	10.3	4.3	18.8	17.7	17.3	17.8	14.6
43	Unallocated[3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
44	Total	12.2	18.2	27.5	34.6	40.4	33.8	35.9	28.2	71.1	70.5	74.3	75.6	52.9
	Benefits (Current Benefits and Pension & OPEB)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
45	Executive	0.8	0.8	0.7	0.8	0.9	1.3	1.5	1.1	1.0	1.0	1.1	1.1	1.1
46	Non-Executive Management	8.1	6.3	8.3	11.3	13.3	19.8	25.5	20.9	24.7	25.2	26.3	26.0	23.3
47	Management Subtotal	8.9	7.0	9.0	12.0	14.2	21.1	27.0	22.0	25.8	26.2	27.3	27.1	24.4
48	Society	20.3	19.1	23.1	38.7	40.4	60.3	83.5	71.5	106.0	108.7	115.3	115.3	99.5
49	PWU	8.1	6.7	8.2	11.6	11.1	16.6	23.2	35.2	76.4	80.1	85.9	86.9	59.8
50	Term/ETE/PECO Temporary	0.0	0.1	0.2	0.3	0.4	0.1	0.2	0.3	0.1	0.1	0.1	0.0	0.0
51	EPSCA	1.8	3.0	4.3	4.9	5.3	2.8	2.6	1.6	4.3	5.3	4.9	4.3	3.4
52	Unallocated[3]	4.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
53	Total	43.2	36.0	45.0	67.6	71.3	100.7	136.5	130.6	212.6	220.4	233.5	233.7	187.0
54	Current Benefits (Statutory)	9.1	8.1	10.3	13.7	18.8	21.5	27.7	25.6	41.1	43.0	44.8	44.4	35.1
55	Current Benefits (Non-Statutory)	6.0	3.5	4.2	6.6	10.9	13.1	17.9	16.3	26.6	27.5	29.3	29.4	23.6
56	Pension & OPEB (Current Service)[1]	28.1	24.4	30.4	47.3	41.7	66.2	90.9	88.8	144.9	149.9	159.4	160.0	128.4
	TOTAL COMPENSATION	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
57	Executive	3.0	2.6	2.2	2.3	3.5	4.5	5.4	3.8	3.5	3.6	3.7	3.7	3.8
58	Non-Executive Management	27.1	22.8	29.2	35.6	50.8	69.8	89.9	73.6	85.1	86.6	90.3	89.6	79.7
59	Management Subtotal	30.1	25.4	31.4	37.9	54.3	74.3	95.3	77.5	88.7	90.2	94.0	93.3	83.5
60	Society	79.0	83.7	95.4	133.7	166.8	227.5	309.9	268.9	379.9	387.4	408.8	408.8	350.5
61	PWU	31.7	36.0	42.8	44.8	54.1	73.5	95.7	136.2	297.8	311.0	333.4	338.7	230.1
62	Term/ETE/PECO Temporary	0.6	2.1	3.5	5.1	5.8	2.2	4.6	5.7	1.2	1.3	1.3	0.0	0.0
63	EPSCA	30.8	59.3	74.9	91.8	90.0	63.4	58.2	35.8	94.7	116.7	108.2	93.4	74.1
64	Unallocated[3]	27.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
65	Total	199.8	206.5	248.0	313.3	371.0	440.9	563.7	524.1	862.2	906.5	945.8	934.3	738.2

[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)

Note: 2020 Actuals have been restated to more accurately reflect labour components, and by employee type and representation.

PROVISION

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 Actual	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Staff (Regular and Non-Regular)	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**
	Nuclear - Direct													
1	Executive	2.2	1.4	2.1	2.1	2.0	1.5	2.0	2.0	2.0	2.0	2.0	2.0	2.0
2	Non-Executive Management	37.6	41.9	42.8	50.0	56.5	58.6	66.2	60.5	60.0	59.5	50.0	52.1	51.6
3	Management Subtotal	39.8	43.2	44.9	52.0	58.5	60.1	68.2	62.5	62.0	61.5	52.0	54.1	53.6
4	Society	141.3	153.9	161.9	186.9	221.1	258.7	303.7	287.6	259.6	245.2	207.4	209.4	211.6
5	PWU	185.6	198.2	202.3	210.2	306.9	575.0	605.5	486.8	434.5	419.5	368.5	369.5	369.5
6	Term/ETE/PECO Temporary	7.8	16.1	20.2	33.0	31.1	21.0	9.0	2.3	0.0	0.0	0.0	0.0	0.0
7	EPSCA	2.9	4.4	4.1	4.0	10.2	45.6	3.3	2.3	2.3	2.2	2.0	2.0	2.0
8	Subtotal	377.3	416.0	433.4	486.1	627.8	960.5	989.7	841.5	758.4	728.4	629.9	635.0	636.7
	Nuclear - Allocated													
9	Executive	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Non-Executive Management	1.2	1.7	3.3	3.8	4.3	7.1	8.2	8.0	7.7	7.2	6.6	6.6	6.6
11	Management Subtotal	1.2	1.7	3.3	3.8	4.3	7.1	8.2	8.0	7.7	7.2	6.6	6.6	6.6
12	Society	3.8	5.2	8.4	8.5	12.8	25.5	29.7	26.1	26.4	26.6	21.8	21.9	22.1
13	PWU	10.1	8.1	6.3	5.5	13.0	21.1	28.6	26.1	25.0	23.7	21.7	22.7	22.7
14	Term/ETE/PECO Temporary	0.6	1.1	0.0	0.0	1.0	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	EPSCA	0.0	0.0	0.0	0.0	0.9	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Subtotal	15.7	16.1	18.1	17.8	31.9	54.9	66.5	60.1	59.1	57.5	50.1	51.2	51.4
	Nuclear Facilities													
17	Executive	2.2	1.4	2.1	2.1	2.0	1.5	2.0	2.0	2.0	2.0	2.0	2.0	2.0
18	Non-Executive Management	38.8	43.5	46.2	53.8	60.7	65.7	74.4	68.5	67.7	66.7	56.6	58.7	58.2
19	Management Subtotal	41.0	44.9	48.2	55.8	62.7	67.2	76.4	70.5	69.7	68.7	58.6	60.7	60.2
20	Society	145.0	159.1	170.3	195.4	233.9	284.2	333.4	313.7	286.0	271.8	229.2	231.4	233.7
21	PWU	195.7	206.3	208.6	215.7	320.0	596.2	634.1	512.8	459.5	443.2	390.2	392.2	392.2
22	Term/ETE/PECO Temporary	8.3	17.2	20.2	33.0	32.1	21.9	9.0	2.3	0.0	0.0	0.0	0.0	0.0
23	EPSCA	2.9	4.4	4.1	4.0	11.0	46.0	3.3	2.3	2.3	2.2	2.0	2.0	2.0
24	Total	392.9	432.1	451.5	503.9	659.7	1,015.4	1,056.2	901.6	817.5	785.9	680.0	686.2	688.1
	Salary & Allowances (including Fiscal Adjustment)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
25	Executive	0.3	0.4	0.5	0.4	0.5	0.3	0.4	0.5	0.5	0.5	0.5	0.5	0.5
26	Non-Executive Management	5.9	6.8	7.7	8.1	9.8	10.8	12.3	11.5	11.7	11.8	10.6	11.2	11.4
27	Management Subtotal	6.2	7.2	8.2	8.6	10.3	11.1	12.8	11.9	12.1	12.3	11.1	11.7	11.9
28	Society	18.4	21.4	23.6	28.2	34.7	44.9	51.2	49.1	46.4	46.0	41.6	42.7	44.7
29	PWU[2]	21.4	23.1	24.3	26.4	43.3	79.5	84.8	69.0	63.5	63.2	58.1	59.3	61.4
30	Term[2]/ETE/PECO Temporary	0.9	2.0	2.3	4.3	4.6	2.8	1.0	0.2	0.0	0.0	0.0	0.0	0.0
31	EPSCA[2]	0.4	0.7	1.0	0.7	2.1	8.1	0.5	0.4	0.4	0.4	0.4	0.4	0.4
32	Unallocated[3]	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33	Total	49.3	54.2	59.4	68.1	95.0	146.5	150.2	130.7	122.4	121.9	111.1	114.0	118.4
	Incentive Pay	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
34	Executive	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Non-Executive Management	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Management Subtotal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Hydro One Shares	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
37	Society	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0
38	PWU	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.2	0.1	0.0
	Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.2	0.2	0.0
	Overtime	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
39	Society	1.8	1.9	2.0	2.3	3.9	4.7	0.6	0.7	0.6	0.6	0.7	0.7	0.7
40	PWU	3.4	3.9	4.9	5.0	7.7	11.6	4.8	4.8	4.8	5.0	5.1	5.3	5.4
41	Term/ETE/PECO Temporary	0.1	0.2	0.3	0.4	0.4	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0
42	EPSCA	0.0	0.1	0.1	0.1	0.3	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
43	Unallocated[3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
44	Total	5.3	6.1	7.3	7.9	12.2	17.5	5.5	5.5	5.5	5.6	5.8	6.0	6.2
	Benefits (Current Benefits and Pension & OPEB)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
45	Executive	0.1	0.1	0.2	0.2	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2
46	Non-Executive Management	2.7	2.9	3.2	3.9	3.5	4.2	4.8	4.7	4.8	4.9	4.4	4.6	4.7
47	Management Subtotal	2.8	3.0	3.4	4.1	3.7	4.3	4.9	4.9	5.0	5.1	4.6	4.8	4.9
48	Society	8.0	8.3	9.4	12.8	12.4	17.7	20.2	20.1	19.3	19.2	17.3	17.8	18.6
49	PWU	8.9	8.4	9.2	11.1	14.4	28.8	31.6	26.9	24.7	24.6	22.7	23.2	24.1
50	Term/ETE/PECO Temporary	0.1	0.1	0.1	0.3	0.3	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
51	EPSCA	0.0	0.0	0.0	0.0	0.1	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
52	Unallocated[3]	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
53	Total	20.4	19.9	22.1	28.4	31.0	51.4	56.9	51.8	49.0	48.8	44.7	45.8	47.6
54	Current Benefits (Statutory)	3.2	3.0	3.3	4.2	6.6	10.4	10.1	8.9	8.3	8.3	7.6	7.8	8.1
55	Current Benefits (Non-Statutory)	2.3	2.1	2.3	3.0	5.0	6.8	7.7	6.7	6.3	6.3	5.7	5.9	6.1
56	Pension & OPEB (Current Service)[1]	15.0	14.8	16.5	21.2	19.3	34.3	39.0	36.3	34.4	34.3	31.3	32.2	33.4
	TOTAL COMPENSATION	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
57	Executive	0.4	0.5	0.7	0.6	0.6	0.5	0.6	0.6	0.7	0.7	0.7	0.7	0.7
58	Non-Executive Management	8.6	9.7	10.9	12.1	13.4	15.0	17.1	16.2	16.5	16.7	15.0	15.8	16.1
59	Management Subtotal	9.0	10.2	11.6	12.7	14.0	15.4	17.7	16.8	17.2	17.4	15.7	16.5	16.8
60	Society	28.2	31.5	35.0	43.4	51.0	67.3	72.1	70.0	66.4	65.9	59.5	61.1	64.1
61	PWU	33.7	35.4	38.3	42.5	65.5	119.9	121.2	100.7	93.1	92.8	86.1	88.0	91.0
62	Term/ETE/PECO Temporary	1.0	2.3	2.8	5.0	5.3	3.2	1.2	0.3	0.0	0.0	0.0	0.0	0.0
63	EPSCA	0.5	0.9	1.1	0.8	2.5	9.6	0.5	0.4	0.4	0.4	0.4	0.4	0.4
64	Unallocated[3]	2.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
65	Total	75.0	80.2	88.8	104.4	138.2	215.4	212.7	188.1	177.0	176.4	161.7	166.0	172.2

[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)

Note: 2020 Actuals have been restated to more accurately reflect labour components, and by employee type and representation.

TOTAL

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 Actual	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Staff (Regular and Non-Regular)	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**
	Nuclear - Direct													
1	Executive	35.5	30.4	31.3	33.3	40.0	40.8	45.1	36.8	32.1	32.1	32.1	31.3	35.3
2	Non-Executive Management	607.2	515.5	518.5	589.7	697.4	734.8	828.2	714.7	662.6	653.1	639.8	633.7	646.7
3	Management Subtotal	642.7	545.9	549.8	623.0	737.4	775.6	873.3	751.5	694.7	685.2	671.9	665.0	682.0
4	Society	2,270.6	2,163.8	2,032.2	2,222.6	2,479.0	2,587.5	3,085.4	2,783.5	2,569.3	2,514.8	2,476.7	2,457.2	2,436.7
5	PWU	3,458.6	3,293.0	2,873.1	2,887.0	3,206.2	3,414.2	3,686.0	3,640.2	3,651.3	3,646.4	3,678.9	3,640.5	3,623.2
6	Term/ETE/PECO Temporary	598.9	794.9	928.0	988.6	657.5	276.0	240.2	215.2	7.0	7.0	7.0	0.0	0.0
7	EPSCA	234.3	355.7	401.3	434.7	427.2	378.0	321.2	194.9	396.9	515.0	450.4	365.1	281.9
8	Subtotal	7,205.1	7,153.3	6,784.4	7,155.9	7,507.3	7,431.3	8,206.1	7,585.4	7,319.2	7,368.4	7,284.9	7,127.7	7,023.8
	Nuclear - Allocated													
9	Executive	23.7	21.1	22.8	24.1	22.7	24.0	25.7	26.7	23.9	23.7	23.9	23.4	22.8
10	Non-Executive Management	245.2	246.3	250.7	290.8	318.5	336.2	378.0	360.3	323.5	320.0	320.5	319.0	313.8
11	Management Subtotal	268.9	267.4	273.5	314.9	341.3	360.2	403.6	387.1	347.4	343.7	344.3	342.4	336.7
12	Society	385.6	385.2	417.1	564.5	643.7	663.9	754.3	690.0	681.6	669.2	664.9	662.9	650.8
13	PWU	434.2	405.0	448.8	490.0	488.3	449.6	498.2	456.3	489.9	485.4	485.1	489.3	493.8
14	Term/ETE/PECO Temporary	60.6	78.5	80.3	64.6	61.6	43.8	39.0	33.3	0.0	0.0	0.0	0.0	0.0
15	EPSCA	42.1	44.4	30.9	31.6	30.8	29.9	37.0	37.0	37.0	37.0	37.0	36.9	38.2
16	Subtotal	1,191.4	1,180.5	1,250.8	1,465.6	1,565.7	1,547.4	1,732.2	1,603.6	1,555.9	1,535.2	1,531.3	1,531.5	1,519.4
	Nuclear Facilities													
17	Executive	59.2	51.5	54.1	57.3	62.7	64.8	70.7	63.5	56.0	55.8	56.0	54.7	58.2
18	Non-Executive Management	852.4	761.8	769.2	880.5	1,015.9	1,071.0	1,206.2	1,075.0	986.1	973.1	960.3	952.7	960.5
19	Management Subtotal	911.6	813.3	823.3	937.9	1,078.6	1,135.8	1,276.9	1,138.6	1,042.2	1,028.9	1,016.2	1,007.4	1,018.7
20	Society	2,656.2	2,549.0	2,449.4	2,787.1	3,122.7	3,251.4	3,839.7	3,473.6	3,250.9	3,184.1	3,141.7	3,120.1	3,087.5
21	PWU	3,892.8	3,698.1	3,321.9	3,377.1	3,694.6	3,863.9	4,184.3	4,096.5	4,141.2	4,131.8	4,164.0	4,129.8	4,116.9
22	Term/ETE/PECO Temporary	659.5	873.4	1,008.4	1,053.2	719.1	319.8	279.2	248.5	7.0	7.0	7.0	0.0	0.0
23	EPSCA	276.4	400.0	432.2	466.3	458.0	407.9	358.2	231.8	433.9	551.9	487.3	402.0	320.0
24	Total	8,396.5	8,333.8	8,035.2	8,621.5	9,073.0	8,978.8	9,938.3	9,189.0	8,875.1	8,903.6	8,816.2	8,659.2	8,543.2
	Salary & Allowances (including Fiscal Adjustment)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
25	Executive	14.4	13.4	13.9	13.9	16.4	18.0	18.0	16.6	14.9	15.1	15.6	15.4	16.8
26	Non-Executive Management	123.6	111.5	120.4	133.7	157.7	177.8	195.0	180.3	172.4	174.3	178.9	181.5	188.2
27	Management Subtotal	138.1	124.9	134.3	147.6	174.1	195.8	212.9	196.9	187.4	189.4	194.5	196.9	205.0
28	Society	347.6	361.9	337.8	425.4	477.2	510.0	597.4	552.5	545.1	551.0	569.6	582.3	598.1
29	PWU[2]	451.9	467.5	405.6	473.3	567.0	539.4	553.1	564.9	593.4	610.3	645.0	656.2	672.8
30	Term[2]/ETE/PECO Temporary	70.7	98.7	120.0	139.2	93.6	41.9	32.2	30.0	1.2	1.2	1.3	0.0	0.0
31	EPSCA[2]	41.1	64.8	70.0	80.9	84.0	75.7	58.5	39.1	79.8	102.1	94.8	80.1	65.5
32	Unallocated[3]	19.5												
33	Total	1,068.9	1,117.8	1,067.7	1,266.5	1,395.8	1,362.8	1,454.2	1,383.4	1,406.9	1,454.0	1,505.1	1,515.5	1,541.4
	Incentive Pay	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
34	Executive	6.9	6.1	6.2	7.8	6.6	8.4	7.7	6.7	6.8	7.3	7.5	7.5	7.9
35	Non-Executive Management	20.3	20.7	18.6	27.7	28.6	35.1	31.3	26.1	26.6	28.4	29.5	29.8	30.7
36	Management Subtotal	27.2	26.7	24.8	35.5	35.2	43.5	39.0	32.7	33.4	35.6	37.0	37.2	38.6
	Hydro One Shares	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
37	Society	4.8	4.6	4.9	5.0	5.4	5.8	2.8	2.5	2.4	2.3	1.8	1.8	1.6
38	PWU	10.6	12.2	12.2	12.7	12.8	15.5	7.2	6.4	6.2	6.0	5.4	5.0	1.2
	Total	15.5	16.8	17.1	17.6	18.2	21.3	10.1	8.9	8.6	8.3	7.2	6.7	2.8
	Overtime	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
39	Society	39.4	44.3	46.1	49.4	56.0	47.4	43.0	37.7	42.2	39.3	43.5	41.8	40.5
40	PWU	75.5	80.9	71.3	79.3	93.9	75.1	71.8	68.4	96.2	87.4	101.6	96.0	91.5
41	Term/ETE/PECO Temporary	8.8	11.7	16.4	21.0	12.3	4.4	3.2	2.5	0.0	0.0	0.0	0.0	0.0
42	EPSCA	4.7	12.2	19.2	22.0	23.8	11.8	11.2	5.0	19.8	18.5	18.3	18.6	15.3
43	Unallocated[3]													
44	Total	128.4	149.1	153.0	171.8	186.0	138.7	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**	**$M**
45	Executive	6.7	7.7	7.5	5.3	6.2	6.9	6.6	6.6	5.8	5.8	6.1	6.0	6.5
46	Non-Executive Management	60.9	61.0	61.9	42.8	62.2	68.5	70.7	69.5	66.5	67.1	69.5	70.0	72.8
47	Management Subtotal	67.5	68.7	69.3	48.1	68.4	75.4	77.3	76.1	72.3	72.9	75.6	76.0	79.3
48	Society	166.0	182.2	176.2	130.8	188.3	192.1	218.0	213.4	212.3	215.8	225.6	229.8	237.0
49	PWU	198.9	210.2	188.2	125.0	192.9	200.2	190.1	206.4	220.6	226.6	239.9	245.2	253.5
50	Term/ETE/PECO Temporary	5.1	6.0	8.4	9.4	7.8	3.0	2.0	1.8	0.1	0.1	0.1	0.0	0.0
51	EPSCA	2.8	3.3	4.7	4.7	5.1	4.5	3.3	2.0	4.8	5.7	5.4	4.7	3.8
52	Unallocated[3]	7.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
53	Total	447.7	470.5	446.7	318.0	462.4	475.2	490.5	499.7	510.1	521.1	546.5	555.7	573.7
54	Current Benefits (Statutory)	68.4	65.8	69.0	77.3	91.3	91.5	102.8	96.8	99.6	101.7	107.1	106.6	108.3
55	Current Benefits (Non-Statutory)	40.8	46.3	45.6	50.1	54.8	66.8	70.1	65.7	68.0	69.9	73.3	74.2	76.6
56	Pension & OPEB (Current Service)[1]	338.5	358.3	332.0	190.6	316.3	317.0	317.7	337.2	342.6	349.5	366.2	375.0	388.8
	TOTAL COMPENSATION	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
57	Executive	28.0	27.2	27.6	27.0	29.2	33.3	32.2	29.9	27.5	28.2	29.2	28.8	31.1
58	Non-Executive Management	204.8	193.1	200.9	204.2	248.5	281.3	297.0	275.8	265.5	269.7	277.8	281.3	291.7
59	Management Subtotal	232.8	220.3	228.5	231.2	277.7	314.6	329.2	305.7	293.1	297.9	307.0	310.1	322.8
60	Society	557.8	592.9	564.9	610.6	726.9	755.4	861.3	806.1	802.1	808.5	840.5	855.8	877.2
61	PWU	736.9	770.9	677.2	690.3	866.5	830.3	822.2	846.0	916.4	930.3	991.9	1,002.4	1,019.0
62	Term/ETE/PECO Temporary	84.6	116.5	144.8	169.6	113.7	49.2	37.4	34.4	1.2	1.3	1.3	0.0	0.0
63	EPSCA	48.7	80.3	93.9	107.6	112.9	92.0	73.0	46.1	104.4	126.4	118.4	103.4	84.7
64	Unallocated[3]	26.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
65	Total	1,687.7	1,780.9	1,709.3	1,809.4	2,097.7	2,041.4	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)

Note: 2020 Actuals have been restated to more accurately reflect labour components, and by employee type and representation.

AMPCO Interrogatory #111

Interrogatory

Reference:
F4-3-1 Attachment 1 p.2

Question(s):

a) Please breakdown the Management category into Executive, Senior management, Managers/Supervisors and Individual Contributors.

b) Please breakdown the Society category in Appendix 2-K into Managers, Supervisors and Individual Contributors.

c) Please separate Salary and Incentive Pay costs.

d) Please provide an excel version of Attachment #1 that reflects part (a) to (c) and in the excel include the allocation of compensation between OM&A and Capital.

Response

a) and b) Refer to Attachment 1 for a breakdown of Management into Executive and Non-Executive Management. Refer to Ex. L-F4-AMPCO-110 for the response to the requested breakdown of Managers and Individual Contributors.

c) Refer to Attachment 1 for split of Salary and Incentive Pay.

d) Refer to Attachment 1 for an excel version and for a breakdown of Compensation costs between OM&A and Capital.

OM&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	Executive	2.0	2.2	2.4	2.5	2.8	2.8
2	Non-Executive Management	18.2	22.6	18.6	18.8	23.6	24.0
3	Management Subtotal	20.2	24.8	21.0	21.4	26.4	26.8
4	Society	42.3	44.8	46.2	44.1	71.6	78.2
5	PWU	34.0	75.3	79.4	57.0	102.6	133.6
6	EPSCA	0.0	0.0	0.0	0.0	0.0	0.0
7	Subtotal	96.4	144.9	146.6	122.5	200.6	238.5
	DNNP LP - Allocated						
8	Executive	1.8	2.5	2.8	2.7	2.8	1.3
9	Non-Executive Management	18.3	23.3	26.3	24.4	25.8	17.7
10	Management Subtotal	20.1	25.8	29.1	27.1	28.6	19.0
11	Society	27.7	33.6	37.8	35.0	36.3	36.0
12	PWU	11.5	15.0	15.7	14.8	11.7	16.1
13	EPSCA	0.0	0.0	0.0	0.0	0.1	0.2
14	Subtotal	59.3	74.4	82.5	76.9	76.7	71.2
	DNNP LP Facilities						
15	Executive	3.8	4.7	5.2	5.2	5.6	4.1
16	Non-Executive Management	36.5	46.0	44.9	43.2	49.4	41.7
17	Management Subtotal	40.3	50.7	50.1	48.4	55.0	45.8
18	Society	70.0	78.4	84.0	79.1	108.0	114.1
19	PWU	45.5	90.2	95.1	71.8	114.3	149.6
20	EPSCA	0.0	0.0	0.0	0.0	0.1	0.2
21	Total	155.7	219.3	229.1	199.4	277.3	309.7
	Salary & Allowances (including Fiscal Adjustment)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
22	Executive	1.0	1.3	1.4	1.5	1.6	1.2
23	Non-Executive Management	6.3	8.5	8.7	9.0	10.9	9.6
24	Management Subtotal	7.3	9.7	10.2	10.5	12.5	10.8
25	Society	11.9	14.1	15.3	15.1	21.4	24.1
26	PWU[2]	6.9	15.5	15.9	13.1	20.5	29.3
27	EPSCA[2]	0.0	0.0	0.0	0.0	0.0	0.0
28	Total	26.0	39.3	41.4	38.7	54.3	64.2
	Incentive Pay	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
29	Executive	0.7	0.9	1.0	1.1	1.1	1.1
30	Non-Executive Management	2.7	3.3	3.9	4.2	4.4	4.3
31	Management Subtotal	3.4	4.2	4.9	5.2	5.5	5.4
	Hydro One Shares	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
32	Society	0.1	0.1	0.2	0.2	0.2	0.2
33	PWU	0.4	0.5	0.5	0.5	0.5	0.1
34	Total	0.5	0.6	0.7	0.8	0.7	0.3
	Overtime	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
35	Management						
36	Society	0.4	0.3	0.4	0.4	0.5	0.7
37	PWU	0.1	0.4	0.4	0.3	0.5	3.0
38	Total	0.5	0.7	0.8	0.7	1.0	3.6
	Benefits (Current Benefits and Pension & OPEB)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
39	Executive	0.4	0.5	0.6	0.6	0.6	0.5
40	Non-Executive Management	2.4	3.2	3.2	3.2	3.7	3.2
41	Management Subtotal	2.8	3.7	3.7	3.8	4.4	3.7
42	Society	4.1	4.7	5.1	5.1	7.5	8.1
43	PWU	1.9	4.9	4.7	3.8	6.3	8.7
44	EPSCA	0.0	0.0	0.0	0.0	0.0	0.0
45	Total	8.9	13.2	13.6	12.7	18.2	20.5
46	Current Benefits (Statutory)	1.7	2.5	2.6	2.4	3.2	3.7
47	Current Benefits (Non-Statutory)	1.3	1.9	2.0	1.9	2.5	2.8
48	Pension & OPEB (Current Service)[1]	5.9	8.8	9.0	8.4	12.4	14.0
	TOTAL COMPENSATION	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
49	Executive	2.0	2.6	3.0	3.1	3.3	2.7
50	Non-Executive Management	11.4	15.0	15.8	16.3	19.0	17.1
51	Management Subtotal	13.5	17.6	18.8	19.4	22.3	19.8
52	Society	16.5	19.2	21.0	20.8	29.6	33.1
53	PWU	9.3	21.2	21.5	17.8	27.7	41.2
54	EPSCA	0.0	0.0	0.0	0.0	0.0	0.0
55	Total	39.3	58.0	61.3	58.0	79.7	94.1

[1]Presented on an accrual basis

[2]Includes employee remittances for purpose of union-administered benefit programs

CAPITAL

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	Executive	4.0	3.8	2.5	1.0	0.3	0.0
2	Non-Executive Management	44.3	46.4	35.3	23.1	5.8	0.0
3	Management Subtotal	48.3	50.2	37.8	24.1	6.1	0.0
4	Society	134.9	133.6	83.5	52.0	13.1	0.0
5	PWU	16.9	41.2	95.2	115.0	37.0	0.0
6	EPSCA	0.0	0.0	0.0	0.0	0.0	0.0
7	Subtotal	200.0	225.0	216.5	191.1	56.2	0.0
	DNNP LP - Allocated						
8	Executive	0.0	0.0	0.0	0.0	0.0	0.0
9	Non-Executive Management	9.7	9.5	8.2	2.8	0.5	0.1
10	Management Subtotal	9.7	9.5	8.2	2.8	0.5	0.1
11	Society	22.8	24.7	22.6	12.2	10.1	8.2
12	PWU	7.9	8.6	7.6	7.6	3.2	1.9
13	EPSCA	0.0	0.0	0.0	0.0	0.0	0.0
14	Subtotal	40.5	42.8	38.4	22.6	13.8	10.2
	DNNP LP Facilities						
15	Executive	4.0	3.8	2.5	1.0	0.3	0.0
16	Non-Executive Management	54.0	55.9	43.5	25.9	6.3	0.1
17	Management Subtotal	58.0	59.7	46.0	26.9	6.6	0.1
18	Society	157.6	158.3	106.1	64.2	23.2	8.2
19	PWU	24.9	49.8	102.8	122.6	40.2	1.9
20	EPSCA	0.0	0.0	0.0	0.0	0.0	0.0
21	Total	240.5	267.8	254.9	213.7	70.0	10.2
	Salary & Allowances (including Fiscal Adjustment)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
22	Executive	1.0	1.0	0.6	0.2	0.1	
23	Non-Executive Management	9.3	10.4	9.0	5.6	1.5	0.0
24	Management Subtotal	10.3	11.4	9.6	5.9	1.5	0.0
25	Society	24.2	25.2	18.1	11.9	4.4	1.5
26	PWU[2]	2.9	7.2	16.5	20.2	6.8	0.3
27	EPSCA[2]	0.0	0.0	0.0	0.0	0.0	0.0
28	Total	37.4	43.8	44.2	38.0	12.7	1.8
	Incentive Pay	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
29	Executive	0.0	0.0	0.0	0.0	0.0	0.0
30	Non-Executive Management	0.0	0.0	0.0	0.0	0.0	0.0
31	Management Subtotal	0.0	0.0	0.0	0.0	0.0	0.0
	Hydro One Shares	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
32	Society	0.0	0.0	0.0	0.0	0.0	0.0
33	PWU	0.0	0.0	0.0	0.0	0.0	0.0
34	Total	0.0	0.0	0.0	0.0	0.0	0.0
	Overtime	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
35	Management						
36	Society	0.7	0.7	0.5	0.3	0.1	0.1
37	PWU	0.1	0.2	0.4	0.5	0.2	0.0
38	Total	0.7	0.9	0.9	0.8	0.3	0.1
	Benefits (Current Benefits and Pension & OPEB)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
39	Executive	0.4	0.4	0.3	0.1	0.0	0.0
40	Non-Executive Management	3.8	4.2	3.4	2.1	0.5	0.0
41	Management Subtotal	4.3	4.6	3.7	2.2	0.6	0.0
42	Society	10.0	10.4	7.4	4.8	1.8	0.7
43	PWU	1.1	2.8	6.1	7.6	2.5	0.1
44	EPSCA	0.0	0.0	0.0	0.0	0.0	0.0
45	Total	15.3	17.8	17.2	14.6	4.9	0.8
46	Current Benefits (Statutory)	2.6	3.0	2.8	2.4	0.8	0.1
47	Current Benefits (Non-Statutory)	2.0	2.3	2.2	1.9	0.6	0.1
48	Pension & OPEB (Current Service)[1]	10.8	12.5	12.1	10.3	3.5	0.5
	TOTAL COMPENSATION	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
49	Executive	1.4	1.4	0.9	0.3	0.1	0.0
50	Non-Executive Management	13.1	14.6	12.4	7.7	2.0	0.0
51	Management Subtotal	14.6	15.9	13.3	8.1	2.1	0.0
52	Society	34.8	36.3	26.0	17.0	6.3	2.2
53	PWU	4.1	10.2	23.0	28.3	9.4	0.4
54	EPSCA	0.0	0.0	0.0	0.0	0.0	0.0
55	Total	53.4	62.4	62.3	53.4	17.9	2.6

[1]Presented on an accrual basis

[2]Includes employee remittances for purpose of union-administered benefit programs

Total

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	Executive	6.0	6.0	4.9	3.5	3.1	2.8
2	Non-Executive Management	62.5	69.0	53.9	41.9	29.3	24.0
3	Management Subtotal	68.4	75.0	58.8	45.4	32.5	26.8
4	Society	177.1	178.4	129.7	96.2	84.7	78.2
5	PWU	50.9	116.4	174.5	172.0	139.6	133.6
6	EPSCA						
7	Subtotal	296.4	369.9	363.1	313.6	256.8	238.5
	DNNP LP - Allocated						
8	Executive	1.8	2.5	2.8	2.7	2.8	1.3
9	Non-Executive Management	28.1	32.8	34.5	27.2	26.3	17.8
10	Management Subtotal	29.9	35.3	37.3	29.9	29.1	19.1
11	Society	50.5	58.3	60.3	47.2	46.4	44.1
12	PWU	19.5	23.5	23.3	22.4	15.0	18.0
13	EPSCA	0.0	0.0	0.0	0.0	0.1	0.2
14	Subtotal	99.8	117.2	120.9	99.5	90.5	81.4
	DNNP LP Facilities						
15	Executive	7.8	8.5	7.7	6.2	5.9	4.1
16	Non-Executive Management	90.5	101.9	88.4	69.2	55.6	41.8
17	Management Subtotal	98.3	110.3	96.1	75.3	61.6	45.9
18	Society	227.6	236.7	190.0	143.4	131.2	122.3
19	PWU	70.3	140.0	197.8	194.3	154.6	151.6
20	EPSCA	0.0	0.0	0.0	0.0	0.1	0.2
21	Total	396.2	487.1	484.0	413.1	347.3	319.9
	Salary & Allowances (including Fiscal Adjustment)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
22	Executive	2.0	2.2	2.1	1.7	1.7	1.2
23	Non-Executive Management	15.6	18.8	17.7	14.6	12.3	9.6
24	Management Subtotal	17.6	21.1	19.8	16.3	14.0	10.8
25	Society	36.1	39.3	33.5	27.0	25.8	25.6
26	PWU[2]	9.7	22.7	32.4	33.3	27.2	29.6
27	EPSCA[2]	0.0	0.0	0.0	0.0	0.0	0.0
28	Total	63.4	83.0	85.6	76.6	67.0	66.0
	Incentive Pay	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
29	Executive	0.7	0.9	1.0	1.1	1.1	1.1
30	Non-Executive Management	2.7	3.3	3.9	4.2	4.4	4.3
31	Management Subtotal	3.4	4.2	4.9	5.2	5.5	5.4
	Hydro One Shares	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
32	Society	0.1	0.1	0.2	0.2	0.2	0.2
33	PWU	0.4	0.5	0.5	0.5	0.5	0.1
34	Total	0.5	0.6	0.7	0.8	0.7	0.3
	Overtime	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
35	Management						
36	Society	1.0	1.0	0.9	0.7	0.7	0.7
37	PWU	0.2	0.6	0.8	0.8	0.6	3.0
38	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**
39	Executive	0.8	0.9	0.8	0.7	0.7	0.5
40	Non-Executive Management	6.3	7.4	6.6	5.3	4.3	3.2
41	Management Subtotal	7.1	8.3	7.4	6.0	4.9	3.7
42	Society	14.1	15.1	12.5	9.9	9.3	8.8
43	PWU	3.0	7.6	10.8	11.4	8.9	8.8
44	EPSCA	0.0	0.0	0.0	0.0	0.0	0.0
45	Total	24.2	31.0	30.8	27.3	23.1	21.3
46	Current Benefits (Statutory)	4.2	5.5	5.4	4.8	4.0	3.8
47	Current Benefits (Non-Statutory)	3.3	4.2	4.2	3.8	3.2	2.9
48	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**
49	Executive	3.5	4.0	3.9	3.5	3.5	2.7
50	Non-Executive Management	24.5	29.6	28.2	24.0	21.0	17.1
51	Management Subtotal	28.0	33.6	32.1	27.5	24.4	19.9
52	Society	51.3	55.5	47.0	37.8	35.9	35.3
53	PWU	13.4	31.4	44.5	46.1	37.2	41.5
54	EPSCA	0.0	0.0	0.0	0.0	0.0	0.0
55	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

AMPCO Interrogatory #112

Interrogatory

Reference:
F4-3-1 Attachment 1 p.1

Question(s):

Please provide Appendix 2-K on a Plan basis (EB-2020-0290) for each of the years 2020 -2031 and include the adjustments requested in F4-AMPCO-110 part (b) to part (d).

Response

Refer to EB-2020-0290, Ex. JT 4.8 for 2020-2026. Refer to Ex. L-F4-AMPCO-110 for 2027-2031.

AMPCO Interrogatory #113

Interrogatory

Reference:
F4-3-1 Attachment 1 p.3

Question(s):

Please provide Appendix 2-K on a Plan basis for each of the years 2020 -2031 and include the adjustments in F4-AMPCO-110 part (b) to part (d).

Response

In accordance with the Motions Resolutions letter filed on May 4, 2026, OPG has revised this interrogatory response.

Refer to Attachment 1 for the requested forecast information for the regulated hydroelectric facilities for the years 2020-2024 from OPG's business plan filed in EB-2020-0290, together with such forecast information for the years 2025-2031 as set out in the pre-filed evidence for this Application.

Having provided this information in accordance with the Motions Resolutions letter filed on May 4, 2026, OPG maintains that forecast information from previous business plans that did not underpin approved payment amounts is not relevant on the basis that the request goes beyond the scope of the OEB's current Filing Requirements, which were subject to extensive consultation in EB-2024-0136 with the "aim to address evolving regulatory landscape *and incorporate lessons learned from past proceedings.*" (emphasis added)[1]

OPG further notes that regulated hydroelectric payments in past applications (EB-2016-0152 and EB-2020-0290) were determined mechanistically, rather than pursuant to cost-of-service rebasing reviews. As such, there are no OEB-approved amounts against which to compare the requested information.

[1] In accordance with the Filing Requirements, OPG has provided in section 6 and 23 Attachment 1 of Ex. F4-3-1 details of the 2020-2031 compensation information for employees working at and supporting OPG's regulated facilities.

TOTAL (including OM&A and Capital)

FTE, Compensation and Benefit Information for OPG's Hydroelectric Regulated Facilities ("Appendix 2k")

Numbers may not add due to rounding

Line No.	Hydroelectric Facilities	2020 Business Plan 2020 Plan	2021 Plan	2022 Plan	2023 Plan	2024 Plan	EB-2025-0297 (2027-2031 Custom IR term) 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**
	Hydroelectric - Direct												
1	Executive	5.0	5.0	5.6	5.5	5.7	5.2	5.6	5.6	5.5	5.4	5.3	5.3
2	Non-Executive Management	80.6	80.5	80.1	79.9	76.9	88.3	90.6	91.0	90.6	89.6	91.4	90.4
3	Management Subtotal	85.6	85.5	85.8	85.4	82.6	93.6	96.2	96.6	96.1	95.0	96.7	95.7
4	Society	378.6	372.6	363.5	371.0	368.5	508.0	522.5	536.3	531.2	528.1	531.1	527.3
5	PWU	677.0	664.0	667.4	683.6	675.1	826.7	883.7	888.6	896.1	908.7	901.2	902.7
6	Subtotal	1,141.2	1,122.1	1,116.7	1,140.0	1,126.2	1,428.3	1,502.4	1,521.5	1,523.4	1,531.8	1,529.0	1,525.6
	Hydroelectric - Allocated												
7	Executive	3.3	3.4	3.3	3.4	3.4	4.7	5.0	4.9	4.7	4.5	4.4	4.5
8	Non-Executive Management	59.5	58.8	57.8	58.1	59.3	66.1	64.8	60.7	59.6	58.9	59.5	61.2
9	Management Subtotal	62.8	62.2	61.1	61.5	62.7	70.9	69.7	65.5	64.3	63.4	64.0	65.7
10	Society	63.7	64.9	56.6	56.5	56.5	96.8	96.5	98.9	98.6	96.3	95.3	94.4
11	PWU	19.3	18.1	15.8	15.9	14.9	29.8	27.7	25.9	25.5	24.5	24.6	25.3
12	Subtotal	145.7	145.2	133.6	133.9	134.1	197.4	193.9	190.3	188.5	184.2	183.9	185.4
	Hydroelectric Facilities												
13	Executive	8.3	8.4	8.9	8.9	9.1	10.0	10.6	10.5	10.2	9.9	9.8	9.8
14	Non-Executive Management	140.1	139.2	138.0	138.0	136.2	154.5	155.4	151.6	150.2	148.5	150.9	151.5
15	Management Subtotal	148.3	147.6	146.9	146.9	145.3	164.5	165.9	162.1	160.4	158.4	160.7	161.3
16	Society	442.3	437.5	420.1	427.5	424.9	604.8	619.0	635.3	629.8	624.4	626.4	621.7
17	PWU	696.3	682.1	683.3	699.5	690.1	856.6	911.4	914.5	921.6	933.2	925.8	928.1
18	Total	1,287.0	1,267.3	1,250.3	1,273.9	1,260.3	1,625.8	1,696.3	1,711.9	1,711.8	1,716.0	1,712.9	1,711.1
	Salary & Allowances (including Fiscal Adjustment)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
19	Executive	2.0	2.1	2.4	2.4	2.5	2.5	2.8	2.8	2.8	2.8	2.8	2.8
20	Non-Executive Management	19.3	19.5	19.5	19.7	19.6	25.8	27.1	27.7	28.1	28.7	29.9	30.8
21	Management Subtotal	21.4	21.6	21.9	22.1	22.1	28.3	29.9	30.5	30.9	31.5	32.7	33.6
22	Society	55.5	56.3	55.1	56.9	57.7	91.2	96.2	102.5	104.5	108.4	112.2	115.6
23	PWU[2]	75.9	76.1	77.4	79.8	80.6	111.7	124.3	128.5	133.4	140.7	143.1	149.3
24	Total	152.7	154.0	154.3	158.8	160.4	231.3	250.4	261.4	268.8	280.6	287.9	298.5
	Incentive Pay	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
25	Executive	0.8	0.9	0.9	0.9	0.9	1.2	1.2	1.2	1.3	1.3	1.4	1.4
26	Non-Executive Management	3.3	3.5	3.5	3.6	3.6	4.8	4.6	4.8	5.1	5.3	5.5	5.6
27	Management Subtotal	4.2	4.3	4.4	4.5	4.5	5.9	5.8	6.0	6.5	6.6	6.8	7.0
	Hydro One Shares	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
28	Society	0.6	0.6	0.6	0.5	0.4	0.4	0.4	0.4	0.4	0.3	0.4	0.3
29	PWU	1.8	1.8	1.6	1.3	1.1	1.3	1.2	1.2	1.2	1.1	1.3	0.3
	Total	2.4	2.4	2.2	1.9	1.6	1.7	1.6	1.6	1.6	1.4	1.7	0.7
	Overtime	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
30	Society	3.3	3.3	3.3	3.3	3.4	7.1	7.8	8.3	8.5	9.0	9.3	9.8
31	PWU	7.8	8.6	8.9	8.7	9.5	19.7	21.0	22.4	23.6	25.8	25.9	26.9
32	Total	11.0	11.9	12.2	12.0	12.8	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**
33	Executive	0.9	1.0	1.1	1.1	1.2	0.9	1.1	1.1	1.1	1.1	1.1	1.1
34	Non-Executive Management	9.9	10.3	10.5	10.6	10.8	9.3	10.5	10.6	10.7	11.0	11.4	11.9
35	Management Subtotal	10.9	11.3	11.6	11.7	12.0	10.2	11.6	11.6	11.7	12.1	12.5	12.9
36	Society	28.2	29.4	29.3	30.2	31.3	33.9	39.3	41.2	42.3	44.5	45.8	47.3
37	PWU	37.5	38.7	39.9	40.7	42.2	39.3	45.3	46.3	47.8	50.7	51.9	54.0
38	Total	76.6	79.4	80.8	82.7	85.5	83.4	96.2	99.2	101.8	107.3	110.2	114.3
39	Current Benefits (Statutory)	8.3	8.4	8.4	8.7	8.9	17.2	18.5	19.3	20.0	21.2	21.5	22.2
40	Current Benefits (Non-Statutory)	8.4	8.2	8.3	9.0	9.1	12.0	12.7	13.2	13.6	14.4	14.6	15.2
41	Pension & OPEB (Current Service)[1]	59.9	62.8	64.1	64.9	67.4	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**
42	Executive	3.0	3.1	3.5	3.5	3.7	4.6	5.0	5.1	5.1	5.2	5.2	5.3
43	Non-Executive Management	29.2	29.8	30.0	30.3	30.4	39.8	42.2	43.0	43.9	45.0	46.8	48.3
44	Management Subtotal	36.4	37.3	37.9	38.3	38.6	44.4	47.2	48.1	49.1	50.2	51.9	53.6
45	Society	87.6	89.6	88.3	91.0	92.9	132.6	143.7	152.4	155.8	162.3	167.7	173.1
46	PWU	123.0	125.2	127.8	130.6	133.3	172.0	191.8	198.4	206.0	218.3	222.1	230.5
47	Total	246.9	252.1	253.9	259.9	264.8	349.0	382.7	398.9	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

AMPCO Interrogatory #114

Interrogatory

Reference:
F4-3-1 Attachment 1 p.1

Question(s):

a) Please complete the following table:

Overtime Hours	2020 A	2021 A	2023 A	2024 A	2025 A	2026 Plan	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
Society											
PWU											
Term/ETE/PECO/ Temporary											
EPSCA											

b) Please provide the variance in overtime costs ($) for each of the years 2027 to 2031 if the overtime rate applied is 1.5 times the wage rate instead of 2.

Response

a) Refer to Attachment 1.

b) Refer to Ex. L-F4-CCC-085 part h), which explains how OPG's overtime budgets are planned, including the use of a standard overtime rate. As the standard overtime rate is a blended average at each resource type, job family and representation based on historical data, in line with collective bargaining agreements, a split of overtime costs at either 1.5 times or 2 times wage rate for the 2027-2031 period cannot be provided.

Overtime Hours for Nuclear excl DNNP Facilities 2020-2031

Nuclear (Excl DNNP)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	Actual	Actual	Actual	Actual	Actual	Actual	Plan	Plan	Plan	Plan	Plan	Plan
Society	300.2	374.0	337.4	387.4	420.9	319.5	215.1	230.8	207.4	221.1	204.8	191.0
PWU	717.2	797.8	690.2	633.4	809.8	615.8	499.1	689.7	606.7	680.2	621.7	569.7
Term/ETE/PECO Temp	111.5	149.6	202.3	231.5	141.8	39.0	18.3					
EPSCA	40.3	144.0	217.4	321.7	249.9	124.3	35.7	133.2	120.8	116.0	115.0	92.3
Total^	**1,169.2**	**1,465.5**	**1,447.3**	**1,574.0**	**1,622.5**	**1,098.5**	**768.3**	**1,053.8**	**934.9**	**1,017.2**	**941.5**	**853.0**

^ Figures in thousands

AMPCO Interrogatory #115

Interrogatory

Reference:
F4-3-1 Attachment 1 p.3

Question(s):

a) Please breakdown the Management category into Executive, Senior management, Managers/Supervisors and Individual Contributors.

b) Please breakdown the Society category in Appendix 2-K into Managers/Supervisors and Individual Contributors.

c) Please separate Salary and Incentive Pay costs.

d) Please quantify “Fiscal Adjustment”.

e) Please provide an excel version of Attachment #1 that reflects part (a) to part (c) and in the excel version please include the allocation of compensation costs between OM&A and Capital.

Response

a) Refer to Attachment 1 and refer to Ex. L-F4-AMPCO-110 parts b) and c).

b) c) and e) Refer to Attachment 1.

d) Refer to Ex. L-F4-AMPCO-110.

AMPCO Interrogatory #116

Interrogatory

Reference:
Ref: F4-3-1 Attachment 1 p.3

Question(s):

a) Please complete the following table:

Overtime Hours	2020 A	2021 A	2023 A	2024 A	2025 A	2026 Plan	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
Society											
PWU											

b) Please provide the variance in overtime costs ($) for each of the years 2027 to 2031 if the overtime rate applied is 1.5 times the wage rate instead of 2.

Response

a) Refer to Attachment 1.

b) Refer to Ex. L-F4-AMPCO-114, part b).

Overtime Hours for Hydroelectric Regulated Facilities 2020-2031

Overtime Hours for Hydroelectric Regulated	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	Actual	Actual	Actual	Actual	Actual	Actual	Plan	Plan	Plan	Plan	Plan	Plan
Society	33.0	40.7	45.1	52.6	50.6	56.4	45.4	46.8	46.3	47.3	46.9	47.5
PWU	88.1	128.5	136.6	144.9	163.1	156.5	152.2	157.3	160.4	168.7	163.8	164.5
Total^	**121.1**	**169.1**	**181.7**	**197.5**	**213.7**	**212.9**	**197.6**	**204.1**	**206.6**	**216.0**	**210.7**	**211.9**

^ Figures in thousands

AMPCO Interrogatory #117

Interrogatory

Reference:
F4-3-1 Attachment 1

Question(s):

a) Please provide Appendix 2-K for Darlington NGS that includes the adjustments in F4-AMPCO-110 part (b) to part (d) and provide an excel version of the response.

b) Please provide Appendix 2-k for Pickering NGS that includes the adjustments in F4-AMPCO-110 parts (b) to part (d) and provide an excel version of the response.

Response

a) and b)

Refer to Attachment 1, including the adjustments requested in Ex. L-F4-AMPCO-110 parts b) and d). Regarding the adjustments requested for Ex. L-F4-AMPCO-110 part c), refer to Ex. L-F4-AMPCO-110 part c).

AMPCO Interrogatory #118

Interrogatory

Reference:
F4-3-1

Question(s):

Please provide the incremental compensations costs due to hiring a Term Employee as a Regular Employee and show the calculation.

Response

As discussed in EB-2020-0290, Ex. F4-3-1, p.7, lines 19-23, the main difference in the compensation costs of a PWU-represented Term Employee and a PWU-repersented Regular Employee results from a Term Employee not being eligible to join OPG's pension and benefit plans. The resulting difference in annual compensation costs (which, for pension and OPEB, comprise the current service cost components) for a newly hired employee is estimated at approximately $35,000, reflecting the pension and OPEB impacts computed by OPG's external actuary, Aon, based on the actuarial assumptions underpinning the forecast costs in this Application.

Aon produced the pension and OPEB estimate using their proprietary actuarial valuation system, using demographic and economic assumptions and projection algorithms that cannot be replicated in this response. The figures provided reflect the output of this system, which is the same used by Aon for OPG's pension and OPEB related reporting in its consolidated financial statements.

AMPCO Interrogatory #119

Interrogatory

Reference:
F4-3-1

Question(s):

a) Please provide the number of forecast and actual layoffs and the associated forecast and actual severance costs for the period 2022-2026 period.

b) Please provide the assumption with respect to severance costs for 2027-2031.

c) Please provide the employee turnover rate for each of the years 2020 to 2025.

d) Please quantify ($) the assumptions in the 2027-2031 budget with respect to total annual merit increases to be paid out.

e) Please provide the merit increases paid in total over the 2020 to 2025 period.

f) Please provide the reduction ($) because of the actual vacancy rate for each of the years 2022 to 2025.

g) Please provide OPG's assumptions with respect to the vacancy rate for each of the years 2027 to 2031.

Response

a) There were no actual layoffs for the 2022-2025 period, none are forecast for 2026, and as such there are no associated severance costs.

b) OPG has not included any severance costs in its proposed revenue requirements for the 2027-2031 IR term.

c) The Regular employee voluntary turnover rate, referring to the percentage of employees that leave due to retirements and resignations over a period and are replaced, is provided in Chart 1.

Chart 1 – Regular Employee Annual Voluntary Turnover Rates

2020	2021	2022	2023	2024	2025
6.0%	4.7%	6.1%	3.6%	3.8%	3.8%

d) Refer to Ex. L-F4-CCC-085, part f).

e) The management merit increases attributable to the regulated business over the 2020-2025 period, as estimated to the regulated operations, are outlined in Chart 2 below:

Chart 2 – Annual Total Management Merit Increases Attributable to the Regulated Business ($M)

2020	2021	2022	2023	2024	2025
2.5	2.1	2.3	4.1	5.8	7.1

f) OPG does not track vacancy rates. OPG's 2025-2031 Business Plan was created based on the work programs and the need to execute them; therefore, any vacancy would require other resources to execute the work. With respect to the historical period, actual FTEs, in aggregate, exceeded the levels forecasted in EB-2020-0290. As such, there are no savings associated with vacancies.

g) OPG did not include any assumptions with respect to a vacancy rate in its 2025-2031 Business Plan. The FTEs in the plan are based on the required resource levels to execute and support planned work programs.

AMPCO Interrogatory #120

Interrogatory

Reference:
F4-3-1 p.25

Preamble:

Chart 1 provides the 2021-2026 Collective Agreement Wage Increases for PWU and Society for the years 2021 to 2026.

Question(s):

a) Please provide the wage increase assumptions built into the plan for the years 2027 to 2031 for PWU and Society.

b) Please provide the average wage increase for management for each of the years 2021 to 2031.

Response

a) Refer to Ex. L-F4-Staff-227, Chart 1.

b) The wage increase assumptions for management for the 2027-2031 period are detailed in Ex. L-F4-Staff-227, Chart 1.

Chart 1 below provides the average wage increase for management for each of the years 2021-2026. As detailed in Ex. F4-3-1, p. 30, line 19, wage increases for management are determined through performance-based merit increase budgets. On an annual basis, OPG submits the merit budget for management to its Board of Directors for approval.

Chart 1 – Average Merit Increase for Management (2021-2026)

2021	2022	2023	2024	2025	2026
1.57%	1.75%	2.89%	3.35%	3.63%	3.11%

AMPCO Interrogatory #121

Interrogatory

Reference:
F4-3-1 p.27

Question(s):

With respect to Figures 5, 6, 7, 8 please provide the underlying data.

Response

The data in the referenced figures was compiled using the applicable publicly available collective agreements (available through the Ontario Labour Relations Board at https://www.lr.labour.gov.on.ca/en-CA/Collective-Agreements/). Refer to Ex. L-F4-Staff-230 for the referenced figures, including the underlying data.

AMPCO Interrogatory #122

Interrogatory

Reference:
F4-3-1

Question(s):

Please compare the percentage of pension and benefit costs allocated to total compensation costs for a Regular FTE compared to a Term/ETE/PECO Temporary FTE and show the calculation.

Response

Refer to Ex. L-F4-CCMBC-005.

AMPCO Interrogatory #123

Interrogatory

Reference:
F4-04-1 Table 3

Question(s):

a) Please explain the increase in Performance Incentive costs in 2025.

b) Please provide the derivation of the Performance Incentive amounts ($M) for each of the years 2027 to 2031.

Response

a) As discussed in Ex. F4-3-1, pp. 30-31, the Applicants use a financial results model for its Stakeholder Return Program ("SRP"), whereby forecasted earnings before tax and corporate balanced scorecard results are key components in determining performance incentive amounts. The increase in performance incentive costs in 2025 compared to 2024 is due to a higher forecast EBT in that year. OPG seeks approval from its Board of Directors for the percentage applied to forecast EBT for any given program year. As discussed in Ex. L-F4-SEC-195, the percentage applied is limited to an industry range provided by Willis Towers Watson, and has been at the lowest end of this range.

b) Chart 1 below provides a derivation of the forecast total OPG performance incentive amounts for each of the years 2027-2031, as presented in Ex. F4-4-1, Table 1, line 4. As noted at Ex. F4-4-1, p. 7, lines 12-14, these total OPG performance incentive costs are attributed, as applicable, to OPG's regulated hydroelectric facilities (Ex. F4-4-1, Table 2, line 3), OPG's nuclear facilities (Ex. F4-4-1, Table 3, line 4) and the DNNP facilities (Ex. F4-4-1, Table 4, line 4), pursuant to OPG's cost allocation methodology.

As shown in Chart 1, the total performance incentive costs are based on a corporate score at target, or 1.0, in the forecast period.

Chart 1 – Calculation of Total OPG Performance Incentive Costs* ($M)

	2027	2028	2029	2030	2031
Forecast Earnings Before Tax [A]					
% of Earnings Before Tax [B]					
Calculation with an assumed Corporate Score of 1.0 (Target) [C] = [A] x [B] x 1.0	41.7	44.8	46.5	47.0	48.4
Adjustment for Individual Performance Distribution Curve of 2.65% [D] = [C] x 2.65%	1.1	1.2	1.2	1.2	1.3
Allowance for CEO Awarded Amounts for Performance Achievement, up to 10% [E] = [C+D] x 10%	4.3	4.6	4.8	4.8	5.0
Total Performance Incentive Cost [C+D+E]	**47.0**	**50.6**	**52.5**	**53.1**	**54.6**

*numbers may not calculate due to rounding

1

AMPCO Interrogatory #124

Interrogatory

Reference:
F4-04-1

Preamble:

The budget for the program is set using a financial results model based on a percentage applied to forecast corporate earnings before tax. Between 2021-2024, 2% was applied on average to forecast EBT and OPG's corporate score ranged from 0.97 to 1.28.

Question(s):

a) Please provide the percentage applied to forecast corporate earnings before tax in 2025 and 2026.

b) Please provide the corporate score in 2025 and show how it was calculated.

c) Please provide the assumptions in the Plan with respect to the percentage applied to forecast corporate earnings before tax for the years 2027 to 2031 for Nuclear. Please confirm the percentages apply to both Nuclear and Hydroelectric. If not please provide separately.

Response

a) Refer to Ex. L-F4-SEC-195.

b) Refer to Attachment 1.

c) Refer to Ex. L-F4-AMPCO-123.

2025 Corporate Balanced Scorecard						2025 Year End Results		
Weight	**Key Performance Indicators**		**Threshold**	**Target**	**Stretch**	**Year-end Result**	**Year-end Weighted Score**	**Year-end Assessment**
20%	**Social Licence*** - Through building and maintaining public trust, positive Indigenous relations, climate change goals, and an engaged and inclusive workforce.							
10%	**Safety: Serious Injury Incidence Rate (SIIR)**		0.04	0.02	0	**0.00**	**1.000**	**Stretch (adjusted to Target)**
10%	5%	**Supply Chain Diversity Program ($M)**	$45	$55	$70	**$103**	**1.500**	**Stretch**
	5%	**Indigenous Economic Empowerment ($M)**	$75	$100	$125	**$241**	**1.500**	**Stretch**
35%	**Financial Strength** - Through regulated and non-regulated asset revenue and expansion of our core business, risk management, commercial focus and financial flexibility							
20%	**Earnings Before Tax**, excl. Nuclear Waste Management segment ($M)		$2,171	$2,311	$2,656	**$2,536**	**1.326**	**Above Target**
15%	**OM&A Expenses From Ongoing Operations** – Total OPG ($M)		$2,753	$2,703	$2,558	**$2,689**	**1.048**	**Above Target**
20%	**Operational Excellence** - Through efficiencies and optimized asset management in a safe and environmentally responsible manner							
20%	**Production** – Total OPG adjusted for SBG (TWh)		69.3	71.8	74.3	**72.3**	**1.100**	**Above Target**
25%	**Project Excellence** - Through delivering project results on time and on budget and achieving industry leading project management							
15%	7.5%	**Refurbishment Cost** – Unit 3,1 & 4 Costs ($M)	N/A	$6,216	$6,073	**$6,005**	**1.500**	**Stretch**
	7.5%	**Refurbishment Schedule –** Unit 4 Schedule - % Complete	Project is 86% complete overall	Project is 91% complete overall	Project is 95% complete overall	**98%**	**1.500**	**Stretch**
10%	**Total In-service Capital - ($M)** not including major projects otherwise on scorecard (e.g., Darlington Refurbishment)		$1,126 +/- 10% to +/- 15%	$1,126 +/- 3% to +/- 10 %	$1,126 +/-3%	**$1,196**	**1.000**	**Target**
100%	**Year-end Result**						**1.218**	

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.

AMPCO Interrogatory #127

Interrogatory

Reference:
F4-3-1 Attachment 1

Question(s):

For the purposes of Attachment 1, please define FTE and confirm at what point in the year the FTEs numbers are based on.

Response

An FTE is not determined at a point in time but rather is a calculation based on annual hours.

The FTE calculations and associated costs are consistently represented in the Application for the historical and forecast period as the number of hours worked over the year converted to an equivalent number of full-time employees. The associated labour costs are determined on the basis of the number of hours worked. Historical FTEs are calculated by dividing the total period of time an employee occupied a position during the year by the scheduled hours associated with the position. The same scheduled hours are utilized whether an employee is a regular full time, regular part time or a non-regular employee. The standard scheduled hours of work are either 35, 37.5 or 40 hours per week.

For example, a part time regular employee who works on average 20 hours per week in a position normally scheduled for 40 hours, would equate to 0.5 of an FTE, provided the employee worked the entire year. Similarly, a full time regular or non-regular employee in this same position working 40 hours a week for half of the year would also equate to 0.5 of an FTE.

Forecast FTEs are determined as part of the business planning process in a manner similar to that described above. Demand for labour resources are identified and hours assigned to different work programs by job family. There are standard scheduled hours of work for each job family, being 35, 37.5 or 40 hours per week. The hours assigned to the various work programs and the standard scheduled hours of work are used to derive the number of FTEs forecasted for each job family. In some cases, forecasted FTEs may be entered directly. In these situations, the associated hours are determined using the scheduled hours of work for the job family.

CCC Interrogatory #083

Interrogatory

Reference:
Exhibit F4, Tab 1, Schedule 1, pp. 10-11

Question(s):

a) For each of the plant accounts listed below, please provide a table that shows the depreciation expense for 2027-2031 related to the asset account using the current average service life and the depreciation expense for 2027-2031 related to the asset account using the updated average service life:

   i. Pickering and Darlington – Security and Other Fencing
   ii. Pickering and Darlington – Nuclear Exciters
   iii. Hydroelectric – Gates, Stoplogs, and Operating Mechanisms
   iv. Hydroelectric – Station Service Electrical Equipment
   v. Hydroelectric – Electronic Security Systems

b) Please provide additional details that support the basis for an initial 60-year useful life for an SMR unit.

c) Please provide additional details supporting the EOL date (December 31, 2070) for Pickering Units 5-8.

Response

a) Chart 1 below provides the requested comparison of the forecasted depreciation expenses for OPG's regulated asset classes using the updated service lives as recommended by Concentric Advisors, ULC in their 2024 Depreciation Study (Ex. F4-1-1, Attachment 1) compared to the previous service lives. As OPG does not budget depreciation expense for forecast in-service additions at the individual asset class level, this analysis is presented on the basis of the actual asset values in service as at December 31, 2024. For clarity, the impacts of these updated service lives have been included in the Application.

Chart 1 – Comparison of Forecasted Depreciation Expense using Updated Service Lives vs. Previous Service Lives

	Updated Service Life					Previous Service Life				
Asset class ($M)	**2027**	**2028**	**2029**	**2030**	**2031**	**2027**	**2028**	**2029**	**2030**	**2031**
Hydro Electric-Gates, Stoplogs and Operating Mechanisms	16.3	16.3	16.3	16.3	16.3	13.7	13.7	13.7	13.7	13.7
Hydroelectric - Station Service Electrical Equipment	4.3	4.2	4.5	4.1	4.1	3.8	3.7	3.5	3.4	3.4
Hydro Electric - Electronic Security Systems	0.3	0.3	0.3	0.3	0.3	0.6	0.6	0.5	0.4	0.3
Nuclear - Security and Other Fencing	0.6	0.6	0.6	0.6	0.6	1.4	1.1	0.6	0.5	0.4
Nuclear - Nuclear Exciters	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Total	**22.1**	**22.0**	**22.3**	**21.9**	**21.9**	**20.1**	**19.7**	**18.8**	**18.6**	**18.4**

b) The 60-year useful life assumption for the DNNP's BWRX-300 SMR unit is supported by the design life set out in Section 16 of the BWRX-300 General Description, Revision H, October 2025 provided by GE Vernova Hitachi.[1]

c) As discussed in F4-1-1, Section 3.5.2 and Ex. F4-1-1, Attachment 3, p. 3, the December 31, 2070 date represents the average station end-of-life assumption for Pickering Units 5-8 that was adopted by OPG, for accounting purposes, effective December 31, 2023, based on the results of the feasibility assessment for the refurbishment of these units and the support of the Province of Ontario for OPG to proceed with the next steps toward such refurbishment. Consistent with OPG's past practice for establishing such nuclear station end-of-life assumptions, the date represents an average of the end-of-life estimates for each of the four units based on the respective estimated return to service dates and an expected operating period of 38 years based on the technical assessments completed (Ex. L-D2-SEC-079, Attachment 1, p. 6).

The use of the December 31, 2070 end-of-life date assumption for Pickering Units 5-8 is supported by Concentric (Ex. F4-1-1, Attachment 1, p. 14), with a

[1] https://www.gevernova.com/content/dam/gevernova-nuclear/global/en_us/documents/carbon-free-power/005N9751-BWRX-300-General-Description.pdf, p.93.

recommendation to re-confirm the date after the refurbishment has been completed.

CCC Interrogatory #084

Interrogatory

Reference:
Exhibit A2, Tab 2, Schedule 1, p. 5
Exhibit F4, Tab 2, Schedule 1, pp. 19-20

Preamble:

The federal government has proposed a 15% refundable tax credit for certain clean electricity investments ("CEITC"), including eligible hydroelectric systems and nuclear energy equipment, that could be available to OPG and would reduce borrowing requirements. At the time of filing, no legislation implementing this credit is in place and the CEITCs are not reflected in OPG's 2025-2031 Business Plan. OPG will account for such credits as a reduction in the capital costs of the underlying projects. The Application proposes to return to customers the revenue requirement of the CEITCs, once available, through a series of variance accounts.

Question(s):

a) Please confirm CCC's understanding that the value of the proposed CEITCs are, if implemented, going to be passed through to customers on a 100% basis through the application of the credits as capital contributions against the related investments and through the tracking of the related revenue requirement reductions in variance accounts. If not confirmed, please explain how OPG proposed to allocate the value of the proposed credits between itself, DNNP and customers.

b) In the circumstance that the refundable CEITC legislation is implemented, please provide a detailed estimate of the value of this tax credit on a revenue requirement basis for each year of the 2027-2031 period.

c) Please further explain the interaction between the CEITC and the CCR proposal. More specifically, if the CEITC rebate is approved will there be a credit to ratepayers associated with the CCR amounts collected during the 2027-2031 period?

d) If the CEITC legislation is approved while the current proceeding is ongoing, please provide OPG's view on implementing that rebate for ratemaking purposes as an application update.

Response

Given the relative significance of both programs and the interrelated nature of the impacts (through the respective effects on capital cost allowance ("CCA") deductions), the Applicants provide their response to parts b) and d) in respect of both the CEITCs and the reinstatement of the accelerated investment incentive property ("RIIP") program proposed in the 2025 Federal Budget that provides an ability to claim higher CCA deductions for qualifying property acquired on or after January 1, 2025. The federal legislation enacting these mechanisms became law on March 26, 2026. Both of these changes are expected to benefit ratepayers and are further discussed at Ex. F4-2-1, Section 3.2.1 and Section 3.5.

a) OPG confirms that, regarding the CEITCs for which OPG is eligible with respect to its prescribed assets, the Application proposes to pass through to customers on a 100% basis, through the application of such actual received credits as reductions of the associated capital costs for this purpose, the associated revenue requirement impacts as recorded for future disposition in OPG's applicable existing or proposed deferral and variance accounts, as identified in Ex. H1-1-1, Section 7.5 and Ex. F4-2-1, Section 3.5.

   DNNP LP confirms that, regarding the CEITCs for which DNNP LP's partners are eligible with respect to the DNNP facilities, the Application proposes to pass through to customers on a 100% basis, through the application of such received credits as reductions of the associated capital costs for this purpose, the associated revenue requirement impacts as recorded for future disposition in DNNP LP's applicable existing or proposed deferral and variance accounts, as identified in Ex. H1-1-1, Section 8.6 and Ex. F4-2-1, Section 3.5.

   For clarity, for both OPG and DNNP LP, the above noted deferral and variance account would also capture any revenue requirement impacts arising from any subsequent changes to the amount of the CEITCs available, including as a result of legislative or regulatory changes, reassessments, adjustments or other reasons.[1]

b) The Applicants have preliminarily estimated the future impacts of the CEITCs and the RIIP program on the respective proposed revenue requirements in the Application, by applying a set of assumptions with respect to these programs to such proposals, with the results summarized in Chart 1 below. The analysis assumes that all partners of DNNP LP are eligible for the CEITCs and, consistent with the pre-filed evidence, that only OPG (and not the other partners of DNNP LP) are subject to income taxes. The estimated impacts reflect the Applicants' current

[1] Refer to Ex. L-H1-Staff-248 for discussion of the interactions of various income tax-related deferral and variance accounts, including in connection with the CEITCs.

c) assumptions around expenditure eligibility and the interpretation of the associated legislation, which may evolve in the future. Any expenditures claimed for the CEITC may be subject to review and audit by the Canada Revenue Agency.

The preliminary estimates provided assume that the refurbishment of Darlington Unit 4 will be eligible for the CEITC. OPG has asked for a Ministerial determination to confirm whether this project will in fact qualify, since the overall Darlington Refurbishment Program commenced before the CEITC project eligibility date, but the Unit 4 refurbishment began after that date.

The CEITC program has numerous requirements that need to be met to receive the full amount of the credit equal to 15% of the qualifying expenditure. Among others, this includes the apprentice requirement, which requires that an entity and its contractors hire enough apprentices so that 10% of the project work performed by members of a Red Seal trade is performed by apprentices registered in a Red Seal trade. Certain of OPG's projects, particularly within the Renewable Generation, do not currently meet these requirements and therefore would be eligible for a reduced tax credit equivalent to 5% of the qualifying expenditure. The preliminary estimates provided have been determined assuming that Renewable Generation projects will receive a 5% CEITC and Nuclear projects will receive a 15% CEITC. OPG is investigating the possibility of meeting the apprentice requirement for Renewable Generation projects, including the implications and timing of doing so.

Chart 1 – Summary of Change on the Proposed Revenue Requirement and Payment Amounts – CEITC and RIIP Preliminary Estimates

Line No.	Item	2027	2028	2029	2030	2031
		(a)	(b)	(c)	(d)	(e)
	Proposed					
1	Revenue Requirement - OPG Nuclear Facilities ($M)	4,062.8	4,257.4	4,677.0	4,882.4	5,737.6
2	Revenue Requirement - DNNP Facilities ($M)	301.0	378.8	404.9	559.3	1,042.0
3	Blended Nuclear Payment Amounts ($/MWh)	206.70	192.42	202.74	199.16	219.60
4	Revenue Requirement - Regulated Hydroelectric ($M)	1,668.3	-	-	-	-
5	Hydroelectric Payment Amounts* ($/MWh)	51.39	54.97	59.20	62.02	64.21
6	Typical Bill Impact ($/Month)	7.93	2.44	1.33	0.69	4.62
7	Typical Bill Impact (%)	5.6%	1.7%	0.9%	0.5%	3.3%
	Adjusted for CEITC and RIIP					
8	Revenue Requirement - OPG Nuclear Facilities ($M)	4,045.5	4,212.1	4,603.5	4,769.3	5,560.6

9	Revenue Requirement - DNNP Facilities ($M)	300.3	368.1	377.1	515.1	969.0
10	Blended Nuclear Payment Amounts ($/MWh)	205.74	190.33	198.70	193.40	211.50
11	Revenue Requirement - Regulated Hydroelectric ($M)	1,635.7	-	-	-	-
12	Hydroelectric Payment Amounts* ($/MWh)	50.39	53.41	59.42	62.22	64.03
13	Typical Bill Impact ($/Month)	7.69	2.21	1.37	0.44	4.16
14	Typical Bill Impact (%)	5.4%	1.6%	1.0%	0.3%	2.9%
	Change					
15	Revenue Requirement - OPG Nuclear Facilities ($M)	(17.3)	(45.3)	(73.5)	(113.1)	(177.0)
16	Revenue Requirement - DNNP Facilities ($M)	(0.8)	(10.7)	(27.8)	(44.3)	(73.0)
17	Blended Nuclear Payment Amounts ($/MWh)	(1.0)	(2.1)	(4.0)	(5.8)	(8.1)
18	Revenue Requirement - Regulated Hydroelectric ($M)	(32.7)				
19	Hydroelectric Payment Amounts ($/MWh)	(1.0)	(1.6)	0.2	0.2	(0.2)
20	Typical Bill Impact ($/Month)	(0.2)	(0.2)	0.0	(0.3)	(0.5)
21	Typical Bill Impact (%)	(0.2)%	(0.1)%	0.1%	(0.2)%	(0.4)%

*2027 is cost of service amount. Subsequent years escalated by the Price Cap Index

In Attachment 1, the Applicants have provided a detailed set of tables that recalculates the proposed revenue requirements and payment amounts with the inclusion of the preliminary assumptions for the CEITCs and the RIIP program, by amending the applicable 2027-2031 tables included in the pre-filed evidence. The adjustments made include reductions to the rate base (and associated depreciation and amortization expense) of each of OPG Nuclear, Regulated Hydroelectric and DNNP LP for the forecast amount of the CEITCs pertaining to such in-service additions during the IR term,[2] reductions to forecast new debt issues on account of lower borrowing requirements reflecting the receipt of CEITCs, adjusting the CCA calculations to reflect the increase in the forecast CCA deductions resulting from the RIIP program and the decrease in the forecast CCA stemming from the amount of the CEITCs received each year, and reducing the concurrent cost recovery interest amounts through the application of CEITCs against the forecast capital expenditures for the Pickering Refurbishment Program and the Darlington New Nuclear Program (as discussed in part b) below).

In applying the preliminary estimates of the CEITCs and the RIIP program to the proposals in the Application, in addition to the assumed revenue requirement

[2] Additional reductions to rate base would be realized due to lower capitalized interest resulting from the application of CEITCs. The associated revenue requirement impacts would be included in the overall CEITC related impacts recorded in the applicable deferral and variance accounts.

impacts, there is an associated impact to the amount of regulatory tax losses carried forward to future IR terms for OPG's regulated nuclear business and for the DNNP facilities, as well as an adjustment to the proposed C-factor for OPG's regulated hydroelectric facilities for the 2028-2031 years. The respective evidence tables showing such recalculated values are included in Attachment 1, Tables 30 and 33.

d) Yes, the Concurrent Cost Recovery interest amounts for the Pickering Refurbishment Program and the Darlington New Nuclear Program in respect of the 2027-2031 period (discussed in Ex. I1-1-3) will be lower as a result of the respective CEITCs received, through their application as reductions of the associated capital expenditures on these projects for this purpose. Such estimated impacts are captured as part of the response in part b) above. Any such impacts not reflected in the approved revenue requirements would be reconciled through the Pickering B Refurbishment Project Variance Account and the Darlington New Nuclear Project Variance Account re Capital Cost Account, respectively.

e) While there remain significant uncertainties with respect to the amount of the CEITCs that the Applicants would ultimately receive, with the CEITCs and the RIIP program having become law since the submission of the Application, the Applicants are not opposed in principle to reflecting the preliminary estimates of these programs in the revenue requirements and other approval items in this proceeding, provided that the proposed Clean Electricity ITC Variance Accounts and Income and Other Taxes Variance Accounts are also approved.[3] To avoid the complexities and any potential delays associated with such a comprehensive update of the Application, however, the Applicants believe that the incorporation of these impacts can be addressed as part of the payment amounts order process. This view is informed by the pervasive nature of the affected elements of the revenue requirement (as demonstrated in Attachment 1), combined with the level of impacts that these changes are forecasted to have on the revenue requirements and payment amounts (as set out in part b) above).

[3] The CEITC and RIIP impacts would be reflected in the revenue requirements approved in this proceeding, reference amounts for the Capacity Refurbishment Variance Account (Ex. H1-1-1, Attachments 5-8) and the Darlington New Nuclear Project Variance Account re Development (Ex. H1-1-1, Attachment 9) would be revised accordingly to reflect such impacts. Non-zero reference amounts would also be required for the proposed Clean Electricity ITC Variance Accounts.

Table 0
Index of Tables - References to Pre-filed Tables

L-F4-CCC-084 Table Reference:	Table Title:	Pre-Filed Table Reference:
1	Prescribed Facility Rate Base - Regulated Hydroelectric	B1-1-1, Table 1
2	Continuity of Gross Property, Plant and Equipment - Regulated Hydroelectric - 2027-2031	B2-3-1, Table 3
3	Continuity of Property, Plant and Equipment - Regulated Hydroelectric - Notes - 2027-2031	B2-3-1, Table 3a
4	Continuity of Accumulated Depreciation and Amortization - Regulated Hydroelectric - 2027-2031	B2-4-1, Table 3
5	Prescribed Facility Rate Base - OPG Nuclear Facilities	B1-1-1, Table 2
6	Prescribed Facility Rate Base - DNNP Facilities	B1-1-1, Table 3
7	Continuity of Property, Plant and Equipment - Combined Nuclear - 2027-2031	B3-3-1, Table 2
8	Continuity of Property, Plant and Equipment - Combined Nuclear - Notes	B3-3-1, Table 2a
9	Continuity of Accumulated Depreciation and Amortization - Combined Nuclear - 2027-2031	B3-4-1, Table 2
10	Summary of Capitalization and Cost of Capital - OPG - 2031	C1-1-1, Table 1
11	Summary of Capitalization and Cost of Capital - OPG - 2030	C1-1-1, Table 2
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13	Summary of Capitalization and Cost of Capital - OPG - 2028	C1-1-1, Table 4
14	Summary of Capitalization and Cost of Capital - OPG - 2027	C1-1-1, Table 5
15	Summary of Existing and Planned Long-Term Debt - OPG - 2027	C1-1-2, Table 9
16	Summary of Existing and Planned Long-Term Debt - OPG - 2027 - Notes	C1-1-2, Table 9a
17	Summary of Existing and Planned Long-Term Debt - OPG - 2028	C1-1-2, Table 10
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21	Summary of Existing and Planned Long-Term Debt - OPG - 2030	C1-1-2, Table 12
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28	Calculation of Regulatory Income Taxes - Regulated Hydroelectric - 2027-2031 - Notes	F4-2-1, Table 3c
29	Calculation of Regulatory Income Taxes - OPG Nuclear Facilities - 2027-2031	F4-2-1, Table 3d
30	Summary of OPG Nuclear Regulatory Losses - 2027-2031	F4-2-1, Table 3e
31	Calculation of Regulatory Income Taxes for OPG Nuclear - 2027-2031 - Notes	F4-2-1, Table 3f
32	Calculation of Regulatory Income Taxes - DNNP Facilities - 2026-2031	F4-2-1, Table 3g
33	Summary of DNNP Facilities Regulatory Losses - Taxable Partners - 2027-2031	F4-2-1, Table 3h
34	Calculation of Regulatory Income Taxes - DNNP Facilities - 2027-2031 - Notes	F4-2-1, Table 3i
35	Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Hydroelectric Operations - 2025	F4-2-1, Table 14 (CCA_H25)
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37	Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Hydroelectric Operations - 2027	F4-2-1, Table 16 (CCA_H27)
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41	Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Hydroelectric Operations - 2031	F4-2-1, Table 20 (CCA_H31)
42	Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Nuclear Operations - 2025	F4-2-1, Table 26 (CCA_N25)
43	Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Nuclear Operations - 2026	F4-2-1, Table 27 (CCA_N26)
44	Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Nuclear Operations - 2027	F4-2-1, Table 28 (CCA_N27)
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52	Undepreciated Capital Cost and Capital Cost Allowance Schedule for DNNP Facilities - 2030	F4-2-1, Table 36 (CCA_N30)
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Numbers may not add due to rounding.

Table 1

Prescribed Facility Rate Base - Regulated Hydroelectric - Updated for CEITC Impact ($M)

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**[1]	12,725.5	13,457.5	14,740.0	15,598.8	16,364.1
2	**Accumulated Depreciation and Amortization**[1]	3,625.3	3,827.3	4,045.4	4,280.1	4,525.9
3	**Net Plant**[1]	9,100.1	9,630.2	10,694.5	11,318.7	11,838.2
4	**Cash Working Capital**[2]	19.3	19.2	19.3	19.3	19.3
5	**Materials & Supplies**[2]	0.3	0.3	0.3	0.3	0.3
6	**Total**	9,119.7	9,649.6	10,714.0	11,338.2	11,857.7

Notes:

1 From Ex. L-F4-CCC-084, Table 2 and 4.

2 From Ex. B2-5-1, Table 2.

Table 2
Continuity of Gross Property, Plant and Equipment - Regulated Hydroelectric - Updated for CEITC Impact ($M)
Years Ending December 31, 2027 to 2031

Line No.	Prescribed Facility Category	Opening Balance	In-Service Additions	CEITC Adjustment on col. (b)	Retirements, Transfers & Adjustments	(b)+(c)+(d) Net Change	(a)+(e) Closing Balance	(a+f)/2 Gross Plant Rate Base Amount
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	2027 Plan:[1]							
1	**Niagara Region**	5,090.1	167.1	(0.5)	(10.6)	156.0	5,246.1	5,176.1
2	**Eastern Region**	5,578.9	265.3	(19.7)	(3.3)	242.4	5,821.3	5,700.1
3	**Western Region**	1,616.1	410.7	(5.3)	(5.2)	400.2	2,016.3	1,849.2
4	**Total**	12,285.1	843.1	(25.4)	(19.1)	798.6	13,083.7	12,725.5
	2028 Plan:[1]							
5	**Niagara Region**	5,246.1	342.9	(1.7)	(12.6)	328.7	5,574.8	5,338.4
6	**Eastern Region**	5,821.3	465.5	(16.1)	(4.8)	444.6	6,265.9	6,029.7
7	**Western Region**	2,016.3	297.9	(29.3)	(2.4)	266.2	2,282.5	2,089.4
8	**Total**	13,083.7	1,106.3	(47.0)	(19.8)	1,039.5	14,123.2	13,457.5
	2029 Plan:[1]							
9	**Niagara Region**	5,574.8	567.7	(12.2)	(15.0)	540.5	6,115.3	5,937.0
10	**Eastern Region**	6,265.9	331.1	(11.0)	(2.4)	317.7	6,583.6	6,424.7
11	**Western Region**	2,282.5	218.3	(24.7)	(2.3)	191.4	2,473.9	2,378.2
12	**Total**	14,123.2	1,117.1	(47.9)	(19.7)	1,049.6	15,172.7	14,740.0
	2030 Plan:[1]							
13	**Niagara Region**	6,115.3	535.6	(17.2)	(14.0)	504.4	6,619.7	6,346.3
14	**Eastern Region**	6,583.6	219.4	(5.7)	(2.5)	211.2	6,794.8	6,689.2
15	**Western Region**	2,473.9	185.1	(2.4)	(3.7)	178.9	2,652.8	2,563.3
16	**Total**	15,172.7	940.0	(25.2)	(20.3)	894.5	16,067.2	15,598.8
	2031 Plan:							
17	**Niagara Region**	6,619.7	48.5	(8.1)	(13.1)	27.3	6,647.0	6,633.4
18	**Eastern Region**	6,794.8	281.1	(5.2)	(2.3)	273.6	7,068.4	6,931.6
19	**Western Region**	2,652.8	298.9	(3.0)	(3.3)	292.6	2,945.4	2,799.1
20	**Total**	16,067.2	628.6	(16.3)	(18.7)	593.6	16,660.9	16,364.1

Notes: Refer to Ex. L-F4-CCC-084, Table 3.

Numbers may not add due to rounding.

Table 3
Continuity of Property, Plant and Equipment - Regulated Hydroelectric Notes - Updated for CEITC Impact ($M)
Years Ending December 31, 2027 to 2031

Notes:

1 For in service amount additions, including the CEITC adjustment, that are equal to or higher than $50M, the month in which the asset is placed in service is used to determine the gross plant rate base amount, rather than applying a mid year average. This comprises of the following projects for the 2027 to 2031 forecast years:

Line No.	Allocated Project	Project Number	Facility	Prescribed Facility Category	Reference	In-Service Date	In-Service Amount Addition	CEITC Adjustment[2]	In-Service Amount Addition Including CEITC Adjustment	First Year Weighting in Months
1	Kakabeka Falls GS Redevelopment	86386	Kakabeka	Western Region	D1-1-2_Table 1	01-Apr-27	134.9	(2.6)	132.3	9
2	Kakabeka Falls GS Redevelopment	86386	Kakabeka	Western Region	D1-1-2_Table 1	01-Jul-27	165.7	(2.6)	163.1	6
3	BK1 G4 Refurbishment	86570	Sir Adam Beck 1	Niagara Region	D1-1-2_Table 1	08-Jun-27	96.5	(0.3)	96.2	7
4	BK2 G20/G19 Refurbishment	87768	Sir Adam Beck 2	Niagara Region	D1-1-2_Table 1	01-Oct-28	176.5	(1.1)	175.4	3
5	BK1 G6 G8 Refurbishment	86372	Sir Adam Beck 1	Niagara Region	D1-1-2_Table 1	01-Oct-28	113.1	(0.4)	112.7	3
6	Matabitchuan GS Redevelopment	86387	Matabitchuan	Eastern Region	D1-1-2_Table 1	07-Aug-28	180.0	(13.0)	166.9	5
7	Kakabeka Falls GS Redevelopment	86386	Kakabeka	Western Region	D1-1-2_Table 1	01-Dec-28	171.9	(27.8)	144.1	1
8	SAB1 Canal Isolation Preparedness Phase 1	89252	Sir Adam Beck 1	Niagara Region	D1-1-2_Table 1	01-Mar-29	65.0	0.0	65.0	10
9	BK2 G20/G19 Refurbishment	87768	Sir Adam Beck 2	Niagara Region	D1-1-2_Table 1	01-Feb-29	176.5	(7.7)	168.8	11
10	BK1 G6 G8 Refurbishment	86372	Sir Adam Beck 1	Niagara Region	D1-1-2_Table 1	01-Mar-30	113.1	(6.3)	106.8	10
11	BK2 G18 G17 Refurbishment	87356	Sir Adam Beck 2	Niagara Region	D1-1-2_Table 1	01-Jul-30	172.1	(1.7)	170.4	6
12	BK2 G18 G17 Refurbishment	87356	Sir Adam Beck 2	Niagara Region	D1-1-2_Table 1	01-Nov-30	172.1	(1.7)	170.4	2

2 Amounts reflect the forecasted CEITC credited to rate base in the associated year for the corresponding project.

Numbers may not add due to rounding.

Table 4
Continuity of Accumulated Depreciation and Amortization - Regulated Hydroelectric - Updated for CEITC Impact ($M)
Years Ending December 31, 2027 to 2031

Line No.	Prescribed Facility Category	Opening Balance	Depreciation and Amortization on Opening Balance	Depreciation and Amortization on In-Service Additions	CEITC Adjustment Depreciation and Amortization on cols. (b) and (c)	Retirements, Transfers & Adjustments	(a)+(b)+(c)+(d)+(e) Closing Balance	(a+f)/2 Accumulated Depreciation and Amortization Rate Base Amount
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	2027 Plan:							
1	**Niagara Region**	1,409.8	68.6	1.6	(0.0)	0.0	1,479.9	1,444.8
2	**Eastern Region**	1,674.7	94.3	2.3	(0.2)	0.0	1,771.1	1,722.9
3	**Western Region**	442.9	25.4	4.0	(0.1)	0.0	472.3	457.6
4	**Total**	3,527.4	188.3	7.9	(0.3)	0.0	3,723.3	3,625.3
	2028 Plan:							
5	**Niagara Region**	1,479.9	71.2	1.7	(0.0)	0.0	1,552.8	1,516.4
6	**Eastern Region**	1,771.1	98.4	3.7	(0.5)	0.0	1,872.8	1,821.9
7	**Western Region**	472.3	32.2	1.3	(0.1)	0.0	505.7	489.0
8	**Total**	3,723.3	201.8	6.8	(0.6)	0.0	3,931.3	3,827.3
	2029 Plan:							
9	**Niagara Region**	1,552.8	76.3	6.4	(0.2)	0.0	1,635.3	1,594.1
10	**Eastern Region**	1,872.8	105.6	2.9	(0.7)	0.0	1,980.5	1,926.6
11	**Western Region**	505.7	37.0	1.8	(0.8)	0.0	543.8	524.7
12	**Total**	3,931.3	218.9	11.1	(1.7)	0.0	4,159.6	4,045.4
	2030 Plan:							
13	**Niagara Region**	1,635.3	85.2	4.1	(0.4)	0.0	1,724.2	1,679.7
14	**Eastern Region**	1,980.5	110.2	1.9	(0.9)	0.0	2,091.8	2,036.2
15	**Western Region**	543.8	40.3	1.6	(1.0)	0.0	584.7	564.2
16	**Total**	4,159.6	235.7	7.6	(2.3)	0.0	4,400.6	4,280.1
	2031 Plan:							
17	**Niagara Region**	1,724.2	93.2	0.5	(0.6)	0.0	1,817.2	1,770.7
18	**Eastern Region**	2,091.8	112.4	2.5	(0.9)	0.0	2,205.7	2,148.8
19	**Western Region**	584.7	42.0	2.5	(1.1)	0.0	628.1	606.4
20	**Total**	4,400.6	247.6	5.5	(2.6)	0.0	4,651.1	4,525.9

Numbers may not add due to rounding.

Table 5

Prescribed Facility Rate Base - OPG Nuclear Facilities - Updated for CEITC Impact ($M)

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**[1]	24,191.0	25,188.7	25,770.2	27,017.6	33,863.0
2	**Accumulated Depreciation and Amortization**[1]	9,395.9	10,074.0	10,782.6	11,526.0	12,390.3
3	**Net Plant**[1]	14,795.1	15,114.7	14,987.7	15,491.7	21,472.7
4	**Cash Working Capital**[2]	(22.5)	(22.4)	(22.5)	(22.5)	(22.5)
5	**Fuel Inventory**[2]	318.6	376.0	441.7	515.8	556.3
6	**Materials & Supplies**[2]	578.5	599.4	598.4	605.0	618.2
7	**Total**	15,669.8	16,067.6	16,005.4	16,590.0	22,624.7

Notes:

1 From Ex. L-F4-CCC-084, Table 7 and 9.

2 From Ex. B3-5-1, Table 2.

Numbers may not add due to rounding.

Table 6

Prescribed Facility Rate Base - DNNP Facilities - Updated for CEITC Impact ($M)

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**[1]	0.0	0.0	0.0	1,236.5	5,935.4
2	**Accumulated Depreciation and Amortization**[1]	0.0	0.0	0.0	10.2	69.9
3	**Net Plant**[1]	0.0	0.0	0.0	1,226.3	5,865.5
4	**Cash Working Capital**[2]	0.0	0.0	0.0	(0.6)	(2.4)
5	**Fuel Inventory**[2]	0.0	0.0	0.0	0.0	0.0
6	**Materials & Supplies**[2]	0.0	0.0	2.1	11.1	25.0
7	**Total**	0.0	0.0	2.1	1,236.9	5,888.1

Notes:

1 From Ex. L-F4-CCC-084, Table 7 and 9.

2 From Ex. B3-5-1, Table 3.

Table 7 (Three Pages)
Continuity of Property, Plant and Equipment - Combined Nuclear - Updated for CEITC Impact ($M)
Years Ending December 31, 2027 to 2031

Line No.	Prescribed Facility Category	Gross Plant Opening Balance	In-Service Additions	CEITC Adjustment on col. (b)	Retirements, Transfers & Adjustments	(b)+(c)+(d) Net Change	(a)+(e) Closing Balance	(a+f)/2 Gross Plant Rate Base Amount
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	2027 Plan:[1]							
	OPG Nuclear Facilities							
	Darlington NGS:							
1	**Darlington NGS (excluding DRP)**	4,648.5	826.9	(10.0)	0.0	816.9	5,465.4	4,966.5
2	**Darlington Refurbishment Program (excluding D2O Storage)**[4]	11,906.5	0.0	(249.1)	0.0	(249.1)	11,657.4	11,781.9
3	**Heavy Water Storage Facility (D2O Storage)**	395.6	0.0	0.0	0.0	0.0	395.6	395.6
4	**Subtotal Darlington NGS**	16,950.6	826.9	(259.1)	0.0	567.8	17,518.4	17,144.1
	Pickering NGS:							
5	**Pickering NGS (excluding PRP)**	2,882.5	119.1	0.0	0.0	119.1	3,001.6	2,942.0
6	**Pickering Refurbishment Program**	159.3	20.6	(0.4)	0.0	20.2	179.5	169.4
7	**Subtotal Pickering NGS**	3,041.8	139.7	(0.4)	0.0	139.3	3,181.0	3,111.4
8	**Operations and Project Support**[2]	812.8	36.0	0.0	0.0	36.0	848.7	830.8
9	**OPG Nuclear Facilities - Excluding Asset Retirement Costs**	20,805.2	1,002.5	(259.5)	0.0	743.0	21,548.2	21,086.3
10	**Asset Retirement Costs**	3,104.7	0.0	0.0	0.0	0.0	3,104.7	3,104.7
11	**Total**	23,909.9	1,002.5	(259.5)	0.0	743.0	24,652.9	24,191.0
	DNNP Facilities							
12	**Darlington New Nuclear Program**	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2028 Plan:[1]							
	OPG Nuclear Facilities							
	Darlington NGS:							
13	**Darlington NGS (excluding DRP)**	5,465.4	741.5	(16.2)	0.0	725.3	6,190.7	5,940.9
14	**Darlington Refurbishment Program (excluding D2O Storage)**	11,657.4	0.0	0.0	0.0	0.0	11,657.4	11,657.4
15	**Heavy Water Storage Facility (D2O Storage)**	395.6	0.0	0.0	0.0	0.0	395.6	395.6
16	**Subtotal Darlington NGS**	17,518.4	741.5	(16.2)	0.0	725.3	18,243.7	17,993.9
	Pickering NGS:							
17	**Pickering NGS (excluding PRP)**	3,001.6	90.6	0.0	0.0	90.6	3,092.2	3,046.9
18	**Pickering Refurbishment Program**	179.5	0.0	0.0	0.0	0.0	179.5	179.5
19	**Subtotal Pickering NGS**	3,181.0	90.6	0.0	0.0	90.6	3,271.7	3,226.4
20	**Operations and Project Support**[2]	848.7	29.7	0.0	0.0	29.7	878.5	863.6
21	**OPG Nuclear Facilities - Excluding Asset Retirement Costs**	21,548.2	861.9	(16.2)	0.0	845.7	22,393.9	22,083.9
22	**Asset Retirement Costs**	3,104.7	0.0	0.0	0.0	0.0	3,104.7	3,104.7
23	**Total**	24,652.9	861.9	(16.2)	0.0	845.7	25,498.6	25,188.7
	DNNP Facilities							
24	**Darlington New Nuclear Program**	0.0	0.0	-	0.0	0.0	0.0	0.0

Table 7 (Three Pages)
Continuity of Property, Plant and Equipment - Combined Nuclear - Updated for CEITC Impact ($M)
Years Ending December 31, 2027 to 2031

Line No.	Prescribed Facility Category	Gross Plant Opening Balance	In-Service Additions	CEITC Adjustment on col. (b)	Retirements, Transfers & Adjustments	(b)+(c)+(d) Net Change	(a)+(e) Closing Balance	(a+f)/2 Gross Plant Rate Base Amount
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	2029 Plan:[1]							
	OPG Nuclear Facilities							
	Darlington NGS:							
25	**Darlington NGS (excluding DRP)**	6,190.7	936.6	(26.9)	0.0	909.7	7,100.4	6,394.8
26	**Darlington Refurbishment Program (excluding D2O Storage)**	11,657.4	0.0	0.0	0.0	0.0	11,657.4	11,657.4
27	**Heavy Water Storage Facility (D2O Storage)**	395.6	0.0	0.0	0.0	0.0	395.6	395.6
28	**Subtotal Darlington NGS**	18,243.7	936.6	(26.9)	0.0	909.7	19,153.4	18,447.8
	Pickering NGS:							
29	**Pickering NGS (excluding PRP)**	3,092.2	102.2	(0.1)	0.0	102.1	3,194.3	3,143.3
30	**Pickering Refurbishment Program**	179.5	0.0	0.0	0.0	0.0	179.5	179.5
31	**Subtotal Pickering NGS**	3,271.7	102.2	(0.1)	0.0	102.1	3,373.8	3,322.7
32	**Operations and Project Support**[2]	878.5	32.9	0.0	0.0	32.9	911.4	894.9
33	**OPG Nuclear Facilities - Excluding Asset Retirement Costs**	22,393.9	1,071.7	(27.0)	0.0	1,044.7	23,438.5	22,665.5
34	**Asset Retirement Costs**	3,104.7	0.0	0.0	0.0	0.0	3,104.7	3,104.7
35	**Total**	25,498.6	1,071.7	(27.0)	0.0	1,044.7	26,543.3	25,770.2
	DNNP Facilities							
36	**Darlington New Nuclear Program**	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2030 Plan:[1]							
	OPG Nuclear Facilities							
	Darlington NGS:							
37	**Darlington NGS (excluding DRP)**	7,100.4	1,059.2	(53.4)	0.0	1,005.8	8,106.2	7,340.9
38	**Darlington Refurbishment Program (excluding D2O Storage)**	11,657.4	0.0	0.0	0.0	0.0	11,657.4	11,657.4
39	**Heavy Water Storage Facility (D2O Storage)**	395.6	0.0	0.0	0.0	0.0	395.6	395.6
40	**Subtotal Darlington NGS**	19,153.4	1,059.2	(53.4)	0.0	1,005.8	20,159.2	19,393.9
	Pickering NGS:							
41	**Pickering NGS (excluding PRP)**	3,194.3	348.9	(1.6)	0.0	347.3	3,541.5	3,392.5
42	**Pickering Refurbishment Program**	179.5	0.0	0.0	0.0	0.0	179.5	179.5
43	**Subtotal Pickering NGS**	3,373.8	348.9	(1.6)	0.0	347.3	3,721.0	3,572.0
44	**Operations and Project Support**[2]	911.4	71.4	0.0	0.0	71.4	982.7	947.1
45	**OPG Nuclear Facilities - Excluding Asset Retirement Costs**	23,438.5	1,479.4	(55.0)	0.0	1,424.4	24,863.0	23,912.9
46	**Asset Retirement Costs**	3,104.7	0.0	0.0	0.0	0.0	3,104.7	3,104.7
47	**Total**	26,543.3	1,479.4	(55.0)	0.0	1,424.4	27,967.7	27,017.6
	DNNP Facilities							
48	**Darlington New Nuclear Program**	0.0	6,584.9	(649.5)	0.0	5,935.4	5,935.4	1,236.5

Table 7 (Three Pages)
Continuity of Property, Plant and Equipment - Combined Nuclear - Updated for CEITC Impact ($M)
Years Ending December 31, 2027 to 2031

Line No.	Prescribed Facility Category	Gross Plant Opening Balance	In-Service Additions	CEITC Adjustment on col. (b)	Retirements, Transfers & Adjustments	(b)+(c)+(d) Net Change	(a)+(e) Closing Balance	(a+f)/2 Gross Plant Rate Base Amount
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	2031 Plan:[1]							
	OPG Nuclear Facilities							
	Darlington NGS:							
49	**Darlington NGS (excluding DRP)**	8,106.2	768.2	(58.6)	0.0	709.6	8,815.8	8,461.0
50	**Darlington Refurbishment Program (excluding D2O Storage)**	11,657.4	0.0	0.0	0.0	0.0	11,657.4	11,657.4
51	**Heavy Water Storage Facility (D2O Storage)**	395.6	0.0	0.0	0.0	0.0	395.6	395.6
52	**Subtotal Darlington NGS**	20,159.2	768.2	(58.6)	0.0	709.6	20,868.8	20,514.0
	Pickering NGS:							
53	**Pickering NGS (excluding PRP)**	3,541.5	178.6	(2.6)	0.0	176.0	3,717.5	3,629.5
54	**Pickering Refurbishment Program**	179.5	9,688.0	(1,005.3)	0.0	8,682.7	8,862.2	5,606.2
55	**Subtotal Pickering NGS**	3,721.0	9,866.6	(1,007.9)	0.0	8,858.7	12,579.7	9,235.7
56	**Operations and Project Support**[2]	982.7	51.5	0.0	0.0	51.5	1,034.3	1,008.5
57	**OPG Nuclear Facilities - Excluding Asset Retirement Costs**	24,863.0	10,686.3	(1,066.5)	0.0	9,619.8	34,482.8	30,758.2
58	**Asset Retirement Costs**	3,104.7	0.0		0.0	0.0	3,104.7	3,104.7
59	**Total**	27,967.7	10,686.3	(1,066.5)	0.0	9,619.8	37,587.5	33,863.0
	DNNP Facilities							
60	**Darlington New Nuclear Program**	5,935.4	0.0	0.0	0.0	0.0	5,935.4	5,935.4

Notes: Refer to Ex. L-F4-CCC-084, Table 8.

Numbers may not add due to rounding.

Table 8
Continuity of Property, Plant and Equipment - Combined Nuclear Notes - Updated for CEITC Impact ($M)
Years Ending December 31, 2027 to 2031

Notes:

1 For in service amount additions, including the CEITC adjustment, that are equal to or higher than $50M, the month in which the asset is placed in service is used to determine the gross plant rate base amount, rather than applying a mid year average. This comprises of the following projects for the 2027 to 2031 forecast years:

Line No.	Allocated Project	Project Number	Prescribed Facility Category	Reference	In-Service Date	In-Service Amount Addition	CEITC Adjustment[3]	In-Service Amount Addition Including CEITC Adjustment	First Year Weighting in Months
1	DN Vacuum Building Outage Power Operated Valves Replacement	84552	Darlington NGS	D2-1-3_Table 1c	1-Dec-27	50.8	0.0	50.8	1
2	Tritium Removal Facility Major Component Replacement Program	84764	Darlington NGS	D2-1-3_Table 1c	1-Dec-27	52.5	0.0	52.5	1
3	DN Unit 2 and 3 Steam Generator Moisture Separator Replacement	87151	Darlington NGS	D2-1-3_Table 1c	1-Dec-27	122.1	(8.4)	113.8	1
4	DN Unit 2 Turbine Control & Auxiliary Systems Upgrade	83664	Darlington NGS	D2-1-3_Table 1a	1-Jan-28	177.2	(3.4)	173.8	12
5	DN Unit 1 and 2 Generator Stator Rewind	89281	Darlington NGS	D2-1-3_Table 1c	1-May-28	159.3	(3.2)	156.1	8
6	DN Turbine Rotors Replacements	87807	Darlington NGS	D2-1-3_Table 1c	1-Dec-29	625.0	(23.3)	601.8	1
7	Tritium Removal Facility Major Component Replacement Program	84764	Darlington NGS	D2-1-3_Table 1c	1-Jul-30	105.1	0.0	105.1	6
8	DN Turbine Rotors Replacements	87807	Darlington NGS	D2-1-3_Table 1c	1-Dec-30	533.9	(36.8)	497.1	1
9	DN Unit 1 and 2 Generator Stator Rewind	89281	Darlington NGS	D2-1-3_Table 1c	1-Dec-30	146.8	(14.1)	132.7	1
10	DN Turbine Rotors Replacements	87807	Darlington NGS	D2-1-3_Table 1c	1-Jul-31	533.8	(45.3)	488.5	6
11	Pickering Water Treatment Plant Lease	89732	Pickering NGS	D2-1-3_Table 4b	31-Mar-30	98.2	0.0	98.2	9
12	Unit Refurbishment - Unit 5	Various	Pickering Refurbishment Program	D2-3-8_Table 2	15-May-31	8,474.1	(879.3)	7,594.8	7.5
13	Deep Water Intake	Various	Pickering Refurbishment Program	D2-3-8_Table 2	15-May-31	1,213.9	(126.0)	1,087.9	7.5
14	DNNP Unit 1 & Common Scope Facilities	Various	Darlington New Nuclear Program	D2-4-8_Table 3	17-Oct-30	6,584.9	(649.5)	5,935.4	2.5

2 Includes Engineering, Advanced Inspection Maintenance (previously Inspection and Reactor Innovation), and Security & Emergency Services.

3 Amounts reflect the forecasted CEITC credited to rate base in the associated year for the corresponding project.

4 Reflects assumed CEITC in respect of Darlington Unit 4. OPG has asked for a Ministerial direction to confirm the eligibility of Darlington Unit 4 for CEITC.

Table 9 (Two Pages)
Continuity of Accumulated Depreciation and Amortization - Combined Nuclear - Updated for CEITC Impact ($M)
Years Ending December 31, 2027 to 2031

Line No.	Prescribed Facility Category	Opening Balance	Depreciation and Amortization on Opening Balance	Depreciation and Amortization on In-Service Additions	CEITC Adjustment Depreciation and Amortization on cols. (b) and (c)	Retirements, Transfers & Adjustments	(a)+(b)+(c)+(d)+(e) Closing Balance	(a+f)/2 Accumulated Depreciation and Amortization Rate Base Amount
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	2027 Plan:							
	OPG Nuclear Facilities							
	Darlington NGS:							
1	**Darlington NGS (excluding DRP)**	1,364.8	162.5	16.0	(0.1)	0.0	1,543.3	1,454.0
2	**Darlington Refurbishment Program (excluding D2O Storage)**	1,800.6	398.5	0.0	(4.9)	0.0	2,194.2	1,997.4
3	**Heavy Water Storage Facility (D2O Storage)**	83.3	12.0	0.0	0.0	0.0	95.3	89.3
4	**Subtotal Darlington NGS**	3,248.7	573.0	16.0	(5.0)	0.0	3,832.8	3,540.7
	Pickering NGS:							
5	**Pickering NGS (excluding PRP)**	2,668.8	18.0	3.6	0.0	0.0	2,690.3	2,679.6
6	**Pickering Refurbishment Project**	1.2	3.6	0.2	(0.0)	0.0	5.0	3.1
7	**Subtotal Pickering NGS**	2,670.0	21.6	3.8	(0.0)	0.0	2,695.4	2,682.7
8	**Operations and Project Support**[1]	542.6	36.4	1.1	0.0	0.0	580.1	561.3
9	**OPG Nuclear Facilities - Excluding Asset Retirement Costs**	6,461.3	631.0	21.0	(5.0)	0.0	7,108.3	6,784.8
10	**Asset Retirement Costs**	2,605.4	11.3	0.0	0.0	0.0	2,616.8	2,611.1
11	**Total**	9,066.7	642.3	21.0	(5.0)	0.0	9,725.0	9,395.9
	DNNP Facilities							
12	**Darlington New Nuclear Program**	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2028 Plan:							
	OPG Nuclear Facilities							
	Darlington NGS:							
13	**Darlington NGS (excluding DRP)**	1,543.3	198.2	21.4	(0.9)	0.0	1,762.0	1,652.6
14	**Darlington Refurbishment Program (excluding D2O Storage)**	2,194.2	398.5	0.0	(9.7)	0.0	2,583.0	2,388.6
15	**Heavy Water Storage Facility (D2O Storage)**	95.3	12.0	0.0	0.0	0.0	107.3	101.3
16	**Subtotal Darlington NGS**	3,832.8	608.7	21.4	(10.6)	0.0	4,452.2	4,142.5
	Pickering NGS:							
17	**Pickering NGS (excluding PRP)**	2,690.3	23.9	2.7	0.0	0.0	2,716.9	2,703.6
18	**Pickering Refurbishment Project**	5.0	4.1	0.0	(0.0)	0.0	9.1	7.1
19	**Subtotal Pickering NGS**	2,695.4	28.0	2.7	(0.0)	0.0	2,726.0	2,710.7
20	**Operations and Project Support**[1]	580.1	35.2	1.3	0.0	0.0	616.5	598.3
21	**OPG Nuclear Facilities - Excluding Asset Retirement Costs**	7,108.3	671.8	25.3	(10.6)	0.0	7,794.8	7,451.5
22	**Asset Retirement Costs**	2,616.8	11.3	0.0	0.0	0.0	2,628.1	2,622.4
23	**Total**	9,725.0	683.2	25.3	(10.6)	0.0	10,422.9	10,074.0
	DNNP Facilities							
24	**Darlington New Nuclear Program**	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2029 Plan:							
	OPG Nuclear Facilities							
	Darlington NGS:							
25	**Darlington NGS (excluding DRP)**	1,762.0	231.7	10.9	(1.3)	0.0	2,003.3	1,882.6
26	**Darlington Refurbishment Program (excluding D2O Storage)**	2,583.0	398.4	0.0	(9.7)	0.0	2,971.6	2,777.3
27	**Heavy Water Storage Facility (D2O Storage)**	107.3	12.0	0.0	0.0	0.0	119.3	113.3
28	**Subtotal Darlington NGS**	4,452.2	642.1	10.9	(11.0)	0.0	5,094.2	4,773.2
	Pickering NGS:							
29	**Pickering NGS (excluding PRP)**	2,716.9	23.7	3.2	(0.0)	0.0	2,743.8	2,730.4
30	**Pickering Refurbishment Project**	9.1	4.1	0.0	(0.0)	0.0	13.1	11.1
31	**Subtotal Pickering NGS**	2,726.0	27.7	3.2	(0.0)	0.0	2,756.9	2,741.5
32	**Operations and Project Support**[1]	616.5	33.8	1.3	0.0	0.0	651.6	634.1
33	**OPG Nuclear Facilities - Excluding Asset Retirement Costs**	7,794.8	703.6	15.3	(11.0)	0.0	8,502.7	8,148.8
34	**Asset Retirement Costs**	2,628.1	11.3	0.0	0.0	0.0	2,639.5	2,633.8
35	**Total**	10,422.9	715.0	15.3	(11.0)	0.0	11,142.2	10,782.6
	DNNP Facilities							
36	**Darlington New Nuclear Program**	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 9 (Two Pages)
Continuity of Accumulated Depreciation and Amortization - Combined Nuclear - Updated for CEITC Impact ($M)
Years Ending December 31, 2027 to 2031

Line No.	Prescribed Facility Category	Opening Balance	Depreciation and Amortization on Opening Balance	Depreciation and Amortization on In-Service Additions	CEITC Adjustment Depreciation and Amortization on cols. (b) and (c)	Retirements, Transfers & Adjustments	(a)+(b)+(c)+(d)+(e) Closing Balance	(a+f)/2 Accumulated Depreciation and Amortization Rate Base Amount
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	2030 Plan:							
	OPG Nuclear Facilities							
	Darlington NGS:							
37	**Darlington NGS (excluding DRP)**	2,003.3	271.7	12.1	(2.5)	0.0	2,284.5	2,143.9
38	**Darlington Refurbishment Program (excluding D2O Storage)**	2,971.6	398.0	0.0	(9.7)	0.0	3,359.8	3,165.7
39	**Heavy Water Storage Facility (D2O Storage)**	119.3	12.0	0.0	0.0	0.0	131.3	125.3
40	**Subtotal Darlington NGS**	5,094.2	681.7	12.1	(12.3)	0.0	5,775.7	5,435.0
	Pickering NGS:							
41	**Pickering NGS (excluding PRP)**	2,743.8	27.0	7.4	(0.0)	0.0	2,778.2	2,761.0
42	**Pickering Refurbishment Project**	13.1	4.1	0.0	(0.0)	0.0	17.2	15.2
43	**Subtotal Pickering NGS**	2,756.9	31.1	7.4	(0.0)	0.0	2,795.4	2,776.2
44	**Operations and Project Support**[1]	651.6	34.0	2.3	0.0	0.0	687.9	669.7
45	**OPG Nuclear Facilities - Excluding Asset Retirement Costs**	8,502.7	746.8	21.7	(12.3)	0.0	9,258.9	8,880.8
46	**Asset Retirement Costs**	2,639.5	11.3	0.0	0.0	0.0	2,650.8	2,645.1
47	**Total**	11,142.2	758.1	21.7	(12.3)	0.0	11,909.8	11,526.0
	DNNP Facilities							
48	**Darlington New Nuclear Program**	0.0	0.0	22.6	(2.2)	0.0	20.4	10.2
	2031 Plan:							
	OPG Nuclear Facilities							
	Darlington NGS:							
49	**Darlington NGS (excluding DRP)**	2,284.5	317.3	18.8	(6.0)	0.0	2,614.5	2,449.5
50	**Darlington Refurbishment Program (excluding D2O Storage)**	3,359.8	398.0	0.0	(9.7)	0.0	3,748.0	3,553.9
51	**Heavy Water Storage Facility (D2O Storage)**	131.3	12.0	0.0	0.0	0.0	143.4	137.4
52	**Subtotal Darlington NGS**	5,775.7	727.2	18.8	(15.8)	0.0	6,505.9	6,140.8
	Pickering NGS:							
53	**Pickering NGS (excluding PRP)**	2,778.2	38.2	3.5	(0.1)	0.0	2,819.8	2,799.0
54	**Pickering Refurbishment Project**	17.2	4.1	152.6	(15.7)	0.0	158.2	87.7
55	**Subtotal Pickering NGS**	2,795.4	42.2	156.1	(15.8)	0.0	2,978.0	2,886.7
56	**Operations and Project Support**[1]	687.9	35.1	1.8	0.0	0.0	724.8	706.3
57	**OPG Nuclear Facilities - Excluding Asset Retirement Costs**	9,258.9	804.6	176.7	(31.6)	0.0	10,208.6	9,733.8
58	**Asset Retirement Costs**	2,650.8	11.3	0.0	0.0	0.0	2,662.2	2,656.5
59	**Total**	11,909.8	815.9	176.7	(31.6)	0.0	12,870.8	12,390.3
	DNNP Facilities							
60	**Darlington New Nuclear Program**	20.4	109.7	0.0	(10.8)	0.0	119.3	69.9

Notes:
1 Includes Engineering, Advanced Inspection Maintenance (previously Inspection and Reactor Innovation), and Security & Emergency Services.

Table 10
Capitalization and Cost of Capital - Updated for CEITC Impact
Summary of Capitalization and Cost of Capital - OPG
Calendar Year Ending December 31, 2031

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1	414.3	1.2%	3.39%	19.9
2	**Existing/Planned Long-Term Debt**	2	11,400.2	33.1%	4.92%	560.6
3	**Other Long-Term Debt Provision**	3	4,737.0	13.7%	4.92%	232.9
4	**Total Debt**	4	16,551.5	48.0%	4.91%	813.4
5	**EB-2020-0290 Settlement Adjustment for Equity at Long-Term Debt Rate**	7	49.6	0.1%	4.92%	2.4
5a	**Common Equity**	4	17,881.2	51.9%	9.11%	1,629.0
5b	**Total Equity**		17,930.8	52.0%	9.10%	1,631.4
6	**Rate Base Financed by Capital Structure**	5	34,482.4	100.0%	7.09%	2,444.9
7	**Adjustment for Lesser of UNL or ARC**	5, 6	0.0	0.0%	4.72%	0.0
8	**Rate Base**		34,482.4	100.0%	7.09%	2,444.9

Notes:

1 Ex. C1-1-3, Table 2: Principal (line 7), Cost Rate (line 2), Cost of Capital (line 8). Cost includes interest at the cost rate shown plus an allocation of the credit facility cost.

2 Ex. L-F4-CCC-084, Table 23, line 38.

3 Debt required to balance capital structure with proposed rate base. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2). See Ex. C1-1-2, Section 5.0.

4 Capital Structure proposed in Ex. C1-1-1, Att. 1. Return on Equity reflects the last Cost of Capital Parameter Update published by the OEB (October 31, 2025).

5 The portion of rate base to be financed by the capital structure approved by the OEB excludes the lesser of the forecast of the average unfunded nuclear liabilities (UNL) related to Pickering and Darlington, and the average unamortized asset retirement costs (ARC) included in fixed asset balances for Pickering and Darlington.

6 Principal from Ex. C2-1-1 Table 2, line 28. Cost rate from Ex. C2-1-1, Table 1b, line 5n, col (d).

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

Table 11
Capitalization and Cost of Capital - Updated for CEITC Impact
Summary of Capitalization and Cost of Capital - OPG
Calendar Year Ending December 31, 2030

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1	414.3	1.5%	3.22%	19.2
2	**Existing/Planned Long-Term Debt**	2	11,141.5	39.9%	4.91%	547.2
3	**Other Long-Term Debt Provision**	3	1,849.7	6.6%	4.91%	90.8
4	**Total Debt**	4	13,405.5	48.0%	4.90%	657.2
5	**EB-2020-0290 Settlement Adjustment for Equity at Long-Term Debt Rate**	7	53.9	0.2%	4.91%	2.6
5a	**Common Equity**	4	14,468.7	51.8%	9.11%	1318.1
5b	**Total Equity**		14,522.6	52.0%	9.09%	1,320.7
6	**Rate Base Financed by Capital Structure**	5	27,928.1	100.0%	7.08%	1,978.0
7	**Adjustment for Lesser of UNL or ARC**	5, 6	0.0	0.0%	4.72%	0.0
8	**Rate Base**		27,928.1	100.0%	7.08%	1,978.0

Notes:

1 Ex. C1-1-3 Table 2: Principal (line 7), Cost Rate (line 2), Cost of Capital (line 8). Cost includes interest at the cost rate shown plus an allocation of the credit facility cost.

2 Ex. L-F4-CCC-084, Table 21, line 38.

3 Debt required to balance capital structure with proposed rate base. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2). See Ex. C1-1-2, Section 5.0.

4 Capital Structure proposed in Ex. C1-1-1, Att. 1. Return on Equity reflects the last Cost of Capital Parameter Update published by the OEB (October 31, 2025).

5 The portion of rate base to be financed by the capital structure approved by the OEB excludes the lesser of the forecast of the average unfunded nuclear liabilities (UNL) related to Pickering and Darlington, and the average unamortized asset retirement costs (ARC) included in fixed asset balances for Pickering and Darlington.

6 Principal from Ex. C2-1-1 Table 2, line 28. Cost rate from Ex. C2-1-1, Table 1b, line 5n, col (d).

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

Table 12
Capitalization and Cost of Capital - Updated for CEITC Impact
Summary of Capitalization and Cost of Capital - OPG
Calendar Year Ending December 31, 2029

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1	414.3	1.6%	3.07%	20.1
2	**Existing/Planned Long-Term Debt**	2	9,834.2	36.8%	4.86%	478.1
3	**Other Long-Term Debt Provision**	3	2,576.7	9.6%	4.86%	125.3
4	**Total Debt**	4	12,825.3	48.0%	4.86%	623.4
5	**EB-2020-0290 Settlement Adjustment for Equity at Long-Term Debt Rate**	7	59.6	0.2%	4.86%	2.9
5a	**Common Equity**	4	13,834.4	51.8%	9.11%	1,260.3
5b	**Total Equity**		13,894.0	52.0%	9.09%	1,263.2
6	**Rate Base Financed by Capital Structure**	5	26,719.3	100.0%	7.06%	1,886.6
7	**Adjustment for Lesser of UNL or ARC**	5, 6	0.0	0.0%	4.72%	0.0
8	**Rate Base**		26,719.3	100.0%	7.06%	1,886.6

Notes:

1 Ex. C1-1-3 Table 2: Principal (line 7), Cost Rate (line 2), Cost of Capital (line 8). Cost includes interest at the cost rate shown plus an allocation of the credit facility cost.

2 Ex. L-F4-CCC-084, Table 19, line 37.

3 Debt required to balance capital structure with proposed rate base. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2). See Ex. C1-1-2, Section 5.0.

4 Capital Structure proposed in Ex. C1-1-1, Att. 1. Return on Equity reflects the last Cost of Capital Parameter Update published by the OEB (October 31, 2025).

5 The portion of rate base to be financed by the capital structure approved by the OEB excludes the lesser of the forecast of the average unfunded nuclear liabilities (UNL) related to Pickering and Darlington, and the average unamortized asset retirement costs (ARC) included in fixed asset balances for Pickering and Darlington.

6 Principal from Ex. C2-1-1 Table 2, line 28. Cost rate from Ex. C2-1-1, Table 1b, line 5n, col (d).

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

Table 13
Capitalization and Cost of Capital - Updated for CEITC Impact
Summary of Capitalization and Cost of Capital - OPG
Calendar Year Ending December 31, 2028

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1	414.3	1.6%	2.93%	19.5
2	**Existing/Planned Long-Term Debt**	2	7,783.0	30.3%	4.75%	370.0
3	**Other Long-Term Debt Provision**	3	4,135.9	16.1%	4.75%	196.6
4	**Total Debt**	4	12,333.2	48.0%	4.75%	586.1
5	**EB-2020-0290 Settlement Adjustment for Equity at Long-Term Debt Rate**	7	66.1	0.3%	4.75%	3.1
5a	**Common Equity**	4	13,294.8	51.7%	9.11%	1,211.2
5b	**Total Equity**		13,360.9	52.0%	9.09%	1,214.3
6	**Rate Base Financed by Capital Structure**	5	25,694.1	99.9%	7.01%	1,800.4
7	**Adjustment for Lesser of UNL or ARC**	5, 6	23.0	0.1%	4.72%	1.1
8	**Rate Base**		25,717.1	100.0%	7.01%	1,801.5

Notes:

1 Ex. C1-1-3 Table 2: Principal (line 7), Cost Rate (line 2), Cost of Capital (line 8). Cost includes interest at the cost rate shown plus an allocation of the credit facility cost.

2 Ex. L-F4-CCC-084, Table 17, line 33.

3 Debt required to balance capital structure with proposed rate base. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2). See Ex. C1-1-2, Section 5.0.

4 Capital Structure proposed in Ex. C1-1-1, Att. 1. Return on Equity reflects the last Cost of Capital Parameter Update published by the OEB (October 25, 2025).

5 The portion of rate base to be financed by the capital structure approved by the OEB excludes the lesser of the forecast of the average unfunded nuclear liabilities (UNL) related to Pickering and Darlington, and the average unamortized asset retirement costs (ARC) included in fixed asset balances for Pickering and Darlington.

6 Principal from Ex. C2-1-1 Table 2, line 28. Cost rate from Ex. C2-1-1, Table 1b, line 5n, col (d).

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

Table 14
Capitalization and Cost of Capital - Updated for CEITC Impact
Summary of Capitalization and Cost of Capital - OPG
Calendar Year Ending December 31, 2027

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1	414.3	1.7%	2.79%	21.0
2	**Existing/Planned Long-Term Debt**	2	6,292.1	25.5%	4.56%	287.1
3	**Other Long-Term Debt Provision**	3	5,144.4	20.8%	4.56%	234.7
4	**Total Debt**	4	11,850.9	48.0%	4.58%	542.7
5	**EB-2020-0290 Settlement Adjustment for Equity at Long-Term Debt Rate**	7	73.9	0.3%	4.56%	3.4
5a	**Common Equity**	4	12,764.5	51.7%	9.11%	1,162.8
5b	**Total Equity**		12,838.4	52.0%	9.08%	1,166.2
6	**Rate Base Financed by Capital Structure**	5	24,689.3	99.6%	6.92%	1,709.0
7	**Adjustment for Lesser of UNL or ARC**	5, 6	100.1	0.4%	4.72%	4.7
8	**Rate Base**		24,789.4	100.0%	6.91%	1,713.7

Notes:

1 Ex. C1-1-3 Table 2: Principal (line 7), Cost Rate (line 2), Cost of Capital (line 8). Cost includes interest at the cost rate shown plus an allocation of the credit facility cost.

2 Ex. L-F4-CCC-084, Table 15, line 31.

3 Debt required to balance capital structure with proposed rate base. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2). See Ex. C1-1-2, Section 5.0.

4 Capital Structure proposed in Ex. C1-1-1, Att. 1. Return on Equity reflects the last Cost of Capital Parameter Update published by the OEB (October 31, 2025).

5 The portion of rate base to be financed by the capital structure approved by the OEB excludes the lesser of the forecast of the average unfunded nuclear liabilities (UNL) related to Pickering and Darlington, and the average unamortized asset retirement costs (ARC) included in fixed asset balances for Pickering and Darlington.

6 Principal from Ex. C2-1-1 Table 2, line 28. Cost rate from Ex. C2-1-1, Table 1b, line 5n, col (d).

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

Table 15
Capitalization and Cost of Capital - Updated for CEITC Impact
Summary of Existing and Planned Long-Term Debt - OPG ($M)
Outstanding During Calendar Year Ending Dec. 31, 2027

Line No.	Issue	Note	Weighted Principal* ($M)	Issue Date	Duration (years)	Maturity Date	Effective Rate (%)	Annual Cost ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Company-Wide Borrowing							
	Issues 1 to 25, 29, 39 Mature Prior to 2027							
1	**Issue 26**		150.0	3/22/2011	30.0	3/22/2041	5.40%	8.1
2	**Issue 27**		150.0	9/22/2011	30.0	9/22/2041	4.74%	7.1
3	**Issue 28**		200.0	3/22/2012	30.0	3/22/2042	4.36%	8.7
4	**Issue 30**		50.0	11/22/2016	30.0	11/22/2046	4.03%	2.0
5	**Issue 31**		200.0	2/22/2017	30.0	2/22/2047	4.12%	8.2
6	**Issue 32**		100.0	6/22/2017	30.0	6/22/2047	3.65%	3.6
7	**Issue 33**		100.0	8/22/2017	30.0	8/22/2047	3.86%	3.9
8	**Issue 34**		400.0	9/22/2017	30.0	9/22/2047	4.07%	16.3
9	**Issue 35**	6	376.8	10/2/2017	10.0	10/4/2027	3.43%	12.9
10	**Issue 36**		200.0	1/22/2018	30.0	1/22/2048	3.87%	7.7
11	**Issue 37**		400.0	3/22/2018	30.0	3/22/2048	4.00%	16.0
12	**Issue 38**		100.0	8/22/2019	20.0	8/22/2039	3.49%	3.5
13	**Issue 40**	1, 9	392.0	3/15/2027	10.0	3/15/2037	4.84%	19.0
14	**Issue 41**	2, 9	392.0	3/15/2027	30.0	3/15/2057	5.41%	21.2
15	**Issue 42**	3, 9	145.0	9/15/2027	10.0	9/15/2037	4.89%	7.1
16	**Issue 43**	4, 9	145.0	9/15/2027	30.0	9/15/2057	5.45%	7.9
17	**Total**		**3,500.7**				**4.38%**	**153.3**
	Regulated Portion of Company-Wide Borrowing							
18	**Allocation**	8	3,257.7				4.38%	142.6
	Project Financing - Regulated Projects							
	Niagara 1 to 24 and ILB 1 to 4 Mature Prior to 2027							
19	**Green Bond 1**		417.1	6/22/2018	30.0	6/22/2048	3.92%	16.3
20	**Green Bond 2**		0.4	1/18/2019	30.0	1/18/2049	4.34%	0.0
21	**Green Bond 3**		297.9	7/18/2022	10.0	7/19/2032	5.08%	15.1
22	**ILB 5**	7	0.3	1/5/2022	5.0	1/5/2027	6.34%	0.0
23	**ILB 6**	5	24.7	1/5/2027	5.0	1/5/2032	7.08%	1.8
24	**Green Bond 4**		496.7	6/28/2024	10.0	6/28/2034	4.98%	24.7
25	**Green Bond 5**		491.0	6/28/2024	30.0	6/28/2054	5.17%	25.4
26	**Green Bond 6**		209.0	9/11/2024	9.8	6/28/2034	4.43%	9.3
27	**Green Bond 7**		104.1	9/11/2024	29.8	6/28/2054	4.85%	5.1
28	**Green Bond 8**		496.8	3/13/2025	10.0	3/13/2035	4.45%	22.1
29	**Green Bond 9**		496.3	3/13/2025	30.0	3/13/2055	4.97%	24.7
30	**Total**		**3,034.4**				**4.76%**	**144.4**
	Total Regulated Funded Long-Term Debt							
31	Line 18+30		**6,292.1**				**4.56%**	**287.1**

See Ex. L-F4-CCC-084, Table 16 for notes

* For debt issues that are issued or mature during the year the face value is reduced to reflect only that portion of the year the debt issue is financing the rate base.

Table 16
Capitalization and Cost of Capital - Updated for CEITC Impact
Summary of Existing and Planned Long-Term Debt - OPG ($M)
Outstanding During Calendar Year Ending Dec. 31, 2027
Notes to Ex. L-F4-CCC-084, Table 15

	Issue	Issue Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 1	Issue 40	3/15/2027	490.0	292.0	392.0
Note 2	Issue 41	3/15/2027	490.0	292.0	392.0
Note 3	Issue 42	9/15/2027	490.0	108.0	145.0
Note 4	Issue 43	9/15/2027	490.0	108.0	145.0
Note 5	ILB 6	1/5/2027	25.0	361.0	24.7
	Issue	Maturity Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 6	Issue 35	10/4/2027	496.5	277.0	376.8
Note 7	ILB 5	1/5/2027	25.0	5.0	0.3

Note 8 Allocation ratio as per Ex. C1-1-2 Table 1, line 13, col (e).

Note 9 Future issue rate reference Bloomberg (Nov 21, 2025).

Issue 40

GOC & OPG Spread	
GOC Q1-27	3.37%
OPG Spread	1.35%
Issuance Cost	0.12%
Effective Rate	4.84%

Issue 41

GOC & OPG Spread	
GOC Q1-27	3.71%
OPG Spread	1.60%
Issuance Cost	0.10%
Effective Rate	5.41%

Issue 42

GOC & OPG Spread	
GOC Q3-27	3.42%
OPG Spread	1.35%
Issuance Cost	0.12%
Effective Rate	4.89%

Issue 43

GOC & OPG Spread	
GOC Q3-27	3.75%
OPG Spread	1.60%
Issuance Cost	0.10%
Effective Rate	5.45%

Table 17
Capitalization and Cost of Capital - Updated for CEITC Impact
Summary of Existing and Planned Long-Term Debt - OPG ($M)
Outstanding During Calendar Year Ending Dec. 31, 2028

Line No.	Issue	Note	Weighted Principal* ($M)	Issue Date	Duration (years)	Maturity Date	Effective Rate (%)	Annual Cost ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Company-Wide Borrowing							
	Issues 1 to 25, 29, 35, 39 Mature Prior to 2028							
1	**Issue 26**		150.0	3/22/2011	30.0	3/22/2041	5.40%	8.1
2	**Issue 27**		150.0	9/22/2011	30.0	9/22/2041	4.74%	7.1
3	**Issue 28**		200.0	3/22/2012	30.0	3/22/2042	4.36%	8.7
4	**Issue 30**		50.0	11/22/2016	30.0	11/22/2046	4.03%	2.0
5	**Issue 31**		200.0	2/22/2017	30.0	2/22/2047	4.12%	8.2
6	**Issue 32**		100.0	6/22/2017	30.0	6/22/2047	3.65%	3.6
7	**Issue 33**		100.0	8/22/2017	30.0	8/22/2047	3.86%	3.9
8	**Issue 34**		400.0	9/22/2017	30.0	9/22/2047	4.07%	16.3
9	**Issue 36**		200.0	1/22/2018	30.0	1/22/2048	3.87%	7.7
10	**Issue 37**		400.0	3/22/2018	30.0	3/22/2048	4.00%	16.0
11	**Issue 38**		100.0	8/22/2019	20.0	8/22/2039	3.49%	3.5
12	**Issue 40**		490.0	3/15/2027	10.0	3/15/2037	4.84%	23.7
13	**Issue 41**		490.0	3/15/2027	30.0	3/15/2057	5.41%	26.5
14	**Issue 42**		490.0	9/15/2027	10.0	9/15/2037	4.89%	24.0
15	**Issue 43**		490.0	9/15/2027	30.0	9/15/2057	5.45%	26.7
16	**Issue 44**	1, 6	398.9	3/15/2028	10.0	3/15/2038	4.89%	19.5
17	**Issue 45**	2, 6	398.9	3/15/2028	30.0	3/15/2058	5.35%	21.3
18	**Issue 46**	3, 6	147.5	9/15/2028	10.0	9/15/2038	5.03%	7.4
19	**Issue 47**	4, 6	147.5	9/15/2028	30.0	9/15/2058	5.48%	8.1
20	**Total**		**5,102.9**				**4.75%**	**242.4**
	Regulated Portion of Company-Wide Borrowing							
21	**Allocation**	5	4,748.6				4.75%	225.6
	Project Financing - Regulated Projects							
	Niagara 1 to 24 and ILB 1 to 5 Mature Prior to 2028							
22	**Green Bond 1**		417.1	6/22/2018	29.9	6/22/2048	3.92%	16.3
23	**Green Bond 2**		0.4	1/18/2019	29.9	1/18/2049	4.34%	0.0
24	**Green Bond 3**		297.9	7/18/2022	10.0	7/19/2032	5.08%	15.1
25	**ILB 6**		25.0	1/5/2027	5.0	1/5/2032	7.08%	1.8
26	**Green Bond 4**		496.7	6/28/2024	10.0	6/28/2034	4.98%	24.7
27	**Green Bond 5**		491.0	6/28/2024	29.9	6/28/2054	5.17%	25.4
28	**Green Bond 6**		209.0	9/11/2024	9.8	6/28/2034	4.43%	9.3
29	**Green Bond 7**		104.1	9/11/2024	29.7	6/28/2054	4.85%	5.1
30	**Green Bond 8**		496.8	3/13/2025	10.0	3/13/2035	4.45%	22.1
31	**Green Bond 9**		496.3	3/13/2025	29.9	3/13/2055	4.97%	24.7
32	**Total**		**3,034.3**				**4.76%**	**144.4**
	Total Regulated Funded Long-Term Debt							
33	Line 20+32		**7,783.0**				**4.75%**	**370.0**

See Ex. L-F4-CCC-084, Table 18 for notes

* For debt issues that are issued or mature during the year the face value is reduced to reflect only that portion of the year the debt issue is financing the rate base.

Table 18
Capitalization and Cost of Capital - Updated for CEITC Impact
Summary of Existing and Planned Long-Term Debt - OPG ($M)
Outstanding During Calendar Year Ending Dec. 31, 2028
Notes to Ex. L-F4-CCC-084, Table 17

	Issue	Issue Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 1	Issue 44	3/15/2028	500	292	398.9
Note 2	Issue 45	3/15/2028	500	292	398.9
Note 3	Issue 46	9/15/2028	500	108	147.5
Note 4	Issue 47	9/15/2028	500	108	147.5
	Issue	Maturity Date	Face Value ($M)	Effective Days	Weighted Principal ($M)

Note 5 Allocation ratio as per Ex. C1-1-2 Table 1, line 13, col (e).

Note 6 Future issue rate reference Bloomberg (Nov 21, 2025).

Issue 44

GOC & OPG Spread	
GOC Q1-28	3.42%
OPG Spread	1.35%
Issuance Cost	0.12%
Effective Rate	4.89%

Issue 45

GOC & OPG Spread	
GOC Q1-28	3.65%
OPG Spread	1.60%
Issuance Cost	0.10%
Effective Rate	5.35%

Issue 46

GOC & OPG Spread	
GOC Q3-28	3.56%
OPG Spread	1.35%
Issuance Cost	0.12%
Effective Rate	5.03%

Issue 47

GOC & OPG Spread	
GOC Q3-28	3.78%
OPG Spread	1.60%
Issuance Cost	0.10%
Effective Rate	5.48%

Table 19
Capitalization and Cost of Capital - Updated for CEITC Impact
Summary of Existing and Planned Long-Term Debt - OPG ($M)
Outstanding During Calendar Year Ending Dec. 31, 2029

Line No.	Issue	Note	Weighted Principal* ($M)	Issue Date	Duration (years)	Maturity Date	Effective Rate (%)	Annual Cost ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Company-Wide Borrowing							
	Issues 1 to 25, 29, 35, 39 Mature Prior to 2029							
1	**Issue 26**		150.0	3/22/2011	30.0	3/22/2041	5.40%	8.1
2	**Issue 27**		150.0	9/22/2011	30.0	9/22/2041	4.74%	7.1
3	**Issue 28**		200.0	3/22/2012	30.0	3/22/2042	4.36%	8.7
4	**Issue 30**		50.0	11/22/2016	30.0	11/22/2046	4.03%	2.0
5	**Issue 31**		200.0	2/22/2017	30.0	2/22/2047	4.12%	8.2
6	**Issue 32**		100.0	6/22/2017	30.0	6/22/2047	3.65%	3.6
7	**Issue 33**		100.0	8/22/2017	30.0	8/22/2047	3.86%	3.9
8	**Issue 34**		400.0	9/22/2017	30.0	9/22/2047	4.07%	16.3
9	**Issue 36**		200.0	1/22/2018	30.0	1/22/2048	3.87%	7.7
10	**Issue 37**		400.0	3/22/2018	30.0	3/22/2048	4.00%	16.0
11	**Issue 38**		100.0	8/22/2019	20.0	8/22/2039	3.49%	3.5
12	**Issue 40**		490.0	3/15/2027	10.0	3/15/2037	4.84%	23.7
13	**Issue 41**		490.0	3/15/2027	30.0	3/15/2057	5.41%	26.5
14	**Issue 42**		490.0	9/15/2027	10.0	9/15/2037	4.89%	24.0
15	**Issue 43**		490.0	9/15/2027	30.0	9/15/2057	5.45%	26.7
16	**Issue 44**		500.0	3/15/2028	10.0	3/15/2038	4.89%	24.5
17	**Issue 45**		500.0	3/15/2028	30.0	3/15/2058	5.35%	26.8
18	**Issue 46**		500.0	9/15/2028	10.0	9/15/2038	5.03%	25.2
19	**Issue 47**		500.0	9/15/2028	30.0	9/15/2058	5.48%	27.4
20	**Issue 48**	1, 6	476.0	3/15/2029	10.0	3/15/2039	5.08%	24.2
21	**Issue 49**	2, 6	472.0	3/15/2029	30.0	3/15/2059	5.50%	26.0
22	**Issue 50**	3, 6	174.6	9/15/2029	10.0	9/15/2039	5.13%	9.0
23	**Issue 51**	4, 6	174.6	9/15/2029	30.0	9/15/2059	5.51%	9.6
24	**Total**		**7,307.2**				**4.91%**	**358.5**
	Regulated Portion of Company-Wide Borrowing							
25	**Allocation**	5	6,799.8				4.91%	333.6
	Project Financing - Regulated Projects							
	Niagara 1 to 24, and ILB 1 to 5 Mature Prior to 2029							
26	**Green Bond 1**		417.1	6/22/2018	30.0	6/22/2048	3.92%	16.3
27	**Green Bond 2**		0.4	1/18/2019	30.0	1/18/2049	4.34%	0.0
28	**Green Bond 3**		297.9	7/18/2022	10.0	7/19/2032	5.08%	15.1
29	**ILB 6**		25.0	1/5/2027	5.0	1/5/2032	7.08%	1.8
30	**Green Bond 4**		496.7	6/28/2024	10.0	6/28/2034	4.98%	24.7
31	**Green Bond 5**		491.0	6/28/2024	30.0	6/28/2054	5.17%	25.4
32	**Green Bond 6**		209.0	9/11/2024	9.8	6/28/2034	4.43%	9.3
33	**Green Bond 7**		104.1	9/11/2024	29.8	6/28/2054	4.85%	5.1
34	**Green Bond 8**		496.8	3/13/2025	10.0	3/13/2035	4.45%	22.1
35	**Green Bond 9**		496.3	3/13/2025	30.0	3/13/2055	4.97%	24.7
36	**Total**		**3,034.3**				**4.76%**	**144.4**
	Total Regulated Funded Long-Term Debt							
37	Line 24+36		**9,834.2**				**4.86%**	**478.1**

See Ex. L-F4-CCC-084, Table 20 for notes

* For debt issues that are issued or mature during the year the face value is reduced to reflect only that portion of the year the debt issue is financing the rate base.

Table 20
Capitalization and Cost of Capital - Updated for CEITC Impact
Summary of Existing and Planned Long-Term Debt - OPG ($M)
Outstanding During Calendar Year Ending Dec. 31, 2029
Notes to Ex. L-F4-CCC-084, Table 19

	Issue	Issue Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 1	Issue 48	3/15/2029	595	292	476.0
Note 2	Issue 49	3/15/2029	590	292	472.0
Note 3	Issue 50	9/15/2029	590	108	174.6
Note 4	Issue 51	9/15/2029	590	108	174.6
	Issue	Maturity Date	Face Value ($M)	Effective Days	Weighted Principal ($M)

Note 5 Allocation ratio as per Ex. C1-1-2 Table 1, line 13, col (e).

Note 6 Future issue rate reference Bloomberg (Nov 21, 2025).

Issue 48

GOC & OPG Spread	
GOC Q1-29	3.61%
OPG Spread	1.35%
Issuance Cost	0.12%
Effective Rate	5.08%

Issue 49

GOC & OPG Spread	
GOC Q1-29	3.80%
OPG Spread	1.60%
Issuance Cost	0.10%
Effective Rate	5.50%

Issue 50

GOC & OPG Spread	
GOC Q3-29	3.66%
OPG Spread	1.35%
Issuance Cost	0.12%
Effective Rate	5.13%

Issue 51

GOC & OPG Spread	
GOC Q3-29	3.81%
OPG Spread	1.60%
Issuance Cost	0.10%
Effective Rate	5.51%

Table 21
Capitalization and Cost of Capital - Updated for CEITC Impact
Summary of Existing and Planned Long-Term Debt - OPG ($M)
Outstanding During Calendar Year Ending Dec. 31, 2030

Line No.	Issue	Note	Weighted Principal* ($M)	Issue Date	Duration (years)	Maturity Date	Effective Rate (%)	Annual Cost ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Company-Wide Borrowing							
	Issues 1 to 25, 29, 35, 39 Mature Prior to 2030							
1	**Issue 26**		150.0	3/22/2011	30.0	3/22/2041	5.40%	8.1
2	**Issue 27**		150.0	9/22/2011	30.0	9/22/2041	4.74%	7.1
3	**Issue 28**		200.0	3/22/2012	30.0	3/22/2042	4.36%	8.7
4	**Issue 30**		50.0	11/22/2016	30.0	11/22/2046	4.03%	2.0
5	**Issue 31**		200.0	2/22/2017	30.0	2/22/2047	4.12%	8.2
6	**Issue 32**		100.0	6/22/2017	30.0	6/22/2047	3.65%	3.6
7	**Issue 33**		100.0	8/22/2017	30.0	8/22/2047	3.86%	3.9
8	**Issue 34**		400.0	9/22/2017	30.0	9/22/2047	4.07%	16.3
9	**Issue 36**		200.0	1/22/2018	30.0	1/22/2048	3.87%	7.7
10	**Issue 37**		400.0	3/22/2018	30.0	3/22/2048	4.00%	16.0
11	**Issue 38**		100.0	8/22/2019	20.0	8/22/2039	3.49%	3.5
12	**Issue 40**		490.0	3/15/2027	10.0	3/15/2037	4.84%	23.7
13	**Issue 41**		490.0	3/15/2027	30.0	3/15/2057	5.41%	26.5
14	**Issue 42**		490.0	9/15/2027	10.0	9/15/2037	4.89%	24.0
15	**Issue 43**		490.0	9/15/2027	30.0	9/15/2057	5.45%	26.7
16	**Issue 44**		500.0	3/15/2028	10.0	3/15/2038	4.89%	24.5
17	**Issue 45**		500.0	3/15/2028	30.0	3/15/2058	5.35%	26.8
18	**Issue 46**		500.0	9/15/2028	10.0	9/15/2038	5.03%	25.2
19	**Issue 47**		500.0	9/15/2028	30.0	9/15/2058	5.48%	27.4
20	**Issue 48**		595.0	3/15/2029	10.0	3/15/2039	5.08%	30.2
21	**Issue 49**		590.0	3/15/2029	30.0	3/15/2059	5.50%	32.5
22	**Issue 50**		590.0	9/15/2029	10.0	9/15/2039	5.13%	30.3
23	**Issue 51**		590.0	9/15/2029	30.0	9/15/2059	5.51%	32.5
24	**Issue 52**	1, 3	337.0	6/15/2030	10.0	6/15/2040	5.19%	17.5
25	**Total**		**8,712.0**				**4.97%**	**432.8**
	Regulated Portion of Company-Wide Borrowing							
26	**Allocation**	2	8,107.2				4.97%	402.7
	Project Financing - Regulated Projects							
	Niagara 1 to 24, and ILB 1 to 5 Mature Prior to 2030							
27	**Green Bond 1**		417.1	6/22/2018	30.0	6/22/2048	3.92%	16.3
28	**Green Bond 2**		0.4	1/18/2019	30.0	1/18/2049	4.34%	0.0
29	**Green Bond 3**		297.9	7/18/2022	10.0	7/19/2032	5.08%	15.1
30	**ILB 6**		25.0	1/5/2027	5.0	1/5/2032	7.08%	1.8
31	**Green Bond 4**		496.7	6/28/2024	10.0	6/28/2034	4.98%	24.7
32	**Green Bond 5**		491.0	6/28/2024	30.0	6/28/2054	5.17%	25.4
33	**Green Bond 6**		209.0	9/11/2024	9.8	6/28/2034	4.43%	9.3
34	**Green Bond 7**		104.1	9/11/2024	29.8	6/28/2054	4.85%	5.1
35	**Green Bond 8**		496.8	3/13/2025	10.0	3/13/2035	4.45%	22.1
36	**Green Bond 9**		496.3	3/13/2025	30.0	3/13/2055	4.97%	24.7
37	**Total**		**3,034.3**				**4.76%**	**144.4**
	Total Regulated Funded Long-Term Debt							
38	Line 26+37		**11,141.5**				**4.91%**	**547.2**

See Ex. L-F4-CCC-084, Table 22 for notes

* For debt issues that are issued or mature during the year the face value is reduced to reflect only that portion of the year the debt issue is financing the rate base.

Table 22
Capitalization and Cost of Capital - Updated for CEITC Impact
Summary of Existing and Planned Long-Term Debt - OPG ($M)
Outstanding During Calendar Year Ending Dec. 31, 2030
Notes to Ex. L-F4-CCC-084, Table 21

	Issue	Issue Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 1	Issue 52	6/15/2030	615	200	337.0
	Issue	Maturity Date	Face Value ($M)	Effective Days	Weighted Principal ($M)

Note 2 Allocation ratio as per Ex. C1-1-2 Table 1, line 13, col (e).

Note 3 Future issue rate reference Bloomberg (Nov 21, 2025).

Issue 52

GOC & OPG Spread	
GOC Q2-30	3.72%
OPG Spread	1.35%
Issuance Cost	0.12%
Effective Rate	5.19%

Table 23
Capitalization and Cost of Capital - Updated for CEITC Impact
Summary of Existing and Planned Long-Term Debt - OPG ($M)
Outstanding During Calendar Year Ending Dec. 31, 2031

Line No.	Issue	Note	Weighted Principal* ($M)	Issue Date	Duration (years)	Maturity Date	Effective Rate (%)	Annual Cost ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Company-Wide Borrowing							
	Issues 1 to 25, 29, 35, 39 Mature Prior to 2031							
1	**Issue 26**		150.0	3/22/2011	30.0	3/22/2041	5.40%	8.1
2	**Issue 27**		150.0	9/22/2011	30.0	9/22/2041	4.74%	7.1
3	**Issue 28**		200.0	3/22/2012	30.0	3/22/2042	4.36%	8.7
4	**Issue 30**		50.0	11/22/2016	30.0	11/22/2046	4.03%	2.0
5	**Issue 31**		200.0	2/22/2017	30.0	2/22/2047	4.12%	8.2
6	**Issue 32**		100.0	6/22/2017	30.0	6/22/2047	3.65%	3.6
7	**Issue 33**		100.0	8/22/2017	30.0	8/22/2047	3.86%	3.9
8	**Issue 34**		400.0	9/22/2017	30.0	9/22/2047	4.07%	16.3
9	**Issue 36**		200.0	1/22/2018	30.0	1/22/2048	3.87%	7.7
10	**Issue 37**		400.0	3/22/2018	30.0	3/22/2048	4.00%	16.0
11	**Issue 38**		100.0	8/22/2019	20.0	8/22/2039	3.49%	3.5
12	**Issue 40**		490.0	3/15/2027	10.0	3/15/2037	4.84%	23.7
13	**Issue 41**		490.0	3/15/2027	30.0	3/15/2057	5.41%	26.5
14	**Issue 42**		490.0	9/15/2027	10.0	9/15/2037	4.89%	24.0
15	**Issue 43**		490.0	9/15/2027	30.0	9/15/2057	5.45%	26.7
16	**Issue 44**		500.0	3/15/2028	10.0	3/15/2038	4.89%	24.5
17	**Issue 45**		500.0	3/15/2028	30.0	3/15/2058	5.35%	26.8
18	**Issue 46**		500.0	9/15/2028	10.0	9/15/2038	5.03%	25.2
19	**Issue 47**		500.0	9/15/2028	30.0	9/15/2058	5.48%	27.4
20	**Issue 48**		595.0	3/15/2029	10.0	3/15/2039	5.08%	30.2
21	**Issue 49**		590.0	3/15/2029	30.0	3/15/2059	5.50%	32.5
22	**Issue 50**		590.0	9/15/2029	10.0	9/15/2039	5.13%	30.3
23	**Issue 51**		590.0	9/15/2029	30.0	9/15/2059	5.51%	32.5
24	**Issue 52**		615.0	6/15/2030	10.0	6/15/2040	5.19%	31.9
25	**Total**		**8,990.0**				**4.97%**	**447.2**
	Regulated Portion of Company-Wide Borrowing							
26	**Allocation**	1	8,365.9				4.97%	416.1
	Project Financing - Regulated Projects							
	Niagara 1 to 24, and ILB 1 to 5 Mature Prior to 2031							
27	**Green Bond 1**		417.1	6/22/2018	30.0	6/22/2048	3.92%	16.3
28	**Green Bond 2**		0.4	1/18/2019	30.0	1/18/2049	4.34%	0.0
29	**Green Bond 3**		297.9	7/18/2022	10.0	7/19/2032	5.08%	15.1
30	**ILB 6**		25.0	1/5/2027	5.0	1/5/2032	7.08%	1.8
31	**Green Bond 4**		496.7	6/28/2024	10.0	6/28/2034	4.98%	24.7
32	**Green Bond 5**		491.0	6/28/2024	30.0	6/28/2054	5.17%	25.4
33	**Green Bond 6**		209.0	9/11/2024	9.8	6/28/2034	4.43%	9.3
34	**Green Bond 7**		104.1	9/11/2024	29.8	6/28/2054	4.85%	5.1
35	**Green Bond 8**		496.8	3/13/2025	10.0	3/13/2035	4.45%	22.1
36	**Green Bond 9**		496.3	3/13/2025	30.0	3/13/2055	4.97%	24.7
37	**Total**		**3,034.3**				**4.76%**	**144.4**
	Total Regulated Funded Long-Term Debt							
38	Line 26+37		**11,400.2**				**4.92%**	**560.6**

See Ex. L-F4-CCC-084, Table 24 for notes

* For debt issues that are issued or mature during the year the face value is reduced to reflect only that portion of the year the debt issue is financing the rate base.

Table 24
Capitalization and Cost of Capital - Updated for CEITC Impact
Summary of Existing and Planned Long-Term Debt - OPG ($M)
Outstanding During Calendar Year Ending Dec. 31, 2031
Notes to Ex. L-F4-CCC-084, Table 23

	Issue	Issue Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
	Issue	Maturity Date	Face Value ($M)	Effective Days	Weighted Principal ($M)

Note 1 Allocation ratio as per Ex. C1-1-2 Table 1, line 13, col (e).

Numbers may not add due to rounding.

Table 25
Depreciation and Amortization - Regulated Hydroelectric ($M)

Line No.	Prescribed Facility Category[1]	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)
6	**Niagara Region**	70.2	72.9	82.5	88.9	93.0
7	**Eastern Region**	96.4	101.7	107.7	111.3	113.9
8	**Western Region**	29.4	33.4	38.1	40.9	43.5
9	**Other[2]**	19.1	19.8	19.7	20.3	18.7
10	**Total**	215.1	227.7	247.9	261.3	269.1

Notes:
1 Operating Region descriptions effective 2021 (see Ex. A1-4-2).
2 Includes losses on retirements, gains on disposal and other related charges.

Numbers may not add due to rounding.

Table 26
Depreciation and Amortization - Combined Nuclear ($M)

Line No.	Prescribed Facility Category	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)
	OPG's Nuclear Facilities					
	Darlington NGS:					
1	**Darlington NGS (excluding DRP)**	178.5	218.8	241.4	281.3	330.0
2	**Darlington Refurbishment Program (excluding D2O Storage)**	393.6	388.8	388.7	388.2	388.2
3	**Heavy Water Storage Facility (D2O Storage)[1]**	12.0	12.0	12.0	12.0	12.0
4	**Subtotal Darlington NGS**	584.2	619.6	642.1	681.6	730.3
	Pickering NGS:					
5	**Pickering NGS (excluding PRP)**	21.5	26.6	26.8	34.4	41.6
6	**Pickering Refurbishment Project**	3.8	4.1	4.1	4.1	141.0
7	**Subtotal Pickering NGS**	25.3	30.6	30.9	38.5	182.6
8	**Operations and Project Support**	37.5	36.4	35.1	36.3	36.9
9	**Asset Retirement Costs**	11.3	11.3	11.3	11.3	11.3
10	**Other[2]**	0.0	0.0	0.0	0.0	0.0
11	**Total**	658.4	698.0	719.4	767.6	961.1
	DNNP Facilities					
12	**Darlington New Nuclear Program**	0.0	0.0	0.0	20.4	98.9

Notes:

1 Amount in line 3 of col. (a) corresponds to EB-2020-0290 Payment Amounts Order, App. A, Table 10a, line 4a of col. (e) and reflects the OEB's findings with respect to the D2O Storage Project in the EB-2020-0290 Decision and Order dated November 15, 2021.

2 Includes losses on retirements, gains on disposal and other related charges.

Numbers may not add due to rounding.

Table 27
Calculation of Regulatory Income Taxes for Regulated Hydroelectric - Updated for CEITC and RIIP Impacts ($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	438.9	491.4	623.1	659.9	683.5
	Additions for Regulatory Tax Purposes:						
2	**Depreciation and Amortization**		215.1	227.7	247.9	261.3	269.1
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**	3	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**		257.1	271.8	292.5	319.6	328.1
	Deductions for Regulatory Tax Purposes:						
10	**CCA**	2	660.1	552.9	408.8	401.4	434.8
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**		727.5	621.9	480.8	475.2	511.3
17	**Regulatory Taxable Income Before Loss Carry-Over** (line 1 + line 9 - line 16)		(31.5)	141.3	434.8	504.3	500.3
18	**Tax Loss Carry-Over**		31.5	(31.5)	0.0	0.0	0.0
19	**Regulatory Taxable Income After Loss Carry-Over** (line 17 + line 18)		(0.0)	109.7	434.8	504.3	500.3
20	**Regulatory Income Taxes - Federal** (line 19 x line 25)		(0.0)	16.5	65.2	75.6	75.0
21	**Regulatory Income Taxes - Provincial** (line 19 x line 26)		(0.0)	11.0	43.5	50.4	50.0
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)		(3.3)	24.1	105.4	122.8	121.8
	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 L-F4-CCC-084, Table 28.

Table 28
Notes to L-F4-CCC-084, Table 27
Calculation of Regulatory Income Taxes for Regulated Hydroelectric - Updated for CEITC and RIIP Impacts ($M)
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. L-F4-CCC-084, Table 54, line 11 Col. (b) to (e): L-F4-CCC-084, Table 60, line 3, cols. (b) to (e)	432.0	457.1	507.5	537.1	561.7
2a	Additions for Regulatory Tax Purposes	line 9	257.1	271.8	292.5	319.6	328.1
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	727.5	621.9	480.8	475.2	511.3
5a		line 1a + line 2a - line 3a - line 4a	(28.2)	117.1	329.4	381.5	378.5
6a	Regulatory Income Taxes - Federal	(lines 5a + 12a + line 22) x line 24/ (1 - line 26)	(4.7)	21.2	65.2	75.6	75.0
7a	Regulatory Income Taxes - Provincial	(lines 5a + 12a + line 22) x line 25 / (1 - line 26)	(3.2)	14.1	43.5	50.4	50.0
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	(11.2)	32.0	105.4	122.8	121.8
10a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	line 18 x line 24	4.7	(4.7)	0.0	0.0	0.0
11a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	line 18 x line 25	3.2	(3.2)	0.0	0.0	0.0
12a	Reduction in Total Regulatory Income Taxes Due to Loss Carry-Over	line 10a + line 11a	7.9	(7.9)	0.0	0.0	0.0
13a	Regulatory Income Taxes After Tax Loss Carry-Over - Federal	line 6a + line 10a	(0.0)	16.5	65.2	75.6	75.0
14a	Regulatory Income Taxes After Tax Loss Carry-Over - Provincial	line 7a + line 11a	(0.0)	11.0	43.5	50.4	50.0
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	(3.3)	24.1	105.4	122.8	121.8
17a	After Tax Return on Equity	line 1a	432.0	457.1	507.5	537.1	561.7
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	(3.3)	24.1	105.4	122.8	121.8
20a	Regulatory Earnings Before Tax	lines 17a - 18a + 19a	438.9	491.4	623.1	659.9	683.5

2 Amounts are from Ex. L-F4-CCC-084, Tables 37-41, col. (j) minus (i).
3 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.

Table 29
Calculation of Regulatory Income Taxes for OPG Nuclear Facilities - Updated for CEITC and RIIP Impacts ($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	722.8	729.1	757.2	759.7	1,070.2
	Additions for Regulatory Tax Purposes:						
2	**Depreciation and Amortization**		658.4	698.0	719.4	767.6	961.1
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**		1,459.0	1,488.7	1,428.6	1,530.9	1,779.2
	Deductions for Regulatory Tax Purposes:						
15	**CCA**	2,3	1,388.1	1,912.8	2,212.9	2,081.9	2,094.1
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**		2,335.1	2,768.8	2,981.4	2,862.5	2,916.9
24	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 14 - line 24)		(153.3)	(551.1)	(795.6)	(572.0)	(67.5)
25	**Tax Loss Carry-Over / (Applied)**	4	153.3	551.1	795.6	572.0	67.5
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 L-F4-CCC-084, Table 31.

Numbers may not add due to rounding.

Table 30
2027 - 2031 Summary of OPG Nuclear Regulatory Losses - Updated for CEITC and RIIP Impacts ($M)

Line No.	Particulars	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
1	**Tax Loss Brought Forward**	1	(373.4)	(526.7)	(1,077.8)	(1,873.4)	(2,445.3)
2	**Income/(Loss) for the Year**	2	(153.3)	(551.1)	(795.6)	(572.0)	(67.5)
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)		(526.7)	(1,077.8)	(1,873.4)	(2,445.3)	(2,512.8)

Notes:
1 2027: Tax Loss Brought Forward per EB-2020-0290 PAO Appendix A, Table 22, line 4, col. (e).
2 Ex. L-F4-CCC-084, Table 29, line 25.

Table 31
Notes to L-F4-CCC-084, Table 29
Calculation of Regulatory Income Taxes for OPG Nuclear Facilities - Updated for CEITC and RIIP Impacts ($M)
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. L-F4-CCC-084, Table 55, line 12 plus line 12a	734.2	757.2	755.7	783.6	1,069.7
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	739.4	745.7	773.8	776.3	1,086.8
4a	Additions for Regulatory Tax Purposes	line 14	1,459.0	1,488.7	1,428.6	1,530.9	1,779.2
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	2,335.1	2,768.8	2,981.4	2,862.5	2,916.9
7a		line 3a + line 4a - line 5a - line 6a	(136.7)	(534.5)	(779.0)	(555.3)	(50.9)
8a	Regulatory Income Taxes - Federal	(lines 7a + 14a + line 29) x line 31/ (1 - line 33)	(23.0)	(82.7)	(119.3)	(85.8)	(10.1)
9a	Regulatory Income Taxes - Provincial	(lines 7a + 15a + line 29) x line 32/ (1 - line 33)	(15.3)	(55.1)	(79.6)	(57.2)	(6.7)
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	(54.9)	(154.4)	(215.5)	(159.6)	(33.5)
12a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	line 25 x line 31	23.0	82.7	119.3	85.8	10.1
13a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	line 25 x line 32	15.3	55.1	79.6	57.2	6.7
14a	Reduction in Total Regulatory Income Taxes Due to Loss Carry-Over	line 12a + line 13a	38.3	137.8	198.9	143.0	16.9
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	734.2	757.2	755.7	783.6	1,069.7
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	722.8	729.1	757.2	759.7	1,070.2

2 Amounts are from Ex. L-F4-CCC-084, Tables 44-48, 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 - $383.0M, 2028 - $862.1M, 2029 - $1,207.9M, 2030 - $1,079.1M, 2031 - $1,106.9M.

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 - $459.7M, 2028 - $423.1M, 2029 - $389.5M, 2030 - $358.6M, 2031 - $330.2M.

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 32
Calculation of Regulatory Income Taxes for DNNP Facilities - Updated for CEITC and RIIP Impacts ($M)
Years Ending December 31, 2026-2031

Line No.	Particulars	Note	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
			(b)	(c)	(d)	(e)	(f)
	Determination of Regulatory Taxable Income						
1	**Regulatory Earnings Before Tax**	1	0.0	0.0	0.2	112.7	536.4
	Additions for Regulatory Tax Purposes:						
2	**Depreciation and Amortization**		0.0	0.0	0.0	20.4	98.9
3	**Pension and OPEB Accrual**	4	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
5	**Taxable SR&ED Investment Tax Credits of Prior Periods & Current Provincial Portion**		0.0	0.0	0.0	0.0	0.0
6	**Other**		0.0	0.0	0.0	0.0	0.0
7	**Total Additions**		14.1	13.3	11.9	30.5	108.4
	Deductions for Regulatory Tax Purposes:						
8	**CCA**	2	268.2	385.6	325.2	337.4	334.5
9	**Pension Plan Contributions**	5	1.4	0.3	0.4	0.2	0.3
10	**OPEB Payments**	5	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
12	**Deductible SR&ED Qualifying Expenditures**		0.0	0.0	0.0	0.0	0.0
13	**Other**		0.0	0.0	0.0	0.0	0.0
14	**Total Deductions**		282.3	398.9	337.1	347.5	344.0
15	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 7 - line 14)		(268.2)	(385.6)	(325.0)	(204.3)	300.8
16	**Tax Loss (Income) Attributable to Non-taxable Partners** (line 15 x 22.5%)	3	60.3	86.8	73.1	46.0	(67.7)
17	**Tax Loss (Income) Attributable to Taxable Partners** (line 15 x 77.5%)	5	207.8	298.8	251.9	158.3	(233.1)
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
19	**Regulatory Income Taxes - Federal** (line 18 x line 24)		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
21	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		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
23	**Total Regulatory Income Taxes** (line 19 + line 20 + line 21 - line 22)		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%
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 L-F4-CCC-084, Table 34.

Numbers may not add due to rounding.

Table 33

2027 - 2031 Summary of DNNP Facilities Regulatory Losses for Taxable Partners - Updated for CEITC and RIIP Impacts ($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	(207.8)	(506.7)	(758.5)	(916.9)
2	**Income/(Loss) for the Year attributable to Taxable Partners**	1	(207.8)	(298.8)	(251.9)	(158.3)	0.0
3	**Tax Loss attributable to Taxable Partners Applied**	2	0.0	0.0	0.0	0.0	233.1
4	**Tax Loss attributable to Taxable Partners Carried Forward -** (Line 1 + Line 2 + Line 3)		(207.8)	(506.7)	(758.5)	(916.9)	(683.7)

Notes:

1 Ex. L-F4-CCC-084, Table 32, line 17, col. (b) to (e), for 2027-2030.

2 Ex. L-F4-CCC-084, Table 32, line 17, col. (f) for 2031.

Table 34
Notes to L-F4-CCC-084, Table 32
Calculation of Regulatory Income Taxes for DNNP Facilities - Updated for CEITC and RIIP Impacts ($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. L-F4-CCC-084, Table 56, line 11	0.0	0.0	0.2	112.7	536.4
2a	Additions for Regulatory Tax Purposes	line 7	14.1	13.3	11.9	30.5	108.4
3a	Deductions for Regulatory Tax Purposes	line 14	282.3	398.9	337.1	347.5	344.0
4a		line 1a + line 2a - line 3a	(268.2)	(385.6)	(325.0)	(204.3)	300.8
5a	Regulatory Income Taxes - Federal	(lines 4a + 11a + line 21) x line 24/ (1 - line 26)	(40.2)	(57.8)	(48.7)	(30.6)	45.1
6a	Regulatory Income Taxes - Provincial	(lines 4a + 11a + line 21) x line 25/ (1 - line 26)	(26.8)	(38.6)	(32.5)	(20.4)	30.1
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	(67.0)	(96.4)	(81.2)	(51.1)	75.2
9a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	(line 16 + line 17) x line 24	40.2	57.8	48.7	30.6	(45.1)
10a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	(line 16 + line 17) x line 25	26.8	38.6	32.5	20.4	(30.1)
11a	Reduction in Total Regulatory Income Taxes Due to Loss Carry-Over	line 9a + line 10a	67.0	96.4	81.2	51.1	(75.2)
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	112.7	536.4
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	112.7	536.4

2 Amounts are from Ex. L-F4-CCC-084, Tables 49-53, 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 35
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Hydroelectric Operations - Updated for CEITC and RIIP Impacts ($M)
Year Ending December 31, 2025

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions[2]	Cost of Acquisitions that are RIIP[3]	CE ITCs[5]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)+(c1)-(d) UCC1	50% Rule or UCC adj for RIIP[4]	(e)-(f) Reduced or increased Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(c1)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	1,857.0	180.5	67.5	(0.1)	0.0	0.0	2,037.5	(33.8)	2,071.2	4%	0.0	82.8	1,954.6
2	**1-rolling start**	215.4	42.8	17.5	0.0	0.0	0.0	258.2	(8.8)	267.0	4%	0.0	10.7	247.5
3	**1.1**	74.2	19.3	7.7	(0.0)	0.0	0.0	93.5	(3.9)	97.4	6%	0.0	5.8	87.7
4	**1.1-rolling start**	0.0	4.4	1.8	0.0	0.0	0.0	4.4	(0.9)	5.3	6%	0.0	0.3	4.1
5	**2**	899.5	0.0	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	0.0	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	0.0	6.2	0.0	6.2	10%	0.0	0.6	5.6
8	**8**	101.2	43.3	15.7	(0.0)	0.0	0.0	144.5	(7.9)	152.3	20%	0.0	30.5	114.0
9	**8-rolling start**	0.0	10.4	4.3	0.0	0.0	0.0	10.4	(2.1)	12.6	20%	0.0	2.5	7.9
10	**10**	0.6	0.0	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	7.6	0.0	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	1.5	0.0	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	(0.0)	n/a	0.0	0.0	(0.0)
14	**14.1**	(0.1)	0.0	0.0	0.0	0.0	0.0	(0.1)	0.0	(0.1)	5%	0.0	(0.0)	(0.1)
15	**17**	429.5	62.6	11.5	(0.0)	0.0	0.0	492.1	(5.7)	497.8	8%	0.0	39.8	452.3
16	**17-rolling start**	0.0	19.4	7.9	0.0	0.0	0.0	19.4	(4.0)	23.3	8%	0.0	1.9	17.5
17	**42**	3.1	0.0	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	22.5	0.0	0.0	0.0	23.2	(53.5)	76.8	30%	0.0	23.0	0.2
19	**43.1-rolling start**	0.0	10.1	10.1	0.0	0.0	0.0	10.1	(23.5)	33.6	30%	0.0	10.1	0.0
20	**43.2**	7.0	0.0	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	0.0	45%	0.0	0.0	0.0
22	**50**	0.4	0.3	0.3	0.0	0.0	0.0	0.7	(0.3)	1.0	55%	0.0	0.5	0.2
23	**Total**	3,594.2	434.2	175.9	(0.1)	0.0	0.0	4,028.2	(144.3)	4,172.5		0.0	284.5	3,743.7

Notes:

1 Amounts are from Ex. F4-2-1, Table 13, col. (k).

2 Includes Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and before January 1, 2025. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 Represents Reinstated Accelerated Investment Incentive Property ("RIIP") for qualifying property acquired on or after January 1, 2025 and becomes available for use before 2034. For further discussion of RIIP, refer to Ex. L-F4-CCC-084.

4 With RIIP rules effective for eligible property acquired on or after 1 January 2025 and becomes available for use before 2034, the half year rule is suspended until the former is phased out.

Numbers may not add due to rounding.

Table 36
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Hydroelectric Operations - Updated for CEITC and RIIP Impacts ($M)
Year Ending December 31, 2026

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions[2]	Cost of Acquisitions that are RIIP[3]	CE ITCs[5]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)+(c1)-(d) UCC1	50% Rule or UCC adj for RIIP[4]	(e)-(f) Reduced or increased Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(c1)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	1,954.6	193.9	191.0	(1.9)	0.0	0.0	2,146.7	(95.5)	2,242.2	4%	0.0	89.7	2,057.0
2	**1-rolling start**	247.5	30.0	30.0	0.0	0.0	0.0	277.6	(15.0)	292.6	4%	0.0	11.7	265.9
3	**1.1**	87.7	20.3	20.0	(0.2)	0.0	0.0	107.8	(10.0)	117.8	6%	0.0	7.1	100.7
4	**1.1-rolling start**	4.1	3.1	3.1	0.0	0.0	0.0	7.1	(1.5)	8.7	6%	0.0	0.5	6.6
5	**2**	845.5	0.0	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	0.0	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	0.0	5.6	0.0	5.6	10%	0.0	0.6	5.0
8	**8**	114.0	44.1	43.4	(0.5)	0.0	0.0	157.7	(21.7)	179.4	20%	0.0	35.9	121.8
9	**8-rolling start**	7.9	7.3	7.3	0.0	0.0	0.0	15.2	(3.7)	18.9	20%	0.0	3.8	11.5
10	**10**	0.4	0.0	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	21.9	0.0	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	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	(0.0)	n/a	0.0	0.0	(0.0)
14	**14.1**	(0.1)	0.0	0.0	0.0	0.0	0.0	(0.1)	0.0	(0.1)	5%	0.0	(0.0)	(0.1)
15	**17**	452.3	69.8	68.5	(0.9)	0.0	0.0	521.2	(34.2)	555.4	8%	0.0	44.4	476.8
16	**17-rolling start**	17.5	13.6	13.6	0.0	0.0	0.0	31.1	(6.8)	37.9	8%	0.0	3.0	28.1
17	**42**	2.7	0.0	0.0	0.0	0.0	0.0	2.7	0.0	2.7	12%	0.0	0.3	2.4
18	**43.1**	0.2	163.1	163.1	(0.5)	0.0	0.0	162.8	(380.7)	543.5	30%	0.0	162.8	0.0
19	**43.1-rolling start**	0.0	51.2	51.2	0.0	0.0	0.0	51.2	(119.4)	170.6	30%	0.0	51.2	0.0
20	**43.2**	3.5	0.0	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	0.0	45%	0.0	0.0	0.0
22	**50**	0.2	0.3	0.3	0.0	0.0	0.0	0.5	(0.3)	0.8	55%	0.0	0.4	0.1
23	**Total**	3,743.7	622.8	617.3	(3.9)	0.0	0.0	4,362.6	(688.8)	5,051.4		0.0	489.9	3,872.7

Notes:

1 Amounts are from Ex. L-F4-CCC-084, Table 35, col. (k).

2 Includes Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and before January 1, 2025. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 Represents Reinstated Accelerated Investment Incentive Property ("RIIP") for qualifying property acquired on or after January 1, 2025 and becomes available for use before 2034. For further discussion of RIIP, refer to Ex. L-F4-CCC-084.

4 With RIIP rules effective for eligible property acquired on or after 1 January 2025 and becomes available for use before 2034, the half year rule is suspended until the former is phased out.

5 The CEITC is taxable in the year received; however an election can be made 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. This column represents this reduction, which, for clarity, will reduce the annual CCA over time.

Numbers may not add due to rounding.

Table 37
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Hydroelectric Operations - Updated for CEITC and RIIP Impacts ($M)
Year Ending December 31, 2027

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions[2]	Cost of Acquisitions that are RIIP[3]	CE ITCs[5]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)+(c1)-(d) UCC1	50% Rule or UCC adj for RIIP[4]	(e)-(f) Reduced or increased Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(c1)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	2,057.0	266.5	266.5	(3.0)	0.0	0.0	2,320.5	(133.2)	2,453.8	4%	0.0	98.2	2,222.4
2	**1-rolling start**	265.9	162.4	162.4	0.0	0.0	0.0	428.3	(81.2)	509.5	4%	0.0	20.4	407.9
3	**1.1**	100.7	28.4	28.4	(0.3)	0.0	0.0	128.9	(14.2)	143.1	6%	0.0	8.6	120.3
4	**1.1-rolling start**	6.6	16.6	16.6	0.0	0.0	0.0	23.2	(8.3)	31.5	6%	0.0	1.9	21.3
5	**2**	794.8	0.0	0.0	0.0	0.0	0.0	794.8	0.0	794.8	6%	0.0	47.7	747.1
6	**3**	0.2	0.0	0.0	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	0.0	5.0	0.0	5.0	10%	0.0	0.5	4.5
8	**8**	121.8	63.5	63.5	(0.7)	0.0	0.0	184.5	(31.7)	216.3	20%	0.0	43.3	141.3
9	**8-rolling start**	11.5	39.6	39.6	0.0	0.0	0.0	51.1	(19.8)	70.8	20%	0.0	14.2	36.9
10	**10**	0.3	0.0	0.0	0.0	0.0	0.0	0.3	(0.0)	0.3	30%	0.0	0.1	0.2
11	**12**	0.0	26.2	26.2	0.0	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	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	(0.0)	n/a	0.0	0.0	(0.0)
14	**14.1**	(0.1)	0.0	0.0	0.0	0.0	0.0	(0.1)	0.0	(0.1)	5%	0.0	(0.0)	(0.1)
15	**17**	476.8	100.0	100.0	(1.3)	0.0	0.0	575.5	(50.0)	625.5	8%	0.0	50.0	525.4
16	**17-rolling start**	28.1	73.5	73.5	0.0	0.0	0.0	101.5	(36.7)	138.3	8%	0.0	11.1	90.5
17	**42**	2.4	0.0	0.0	0.0	0.0	0.0	2.4	0.0	2.4	12%	0.0	0.3	2.1
18	**43.1**	0.0	116.7	116.7	(26.6)	0.0	0.0	90.1	(272.2)	362.3	30%	0.0	90.1	0.0
19	**43.1-rolling start**	0.0	227.9	227.9	0.0	0.0	0.0	227.9	(531.8)	759.8	30%	0.0	227.9	0.0
20	**43.2**	1.7	0.0	0.0	0.0	0.0	0.0	1.7	0.0	1.7	50%	0.0	0.9	0.9
21	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
22	**50**	0.1	0.4	0.4	0.0	0.0	0.0	0.4	(0.2)	0.6	55%	0.0	0.4	0.1
23	**Total**	3,872.7	1,140.3	1,140.3	(31.9)	0.0	0.0	4,981.1	(1,179.5)	6,160.6		0.0	660.1	4,321.0

Notes:

1 Amounts are from Ex. L-F4-CCC-084, Table 36, col. (k).

2 Includes Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and before January 1, 2025. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 Represents Reinstated Accelerated Investment Incentive Property ("RIIP") for qualifying property acquired on or after January 1, 2025 and becomes available for use before 2034. For further discussion of RIIP, refer to Ex. L-F4-CCC-084.

4 With RIIP rules effective for eligible property acquired on or after 1 January 2025 and becomes available for use before 2034, the half year rule is suspended until the former is phased out.

5 The CEITC is taxable in the year received; however an election can be made 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. This column represents this reduction, which, for clarity, will reduce the annual CCA over time.

Numbers may not add due to rounding.

Table 38
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Hydroelectric Operations - Updated for CEITC and RIIP Impacts ($M)
Year Ending December 31, 2028

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions[2]	Cost of Acquisitions that are RIIP[3]	CE ITCs[5]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)+(c1)-(d) UCC1	50% Rule or UCC adj for RIIP[4]	(e)-(f) Reduced or increased Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(c1)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	2,222.4	336.9	336.9	(6.0)	0.0	0.0	2,553.3	(168.5)	2,721.8	4%	0.0	108.9	2,444.4
2	**1-rolling start**	407.9	122.7	122.7	0.0	0.0	0.0	530.6	(61.3)	591.9	4%	0.0	23.7	506.9
3	**1.1**	120.3	37.0	37.0	(0.6)	0.0	0.0	156.7	(18.5)	175.2	6%	0.0	10.5	146.2
4	**1.1-rolling start**	21.3	12.5	12.5	0.0	0.0	0.0	33.8	(6.3)	40.1	6%	0.0	2.4	31.4
5	**2**	747.1	0.0	0.0	0.0	0.0	0.0	747.1	0.0	747.1	6%	0.0	44.8	702.3
6	**3**	0.2	0.0	0.0	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	0.0	4.5	0.0	4.5	10%	0.0	0.5	4.1
8	**8**	141.3	84.0	84.0	(1.5)	0.0	0.0	223.9	(42.0)	265.9	20%	0.0	53.2	170.7
9	**8-rolling start**	36.9	29.9	29.9	0.0	0.0	0.0	66.8	(15.0)	81.7	20%	0.0	16.3	50.4
10	**10**	0.2	0.0	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	28.7	0.0	0.0	0.0	28.7	0.0	28.7	100%	0.0	28.7	0.0
12	**12-rolling start**	0.0	15.1	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	(0.0)	n/a	0.0	0.0	(0.0)
14	**14.1**	(0.1)	0.0	0.0	0.0	0.0	0.0	(0.1)	0.0	(0.1)	5%	0.0	(0.0)	(0.1)
15	**17**	525.4	126.6	126.6	(2.7)	0.0	0.0	649.4	(63.3)	712.7	8%	0.0	57.0	592.3
16	**17-rolling start**	90.5	55.5	55.5	0.0	0.0	0.0	146.0	(27.8)	173.7	8%	0.0	13.9	132.1
17	**42**	2.1	0.0	0.0	0.0	0.0	0.0	2.1	0.0	2.1	12%	0.0	0.3	1.8
18	**43.1**	0.0	17.2	17.2	(42.8)	0.0	0.0	(25.6)	(40.2)	14.6	30%	25.6		0.0
19	**43.1-rolling start**	0.0	202.4	202.4	0.0	0.0	0.0	202.4	(472.2)	674.5	30%	0.0	202.4	0.0
20	**43.2**	0.9	0.0	0.0	0.0	0.0	0.0	0.9	0.0	0.9	50%	0.0	0.4	0.4
21	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
22	**50**	0.1	0.5	0.5	0.0	0.0	0.0	0.5	(0.2)	0.8	55%	0.0	0.4	0.1
23	**Total**	4,321.0	1,069.1	1,069.1	(53.6)	0.0	0.0	5,336.4	(915.2)	6,251.6		25.6	578.5	4,783.6

Notes:

1 Amounts are from Ex. L-F4-CCC-084, Table 37, col. (k).

2 Includes Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and before January 1, 2025. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 Represents Reinstated Accelerated Investment Incentive Property ("RIIP") for qualifying property acquired on or after January 1, 2025 and becomes available for use before 2034. For further discussion of RIIP, refer to Ex. L-F4-CCC-084.

4 With RIIP rules effective for eligible property acquired on or after 1 January 2025 and becomes available for use before 2034, the half year rule is suspended until the former is phased out.

5 The CEITC is taxable in the year received; however an election can be made 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. This column represents this reduction, which, for clarity, will reduce the annual CCA over time.

Numbers may not add due to rounding.

Table 39
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Hydroelectric Operations - Updated for CEITC and RIIP Impacts ($M)
Year Ending December 31, 2029

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions[2]	Cost of Acquisitions that are RIIP[3]	CE ITCs[5]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)+(c1)-(d) UCC1	50% Rule or UCC adj for RIIP[4]	(e)-(f) Reduced or increased Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(c1)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	2,444.4	473.9	473.9	(11.4)	0.0	0.0	2,906.9	(236.9)	3,143.8	4%	0.0	125.8	2,781.1
2	**1-rolling start**	506.9	129.7	129.7	0.0	0.0	0.0	636.6	(64.9)	701.5	4%	0.0	28.1	608.6
3	**1.1**	146.2	51.2	51.2	(1.2)	0.0	0.0	196.2	(25.6)	221.8	6%	0.0	13.3	182.9
4	**1.1-rolling start**	31.4	13.3	13.3	0.0	0.0	0.0	44.7	(6.6)	51.3	6%	0.0	3.1	41.6
5	**2**	702.3	0.0	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	0.0	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	0.0	4.1	0.0	4.1	10%	0.0	0.4	3.7
8	**8**	170.7	117.9	117.9	(2.8)	0.0	0.0	285.8	(58.9)	344.7	20%	0.0	68.9	216.8
9	**8-rolling start**	50.4	31.6	31.6	0.0	0.0	0.0	82.1	(15.8)	97.9	20%	0.0	19.6	62.5
10	**10**	0.2	0.0	0.0	0.0	0.0	0.0	0.2	(0.0)	0.2	30%	0.0	0.1	0.1
11	**12**	0.0	37.4	37.4	0.0	0.0	0.0	37.4	0.0	37.4	100%	0.0	37.4	0.0
12	**12-rolling start**	0.0	8.3	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	(0.0)	n/a	0.0	0.0	(0.0)
14	**14.1**	(0.1)	0.0	0.0	0.0	0.0	0.0	(0.1)	0.0	(0.1)	5%	0.0	(0.0)	(0.1)
15	**17**	592.3	188.0	188.0	(5.2)	0.0	0.0	775.1	(94.0)	869.1	8%	0.0	69.5	705.6
16	**17-rolling start**	132.1	58.7	58.7	0.0	0.0	0.0	190.8	(29.3)	220.1	8%	0.0	17.6	173.2
17	**42**	1.8	0.0	0.0	0.0	0.0	0.0	1.8	0.0	1.8	12%	0.0	0.2	1.6
18	**43.1**	0.0	0.2	0.2	(27.3)	0.0	0.0	(27.0)	(0.6)	(26.5)	30%	27.0		0.0
19	**43.1-rolling start**	0.0	0.7	0.7	0.0	0.0	0.0	0.7	(1.7)	2.5	30%	0.0	0.7	0.0
20	**43.2**	0.4	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.4	50%	0.0	0.2	0.2
21	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
22	**50**	0.1	0.5	0.5	0.0	0.0	0.0	0.7	(0.3)	0.9	55%	0.0	0.5	0.1
23	**Total**	4,783.6	1,111.4	1,111.4	(47.8)	0.0	0.0	5,847.1	(534.6)	6,381.7		27.0	435.8	5,438.3

Notes:

1 Amounts are from Ex. L-F4-CCC-084, Table 38, col. (k).

2 Includes Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and before January 1, 2025. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 Represents Reinstated Accelerated Investment Incentive Property ("RIIP") for qualifying property acquired on or after January 1, 2025 and becomes available for use before 2034. For further discussion of RIIP, refer to Ex. L-F4-CCC-084.

4 With RIIP rules effective for eligible property acquired on or after 1 January 2025 and becomes available for use before 2034, the half year rule is suspended until the former is phased out.

5 The CEITC is taxable in the year received; however an election can be made 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. This column represents this reduction, which, for clarity, will reduce the annual CCA over time.

Numbers may not add due to rounding.

Table 40
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Hydroelectric Operations - Updated for CEITC and RIIP Impacts ($M)
Year Ending December 31, 2030

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions[2]	Cost of Acquisitions that are RIIP[3]	CE ITCs[5]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)+(c1)-(d) UCC1	50% Rule or UCC adj for RIIP[4]	(e)-(f) Reduced or increased Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(c1)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	2,781.1	306.6	306.6	(12.1)	0.0	0.0	3,075.5		3,075.5	4%	0.0	123.0	2,952.5
2	**1-rolling start**	608.6	108.3	108.3	0.0	0.0	0.0	716.9		716.9	4%	0.0	28.7	688.2
3	**1.1**	182.9	34.0	34.0	(1.2)	0.0	0.0	215.7		215.7	6%	0.0	12.9	202.8
4	**1.1-rolling start**	41.6	11.1	11.1	0.0	0.0	0.0	52.7		52.7	6%	0.0	3.2	49.5
5	**2**	660.2	0.0	0.0	0.0	0.0	0.0	660.2		660.2	6%	0.0	39.6	620.5
6	**3**	0.2	0.0	0.0	0.0	0.0	0.0	0.2		0.2	5%	0.0	0.0	0.2
7	**6**	3.7	0.0	0.0	0.0	0.0	0.0	3.7		3.7	10%	0.0	0.4	3.3
8	**8**	216.8	76.9	76.9	(3.0)	0.0	0.0	290.8		290.8	20%	0.0	58.2	232.6
9	**8-rolling start**	62.5	26.4	26.4	0.0	0.0	0.0	88.9		88.9	20%	0.0	17.8	71.1
10	**10**	0.1	0.0	0.0	0.0	0.0	0.0	0.1		0.1	30%	0.0	0.0	0.1
11	**12**	0.0	27.4	27.4	0.0	0.0	0.0	27.4		27.4	100%	0.0	27.4	0.0
12	**12-rolling start**	0.0	6.9	6.9	0.0	0.0	0.0	6.9		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	0.0	(0.1)		(0.1)	5%	0.0	(0.0)	(0.1)
15	**17**	705.6	112.6	112.6	(5.5)	0.0	0.0	812.7		812.7	8%	0.0	65.0	747.6
16	**17-rolling start**	173.2	49.0	49.0	0.0	0.0	0.0	222.2		222.2	8%	0.0	17.8	204.4
17	**42**	1.6	0.0	0.0	0.0	0.0	0.0	1.6		1.6	12%	0.0	0.2	1.4
18	**43.1**	0.0	0.2	0.2	(0.1)	0.0	0.0	0.1	(0.3)	0.4	30%	0.0	0.1	(0.0)
19	**43.1-rolling start**	0.0	(0.2)	(0.2)	0.0	0.0	0.0	(0.2)	0.0	(0.2)	30%	0.2		(0.0)
20	**43.2**	0.2	0.0	0.0	0.0	0.0	0.0	0.2		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**	0.1	0.5	0.5	0.0	0.0	0.0	0.7		0.7	55%	0.0	0.4	0.3
23	**Total**	5,438.3	759.7	759.7	(21.9)	0.0	0.0	6,176.0	(0.3)	6,176.4		0.2	401.7	5,774.6

Notes:

1 Amounts are from Ex. L-F4-CCC-084, Table 39, col. (k).

2 Includes Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and before January 1, 2025. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 Represents Reinstated Accelerated Investment Incentive Property ("RIIP") for qualifying property acquired on or after January 1, 2025 and becomes available for use before 2034. For further discussion of RIIP, refer to Ex. L-F4-CCC-084.

4 With RIIP rules effective for eligible property acquired on or after 1 January 2025 and becomes available for use before 2034, the half year rule is suspended until the former is phased out.

5 The CEITC is taxable in the year received; however an election can be made 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. This column represents this reduction, which, for clarity, will reduce the annual CCA over time.

Numbers may not add due to rounding.

Table 41
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Hydroelectric Operations - Updated for CEITC and RIIP Impacts ($M)
Year Ending December 31, 2031

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions[2]	Cost of Acquisitions that are RIIP[3]	CE ITCs[5]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)+(c1)-(d) UCC1	50% Rule or UCC adj for RIIP[4]	(e)-(f) Reduced or increased Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(c1)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	2,952.5	353.8	353.8	(10.3)	0.0	0.0	3,296.0		3,296.0	4%	0.0	131.8	3,164.1
2	**1-rolling start**	688.2	125.4	125.4	0.0	0.0	0.0	813.6		813.6	4%	0.0	32.5	781.1
3	**1.1**	202.8	38.7	38.7	(1.1)	0.0	0.0	240.4		240.4	6%	0.0	14.4	226.0
4	**1.1-rolling start**	49.5	12.8	12.8	0.0	0.0	0.0	62.3		62.3	6%	0.0	3.7	58.6
5	**2**	620.5	0.0	0.0	0.0	0.0	0.0	620.5		620.5	6%	0.0	37.2	583.3
6	**3**	0.2	0.0	0.0	0.0	0.0	0.0	0.2		0.2	5%	0.0	0.0	0.1
7	**6**	3.3	0.0	0.0	0.0	0.0	0.0	3.3		3.3	10%	0.0	0.3	3.0
8	**8**	232.6	88.2	88.2	(2.5)	0.0	0.0	318.3		318.3	20%	0.0	63.7	254.6
9	**8-rolling start**	71.1	30.6	30.6	0.0	0.0	0.0	101.7		101.7	20%	0.0	20.3	81.3
10	**10**	0.1	0.0	0.0	0.0	0.0	0.0	0.1		0.1	30%	0.0	0.0	0.1
11	**12**	0.0	30.9	30.9	0.0	0.0	0.0	30.9		30.9	100%	0.0	30.9	0.0
12	**12-rolling start**	0.0	8.0	8.0	0.0	0.0	0.0	8.0		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	0.0	(0.1)		(0.1)	5%	0.0	(0.0)	(0.1)
15	**17**	747.6	134.4	134.4	(4.7)	0.0	0.0	877.4		877.4	8%	0.0	70.2	807.2
16	**17-rolling start**	204.4	56.8	56.8	0.0	0.0	0.0	261.2		261.2	8%	0.0	20.9	240.3
17	**42**	1.4	0.0	0.0	0.0	0.0	0.0	1.4		1.4	12%	0.0	0.2	1.3
18	**43.1**	(0.0)	(0.0)	(0.0)	0.0	0.0	0.0	(0.1)	0.0	(0.1)	30%	0.0	(0.0)	(0.0)
19	**43.1-rolling start**	(0.0)	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	30%	0.0	(0.0)	(0.0)
20	**43.2**	0.1	0.0	0.0	0.0	0.0	0.0	0.1		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**	0.3	0.5	0.5	0.0	0.0	0.0	0.9		0.9	55%	0.0	0.5	0.4
23	**Total**	5,774.6	880.1	880.1	(18.6)	0.0	0.0	6,636.2	0.0	6,636.2		0.0	434.8	6,201.4

Notes:

1 Amounts are from Ex. L-F4-CCC-084, Table 40, col. (k).

2 Includes Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and before January 1, 2025. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 Represents Reinstated Accelerated Investment Incentive Property ("RIIP") for qualifying property acquired on or after January 1, 2025 and becomes available for use before 2034. For further discussion of RIIP, refer to Ex. L-F4-CCC-084.

4 With RIIP rules effective for eligible property acquired on or after 1 January 2025 and becomes available for use before 2034, the half year rule is suspended until the former is phased out.

5 The CEITC is taxable in the year received; however an election can be made 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. This column represents this reduction, which, for clarity, will reduce the annual CCA over time.

Numbers may not add due to rounding.

Table 42
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Nuclear Operations - Updated for CEITC and RIIP Impacts ($M)
Year Ending December 31, 2025

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions[2]	Cost of Acquisitions that are RIIP[3]	CE ITCs[7]	Net Adjustments	Proceeds of Dispositions[6]	(a)+(b)+(c)+(c1)-(d) UCC1	50% Rule or UCC adj for RIIP[4]	(e)-(f) Reduced or increased Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss[5]	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(c1)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	1,112.6	30.1	0.0	(0.1)	0.0	0.0	1,142.7	0.0	1,142.7	4%	0.0	45.7	1,097.0
2	**1-DNNP**	25.4	0.0	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	0.0	0.0	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	0.0	26.5	(1.1)	0.0	(1.1)	4%	1.1	0.0	0.0
5	**1.1**	540.1	34.7	0.6	(0.1)	0.0	0.0	574.8	(0.3)	575.0	6%	0.0	34.5	540.3
6	**1.1-rolling start**	194.9	32.7	0.0	0.0	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	(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	(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	0.0	10%	0.0	0.0	0.0
10	**8**	348.6	78.5	9.4	(0.2)	0.0	0.0	426.9	(4.7)	431.6	20%	0.0	86.3	340.6
11	**8-rolling start**	15.7	66.1	0.0	0.0	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	0.0	9.1	(1.9)	11.0	30%	0.0	3.3	5.8
13	**12**	0.0	77.7	43.5	0.0	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	0.0	0.0	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	0.0	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	0.0	4.2		4.2	7%	0.0	0.3	3.9
17	**14.1**	11.5	0.0	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	728.0	(0.3)	0.0	0.0	6,527.7	(364.0)	6,891.7	8%	0.0	551.3	5,976.4
19	**17-DNNP**	105.7	0.0	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	0.0	0.0	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	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	0.0	5%	0.0	0.0	0.0
23	**42**	24.1	(0.1)	(0.1)	0.0	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	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	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	0.0	45%	0.0	0.0	0.0
27	**50**	2.4	1.7	1.7	0.0	0.0	0.0	4.1	(1.4)	5.4	55%	0.0	3.0	1.1
28	**Total**	9,151.5	1,363.9	786.9	(0.6)	0.0	282.7	10,232.1	(372.2)	10,604.3		20.5	951.3	9,301.3

Notes:

1 Amounts are from Ex. F4-2-1, Table 25, col. (k).

2 Includes Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and before January 1, 2025. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 Represents Reinstated Accelerated Investment Incentive Property ("RIIP") for qualifying property acquired on or after January 1, 2025 and becomes available for use before 2034. For further discussion of RIIP, refer to Ex. L-F4-CCC-084.

4 With RIIP rules effective for eligible property acquired on or after 1 January 2025 and becomes available for use before 2034, the half year rule is suspended until the former is phased out.

5 As discussed in Ex. L-A1-CCC-010, in December 2025 OPG transfered assets related to the DNNP facilities to DNNP LP. The transfer of these resulted in taxable income in the form of 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.

6 Represents the capital cost of assets related to the DNNP facilities that OPG transferred to DNNP LP in December 2025. Refer to discussion in Ex. L-A1-CCC-010.

7 The CEITC is taxable in the year received; however an election can be made 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. This column represents this reduction, which, for clarity, will reduce the annual CCA over time.

Numbers may not add due to rounding.

Table 43
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Nuclear Operations - Updated for CEITC and RIIP Impacts ($M)
Year Ending December 31, 2026

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions[2]	Cost of Acquisitions that are RIIP[3]	CE ITCs[5]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)+(c1)-(d) UCC1	50% Rule or UCC adj for RIIP[4]	(e)-(f) Reduced or increased Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(c1)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	1,097.0	128.1	101.3	(0.2)	0.0	0.0	1,224.8	(50.6)	1,275.5	4%	0.0	51.0	1,173.8
2	**1-DNNP**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4%	0.0	0.0	0.0
3	**1-rolling start**	138.0	40.5	23.2	0.0	0.0	0.0	178.6	(11.6)	190.2	4%	0.0	7.6	171.0
4	**1-rolling start DNNP**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4%	0.0	0.0	0.0
5	**1.1**	540.3	58.2	51.2	(0.2)	0.0	0.0	598.3	(25.6)	623.9	6%	0.0	37.4	560.8
6	**1.1-rolling start**	214.0	10.3	8.9	0.0	0.0	0.0	224.3	(4.4)	228.7	6%	0.0	13.7	210.5
7	**2**	(0.0)	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	6%	0.0	(0.0)	(0.0)
8	**3**	(0.0)	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	5%	0.0	(0.0)	(0.0)
9	**6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	0.0	0.0
10	**8**	340.6	117.8	101.8	(0.4)	0.0	0.0	458.0	(50.9)	508.9	20%	0.0	101.8	356.2
11	**8-rolling start**	65.4	24.1	19.5	0.0	0.0	0.0	89.5	(9.7)	99.2	20%	0.0	19.8	69.6
12	**10**	5.8	1.0	1.0	0.0	0.0	0.0	6.7	(0.5)	7.2	30%	0.0	2.2	4.6
13	**12**	0.0	113.0	105.9	0.0	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	8.9	0.0	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	0.0	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	0.0	3.9		3.9	7%	0.0	0.3	3.6
17	**14.1**	10.9	0.0	0.0	0.0	0.0	0.0	10.9	0.0	10.9	5%	0.0	0.5	10.4
18	**17**	5,976.4	761.4	580.7	(0.7)	0.0	0.0	6,737.1	(290.3)	7,027.5	8%	0.0	562.2	6,174.9
19	**17-DNNP**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
20	**17-rolling start**	886.6	372.4	209.6	0.0	0.0	0.0	1,259.0	(104.8)	1,363.9	8%	0.0	109.1	1,149.9
21	**17-rolling start DNNP**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
22	**26**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
23	**42**	21.2	(0.1)	(0.1)	0.0	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	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	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	0.0	45%	0.0	0.0	0.0
27	**50**	1.1	1.3	1.3	0.0	0.0	0.0	2.3	(1.0)	3.4	55%	0.0	1.9	0.5
28	**Total**	9,301.3	1,638.2	1,213.2	(1.5)	0.0	0.0	10,938.0	(549.6)	11,487.6		0.0	1,033.4	9,904.6

Notes:

1 Amounts are from Ex. L-F4-CCC-084, Table 42, col. (k).

2 Includes Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and before January 1, 2025. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 Represents Reinstated Accelerated Investment Incentive Property ("RIIP") for qualifying property acquired on or after January 1, 2025 and becomes available for use before 2034. For further discussion of RIIP, refer to Ex. L-F4-CCC-084.

4 With RIIP rules effective for eligible property acquired on or after 1 January 2025 and becomes available for use before 2034, the half year rule is suspended until the former is phased out.

5 The CEITC is taxable in the year received; however an election can be made 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. This column represents this reduction, which, for clarity, will reduce the annual CCA over time.

Table 44
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Nuclear Operations - Updated for CEITC and RIIP Impacts ($M)
Year Ending December 31, 2027

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions[2]	Cost of Acquisitions that are RIIP[3]	CE ITCs[5]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)+(c1)-(d) UCC1	50% Rule or UCC adj for RIIP[4]	(e)-(f) Reduced or increased Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(c1)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	1,173.8	232.6	232.6	(7.9)	0.0	0.0	1,398.5	(116.3)	1,514.8	4%	0.0	60.6	1,337.9
2	**1-DNNP**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4%	0.0	0.0	0.0
3	**1-rolling start**	171.0	152.5	152.5	0.0	0.0	0.0	323.5	(76.3)	399.7	4%	0.0	16.0	307.5
4	**1-rolling start DNNP**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4%	0.0	0.0	0.0
5	**1.1**	560.8	89.1	89.1	(1.8)	0.0	0.0	648.1	(44.5)	692.7	6%	0.0	41.6	606.6
6	**1.1-rolling start**	210.5	21.0	21.0	0.0	0.0	0.0	231.5	(10.5)	242.0	6%	0.0	14.5	217.0
7	**2**	(0.0)	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	6%	0.0	(0.0)	(0.0)
8	**3**	(0.0)	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	5%	0.0	(0.0)	(0.0)
9	**6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	0.0	0.0
10	**8**	356.2	189.5	189.5	(4.3)	0.0	0.0	541.4	(94.7)	636.1	20%	0.0	127.2	414.2
11	**8-rolling start**	69.6	56.8	56.8	0.0	0.0	0.0	126.5	(28.4)	154.9	20%	0.0	31.0	95.5
12	**10**	4.6	0.0	0.0	0.0	0.0	0.0	4.6	0.0	4.6	30%	0.0	1.4	3.2
13	**12**	0.0	147.7	147.7	0.0	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	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	0.0	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	0.0	3.6		3.6	7%	0.0	0.3	3.4
17	**14.1**	10.4	0.0	0.0	0.0	0.0	0.0	10.4	0.0	10.4	5%	0.0	0.5	9.9
18	**17**	6,174.9	1,600.0	1,600.0	(315.6)	0.0	0.0	7,459.4	(800.0)	8,259.4	8%	0.0	660.8	6,798.6
19	**17-DNNP**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
20	**17-rolling start**	1,149.9	1,414.7	1,414.7	0.0	0.0	0.0	2,564.7	(707.4)	3,272.0	8%	0.0	261.8	2,302.9
21	**17-rolling start DNNP**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
22	**26**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
23	**42**	18.6	(0.1)	(0.1)	0.0	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	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	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	0.0	45%	0.0	0.0	0.0
27	**50**	0.5	1.6	1.6	0.0	0.0	0.0	2.1	(0.8)	2.9	55%	0.0	1.6	0.5
28	**Total**	9,904.6	3,926.4	3,926.4	(329.6)	0.0	0.0	13,501.5	(1,878.9)	15,380.3		0.0	1,388.1	12,113.4

Notes:

1 Amounts are from Ex. L-F4-CCC-084, Table 43, col. (k).

2 Includes Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and before January 1, 2025. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 Represents Reinstated Accelerated Investment Incentive Property ("RIIP") for qualifying property acquired on or after January 1, 2025 and becomes available for use before 2034. For further discussion of RIIP, refer to Ex. L-F4-CCC-084.

4 With RIIP rules effective for eligible property acquired on or after 1 January 2025 and becomes available for use before 2034, the half year rule is suspended until the former is phased out.

5 The CEITC is taxable in the year received; however an election can be made 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. This column represents this reduction, which, for clarity, will reduce the annual CCA over time.

Numbers may not add due to rounding.

Table 45
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Nuclear Operations - Updated for CEITC and RIIP Impacts ($M)
Year Ending December 31, 2028

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions[2]	Cost of Acquisitions that are RIIP[3]	CE ITCs[5]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)+(c1)-(d) UCC1	50% Rule or UCC adj for RIIP[4]	(e)-(f) Reduced or increased Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(c1)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	1,337.9	345.6	345.6	(34.1)	0.0	0.0	1,649.4	(172.8)	1,822.2	4%	0.0	72.9	1,576.5
2	**1-DNNP**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4%	0.0	0.0	0.0
3	**1-rolling start**	307.5	273.0	273.0	0.0	0.0	0.0	580.4	(136.5)	716.9	4%	0.0	28.7	551.8
4	**1-rolling start DNNP**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4%	0.0	0.0	0.0
5	**1.1**	606.6	80.9	80.9	(3.2)	0.0	0.0	684.2	(40.4)	724.6	6%	0.0	43.5	640.7
6	**1.1-rolling start**	217.0	35.2	35.2	0.0	0.0	0.0	252.2	(17.6)	269.8	6%	0.0	16.2	236.0
7	**2**	(0.0)	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	6%	0.0	(0.0)	(0.0)
8	**3**	(0.0)	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	5%	0.0	(0.0)	(0.0)
9	**6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	0.0	0.0
10	**8**	414.2	185.0	185.0	(10.0)	0.0	0.0	589.2	(92.5)	681.6	20%	0.0	136.3	452.8
11	**8-rolling start**	95.5	97.4	97.4	0.0	0.0	0.0	192.9	(48.7)	241.5	20%	0.0	48.3	144.6
12	**10**	3.2	0.0	0.0	0.0	0.0	0.0	3.2	0.0	3.2	30%	0.0	1.0	2.2
13	**12**	0.0	144.3	144.3	0.0	0.0	0.0	144.3	0.0	144.3	100%	0.0	144.3	0.0
14	**12-rolling start**	0.0	35.2	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	0.0	n/a	0.0	0.0	0.0
16	**14.1**	3.4	0.0	0.0	0.0	0.0	0.0	3.4		3.4	7%	0.0	0.2	3.1
17	**14.1**	9.9	0.0	0.0	0.0	0.0	0.0	9.9	0.0	9.9	5%	0.0	0.5	9.4
18	**17**	6,798.6	3,032.1	3,032.1	(327.6)	0.0	0.0	9,503.1	(1,516.0)	11,019.1	8%	0.0	881.5	8,621.6
19	**17-DNNP**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
20	**17-rolling start**	2,302.9	2,632.9	2,632.9	0.0	0.0	0.0	4,935.8	(1,316.5)	6,252.3	8%	0.0	500.2	4,435.7
21	**17-rolling start DNNP**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
22	**26**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
23	**42**	16.3	(0.1)	(0.1)	0.0	0.0	0.0	16.2	0.0	16.2	12%	0.0	1.9	14.3
24	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
25	**43.2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50%	0.0	0.0	0.0
26	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
27	**50**	0.5	2.1	2.1	0.0	0.0	0.0	2.6	(1.1)	3.7	55%	0.0	2.0	0.6
28	**Total**	12,113.4	6,863.6	6,863.6	(374.9)	0.0	0.0	18,602.0	(3,342.0)	21,944.1		0.0	1,912.8	16,689.2

Notes:

1 Amounts are from Ex. L-F4-CCC-084, Table 44, col. (k).

2 Includes Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and before January 1, 2025. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 Represents Reinstated Accelerated Investment Incentive Property ("RIIP") for qualifying property acquired on or after January 1, 2025 and becomes available for use before 2034. For further discussion of RIIP, refer to Ex. L-F4-CCC-084.

4 With RIIP rules effective for eligible property acquired on or after 1 January 2025 and becomes available for use before 2034, the half year rule is suspended until the former is phased out.

5 The CEITC is taxable in the year received; however an election can be made 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. This column represents this reduction, which, for clarity, will reduce the annual CCA over time.

Numbers may not add due to rounding.

Table 46
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Nuclear Operations - Updated for CEITC and RIIP Impacts ($M)
Year Ending December 31, 2029

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions[2]	Cost of Acquisitions that are RIIP[3]	CE ITCs[5]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)+(c1)-(d) UCC1	50% Rule or UCC adj for RIIP[4]	(e)-(f) Reduced or increased Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(c1)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	1,576.5	383.3	383.3	(63.3)	0.0	0.0	1,896.5	(191.7)	2,088.2	4%	0.0	83.5	1,813.0
2	**1-DNNP**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4%	0.0	0.0	0.0
3	**1-rolling start**	551.8	222.6	222.6	0.0	0.0	0.0	774.4	(111.3)	885.7	4%	0.0	35.4	738.9
4	**1-rolling start DNNP**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4%	0.0	0.0	0.0
5	**1.1**	640.7	57.0	57.0	(3.8)	0.0	0.0	693.9	(28.5)	722.4	6%	0.0	43.3	650.6
6	**1.1-rolling start**	236.0	23.5	23.5	0.0	0.0	0.0	259.6	(11.8)	271.3	6%	0.0	16.3	243.3
7	**2**	(0.0)	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	6%	0.0	(0.0)	(0.0)
8	**3**	(0.0)	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	5%	0.0	(0.0)	(0.0)
9	**6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	0.0	0.0
10	**8**	452.8	137.5	137.5	(14.3)	0.0	0.0	576.1	(68.8)	644.8	20%	0.0	129.0	447.1
11	**8-rolling start**	144.6	69.5	69.5	0.0	0.0	0.0	214.0	(34.7)	248.8	20%	0.0	49.8	164.3
12	**10**	2.2	0.0	0.0	0.0	0.0	0.0	2.2	0.0	2.2	30%	0.0	0.7	1.6
13	**12**	0.0	125.8	125.8	0.0	0.0	0.0	125.8	0.0	125.8	100%	0.0	125.8	0.0
14	**12-rolling start**	0.0	23.5	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	0.0	n/a	0.0	0.0	0.0
16	**14.1**	3.1	0.0	0.0	0.0	0.0	0.0	3.1		3.1	7%	0.0	0.2	2.9
17	**14.1**	9.4	0.0	0.0	0.0	0.0	0.0	9.4	0.0	9.4	5%	0.0	0.5	8.9
18	**17**	8,621.6	3,659.4	3,659.4	(642.8)	0.0	0.0	11,638.2	(1,829.7)	13,467.9	8%	0.0	1,077.4	10,560.7
19	**17-DNNP**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
20	**17-rolling start**	4,435.7	2,234.9	2,234.9	0.0	0.0	0.0	6,670.5	(1,117.4)	7,787.9	8%	0.0	623.0	6,047.5
21	**17-rolling start DNNP**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
22	**26**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
23	**42**	14.3	(0.1)	(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	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	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	0.0	45%	0.0	0.0	0.0
27	**50**	0.6	2.9	2.9	0.0	0.0	0.0	3.5	(1.5)	5.0	55%	0.0	2.7	0.8
28	**Total**	16,689.2	6,939.9	6,939.9	(724.1)	0.0	0.0	22,905.0	(3,395.3)	26,300.3		0.0	2,212.9	20,692.1

Notes:

1 Amounts are from Ex. L-F4-CCC-084, Table 45, col. (k).

2 Includes Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and before January 1, 2025. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 Represents Reinstated Accelerated Investment Incentive Property ("RIIP") for qualifying property acquired on or after January 1, 2025 and becomes available for use before 2034. For further discussion of RIIP, refer to Ex. L-F4-CCC-084.

4 With RIIP rules effective for eligible property acquired on or after 1 January 2025 and becomes available for use before 2034, the half year rule is suspended until the former is phased out.

5 The CEITC is taxable in the year received; however an election can be made 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. This column represents this reduction, which, for clarity, will reduce the annual CCA over time.

Numbers may not add due to rounding.

Table 47
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Nuclear Operations - Updated for CEITC and RIIP Impacts ($M)
Year Ending December 31, 2030

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions[2]	Cost of Acquisitions that are RIIP[3]	CE ITCs[5]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)+(c1)-(d) UCC1	50% Rule or UCC adj for RIIP[4]	(e)-(f) Reduced or increased Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(c1)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	1,813.0	306.2	306.2	(57.5)		0.0	2,061.7		2,061.7	4%	0.0	82.5	1,979.2
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**	738.9	79.4	79.4	0.0	0.0	0.0	818.3		818.3	4%	0.0	32.7	785.6
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**	650.6	91.5	91.5	(1.4)	0.0	0.0	740.7		740.7	6%	0.0	44.4	696.3
6	**1.1-rolling start**	243.3	14.2	14.2	0.0	0.0	0.0	257.5		257.5	6%	0.0	15.4	242.0
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**	447.1	200.9	200.9	(9.0)	0.0	0.0	639.0		639.0	20%	0.0	127.8	511.2
11	**8-rolling start**	164.3	35.8	35.8	0.0	0.0	0.0	200.1		200.1	20%	0.0	40.0	160.1
12	**10**	1.6	0.0	0.0	0.0	0.0	0.0	1.6		1.6	30%	0.0	0.5	1.1
13	**12**	0.0	167.4	167.4	0.0	0.0	0.0	167.4		167.4	100%	0.0	167.4	0.0
14	**12-rolling start**	0.0	14.2	14.2	0.0	0.0	0.0	14.2		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	0.0	2.9		2.9	7%	0.0	0.2	2.7
17	**14.1**	8.9	0.0	0.0	0.0	0.0	0.0	8.9		8.9	5%	0.0	0.4	8.5
18	**17**	10,560.7	2,589.9	2,589.9	(613.2)	0.0	0.0	12,537.5		12,537.5	8%	0.0	1,003.0	11,534.5
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**	6,047.5	822.8	822.8	0.0	0.0	0.0	6,870.3		6,870.3	8%	0.0	549.6	6,320.7
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**	12.5	(0.1)	(0.1)	0.0	0.0	0.0	12.5		12.5	12%	0.0	1.5	11.0
24	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
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**	0.8	3.2	3.2	0.0	0.0	0.0	4.0		4.0	55%	0.0	2.2	1.8
								0.0						
28	**Total**	20,692.1	4,325.4	4,325.4	(681.0)	0.0	0.0	24,336.5	0.0	24,336.5		0.0	2,081.9	22,254.6

Notes:

1 Amounts are from Ex. L-F4-CCC-084, Table 46, col. (k).

2 Includes Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and before January 1, 2025. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 Represents Reinstated Accelerated Investment Incentive Property ("RIIP") for qualifying property acquired on or after January 1, 2025 and becomes available for use before 2034. For further discussion of RIIP, refer to Ex. L-F4-CCC-084.

4 With RIIP rules effective for eligible property acquired on or after 1 January 2025 and becomes available for use before 2034, the half year rule is suspended until the former is phased out.

5 The CEITC is taxable in the year received; however an election can be made 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. This column represents this reduction, which, for clarity, will reduce the annual CCA over time.

Numbers may not add due to rounding.

Table 48
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Nuclear Operations - Updated for CEITC and RIIP Impacts ($M)
Year Ending December 31, 2031

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions[2]	Cost of Acquisitions that are RIIP[3]	CE ITCs[5]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)+(c1)-(d) UCC1	50% Rule or UCC adj for RIIP[4]	(e)-(f) Reduced or increased Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(c1)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	1,979.2	215.3	215.3	(37.9)		0.0	2,156.6		2,156.6	4%	0.0	86.3	2,070.4
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**	785.6	13.3	13.3	0.0	0.0	0.0	798.9		798.9	4%	0.0	32.0	766.9
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**	696.3	54.5	54.5	(3.3)	0.0	0.0	747.5		747.5	6%	0.0	44.9	702.7
6	**1.1-rolling start**	242.0	12.8	12.8	0.0	0.0	0.0	254.8		254.8	6%	0.0	15.3	239.5
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**	511.2	117.4	117.4	(10.5)	0.0	0.0	618.1		618.1	20%	0.0	123.6	494.5
11	**8-rolling start**	160.1	25.8	25.8	0.0	0.0	0.0	185.8		185.8	20%	0.0	37.2	148.7
12	**10**	1.1	0.0	0.0	0.0	0.0	0.0	1.1		1.1	30%	0.0	0.3	0.8
13	**12**	0.0	141.4	141.4	0.0	0.0	0.0	141.4		141.4	100%	0.0	141.4	0.0
14	**12-rolling start**	0.0	12.8	12.8	0.0	0.0	0.0	12.8		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	0.0	2.7		2.7	7%	0.0	0.2	2.5
17	**14.1**	8.5	0.0	0.0	0.0	0.0	0.0	8.5		8.5	5%	0.0	0.4	8.0
18	**17**	11,534.5	2,181.0	2,181.0	(389.1)	0.0	0.0	13,326.4		13,326.4	8%	0.0	1,066.1	12,260.3
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**	6,320.7	291.3	291.3	0.0	0.0	0.0	6,611.9		6,611.9	8%	0.0	529.0	6,083.0
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**	11.0	(0.1)	(0.1)	0.0	0.0	0.0	10.9		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	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	4.4	4.4	0.0	0.0	0.0	6.2		6.2	55%	0.0	3.4	2.8
								0.0						
28	**Total**	22,254.6	3,069.8	3,069.8	(440.8)	0.0	0.0	24,883.7	0.0	24,883.7		0.0	2,094.1	22,789.6

Notes:

1 Amounts are from Ex. L-F4-CCC-084, Table 47, col. (k).

2 Includes Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and before January 1, 2025. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 Represents Reinstated Accelerated Investment Incentive Property ("RIIP") for qualifying property acquired on or after January 1, 2025 and becomes available for use before 2034. For further discussion of RIIP, refer to Ex. L-F4-CCC-084.

4 With RIIP rules effective for eligible property acquired on or after 1 January 2025 and becomes available for use before 2034, the half year rule is suspended until the former is phased out.

5 The CEITC is taxable in the year received; however an election can be made 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. This column represents this reduction, which, for clarity, will reduce the annual CCA over time.

Numbers may not add due to rounding.

Table 49
Undepreciated Capital Cost and Capital Cost Allowance Schedule for DNNP Facilities - Updated for CEITC and RIIP Impacts ($M)
Year Ending December 31, 2027

Line No.	Class	Undepreciated Capital Cost at Beginning of Year	Cost of Acquisitions[1]	Cost of Acquisitions that are RIIP[2]	CE ITCs[4]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)+(c1)-(d) UCC1	50% Rule or UCC adj for RIIP[3]	(e)-(f) Reduced or increased Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(c1)	(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	0.0	4%	0.0	0.0	0.0
2	**1-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4%	0.0	0.0	0.0
3	**1.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6%	0.0	0.0	0.0
4	**1.1-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6%	0.0	0.0	0.0
5	**2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6%	0.0	0.0	0.0
6	**3**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
7	**6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	0.0	0.0
8	**8**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20%	0.0	0.0	0.0
9	**8-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20%	0.0	0.0	0.0
10	**10**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
11	**12**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100%	0.0	0.0	0.0
12	**13**	0.0	1,620.7	669.4	0.0	0.0	0.0	1,620.7	0.0	1,620.7	n/a	0.0	102.9	1,517.8
13	**13-rolling start**	0.0	2,093.2	2,093.2	0.0	0.0	0.0	2,093.2	0.0	2,093.2	n/a	0.0	165.2	1,927.9
14	**14.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7%	0.0	0.0	0.0
15	**14.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
16	**17**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
17	**17-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
18	**42**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12%	0.0	0.0	0.0
19	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
20	**43.2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50%	0.0	0.0	0.0
21	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
22	**50**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	55%	0.0	0.0	0.0
23	**50R**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	55%	0.0	0.0	0.0
24	**Total**	0.0	3,713.8	2,762.5	0.0	0.0	0.0	3,713.8	0.0	3,713.8		0.0	268.2	3,445.7

Notes:

1 Includes Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and before January 1, 2025. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

2 Represents Reinstated Accelerated Investment Incentive Property ("RIIP") for qualifying property acquired on or after January 1, 2025 and becomes available for use before 2034. For further discussion of RIIP, refer to Ex. L-F4-CCC-084.

3 With RIIP rules effective for eligible property acquired on or after 1 January 2025 and becomes available for use before 2034, the half year rule is suspended until the former is phased out.

4 The CEITC is taxable in the year received; however an election can be made 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. This column represents this reduction, which, for clarity, will reduce the annual CCA over time.

Numbers may not add due to rounding.

Table 50
Undepreciated Capital Cost and Capital Cost Allowance Schedule for DNNP Facilities - Updated for CEITC and RIIP Impacts ($M)
Year Ending December 31, 2028

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions[2]	Cost of Acquisitions that are RIIP[3]	CE ITCs[5]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)+(c1)-(d) UCC1	50% Rule or UCC adj for RIIP[4]	(e)-(f) Reduced or increased Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(c1)	(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	0.0	4%	0.0	0.0	0.0
2	**1-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4%	0.0	0.0	0.0
3	**1.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6%	0.0	0.0	0.0
4	**1.1-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6%	0.0	0.0	0.0
5	**2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6%	0.0	0.0	0.0
6	**3**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
7	**6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	0.0	0.0
8	**8**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20%	0.0	0.0	0.0
9	**8-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20%	0.0	0.0	0.0
10	**10**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
11	**12**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100%	0.0	0.0	0.0
12	**13**	1,517.8	896.7	896.7	(372.7)	0.0	0.0	2,041.8	0.0	2,041.8	n/a	0.0	139.3	1,902.4
13	**13-rolling start**	1,927.9	1,633.4	1,633.4	0.0	0.0	0.0	3,561.4	0.0	3,561.4	n/a	0.0	246.3	3,315.1
14	**14.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7%	0.0	0.0	0.0
15	**14.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
16	**17**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
17	**17-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
18	**42**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12%	0.0	0.0	0.0
19	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
20	**43.2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50%	0.0	0.0	0.0
21	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
22	**50**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	55%	0.0	0.0	0.0
23	**50R**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	55%	0.0	0.0	0.0
24	**Total**	3,445.7	2,530.1	2,530.1	(372.7)	0.0	0.0	5,603.1	0.0	5,603.1		0.0	385.6	5,217.5

Notes:

1 Amounts are from Ex. L-F4-CCC-084, Table 49, col. (k).

2 Includes Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and before January 1, 2025. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 Represents Reinstated Accelerated Investment Incentive Property ("RIIP") for qualifying property acquired on or after January 1, 2025 and becomes available for use before 2034. For further discussion of RIIP, refer to Ex. L-F4-CCC-084.

4 With RIIP rules effective for eligible property acquired on or after 1 January 2025 and becomes available for use before 2034, the half year rule is suspended until the former is phased out.

5 The CEITC is taxable in the year received; however an election can be made 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. This column represents this reduction, which, for clarity, will reduce the annual CCA over time.

Numbers may not add due to rounding.

Table 51
Undepreciated Capital Cost and Capital Cost Allowance Schedule for DNNP Facilities - Updated for CEITC and RIIP Impacts ($M)
Year Ending December 31, 2029

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions[2]	Cost of Acquisitions that are RIIP[3]	CE ITCs[5]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)+(c1)-(d) UCC1	50% Rule or UCC adj for RIIP[4]	(e)-(f) Reduced or increased Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(c1)	(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	0.0	4%	0.0	0.0	0.0
2	**1-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4%	0.0	0.0	0.0
3	**1.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6%	0.0	0.0	0.0
4	**1.1-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6%	0.0	0.0	0.0
5	**2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6%	0.0	0.0	0.0
6	**3**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
7	**6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	0.0	0.0
8	**8**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20%	0.0	0.0	0.0
9	**8-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20%	0.0	0.0	0.0
10	**10**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
11	**12**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100%	0.0	0.0	0.0
12	**13**	1,902.4	304.7	304.7	(289.6)	0.0	0.0	1,917.6	0.0	1,917.6	n/a	0.0	124.3	1,793.3
13	**13-rolling start**	3,315.1	0.0	0.0	0.0	0.0	0.0	3,315.1	0.0	3,315.1	n/a	0.0	200.9	3,114.2
14	**14.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7%	0.0	0.0	0.0
15	**14.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
16	**17**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
17	**17-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
18	**42**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12%	0.0	0.0	0.0
19	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
20	**43.2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50%	0.0	0.0	0.0
21	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
22	**50**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	55%	0.0	0.0	0.0
23	**50R**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	55%	0.0	0.0	0.0
24	**Total**	5,217.5	304.7	304.7	(289.6)	0.0	0.0	5,232.7	0.0	5,232.7		0.0	325.2	4,907.5

Notes:

1 Amounts are from Ex. L-F4-CCC-084, Table 50, col. (k).

2 Includes Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and before January 1, 2025. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 Represents Reinstated Accelerated Investment Incentive Property ("RIIP") for qualifying property acquired on or after January 1, 2025 and becomes available for use before 2034. For further discussion of RIIP, refer to Ex. L-F4-CCC-084.

4 With RIIP rules effective for eligible property acquired on or after 1 January 2025 and becomes available for use before 2034, the half year rule is suspended until the former is phased out.

5 The CEITC is taxable in the year received; however an election can be made 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. This column represents this reduction, which, for clarity, will reduce the annual CCA over time.

Numbers may not add due to rounding.

Table 52
Undepreciated Capital Cost and Capital Cost Allowance Schedule for DNNP Facilities - Updated for CEITC and RIIP Impacts ($M)
Year Ending December 31, 2030

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions[2]	Cost of Acquisitions that are RIIP[3]	CE ITCs[5]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)+(c1)-(d) UCC1	50% Rule or UCC adj for RIIP[4]	(e)-(f) Reduced or increased Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(c1)	(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	0.0	4%	0.0	0.0	0.0
2	**1-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4%	0.0	0.0	0.0
3	**1.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6%	0.0	0.0	0.0
4	**1.1-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6%	0.0	0.0	0.0
5	**2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6%	0.0	0.0	0.0
6	**3**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
7	**6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	0.0	0.0
8	**8**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20%	0.0	0.0	0.0
9	**8-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20%	0.0	0.0	0.0
10	**10**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
11	**12**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100%	0.0	0.0	0.0
12	**13**	1,793.3	373.2	373.2	(34.9)	0.0	0.0	2,131.7	0.0	2,131.7	n/a	0.0	136.4	1,995.2
13	**13-rolling start**	3,114.2	0.0	0.0	0.0	0.0	0.0	3,114.2	0.0	3,114.2	n/a	0.0	200.9	2,913.2
14	**14.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7%	0.0	0.0	0.0
15	**14.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
16	**17**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
17	**17-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
18	**42**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12%	0.0	0.0	0.0
19	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
20	**43.2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50%	0.0	0.0	0.0
21	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
22	**50**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	55%	0.0	0.0	0.0
23	**50R**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	55%	0.0	0.0	0.0
24	**Total**	4,907.5	373.2	373.2	(34.9)	0.0	0.0	5,245.9	0.0	5,245.9		0.0	337.4	4,908.5

Notes:

1 Amounts are from Ex. L-F4-CCC-084, Table 51, col. (k).

2 Includes Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and before January 1, 2025. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 Represents Reinstated Accelerated Investment Incentive Property ("RIIP") for qualifying property acquired on or after January 1, 2025 and becomes available for use before 2034. For further discussion of RIIP, refer to Ex. L-F4-CCC-084.

4 With RIIP rules effective for eligible property acquired on or after 1 January 2025 and becomes available for use before 2034, the half year rule is suspended until the former is phased out.

5 The CEITC is taxable in the year received; however an election can be made 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. This column represents this reduction, which, for clarity, will reduce the annual CCA over time.

Numbers may not add due to rounding.

Table 53
Undepreciated Capital Cost and Capital Cost Allowance Schedule for DNNP Facilities - Updated for CEITC and RIIP Impacts ($M)
Year Ending December 31, 2031

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions[2]	Cost of Acquisitions that are RIIP[3]	CE ITCs[5]	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)+(c1)-(d) UCC1	50% Rule or UCC adj for RIIP[4]	(e)-(f) Reduced or increased Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(b1)	(c)	(c1)	(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	0.0	4%	0.0	0.0	0.0
2	**1-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4%	0.0	0.0	0.0
3	**1.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6%	0.0	0.0	0.0
4	**1.1-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6%	0.0	0.0	0.0
5	**2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6%	0.0	0.0	0.0
6	**3**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
7	**6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	0.0	0.0
8	**8**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20%	0.0	0.0	0.0
9	**8-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20%	0.0	0.0	0.0
10	**10**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
11	**12**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100%	0.0	0.0	0.0
12	**13**	1,995.2	0.0	0.0	(42.7)	0.0	0.0	1,952.5	0.0	1,952.5	n/a	0.0	133.6	1,818.9
13	**13-rolling start**	2,913.2	0.0	0.0	0.0	0.0	0.0	2,913.2	0.0	2,913.2	n/a	0.0	200.9	2,712.3
14	**14.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7%	0.0	0.0	0.0
15	**14.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
16	**17**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
17	**17-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
18	**42**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12%	0.0	0.0	0.0
19	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
20	**43.2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50%	0.0	0.0	0.0
21	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
22	**50**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	55%	0.0	0.0	0.0
23	**50R**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	55%	0.0	0.0	0.0
24	**Total**	4,908.5	0.0	0.0	(42.7)	0.0	0.0	4,865.8	0.0	4,865.8		0.0	334.5	4,531.3

Notes:

1 Amounts are from Ex. L-F4-CCC-084, Table 52, col. (k).

2 Includes Accelerated Investment Incentive Property ("AIIP"), other than those in classes 54-56, acquired after Nov 20, 2018 and before January 1, 2025. For further discussion of AIIP, refer to EB-2020-0290, Ex. F4-2-1, p. 5, lines 1 to 9.

3 Represents Reinstated Accelerated Investment Incentive Property ("RIIP") for qualifying property acquired on or after January 1, 2025 and becomes available for use before 2034. For further discussion of RIIP, refer to Ex. L-F4-CCC-084.

4 With RIIP rules effective for eligible property acquired on or after 1 January 2025 and becomes available for use before 2034, the half year rule is suspended until the former is phased out.

5 The CEITC is taxable in the year received; however an election can be made 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. This column represents this reduction, which, for clarity, will reduce the annual CCA over time.

Table 54
Summary of Revenue Requirement for Regulated Hydroelectric - Updated for CEITC and RIIP Impacts ($M)
Year Ending December 31, 2027

Line No.	Description	Note	2027
			(a)
	Rate Base		
1	**Net Fixed Assets**	1	9,100.0
2	**Working Capital**	1	0.3
3	**Cash Working Capital**	1	19.3
4	**Total Rate Base**		9,119.6
	Capitalization		
5	**Short-Term Debt**	2	153.0
6	**Long-Term Debt**	2	4,224.3
7	**Common Equity**	2	4,742.2
8	**Total Capital**		9,119.6
	Cost of Capital		
9	**Short-Term Debt**	3	7.7
10	**Long-Term Debt**	3	192.7
11	**Common Equity**	3	432.0
12	**Total Cost of Capital**		632.5
	Expenses:		
13	**OM&A**	4	499.3
14	**GRC**	5	352.2
15	**Depreciation & Amortization**	6	215.1
16	**Property Tax**	7	2.1
17	**Total Expenses**		1,068.7
	Less:		
	Other Revenues		
18	**Ancillary and Other Revenue**	8	62.2
19	**Total Other Revenues**		62.2
20	**Income Tax**	9	(3.3)
21	**Revenue Requirement** (line 12 + line 17 - line 19 + line 20)		1,635.7
22	**Amortization of Variance & Deferral Account Amounts**	10	(37.9)
23	**Revenue Requirement Plus Variance & Deferral Account Amounts** (line 21 + line 22)		1,597.7

Notes:

1 Per Ex. L-F4-CCC-084, Table 1
2 Regulated hydroelectric portion of totals from Ex. L-F4-CCC-084, Table 14, (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. L-F4-CCC-084, Table 14, (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. L-F4-CCC-084, Table 25, 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. L-F4-CCC-084, Table 27, line 23.
10 Per Ex. H1-2-1 Table 1, col. (h), line 19.

Table 55
Summary of Revenue Requirement for OPG Nuclear Facilities - Updated for CEITC and RIIP Impacts ($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	14,795.1	15,114.7	14,987.7	15,491.7	21,472.7
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**		15,669.8	16,067.6	16,005.4	16,590.0	22,624.7
	Capitalization						
5	**Short-Term Debt**	2	261.3	258.7	248.2	246.1	271.9
6	**Long-Term Debt**	2	7,212.2	7,442.7	7,434.4	7,717.1	10,588.0
7	**Common Equity**	2	8,022.3	8,277.1	8,263.2	8,572.9	11,715.2
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**		15,669.8	16,067.6	16,005.4	16,590.0	22,624.7
	Cost of Capital						
10	**Short-Term Debt**	3	13.2	12.2	12.0	11.4	13.1
11	**Long-Term Debt**	3	329.0	353.9	361.4	379.0	520.6
12	**Common Equity**	3	730.8	754.0	752.8	781.0	1,067.3
12a	**EB-2020-0290 Settlement Adjustment for Equity at Long-Term Debt Rate**	13	3.4	3.1	2.9	2.6	2.4
13	**Adjustment for Lesser of UNL or ARC**	3	4.7	1.1	0.0	0.0	0.0
14	**Total Cost of Capital**		1,081.2	1,124.3	1,129.1	1,174.0	1,603.4
	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	658.4	698.0	719.4	767.6	961.1
18	**Property Tax**	7	14.0	14.2	14.5	14.8	15.0
19	**Total Expenses**		2,687.0	2,689.9	2,874.8	2,899.9	3,435.7
	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	295.0	465.5	626.3	755.0	576.0
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)		4,045.5	4,218.9	4,617.9	4,791.5	5,592.0
25	**Cumulative Nuclear Stretch Dollars**	11	0.0	6.8	14.4	22.2	31.4
26	**Revenue Requirement Net of Stretch Factor** (line 24 - line 25)		4,045.5	4,212.1	4,603.5	4,769.3	5,560.6
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)		4,179.9	4,346.6	4,738.0	4,837.0	5,628.4

Notes:

1 Per Ex. L-F4-CCC-084, Table 5.
2 OPG's nuclear facilities portion of totals from Ex. L-F4-CCC-084, Tables 10 through 14, (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. L-F4-CCC-084, Tables 10 through 14, (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. L-F4-CCC-084, Table 26, 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. L-F4-CCC-084, Table 27, line 30.
11 Per Ex. L-F4-CCC-084, Table 62, line 23.
12 Per Ex. H1-2-1 Table 2, col. (h)-(l), line 32.
13 Per Ex. L-F4-CCC-084, Tables 10-14, 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. L-F4-CCC-084, Table 58, line 7.

Table 56
Summary of Revenue Requirement for DNNP Facilities - Updated for CEITC and RIIP Impacts ($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	1,226.3	5,865.5
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	1,236.9	5,888.1
	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	1,236.9	5,888.1
8	**Total Capital**		0.0	0.0	2.1	1,236.9	5,888.1
	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	112.7	536.4
12	**Total Cost of Capital**		0.0	0.0	0.2	112.7	536.4
	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	20.4	98.9
16	**Property Tax**	6	0.0	0.0	0.0	0.8	3.7
17	**Total Expenses**		86.1	93.9	83.5	158.0	411.7
	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	214.2	274.2	293.4	244.4	20.9
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)		300.3	368.1	377.1	515.1	969.0
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)		300.3	368.1	377.1	515.1	969.0

Notes:
1 Per Ex. L-F4-CCC-084, Table 6.
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. L-F4-CCC-084, Table 26, line 12.
6 Per Ex. F4-2-1, Table 2a, line 2.
7 Per Ex. L-F4-CCC-084, Table 57, line 7.
8 Per Ex. F4-2-1, Table 2a, line 1.

Table 57
Calculation of Forecast Concurrent Cost Recovery - Darlington New Nuclear Program - Updated for CEITC and RIIP Impacts ($M)
January 1, 2027 to December 31, 2031 ($M)

Line No.	Description	Note	2027	2028	2029	2030	2031
			(b)	(c)	(d)	(e)	(f)
1	**Opening Balance**	1	3,884.0	5,504.7	6,028.7	6,043.8	446.7
2	**Capital Expenditures**	1	1,620.7	896.7	304.7	373.2	0.0
2a	**CEITC Capital Expenditure Adjustment**		0.0	(372.7)	(289.6)	(34.9)	(42.7)
3	**In-Service**	2	0.0	0.0	0.0	5,935.4	0.0
4	**Closing Balance** (line 1 + line 2 - line 3)		5,504.7	6,028.7	6,043.8	446.7	404.0
5	**Capital Costs for Purposes of Calculating CCR** ((line 1 + line 4) / 2	2	4,694.3	5,766.7	6,036.2	4,976.4	425.4
6	**OPG Cost of Long-Term Borrowing**	3	4.56%	4.75%	4.86%	4.91%	4.92%
7	**Concurrent Cost Recovery** (line 5 x line 6)		214.2	274.2	293.4	244.4	20.9

Notes

1 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. L-F4-CCC-084, Table 8, Note 1.

3 Per Ex. L-F4-CCC-084, Tables 10-14: line 2, col. (c).

Numbers may not add due to rounding.

Table 58
Calculation of Forecast Concurrent Cost Recovery - Pickering Refurbishment Program - Updated for CEITC and RIIP Impacts ($M)
January 1, 2027 to December 31, 2031 ($M)

Line No.	Description	Note	2027	2028	2029	2030	2031
			(b)	(c)	(d)	(e)	(f)
1	**Opening Balance**	1	4,773.3	8,158.8	11,424.8	14,344.3	16,402.4
2	**Capital Expenditures**	1	3,473.2	3,607.6	3,578.3	2,681.4	1,860.5
2a	**CEITC Capital Expenditure Adjustment**		(67.5)	(341.6)	(658.7)	(623.3)	(383.2)
3	**In-Service**	2	20.2	0.0	0.0	0.0	8,682.7
4	**Closing Balance** (line 1 + line 2 - line 3)		8,158.8	11,424.8	14,344.3	16,402.4	9,197.0
5	**Capital Costs for Purposes of Calculating CCR** ((line 1 + line 4) / 2	2	6,466.0	9,791.8	12,884.6	15,373.4	11,714.4
6	**OPG Cost of Long-Term Borrowing**	3	4.56%	4.75%	4.86%	4.91%	4.92%
7	**Concurrent Cost Recovery**		295.0	465.5	626.3	755.0	576.0

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. L-F4-CCC-084, Table 8, Note 1 for further details.

3 Per Ex. L-F4-CCC-084, Tables 10-14: line 2, col. (c).

Numbers may not add due to rounding.

Table 59
Payment Amounts and Riders – Regulated Hydroelectric Facilities - Updated for CEITC and RIIP Impacts
January 1, 2027 to December 31, 2027

Line No.	Description	Note	2027	Illustrative Payment Amounts[1] 2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
1	**Price Escalator (I-Factor)**	2	**3.49%**	**3.49%**	**3.49%**	**3.49%**	**3.49%**
2	Labour: Average Weekly Earnings - Ontario	2	4.85%	4.85%	4.85%	4.85%	4.85%
3	Non-Labour: Canadian Gross Domestic Product Implicit Price Index - Final Domestic Demand	2	3.24%	3.24%	3.24%	3.24%	3.24%
4	**Productivity Factor**	3	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**
5	**Stretch Factor**	4	**0.15%**	**0.15%**	**0.15%**	**0.15%**	**0.15%**
6	**"I-X"** (line 1 - line 4 - line 5)		**3.34%**	**3.34%**	**3.34%**	**3.34%**	**3.34%**
7	**Custom Capital Factor** (Ex. L-F4-CCC-084, Table 60, line 10)	5		**3.38%**	**8.60%**	**1.99%**	**0.15%**
8	**GRC Adjustment** (Ex. L-F4-CCC-084, Table 60, Note 3, line 3c)	6		**-0.72%**	**-0.68%**	**-0.61%**	**-0.58%**
9	**Price Cap Index**			**6.00%**	**11.26%**	**4.72%**	**2.90%**
10	**Prior Year Hydroelectric Payment Amount ($/MWh)**			50.39	53.41	59.42	62.22
11	**Prior Year Price Cap Adjusted Hydroelectric Payment Amount ($/MWh)**	7	50.39	53.41	59.42	62.22	64.03
12	**Hydroelectric Payment Rider ($/MWh)**	8	(1.17)	(1.17)	(1.17)	0.00	0.00
13	**Total of Hydroelectric Payment Amounts Plus Riders** (line 11 + line 12)		49.22	52.24	58.25	62.22	64.03

Notes:

1 Payment amounts for 2028-2031 are illustrative only - final payment amounts to be determined annually using I-factor values.

2 2027 inflation factor per 2026 inflation parameters published by the OEB in June 2025, and weightings per Ex. A1-3-2 Chart 3: 15.3% labour cost (line 4), 9.3% non-labour cost (line 2) and 75.4% capital cost (line 1).

3 Per Ex. A1-3-2, Section 2.3.2.1.

4 Per Ex. A1-3-2, Section 2.3.2.2.

5 Per Ex. A1-3-2, Section 2.3.3.

6 Per Ex. A1-3-2, Section 2.3.4.

7 2027 is cost of service amount. Subsequent years escalated by the Price Cap Index (line 9).

8 Per Ex. H1-2-1, Table 1, line 21.

Numbers may not add due to rounding.

Table 60
Calculation of Capital Factor for Regulated Hydroelectric Facilities - Updated for CEITC and RIIP Impacts ($M)
January 1, 2027 to December 31, 2031 ($M)

Line No.	Description	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
			Note 1				
1	**Depreciation**	Ex. L-F4-CCC-084, Table 25, line 10	215.1	227.7	247.9	261.3	269.1
2	**Cost of Debt**	Note 2	200.5	220.1	250.0	266.8	279.7
3	**Return on Equity**	Note 2	432.0	457.1	507.5	537.1	561.7
4	**Income Taxes**	Ex. L-F4-CCC-084, Table 27, line 23	(3.3)	24.1	105.4	122.8	121.8
5	**Capital Related Revenue Requirement**	Sum lines 1 to 4	844.3	929.1	1,110.9	1,188.0	1,232.3
6	**Regulated Hydroelectric Stretch Factor Capital Related Revenue Requirement Adjustment**	0.15% * line 5 (cumulative)		1.4	3.1	4.8	6.7
7	**Capital Related Revenue Requirement after Stretch**	line 5 - line 6	844.3	927.7	1,107.8	1,183.2	1,225.6
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)	844.3	872.5	958.7	1,144.8	1,222.7
9	**Capital Related Revenue Requirement Shortfall**	line 7 - line 8	-	55.2	149.1	38.4	3.0
10	**Custom Capital Factor (C-Factor)**	line 9_t / line 14_{t-1}		3.4%	8.6%	2.0%	0.1%
11	**OM&A (excluding GRC)**	2028-2031: escalated by (I - X)	501.4	518.2	535.5	553.3	571.8
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)	(64.3)	(66.5)	(68.7)	(71.0)
14	**Total Revenue Requirement**	line 7 + (lines 11 to 13)	1,635.7	1,733.8	1,929.0	2,020.0	2,078.7

Notes:

1 Per Ex. L-F4-CCC-084, Table 55.

2 Determination of cost of capital amounts included in the C-factor is based on the following:

Line No.	Description	Reference	2027	2028	2029	2030	2031
2a	Rate Base	Ex. L-F4-CCC-084, Table 1	9,119.6	9,649.5	10,713.9	11,338.1	11,857.6
2b	Short-Term Debt	Ex. L-F4-CCC-084, Tables 10-14	7.7	7.3	8.0	7.8	6.9
2c	Long-Term Debt	Ex. L-F4-CCC-084, Tables 10-14	192.7	212.8	241.9	259.0	272.9
2d	Common Equity	Ex. L-F4-CCC-084, Tables 10-14	432.0	457.1	507.5	537.1	561.7

3 The 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	364.0	364.0	364.0	364.0
3b	Variance to Fixed GRC	line 12 less line 3a	-	(11.8)	(11.8)	(11.8)	(11.8)
3c	Variance as Percentage of Prior Year Revenue Requirement	line 3b, col. b / line 14, col. a	-	-0.7%	-0.7%	-0.6%	-0.6%

Numbers may not add due to rounding.

Table 61
Annualized Residential Consumer Impact - Updated for CEITC and RIIP Impacts
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)	7.69	2.21	1.37	0.44	4.16	3.17
5	**Typical Bill Impact (%)** (line 4 / line 3)	5.4%	1.6%	1.0%	0.3%	2.9%	2.2%
6	Prior Year weighted average rate with proposed payment amounts and riders[2,3] ($/MWh)	77.75	109.04	116.82	121.78	123.31	
7	Current Year weighted average rate with proposed payment amounts and riders[2,3] ($/MWh)	109.04	116.82	121.78	123.31	136.98	
8	Change in weighted average rate ($/MWh) (line 7 - line 6)	31.29	7.78	4.96	1.53	13.67	
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. L-F4-CCC-084, Table 62, line 9.

3 Per Ex. L-F4-CCC-084, Table 63.

4 From Ex. L-F4-CCC-084, Table 62, 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.

Table 62
Computation of Percent Change in Payment Amounts - Updated for CEITC and RIIP Impacts
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) ($/MWh)**	3	43.88	50.39	53.41	59.42	62.22	64.03
2	**Hydroelectric Payment Rider (HPR) ($/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) ($/MWh)**	6	111.33	205.74	190.33	198.70	193.40	211.50
5	**Nuclear Payment Rider (NPR) ($/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 ($/MWh)** (HPA + HPR) x HPF / (NPF+HPF)		28.35	31.23	28.67	32.87	33.78	32.82
8	**Nuclear Portion of Weighted Average Payment Amount ($/MWh)** (NPA + NPR) x NPF / (NPF+HPF)		49.41	77.81	88.16	88.91	89.52	104.16
9	**Weighted Average Payment Amount ($/MWh)** (((NPA + NPR) x NPF) + (HPA + HPR) x HPF) / (NPF + HPF)		77.75	109.04	116.82	121.78	123.31	136.98
10	**Percentage Change in Weighted Average Payment Amount (Year over Year)**			40.2%	7.1%	4.2%	1.3%	11.1%

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. L-F4-CCC-084, Table 59. 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. L-F4-CCC-084, Table 63, 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.

Numbers may not add due to rounding.

Table 63
Payment Amounts - Combined Nuclear - Updated for CEITC and RIIP Impacts
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	4,045.5	4,212.1	4,603.5	4,769.3	5,560.6
2	Revenue Requirement - DNNP Facilities	2	300.3	368.1	377.1	515.1	969.0
3	**Combined Nuclear Revenue Requirement Net of Stretch Factor ($M)**		4,345.7	4,580.2	4,980.6	5,284.4	6,529.7
4	**OPG Nuclear Revenue Requirement Shaping Adjustment ($M)**	3	(500.0)	500.0	0.0	0.0	0.0
5	**Combined Nuclear Revenue Requirement After Shaping Adjustment ($M)** (line 3 + line 4)		3,845.7	5,080.2	4,980.6	5,284.4	6,529.7
6	Production Forecast - OPG Nuclear Facilities	4	18.7	26.7	25.1	26.8	28.9
7	Production Forecast - DNNP Facilities	5	0.0	0.0	0.0	0.5	1.9
8	**Combined Nuclear Forecast Production (TWh)**		18.7	26.7	25.1	27.3	30.9
9	**Blended Nuclear Payment Amount ($/MWh)** (line 5 / line 8)		205.74	190.33	198.70	193.40	211.50

Notes:

1 From Ex. L-F4-CCC-084, Table 55, line 26.
2 From Ex. L-F4-CCC-084, Table 56, 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.

Numbers may not add due to rounding.

Table 64
Calculation of OPG Nuclear Facilities Stretch Factor - Updated for CEITC and RIIP Impacts ($M)
January 1, 2027 to December 31, 2031 ($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		316.7	334.9	385.9	445.9
14	Depreciation Expense	10		255.1	276.4	317.5	366.9
15	Income Tax Expense on Cost of Capital and Depreciation Expense	10		156.0	166.6	191.5	221.3
16	**Total Darlington and Operations & Project Support Capital Related Revenue Requirement Subject to Stretch Factor** (line 13 + line 14 + line 15)			727.8	778.0	894.9	1,034.1
	Pickering Capital Related Revenue Requirement						
17	Cost of Capital	11		24.1	29.2	44.8	58.9
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	21.4	27.0
20	**Total Pickering Capital Related Revenue Requirement Subject to Stretch Factor** (line 18 + line 19 + line 20)			65.0	71.5	100.6	127.5
21	Income Tax Expense- Capital Cost Allowance	13		(209.2)	(205.2)	(214.7)	(219.0)
22	**Total Revenue Requirement Amount Subject to Stretch Factor** (line 5 + line 11 + line 12 + line 16 + line 20 + line 21)			2,264.7	2,526.3	2,607.5	3,064.7
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		**6.8**	**14.4**	**22.2**	**31.4**

Notes:
Refer to L-F4-CCC-084, Table 65.

Table 65
Notes to Ex. L-F4-CCC-084, Table 64

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. L-F4-CCC-084, Table 7, col. (g), lines 13 and 20 less Ex. L-F4-CCC-084, Table 9, col. (g), lines 13 and 20. Less line 10b. 2029: Ex. L-F4-CCC-084, Table 7, col. (g), lines 25 and 32 less Ex. L-F4-CCC-084, Table 9, col. (g), lines 25 and 32. Less line 10b. 2030: Ex. L-F4-CCC-084, Table 7, col. (g), lines 37 and 44 less Ex. L-F4-CCC-084, Table 9, col. (g), lines 37 and 44. Less line 10b. 2031: Ex. L-F4-CCC-084, Table 7, col. (g), lines 49 and 56 less Ex. L-F4-CCC-084, Table 9, col. (g), lines 49 and 56. Less line 10b.		4,426.5	4,658.4	5,370.6	6,218.2
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%)		209.7	220.7	254.4	294.6
10d	Return on Equity at Long-Term Debt Rate (line 10b x 52% x Ex. L-F4-CCC-084, Tables 10-13, col. (c), line 3)		3.1	2.9	2.6	2.4
10e	Cost of Debt ((line 10a + line 10b) x 48% x Ex. L-F4-CCC-084, Tables 10-13, col. (c), line 4)		103.9	111.4	128.8	148.9
10f	Total Cost of Capital (lines 10c + 10d + 10e)		**316.7**	**334.9**	**385.9**	**445.9**
10g	Depreciation Expense (Ex. L-F4-CCC-084, Table 9, col. (b) plus col. (c) plus col. (d): lines 13 & 20; lines 25 & 32; lines 37 & 44; lines 49 & 56)		255.1	276.4	317.5	366.9
10h	Net Regulatory Taxable Income Increase / (Decrease) (line 10c + line 10d + line 10g)		468.0	499.9	574.6	663.9
10i	Income Tax Expense (line 10h x 25% / (1 - 25%))		**156.0**	**166.6**	**191.5**	**221.3**

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. L-F4-CCC-084, Table 7, col. (g), line 17 less Ex. L-F4-CCC-084, Table 9, col. (g), line 17. Less line 11b. 2029: Ex. L-F4-CCC-084, Table 7, col. (g), line 29 less Ex. L-F4-CCC-084, Table 9, col. (g), line 29. Less line 11b. 2030: Ex. L-F4-CCC-084, Table 7, col. (g), line 41 less Ex. L-F4-CCC-084, Table 9, col. (g), line 41. Less line 11b. 2031: Ex. L-F4-CCC-084, Table 7, col. (g), line 53 less Ex. L-F4-CCC-084, Table 9, col. (g), line 53. Less line 11b.		343.2	412.9	631.5	830.6
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	29.9	39.3
11d	Return on Equity at Long-Term Debt Rate (line 10b x 52% x Ex. L-F4-CCC-084, Tables 10-13, col. (c), line 3)		-	-	-	-
11e	Cost of Debt ((line 10a + line 10b) x 48% x Ex. L-F4-CCC-084, Tables 10-13, col. (c), line 4)		7.8	9.6	14.9	19.6
11f	Total Cost of Capital (lines 10c + 10d + 10e)		**24.1**	**29.2**	**44.8**	**58.9**
11g	Depreciation Expense (Ex. L-F4-CCC-084, Table 9, col. (b) plus col. (c) plus col. (d): lines 17, 29, 41, 53)		**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	64.3	80.9
11i	Income Tax Expense (line 10h x 25% / (1 - 25%))		**14.3**	**15.5**	**21.4**	**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. L-F4-CCC-084, Table 27, line 15 less DRP and PRP amounts per Ex. L-F4-CCC-084, Table 31, Note 3)		(627.6)	(615.5)	(644.2)	(657.0)
(b)	Income Tax Expense (line (a) x 25% / (1 - 25%))		**(209.2)**	**(205.2)**	**(214.7)**	**(219.0)**

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)		1.8	3.7	6.0	8.9
14c	Total Nuclear Stretch Factor Revenue Requirement Adjustment (line 14a + line 14b)		6.8	14.4	22.2	31.4

CCC Interrogatory #085

Interrogatory

Reference:
Exhibit F4, Tab 3, Schedule 1, p. 5, 17, 21, 30-31, 37-39

Question(s):

a) For the 2027-2031 period, please provide the assumptions applied with respect to wage/compensation escalation for each of the next Society (January 2026) and PWU (April 2027) contracts that are reflected in the application.

b) Please discuss whether, at the time of filing the interrogatory responses, collective bargaining with the Society was completed for 2026. If so, please provide the wage/compensation escalation established in the relevant agreement. If not yet completed, please provide an update on the expected timing of the completion of collective bargaining.

c) OPG notes that it hired approximately 60% of term employees to regular positions in 2024. By the end of 2026, there will be substantially no term employees. Please further discuss the remaining 40% of term employees and whether they have also been hired on a regular basis or have otherwise left the company. As part of the response, please discuss whether the Company still has the right/ability under the relevant collective agreements to hire term employees to address shorter term needs.

d) With respect to Figure 4a:
   i. Please confirm that only the “Mgmt-Supervisory” category includes employees that have direct reports/supervisory responsibilities.
   ii. If other categories of FTEs include employees with supervisory responsibilities, please provide a breakout of the supervisors/managers in each of the other categories of FTEs.
   iii. Please advise whether there are any other categories of OPG’s employees that are not reflected in this figure. If so, please update the figure to reflect those employees.

e) With respect to Figure 4b:
   i. Please confirm that only the “Mgmt-Supervisory” category includes employees that have direct reports/supervisory responsibilities.
   ii. If other categories of FTEs include employees with supervisory responsibilities, please provide a breakout of the supervisors/managers in each of the other categories of FTEs.

iii. Please advise whether there are any other categories of OPG's employees that are not reflected in this figure. If so, please update the figure to reflect those employees.

f) With respect to the salary adjustments for performance-based merit increases, please explain how those increases have been estimated and forecast for the 2027-2031 period. As part of the response, please provide the detailed assumptions made and the dollar value of the performance-based merit increases that are included in the costs proposed for recovery during the test period.

g) With respect to management staff, please further discuss the statement that the "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." As part of the response, please provide an illustrative example of this effort for a sample management role.

h) Please provide the detailed methodology, and underlying calculation, supporting the annual overtime budget estimate for the 2027-2031 period. As part of the response, please discuss any changes relative to the overtime forecasting approach applied in EB-2020-0290.

Response

a) Refer to Ex. L-F4-Staff-227.

b) The collective agreement between OPG and the Society of United Professionals expired on December 31, 2025. A binding interest arbitration award was received on January 26, 2026, concluding the renewal process. The renewed agreement covers a three (3) year term from January 1, 2026 through December 31, 2028. The awarded wage increases were 3.5% in 2026, 2.5% in 2027, and 2.0% in 2028.

c) Since EB-2020-0290, OPG's focus shifted from downsizing its operations to undertaking significant projects. OPG's evolving workforce reflects this change in direction and aligns to the current and upcoming operations and project demands, which require a stable and skilled workforce. Given the existing and future resource demands, labour market conditions, and the need to attract and retain skilled talent, many of the remaining Term Employees have been identified for, and offered, placement into regular positions, where those positions are required to support ongoing operational or refurbishment needs.

In accordance with the most current collective agreement provisions, Term Employees may only be hired in place of regular staff in circumstances where the

employee is likely to be surplus and/or to be laid off as a result of Pickering's shutdown or transition to refurbishment. For clarity, OPG can no longer hire Term Employees once Pickering units have been defueled and dewatered, and cannot retain Term Employees past the completion of this preparation for the current safe storage project for Pickering. Accordingly, any further hiring of Term employees is expected to be minimal, and would occur outside of operations and maintenance job classifications. Any additional hiring of Term Employees requires joint agreement with the PWU.

d) i) Confirmed.

ii) Refer to Ex. L-F4-AMPCO-110, parts b) and c).

iii) None.

e) i) Confirmed.

ii) Refer to Ex. L-F4-AMPCO-110, parts b) and c)

iii) None.

f) The salary escalation rates for management performance-based merit increases are a best estimate informed by long-term inflation assumptions and compensation benchmarking results. The assumptions made for the 2027-2031 period are detailed in Ex. L-F4-Staff-227.

The estimated cumulative dollar value of the performance-based merit increases for management salaries included in the costs proposed for cost recovery over the 2027-2031 period for OPG Nuclear Facilities and DNNP LP Facilities is approximately $53M and $5M, respectively, and approximately $1M for Regulated Hydroelectric Facilities in 2027, based on OM&A expenses.

g) OPG conducts an annual review of its management salary band structures, consistent with industry best practice. The review is informed by pay compression considerations, market survey forecasts for average salary structure increases and OPG's competitive market. Any compensation-related adjustments to the salary structure are subject to approval by OPG's Board of Directors.

Chart 1 below provides an illustrative example of the salary band structure for an Engineering Manager role, assuming OPG was to increase its salary band structure by 2.5% in its next review.

Chart 1 - Illustrative Example of 2.5% Salary Band Adjustment for Engineering Manager Role

	Minimum	Midpoint	Maximum
Before Adjustment	$111,000	$145,000	$179,000
After Adjustment	$114,000	$148,500	$183,500

h) OPG's annual overtime budget estimate for the 2027–2031 period is developed by (i) forecasting overtime hours required to execute planned work programs and (ii) valuing those hours using a standard overtime rate (SOR) that is calculated using an hourly rate, the applicable overtime premium, and applicable employer burdens and allowances (as relevant).

In EB-2020-0290, overtime was budgeted on a dollar-only basis rather than in hours. The approach has been updated so that forecast overtime hours are multiplied by the SOR to determine the overtime budget. This improves transparency into forecast overtime volumes and enables more appropriate comparison of planned versus actual overtime usage relative to regular labour budgets.

CCC Interrogatory #086

Interrogatory

Reference:
Exhibit F4, Tab 3, Schedule 1, Attachment 1

Question(s):

Please provide a revised version of Appendix 2-K for the Nuclear Facilities (excluding DNNP LP) that shows the following:

i. A breakout of executives from the management category for both the FTE count and all categories of compensation.
ii. A breakout of salary from incentive pay for each category of employee.
iii. A breakout of total compensation between capital and OM&A costs.

Response

i) to iii)

Refer to Ex. L-F4-AMPCO-110, Attachment 1.

CCC Interrogatory #087

Interrogatory

Reference:
Exhibit F4, Tab 3, Schedule 1, Attachment 2

Question(s):

Please provide a redacted version of Appendix 2-K for the DNNP LP that shows the following:

i. A breakout of executives from the management category for both the FTE count and all categories of compensation.
ii. A breakout of salary from incentive pay for each category of employee.
iii. A breakout of total compensation between capital and OM&A costs.

Response

i), ii) and iii) Refer to Ex. L-F4-AMPCO-111, Attachment 1.

CCC Interrogatory #088

Interrogatory

Reference:
Exhibit F4, Tab 3, Schedule 1, Attachment 3

Question(s):

Please provide a redacted version of Appendix 2-K for the Hydroelectric Facilities that shows the following:

i. A breakout of executives from the management category for both the FTE count and all categories of compensation.
ii. A breakout of salary from incentive pay for each category of employee.
iii. A breakout of total compensation between capital and OM&A costs.

Response

i), ii) and iii) Refer to Ex. L-F4-AMPCO-115, Attachment 1.

CCC Interrogatory #089

Interrogatory

Reference:
Exhibit F4, Tab 3, Schedule 1, Attachments 1-3

Question(s):

Please provide a revised version of Appendix 2-K for the combined regulated business (i.e., all of Nuclear, DNNP LP, and Hydroelectric FTEs and compensation combined) that has all the same information as in the pre-filed Appendix 2-K and also includes:

i. A breakout of executives from the management category for both the FTE count and all categories of compensation.
ii. A breakout of salary from incentive pay for each category of employee.
iii. A breakout of total compensation between capital and OM&A costs.

Response

i. ii. and iii.

Refer to Attachment 1.

Regulated - OM&A

FTE, Compensation and Benefit Information for Regulated Facilities ("Appendix 2k") EB-2025-0297 (2027-2031 Custom IR term)

Numbers may not add due to rounding

Line No.	Regulated Facilities	Hydroelectric Regulated Only				Regulated Facilities (Nuclear including DNNP, and Hydroelectric Facilities)											
		2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 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)	(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**	**FTEs**
	OPG Regulated - Direct																	
1	Executive	5.9	6.7	6.3	6.1	31.3	25.3	28.0	30.0	33.3	32.3	32.3	31.9	28.6	28.6	28.7	28.0	32.2
2	Non-Executive Management	77.5	77.7	78.4	72.9	523.6	425.1	407.8	458.4	493.7	471.7	469.6	464.2	389.1	377.8	377.5	380.4	426.4
3	Management Subtotal	83.4	84.4	84.8	79.1	554.9	450.5	435.8	488.4	527.0	504.0	501.9	496.1	417.7	406.4	406.1	408.4	458.6
4	Society	241.0	247.5	276.4	260.9	1,993.1	1,836.6	1,697.1	1,789.9	1,888.1	1,753.2	1,844.4	1,804.4	1,350.2	1,324.0	1,325.6	1,362.4	1,558.6
5	PWU	646.9	613.9	635.1	618.7	3,693.3	3,514.2	3,056.5	3,089.5	3,270.2	3,168.9	3,329.0	3,291.4	2,794.4	2,793.9	2,844.4	2,845.3	3,255.6
6	Term/ETE/PECO Temporary	0.0	0.0	0.0	0.0	586.2	767.0	887.8	930.0	600.5	237.9	202.2	174.7	0.0	0.0	0.0	0.0	0.0
7	EPSCA	0.0	0.0	0.0	0.0	77.3	94.4	99.4	88.2	100.0	51.5	54.2	25.4	22.0	21.6	21.6	21.0	20.0
8	Subtotal	971.3	945.9	996.3	958.7	6,904.8	6,662.7	6,176.6	6,385.9	6,385.8	5,715.5	5,931.6	5,792.1	4,584.2	4,546.0	4,597.8	4,637.3	5,292.7
	OPG Regulated - Allocated																	
9	Executive	6.3	4.8	3.6	3.3	27.1	25.3	26.8	28.4	27.4	29.5	30.4	33.5	31.3	31.2	31.1	30.6	28.7
10	Non-Executive Management	61.3	56.8	55.4	56.7	289.3	281.5	286.0	325.5	352.5	347.4	395.7	398.5	358.1	358.9	358.0	360.0	358.7
11	Management Subtotal	67.7	61.6	59.1	60.1	316.5	306.7	312.8	353.9	380.0	376.9	426.1	432.0	389.4	390.1	389.1	390.7	387.4
12	Society	72.2	67.9	74.6	77.0	407.4	396.6	419.2	548.3	601.1	570.6	619.2	598.6	534.3	537.1	530.0	536.3	560.3
13	PWU	37.3	38.8	39.3	34.0	427.9	397.4	451.0	482.7	470.3	395.3	420.0	386.0	357.8	354.7	353.0	354.2	388.1
14	Term/ETE/PECO Temporary	0.0	0.0	0.0	0.0	57.6	76.1	79.2	61.9	53.0	39.9	39.0	33.3	0.0	0.0	0.0	0.0	0.0
15	EPSCA	0.0	0.0	0.0	0.0	24.7	25.3	22.1	21.6	15.7	18.4	27.1	28.1	23.1	23.1	23.1	23.1	27.1
16	Subtotal	177.1	168.4	172.9	171.1	1,234.1	1,202.1	1,284.3	1,468.4	1,520.0	1,401.1	1,531.4	1,477.9	1,304.6	1,305.0	1,295.2	1,304.3	1,362.9
	OPG Regulated Facilities																	
17	Executive	12.2	11.5	9.9	9.5	58.4	50.6	54.8	58.3	60.7	61.8	62.7	65.5	59.8	59.8	59.7	58.7	60.8
18	Non-Executive Management	138.8	134.6	133.9	129.6	812.9	706.6	693.8	783.9	846.2	819.1	865.2	862.7	747.2	736.7	735.5	740.4	785.1
19	Management Subtotal	151.0	146.1	143.8	139.1	871.3	757.2	748.6	842.2	907.0	880.9	927.9	928.2	807.0	796.5	795.2	799.1	845.9
20	Society	313.2	315.5	351.0	337.9	2,400.4	2,233.3	2,116.2	2,338.3	2,489.1	2,323.8	2,463.6	2,403.0	1,884.4	1,861.2	1,855.6	1,898.7	2,118.9
21	PWU	684.2	652.7	674.4	652.7	4,121.2	3,911.6	3,507.5	3,572.1	3,740.5	3,564.2	3,749.0	3,677.4	3,152.3	3,148.7	3,197.4	3,199.6	3,643.8
22	Term/ETE/PECO Temporary	0.0	0.0	0.0	0.0	643.9	843.1	967.1	991.9	653.4	277.8	241.2	208.0	0.0	0.0	0.0	0.0	0.0
23	EPSCA	0.0	0.0	0.0	0.0	102.0	119.7	121.5	109.8	115.7	69.9	81.3	53.5	45.1	44.7	44.7	44.1	47.1
24	Total	1,148.5	1,114.3	1,169.2	1,129.8	8,138.8	7,864.8	7,461.0	7,854.3	7,905.7	7,116.6	7,463.0	7,270.0	5,888.8	5,851.0	5,892.9	5,941.5	6,655.7
	Salary & Allowances (including Fiscal Adjustment)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
25	Executive	3.0	3.2	2.8	2.5	15.1	13.6	14.4	14.1	16.0	17.8	16.2	17.2	16.1	16.3	16.7	16.6	17.6
26	Non-Executive Management	18.5	18.1	18.6	18.5	116.0	102.1	108.0	119.4	131.3	138.5	140.2	145.7	132.1	133.3	137.5	143.0	156.3
27	Management Subtotal	21.5	21.3	21.4	21.0	131.1	115.6	122.4	133.5	147.3	156.3	156.4	162.9	148.1	149.6	154.2	159.7	173.9
28	Society	37.8	39.0	42.8	42.2	316.3	319.8	291.0	353.8	380.3	366.5	395.7	393.5	324.8	328.0	338.4	360.8	418.4
29	PWU[2]	73.7	69.3	70.1	69.9	478.7	489.2	418.1	495.6	577.2	497.5	496.1	507.9	453.3	465.2	493.4	509.7	603.8
30	Term[2]/ETE/PECO Temporary	0.0	0.0	0.0	0.0	69.3	95.0	114.9	130.9	84.3	37.2	26.8	24.3	0.0	0.0	0.0	0.0	0.0
31	EPSCA[2]	0.0	0.0	0.0	0.0	14.9	17.1	13.8	11.5	15.7	15.8	12.8	8.8	8.0	8.1	8.5	8.4	9.1
32	Unallocated[3]	(5.1)	(4.9)	(11.7)	(11.0)	(11.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33	Total	127.9	124.7	122.5	122.1	998.9	1,036.7	960.2	1,125.2	1,204.8	1,073.4	1,087.8	1,097.5	934.2	950.9	994.4	1,038.6	1,205.3
	Incentive Pay	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
34	Executive	0.8	1.0	1.1	1.0	7.9	6.8	7.0	9.1	7.7	9.8	8.8	8.5	8.9	9.6	9.9	9.9	10.4
35	Non-Executive Management	2.3	3.1	2.9	2.8	23.0	23.2	20.9	32.0	32.9	40.7	36.1	33.3	34.8	37.4	38.9	39.6	40.6
36	Management Subtotal	3.1	4.1	4.0	3.8	30.9	30.0	27.9	41.1	40.6	50.4	44.9	41.9	43.7	47.0	48.8	49.6	51.0
	Hydro One Shares	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
37	Society	0.4	0.8	1.8	0.9	5.5	5.8	5.6	5.7	6.3	6.7	3.2	3.0	2.9	2.9	2.4	2.3	2.2
38	PWU	0.0	1.2	2.4	1.9	12.4	14.2	14.5	14.9	15.0	18.4	8.5	8.0	7.8	7.6	6.9	6.6	1.6
39	Total	0.4	2.0	4.3	2.8	17.9	20.0	20.1	20.7	21.3	25.1	11.7	11.0	10.7	10.5	9.3	8.9	3.8
	Overtime	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
40	Society	1.9	2.4	2.4	2.8	34.3	38.5	40.3	40.3	40.2	28.9	27.8	26.2	24.1	21.2	24.7	23.6	27.5
41	PWU	5.5	7.6	7.7	8.4	75.4	83.7	72.7	82.9	92.1	68.1	71.6	66.9	73.8	64.9	77.0	70.5	83.5
42	Term/ETE/PECO Temporary	0.0	0.0	0.0	0.0	8.7	11.3	15.6	19.9	11.2	3.9	3.1	2.5	0.0	0.0	0.0	0.0	0.0
43	EPSCA	0.0	0.0	0.0	0.0	1.5	2.8	3.8	3.7	5.0	1.9	0.9	0.6	1.0	0.8	0.9	0.8	0.7
44	Unallocated[3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
45	Total	7.3	10.0	10.1	11.2	119.8	136.2	132.4	146.9	148.5	102.7	103.4	96.2	98.8	87.0	102.6	95.0	111.7
	Benefits (Current Benefits and Pension & OPEB)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
46	Executive	1.2	1.3	1.1	1.0	6.7	7.8	7.8	4.9	6.0	6.4	5.8	6.7	6.1	6.2	6.4	6.4	6.8
47	Non-Executive Management	8.1	7.9	9.5	8.8	59.0	60.6	60.1	32.6	53.7	52.7	48.2	55.3	48.9	49.0	51.2	52.7	58.0
48	Management Subtotal	9.3	9.1	10.6	9.9	65.7	68.4	67.9	37.5	59.7	59.2	54.1	62.0	55.0	55.2	57.7	59.1	64.8
49	Society	16.6	16.7	21.6	20.2	158.9	178.0	168.7	88.8	155.5	131.1	134.1	149.5	116.0	117.6	123.9	131.6	156.1
50	PWU	31.0	29.6	34.1	32.1	215.1	234.8	206.9	127.6	201.4	189.5	167.5	182.5	160.8	163.9	174.5	181.9	220.6
51	Term/ETE/PECO Temporary	0.0	0.0	0.0	0.0	5.0	5.8	8.0	8.8	7.1	2.8	1.7	1.5	0.0	0.0	0.0	0.0	0.0
52	EPSCA	0.0	0.0	0.0	0.0	1.0	0.2	0.3	(0.3)	(0.3)	1.3	0.6	0.4	0.4	0.4	0.4	0.4	0.4
53	Unallocated[3]	(1.0)	(1.4)	(3.0)	(1.8)	3.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
54	Total	55.9	54.0	63.4	60.4	449.1	487.2	451.8	262.4	423.3	383.9	357.9	395.9	332.3	337.1	356.5	373.0	441.9
55	Current Benefits (Statutory)	8.3	8.3	8.1	7.9	63.5	61.1	64.8	69.2	76.7	70.7	77.5	77.1	66.0	66.7	71.6	72.5	84.3
56	Current Benefits (Non-Statutory)	5.7	6.5	5.9	5.9	38.2	48.9	46.8	48.3	46.4	56.2	53.4	53.5	46.7	48.0	50.6	52.2	61.0
57	Pension & OPEB (Current Service)[1]	41.9	39.2	49.4	46.6	347.3	377.2	340.1	144.9	300.3	257.1	226.9	265.4	219.5	222.3	234.3	248.3	296.6
	TOTAL COMPENSATION	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
58	Executive	5.0	5.5	5.0	4.5	29.7	28.2	29.2	28.1	29.8	34.0	30.8	32.5	31.1	32.1	33.1	32.9	34.8
59	Non-Executive Management	28.9	29.0	31.0	30.1	198.0	185.9	189.1	184.0	217.9	231.9	224.5	234.3	215.8	219.7	227.6	235.4	254.9
60	Management Subtotal	33.9	34.5	35.9	34.7	227.8	214.0	218.3	212.1	247.6	265.9	255.3	266.8	246.9	251.9	260.7	268.3	289.7
61	Society	56.6	58.8	68.7	66.1	514.9	542.0	505.7	488.7	582.2	533.2	560.7	572.1	467.8	469.6	489.4	518.4	604.1
62	PWU	110.2	107.7	114.3	112.3	781.7	821.9	712.1	721.1	885.8	773.6	743.7	765.2	695.6	701.6	751.8	768.7	909.6
63	Term/ETE/PECO Temporary	0.0	0.0	0.0	0.0	82.9	112.0	138.5	159.5	102.7	43.8	31.6	28.4	0.0	0.0	0.0	0.0	0.0
64	EPSCA	0.0	0.0	0.0	0.0	17.4	20.1	17.9	14.9	20.3	19.0	14.3	9.9	9.3	9.3	9.8	9.6	10.3
65	Unallocated[3]	(6.1)	(6.3)	(14.7)	(12.8)	(8.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
66	Total	194.6	194.8	204.2	200.2	1,616.5	1,710.1	1,592.5	1,596.3	1,838.6	1,635.6	1,605.7	1,642.4	1,419.7	1,432.4	1,511.6	1,565.1	1,813.7

[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)

Regulated - CAPITAL

FTE, Compensation and Benefit Information for Regulated Facilities ("Appendix 2k")

Numbers may not add due to rounding

		Hydroelectric Regulated Only				Regulated Facilities (Nuclear including DNNP, and Hydroelectric Facilities)											
Line No.	Regulated Facilities	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 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)	(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**	**FTEs**
	OPG Regulated - Direct																	
1	Executive	0.0	0.0	0.0	0.0	6.9	7.2	6.4	6.2	10.2	13.1	16.0	14.4	13.2	11.9	10.4	9.7	9.3
2	Non-Executive Management	1.2	2.1	2.7	5.0	123.6	114.7	135.9	151.3	227.5	290.9	380.8	343.0	373.4	360.3	343.9	322.0	283.1
3	Management Subtotal	1.2	2.1	2.7	5.0	130.5	121.9	142.2	157.5	237.7	304.0	396.8	357.4	386.6	372.2	354.3	331.7	292.3
4	Society	24.7	34.8	44.4	63.5	477.4	520.0	537.9	616.3	793.3	1,036.4	1,445.4	1,391.1	1,674.3	1,606.5	1,568.0	1,501.2	1,272.0
5	PWU	18.1	25.1	35.3	45.9	247.5	257.1	284.6	289.3	356.4	446.7	578.2	796.6	1,427.4	1,503.6	1,546.7	1,466.4	1,034.3
6	Term/ETE/PECO Temporary	0.0	0.0	0.0	0.0	4.9	11.7	20.0	25.7	25.9	17.1	29.0	38.3	7.0	7.0	7.0	0.0	0.0
7	EPSCA	0.0	0.0	0.0	0.0	154.1	256.9	297.7	342.5	317.0	280.9	263.7	167.2	372.6	491.2	426.8	342.0	259.9
8	Subtotal	44.1	62.0	82.4	114.4	1,014.4	1,167.6	1,282.3	1,431.2	1,730.3	2,085.2	2,713.1	2,750.6	3,867.9	3,980.5	3,902.7	3,641.3	2,858.5
	OPG Regulated - Allocated																	
9	Executive	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Non-Executive Management	0.0	0.7	0.7	0.7	7.9	9.5	13.3	16.0	26.9	39.4	40.2	46.7	51.3	48.0	42.0	38.2	27.5
11	Management Subtotal	0.0	0.7	0.7	0.7	7.9	9.6	13.3	16.0	26.9	39.4	40.2	46.7	51.3	48.0	42.0	38.2	27.5
12	Society	1.8	1.8	2.6	4.5	37.3	41.7	51.7	79.0	112.8	155.9	202.1	212.3	278.2	264.4	256.6	246.3	207.0
13	PWU	0.0	0.0	0.1	0.1	14.6	16.0	16.4	26.9	31.2	58.5	79.5	91.3	156.4	155.7	157.2	151.9	126.3
14	Term/ETE/PECO Temporary	0.0	0.0	0.0	0.0	2.4	1.3	1.1	2.7	7.7	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	EPSCA	0.0	0.0	0.0	0.0	17.4	19.1	8.9	10.0	14.3	11.1	9.9	8.9	13.9	13.9	13.9	13.9	11.2
16	Subtotal	1.8	2.4	3.3	5.2	79.6	87.6	91.4	134.6	192.8	268.0	331.7	359.3	499.8	482.1	469.6	450.3	372.0
	OPG Regulated Facilities																	
17	Executive	0.0	0.0	0.0	0.0	6.9	7.3	6.4	6.2	10.2	13.1	16.0	14.4	13.2	11.9	10.4	9.7	9.3
18	Non-Executive Management	1.2	2.8	3.3	5.7	131.5	124.2	149.2	167.3	254.3	330.3	421.0	389.7	424.7	408.3	385.9	360.1	310.5
19	Management Subtotal	1.2	2.8	3.3	5.7	138.4	131.5	155.5	173.5	264.5	343.4	437.0	404.1	437.9	420.2	396.2	369.9	319.8
20	Society	26.5	36.6	47.0	68.0	514.7	561.7	589.6	695.3	906.1	1,192.3	1,647.5	1,603.5	1,952.5	1,871.0	1,824.5	1,747.6	1,479.0
21	PWU	18.1	25.1	35.4	46.0	262.0	273.1	301.0	316.2	387.6	505.3	657.7	888.0	1,583.9	1,659.3	1,703.9	1,618.3	1,160.6
22	Term/ETE/PECO Temporary	0.0	0.0	0.0	0.0	7.3	13.1	21.1	28.3	33.6	20.2	29.0	38.3	7.0	7.0	7.0	0.0	0.0
23	EPSCA	0.0	0.0	0.0	0.0	171.6	275.9	306.6	352.5	331.3	292.0	273.6	176.1	386.5	505.1	440.7	355.9	271.1
24	Total	45.9	64.5	85.7	119.6	1,094.0	1,255.2	1,373.7	1,565.9	1,923.1	2,353.2	3,044.9	3,109.9	4,367.7	4,462.6	4,372.3	4,091.7	3,230.5
	Salary & Allowances (including Fiscal Adjustment)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
25	Executive	0.0	0.0	0.0	0.0	2.2	1.9	1.5	1.6	2.6	3.2	3.9	3.7	3.5	3.2	2.9	2.7	2.7
26	Non-Executive Management	0.2	0.4	0.5	0.9	20.0	17.9	22.5	25.8	40.3	53.6	68.3	65.8	75.1	74.9	74.1	69.5	60.9
27	Management Subtotal	0.2	0.4	0.5	0.9	22.2	19.8	24.1	27.4	42.9	56.9	72.1	69.5	78.6	78.1	77.0	72.2	63.5
28	Society	3.3	4.6	5.8	8.6	64.7	75.1	81.5	103.2	134.4	181.2	241.8	242.2	315.6	315.0	325.0	316.8	276.2
29	PWU[2]	2.1	3.0	4.1	5.4	28.3	38.4	42.1	40.1	51.3	64.9	83.9	122.0	227.8	247.8	267.6	257.5	186.4
30	Term[3]/ETE/PECO Temporary	0.0	0.0	0.0	0.0	0.5	1.8	2.7	4.1	4.6	1.8	4.4	5.4	1.2	1.2	1.3	0.0	0.0
31	EPSCA[2]	0.0	0.0	0.0	0.0	25.9	47.0	55.3	68.7	66.3	51.7	45.2	29.9	71.5	93.7	86.0	71.3	56.1
32	Unallocated[3]	1.8	2.6	3.7	4.4	29.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33	Total	7.3	10.6	14.1	19.3	171.0	182.1	205.7	243.6	299.5	356.5	447.4	469.0	694.7	735.7	756.8	717.8	582.2
	Incentive Pay	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
34	Executive	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Non-Executive Management	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Management Subtotal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Hydro One Shares	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
37	Society	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
38	PWU	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
39	Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Overtime	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
40	Society	0.4	0.7	1.0	1.4	7.6	8.4	9.9	13.9	18.6	21.7	21.7	19.6	26.8	26.9	27.9	27.5	22.8
41	PWU	0.4	0.9	1.4	1.8	6.2	7.0	8.3	9.0	12.7	14.3	15.1	17.9	40.5	41.9	46.1	46.7	32.4
42	Term/ETE/PECO Temporary	0.0	0.0	0.0	0.0	0.1	0.2	0.6	0.7	0.7	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
43	EPSCA	0.0	0.0	0.0	0.0	3.2	9.3	15.3	18.2	18.5	8.9	10.3	4.3	18.8	17.7	17.3	17.8	14.6
44	Unallocated[3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
45	Total	0.8	1.5	2.4	3.2	17.0	24.9	33.9	41.8	50.6	45.2	47.1	41.9	86.1	86.5	91.3	92.1	69.8
	Benefits (Current Benefits and Pension & OPEB)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
46	Executive	0.0	0.0	0.0	0.0	0.8	0.8	0.7	0.8	0.9	1.3	1.5	1.5	1.4	1.3	1.2	1.1	1.1
47	Non-Executive Management	0.1	0.2	0.2	0.4	8.6	6.6	8.8	12.0	14.3	21.2	27.0	26.3	30.7	30.5	30.2	28.4	25.1
48	Management Subtotal	0.1	0.2	0.2	0.4	9.3	7.4	9.5	12.8	15.2	22.5	28.5	27.8	32.2	31.8	31.4	29.5	26.2
49	Society	1.4	2.0	2.5	3.7	25.6	25.4	29.6	48.0	48.9	73.0	97.6	97.2	133.4	133.9	138.8	135.5	118.5
50	PWU	0.9	1.3	1.7	2.3	11.7	10.7	12.1	16.8	16.1	22.8	30.3	45.4	89.1	96.7	104.8	100.8	71.7
51	Term/ETE/PECO Temporary	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.3	0.4	0.1	0.2	0.3	0.1	0.1	0.1	0.0	0.0
52	EPSCA	0.0	0.0	0.0	0.0	1.8	3.0	4.3	4.9	5.3	2.8	2.6	1.6	4.3	5.3	4.9	4.3	3.4
53	Unallocated[3]	0.2	0.2	0.3	0.5	5.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
54	Total	2.6	3.8	4.8	6.8	53.6	46.7	55.8	82.9	85.9	121.0	159.2	172.3	259.0	267.8	280.0	270.1	219.8
55	Current Benefits (Statutory)	0.5	0.7	1.0	1.3	10.9	9.7	11.9	15.9	21.9	25.6	32.4	33.6	50.0	52.1	53.9	51.8	41.9
56	Current Benefits (Non-Statutory)	0.4	0.6	0.7	1.0	7.3	4.6	5.4	8.2	13.2	15.7	20.9	21.5	32.4	33.4	35.0	33.8	27.6
57	Pension & OPEB (Current Service)[1]	1.7	2.5	3.0	4.6	35.4	32.4	38.5	58.8	50.7	79.7	105.9	117.2	176.6	182.2	191.0	184.5	150.2
	TOTAL COMPENSATION	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
58	Executive	0.0	0.0	0.0	0.0	3.0	2.7	2.2	2.3	3.5	4.5	5.4	5.3	4.9	4.5	4.1	3.8	3.8
59	Non-Executive Management	0.3	0.6	0.8	1.3	28.6	24.5	31.3	37.9	54.7	74.8	95.2	92.1	105.9	105.4	104.3	97.9	86.0
60	Management Subtotal	0.3	0.6	0.8	1.3	31.6	27.2	33.6	40.2	58.1	79.3	100.6	97.4	110.8	109.9	108.4	101.7	89.7
61	Society	5.1	7.3	9.3	13.7	97.8	108.8	121.0	165.2	201.9	275.9	361.1	359.1	475.8	475.8	491.7	479.9	417.4
62	PWU	3.4	5.1	7.2	9.5	46.2	56.1	62.4	66.0	80.1	101.9	129.2	185.3	357.4	386.4	418.5	405.0	290.5
63	Term/ETE/PECO Temporary	0.0	0.0	0.0	0.0	0.6	2.1	3.5	5.1	5.8	2.2	4.6	5.7	1.2	1.3	1.3	0.0	0.0
64	EPSCA	0.0	0.0	0.0	0.0	30.8	59.3	74.9	91.8	90.0	63.4	58.2	35.8	94.7	116.7	108.2	93.4	74.1
65	Unallocated[3]	2.0	2.8	4.0	4.9	34.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
66	Total	10.8	15.9	21.3	29.4	241.6	253.6	295.4	368.2	435.9	522.7	653.7	683.3	1,039.8	1,090.0	1,128.1	1,080.0	871.8

[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)

Regulated - PROVISION (Nuclear Facilities only)

FTE, Compensation and Benefit Information for Regulated Facilities ("Appendix 2k")

Numbers may not add due to rounding

Line No.	Regulated Facilities	Regulated Facilities (Nuclear)												
		2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Actual	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Staff (Regular and Non-Regular)	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**
	OPG Regulated - Direct													
1	Executive	2.2	1.4	2.1	2.1	2.0	1.5	2.0	2.0	2.0	2.0	2.0	2.0	2.0
2	Non-Executive Management	37.6	41.9	42.8	50.0	56.5	58.6	66.2	60.5	60.0	59.5	50.0	52.1	51.6
3	Management Subtotal	39.8	43.2	44.9	52.0	58.5	60.1	68.2	62.5	62.0	61.5	52.0	54.1	53.6
4	Society	141.3	153.9	161.9	186.9	221.1	258.7	303.7	287.6	259.6	245.2	207.4	209.4	211.6
5	PWU	185.6	198.2	202.3	210.2	306.9	575.0	605.5	486.8	434.5	419.5	368.5	369.5	369.5
6	Term/ETE/PECO Temporary	7.8	16.1	20.2	33.0	31.1	21.0	9.0	2.3	0.0	0.0	0.0	0.0	0.0
7	EPSCA	2.9	4.4	4.1	4.0	10.2	45.6	3.3	2.3	2.3	2.2	2.0	2.0	2.0
8	Subtotal	377.3	416.0	433.4	486.1	627.8	960.5	989.7	841.5	758.4	728.4	629.9	635.0	636.7
	OPG Regulated - Allocated													
9	Executive	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Non-Executive Management	1.2	1.7	3.3	3.8	4.3	7.1	8.2	8.0	7.7	7.2	6.6	6.6	6.6
11	Management Subtotal	1.2	1.7	3.3	3.8	4.3	7.1	8.2	8.0	7.7	7.2	6.6	6.6	6.6
12	Society	3.8	5.2	8.4	8.5	12.8	25.5	29.7	26.1	26.4	26.6	21.8	21.9	22.1
13	PWU	10.1	8.1	6.3	5.5	13.0	21.1	28.6	26.1	25.0	23.7	21.7	22.7	22.7
14	Term/ETE/PECO Temporary	0.6	1.1	0.0	0.0	1.0	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	EPSCA	0.0	0.0	0.0	0.0	0.9	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Subtotal	15.7	16.1	18.1	17.8	31.9	54.9	66.5	60.1	59.1	57.5	50.1	51.2	51.4
	OPG Regulated Facilities													
17	Executive	2.2	1.4	2.1	2.1	2.0	1.5	2.0	2.0	2.0	2.0	2.0	2.0	2.0
18	Non-Executive Management	38.8	43.5	46.2	53.8	60.7	65.7	74.4	68.5	67.7	66.7	56.6	58.7	58.2
19	Management Subtotal	41.0	44.9	48.2	55.8	62.7	67.2	76.4	70.5	69.7	68.7	58.6	60.7	60.2
20	Society	145.0	159.1	170.3	195.4	233.9	284.2	333.4	313.7	286.0	271.8	229.2	231.4	233.7
21	PWU	195.7	206.3	208.6	215.7	320.0	596.2	634.1	512.8	459.5	443.2	390.2	392.2	392.2
22	Term/ETE/PECO Temporary	8.3	17.2	20.2	33.0	32.1	21.9	9.0	2.3	0.0	0.0	0.0	0.0	0.0
23	EPSCA	2.9	4.4	4.1	4.0	11.0	46.0	3.3	2.3	2.3	2.2	2.0	2.0	2.0
24	Total	392.9	432.1	451.5	503.9	659.7	1,015.4	1,056.2	901.6	817.5	785.9	680.0	686.2	688.1
	Salary & Allowances (including Fiscal Adjustment)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
25	Executive	0.3	0.4	0.5	0.4	0.5	0.3	0.4	0.5	0.5	0.5	0.5	0.5	0.5
26	Non-Executive Management	5.9	6.8	7.7	8.1	9.8	10.8	12.3	11.5	11.7	11.8	10.6	11.2	11.4
27	Management Subtotal	6.2	7.2	8.2	8.6	10.3	11.1	12.8	11.9	12.1	12.3	11.1	11.7	11.9
28	Society	18.4	21.4	23.6	28.2	34.7	44.9	51.2	49.1	46.4	46.0	41.6	42.7	44.7
29	PWU[2]	21.4	23.1	24.3	26.4	43.3	79.5	84.8	69.0	63.5	63.2	58.1	59.3	61.4
30	Term[1]/ETE/PECO Temporary	0.9	2.0	2.3	4.3	4.6	2.8	1.0	0.2	0.0	0.0	0.0	0.0	0.0
31	EPSCA[2]	0.4	0.7	1.0	0.7	2.1	8.1	0.5	0.4	0.4	0.4	0.4	0.4	0.4
32	Unallocated[3]	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33	Total	49.3	54.2	59.4	68.1	95.0	146.5	150.2	130.7	122.4	121.9	111.1	114.0	118.4
	Incentive Pay	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
34	Executive	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Non-Executive Management	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Management Subtotal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Hydro One Shares	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
37	Society	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0
38	PWU	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.2	0.1	0.0
39	Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.2	0.2	0.0
	Overtime	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
40	Society	1.8	1.9	2.0	2.3	3.9	4.7	0.6	0.7	0.6	0.6	0.7	0.7	0.7
41	PWU	3.4	3.9	4.9	5.0	7.7	11.6	4.8	4.8	4.8	5.0	5.1	5.3	5.4
42	Term/ETE/PECO Temporary	0.1	0.2	0.3	0.4	0.4	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0
43	EPSCA	0.0	0.1	0.1	0.1	0.3	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
44	Unallocated[3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
45	Total	5.3	6.1	7.3	7.9	12.2	17.5	5.5	5.5	5.5	5.6	5.8	6.0	6.2
	Benefits (Current Benefits and Pension & OPEB)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
46	Executive	0.1	0.1	0.2	0.2	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2
47	Non-Executive Management	2.7	2.9	3.2	3.9	3.5	4.2	4.8	4.7	4.8	4.9	4.4	4.6	4.7
48	Management Subtotal	2.8	3.0	3.4	4.1	3.7	4.3	4.9	4.9	5.0	5.1	4.6	4.8	4.9
49	Society	8.0	8.3	9.4	12.8	12.4	17.7	20.2	20.1	19.3	19.2	17.3	17.8	18.6
50	PWU	8.9	8.4	9.2	11.1	14.4	28.8	31.6	26.9	24.7	24.6	22.7	23.2	24.1
51	Term/ETE/PECO Temporary	0.1	0.1	0.1	0.3	0.3	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
52	EPSCA	0.0	0.0	0.0	0.0	0.1	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
53	Unallocated[3]	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
54	Total	20.4	19.9	22.1	28.4	31.0	51.4	56.9	51.8	49.0	48.8	44.7	45.8	47.6
55	Current Benefits (Statutory)	3.2	3.0	3.3	4.2	6.6	10.4	10.1	8.9	8.3	8.3	7.6	7.8	8.1
56	Current Benefits (Non-Statutory)	2.3	2.1	2.3	3.0	5.0	6.8	7.7	6.7	6.3	6.3	5.7	5.9	6.1
57	Pension & OPEB (Current Service)[1]	15.0	14.8	16.5	21.2	19.3	34.3	39.0	36.3	34.4	34.3	31.3	32.2	33.4
	TOTAL COMPENSATION	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
58	Executive	0.4	0.5	0.7	0.6	0.6	0.5	0.6	0.6	0.7	0.7	0.7	0.7	0.7
59	Non-Executive Management	8.6	9.7	10.9	12.1	13.4	15.0	17.1	16.2	16.5	16.7	15.0	15.8	16.1
60	Management Subtotal	9.0	10.2	11.6	12.7	14.0	15.4	17.7	16.8	17.2	17.4	15.7	16.5	16.8
61	Society	28.2	31.5	35.0	43.4	51.0	67.3	72.1	70.0	66.4	65.9	59.5	61.1	64.1
62	PWU	33.7	35.4	38.3	42.5	65.5	119.9	121.2	100.7	93.1	92.8	86.1	88.0	91.0
63	Term/ETE/PECO Temporary	1.0	2.3	2.8	5.0	5.3	3.2	1.2	0.3	0.0	0.0	0.0	0.0	0.0
64	EPSCA	0.5	0.9	1.1	0.8	2.5	9.6	0.5	0.4	0.4	0.4	0.4	0.4	0.4
65	Unallocated[3]	2.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
66	Total	75.0	80.2	88.8	104.4	138.2	215.4	212.7	188.1	177.0	176.4	161.7	166.0	172.2

[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)

Regulated - Total

FTE, Compensation and Benefit Information for Regulated Facilities ("Appendix 2k")

Numbers may not add due to rounding

Line No.	OPG Regulated Facilities	Hydroelectric Regulated Only				Regulated Facilities (Nuclear including DNNP, and Hydroelectric Facilities)											
		2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 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)	(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**	**FTEs**
	OPG Regulated - Direct																	
1	Executive	5.9	6.7	6.3	6.1	40.4	34.0	36.4	38.2	45.5	46.9	50.3	48.4	43.7	42.5	41.0	39.7	43.4
2	Non-Executive Management	78.7	79.8	81.1	77.9	684.8	581.7	586.5	659.7	777.6	821.2	916.6	867.8	822.6	797.6	771.3	754.4	761.0
3	Management Subtotal	84.6	86.5	87.4	84.1	725.2	615.6	622.9	697.9	823.1	868.1	966.9	916.1	866.3	840.1	812.4	794.2	804.4
4	Society	265.7	282.4	320.8	324.5	2,611.8	2,510.5	2,396.8	2,593.2	2,902.5	3,048.3	3,593.4	3,483.2	3,284.0	3,175.8	3,101.0	3,073.1	3,042.2
5	PWU	665.1	639.0	670.4	664.6	4,126.3	3,969.5	3,543.3	3,588.9	3,933.5	4,190.7	4,512.8	4,574.8	4,656.4	4,717.0	4,759.6	4,681.2	4,659.4
6	Term/ETE/PECO Temporary	0.0	0.0	0.0	0.0	598.9	794.9	928.0	988.6	657.5	276.0	240.2	215.2	7.0	7.0	7.0	0.0	0.0
7	EPSCA	0.0	0.0	0.0	0.0	234.3	355.7	401.3	434.7	427.2	378.0	321.2	194.9	396.9	515.0	450.4	365.1	281.9
8	Subtotal	1,015.4	1,008.0	1,078.6	1,073.1	8,296.5	8,246.3	7,892.4	8,303.3	8,743.8	8,761.2	9,634.4	9,384.2	9,210.6	9,254.8	9,130.3	8,913.6	8,787.9
	OPG Regulated - Allocated																	
9	Executive	6.3	4.8	3.6	3.3	27.1	25.3	26.8	28.4	27.4	29.5	30.4	33.5	31.3	31.2	31.1	30.6	28.7
10	Non-Executive Management	61.3	57.5	56.1	57.4	298.4	292.7	302.7	345.3	383.7	393.9	444.1	453.2	417.0	414.1	406.6	404.8	392.8
11	Management Subtotal	67.7	62.3	59.7	60.7	325.5	317.9	329.5	373.6	411.1	423.4	474.5	486.7	448.3	445.3	437.6	435.4	421.5
12	Society	74.0	69.7	77.2	81.5	448.4	443.6	479.3	635.8	726.6	752.0	851.0	837.0	838.9	828.2	808.4	804.6	789.3
13	PWU	37.3	38.8	39.4	34.1	452.6	421.5	473.7	515.1	514.5	475.0	528.1	503.4	539.3	534.2	531.9	528.8	537.1
14	Term/ETE/PECO Temporary	0.0	0.0	0.0	0.0	60.6	78.5	80.3	64.6	61.6	43.8	39.0	33.3	0.0	0.0	0.0	0.0	0.0
15	EPSCA	0.0	0.0	0.0	0.0	42.1	44.4	30.9	31.6	30.8	29.9	37.0	37.0	37.0	37.0	37.0	37.0	38.3
16	Subtotal	179.0	170.8	176.2	176.3	1,329.3	1,305.8	1,393.8	1,620.8	1,744.7	1,724.0	1,929.6	1,897.3	1,863.5	1,844.6	1,814.9	1,805.8	1,786.2
	OPG Regulated Facilities																	
17	Executive	12.2	11.5	9.9	9.5	67.5	59.2	63.2	66.6	72.9	76.4	80.7	81.9	75.0	73.7	72.1	70.4	72.1
18	Non-Executive Management	140.0	137.3	137.2	135.3	983.2	874.3	889.2	1,005.0	1,161.3	1,215.1	1,360.7	1,320.9	1,239.6	1,211.7	1,177.9	1,159.3	1,153.8
19	Management Subtotal	152.2	148.8	147.1	144.8	1,050.7	933.6	952.4	1,071.5	1,234.2	1,291.5	1,441.4	1,402.8	1,314.6	1,285.4	1,250.0	1,229.6	1,225.9
20	Society	339.8	352.1	398.0	405.9	3,060.2	2,954.1	2,876.1	3,229.0	3,629.2	3,800.3	4,444.5	4,320.2	4,122.9	4,003.9	3,909.4	3,877.7	3,831.5
21	PWU	702.3	677.8	709.8	698.7	4,578.9	4,391.0	4,017.1	4,104.0	4,448.0	4,665.7	5,040.8	5,078.2	5,195.6	5,251.2	5,291.5	5,210.1	5,196.6
22	Term/ETE/PECO Temporary	0.0	0.0	0.0	0.0	659.5	873.4	1,008.4	1,053.2	719.1	319.8	279.2	248.5	7.0	7.0	7.0	0.0	0.0
23	EPSCA	0.0	0.0	0.0	0.0	276.4	400.0	432.2	466.3	458.0	407.9	358.2	231.8	433.9	551.9	487.4	402.0	320.2
24	Total	1,194.4	1,178.8	1,254.9	1,249.4	9,625.8	9,552.1	9,286.2	9,924.0	10,488.5	10,485.2	11,564.0	11,281.5	11,074.0	11,099.4	10,945.2	10,719.4	10,574.2
	Salary & Allowances (including Fiscal Adjustment)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
25	Executive	3.0	3.2	2.8	2.5	17.6	15.9	16.4	16.1	19.0	21.3	20.5	21.4	20.0	20.0	20.1	19.9	20.8
26	Non-Executive Management	18.7	18.5	19.1	19.5	141.9	126.8	138.3	153.4	181.5	202.9	220.7	223.0	218.9	220.1	222.2	223.7	228.6
27	Management Subtotal	21.7	21.7	21.9	22.0	159.6	142.6	154.7	169.5	200.5	224.3	241.3	244.4	238.9	240.0	242.3	243.5	249.4
28	Society	41.0	43.6	48.6	50.8	399.4	416.2	396.2	485.2	549.4	592.7	688.6	684.9	686.8	689.0	704.9	720.3	739.3
29	PWU[2]	75.8	72.3	74.2	75.3	528.4	550.7	484.4	562.1	671.8	641.9	664.8	698.9	744.5	776.1	819.1	826.5	851.7
30	Term[1]/ETE/PECO Temporary	0.0	0.0	0.0	0.0	70.7	98.7	120.0	139.2	93.6	41.9	32.2	30.0	1.2	1.2	1.3	0.0	0.0
31	EPSCA[2]	0.0	0.0	0.0	0.0	41.1	64.8	70.0	80.9	84.0	75.7	58.5	39.1	79.8	102.1	94.8	80.1	65.5
32	Unallocated[3]	(3.3)	(2.3)	(8.0)	(6.6)	19.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33	Total	135.2	135.3	136.7	141.5	1,219.1	1,273.0	1,225.2	1,436.9	1,599.3	1,576.4	1,685.5	1,697.2	1,751.3	1,808.5	1,862.4	1,870.5	1,905.9
	Incentive Pay	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
34	Executive	0.8	1.0	1.1	1.0	7.9	6.8	7.0	9.1	7.7	9.8	8.8	8.5	8.9	9.6	9.9	9.9	10.4
35	Non-Executive Management	2.3	3.1	2.9	2.8	23.0	23.2	20.9	32.0	32.9	40.7	36.1	33.3	34.8	37.4	38.9	39.6	40.6
36	Management Subtotal	3.1	4.1	4.0	3.8	30.9	30.0	27.9	41.1	40.6	50.4	44.9	41.9	43.7	47.0	48.8	49.6	51.0
	Hydro One Shares	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
37	Society	0.4	0.8	1.8	0.9	5.5	5.8	5.6	5.7	6.3	6.7	3.3	3.0	3.0	2.9	2.4	2.3	2.2
38	PWU	0.0	1.2	2.4	1.9	12.4	14.2	14.5	14.9	15.0	18.4	8.5	8.0	7.9	7.6	7.0	6.7	1.6
39	Total	0.4	2.0	4.3	2.8	17.9	20.0	20.1	20.7	21.3	25.1	11.8	11.1	10.8	10.5	9.4	9.0	3.8
	Overtime	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
40	Society	2.3	3.0	3.4	4.2	43.6	48.7	52.2	56.5	62.6	55.3	50.1	46.5	51.5	48.7	53.3	51.8	51.0
41	PWU	5.9	8.5	9.1	10.1	84.9	94.6	85.8	97.0	112.6	94.0	91.5	89.6	119.1	111.8	128.2	122.5	121.4
42	Term/ETE/PECO Temporary	0.0	0.0	0.0	0.0	8.8	11.7	16.4	21.0	12.3	4.4	3.2	2.5	0.0	0.0	0.0	0.0	0.0
43	EPSCA	0.0	0.0	0.0	0.0	4.7	12.2	19.2	22.0	23.8	11.8	11.2	5.0	19.8	18.5	18.3	18.6	15.3
44	Unallocated[3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
45	Total	8.2	11.5	12.5	14.4	142.1	167.2	173.7	196.5	211.3	165.4	156.0	143.6	190.4	179.0	199.7	193.0	187.7
	Benefits (Current Benefits and Pension & OPEB)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
46	Executive	1.2	1.3	1.1	1.0	7.7	8.7	8.8	5.9	7.1	7.9	7.5	8.5	7.8	7.7	7.8	7.7	8.1
47	Non-Executive Management	8.2	8.0	9.7	9.2	70.2	70.1	72.1	48.5	71.5	78.1	80.0	86.3	84.5	84.4	85.8	85.7	87.8
48	Management Subtotal	9.4	9.3	10.8	10.3	77.9	78.8	80.8	54.4	78.6	85.9	87.5	94.7	92.2	92.1	93.6	93.4	95.9
49	Society	18.0	18.7	24.1	23.9	192.5	211.6	207.7	149.7	216.8	221.8	251.9	266.7	268.7	270.6	280.0	284.9	293.1
50	PWU	31.9	30.9	35.9	34.4	235.8	254.0	228.2	155.5	232.0	241.1	229.3	254.7	274.6	285.2	302.0	305.9	316.4
51	Term/ETE/PECO Temporary	0.0	0.0	0.0	0.0	5.1	6.0	8.4	9.4	7.8	3.0	2.0	1.8	0.1	0.1	0.1	0.0	0.0
52	EPSCA	0.0	0.0	0.0	0.0	2.8	3.3	4.7	4.7	5.1	4.5	3.3	2.0	4.8	5.7	5.4	4.7	3.8
53	Unallocated[3]	(0.8)	(1.1)	(2.6)	(1.3)	9.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
54	Total	58.5	57.8	68.1	67.2	523.1	553.8	529.7	373.7	540.2	556.4	574.0	620.0	640.3	653.7	681.1	688.9	709.3
55	Current Benefits (Statutory)	8.7	9.0	9.1	9.2	77.6	73.8	80.1	89.3	105.3	106.6	120.0	119.5	124.3	127.2	133.1	132.1	134.3
56	Current Benefits (Non-Statutory)	6.1	7.1	6.6	6.8	47.7	55.6	54.5	59.5	64.7	78.6	82.0	81.6	85.4	87.7	91.4	92.0	94.6
57	Pension & OPEB (Current Service)[1]	43.7	41.7	52.4	51.2	397.7	424.4	395.2	224.9	370.3	371.1	371.9	418.9	430.6	438.8	456.6	464.9	480.3
	TOTAL COMPENSATION	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
58	Executive	5.0	5.5	5.0	4.5	33.2	31.3	32.1	31.1	33.8	38.9	36.8	38.4	36.6	37.3	37.9	37.5	39.2
59	Non-Executive Management	29.2	29.7	31.7	31.5	235.2	220.1	231.3	234.0	285.9	321.7	336.8	342.6	338.2	341.8	346.9	349.0	357.0
60	Management Subtotal	34.1	35.2	36.7	36.0	268.3	251.4	263.4	265.0	319.7	360.6	373.6	381.0	374.8	379.1	384.8	386.5	396.3
61	Society	61.7	66.1	77.9	79.8	640.9	682.4	661.7	697.2	835.1	876.5	993.9	1,001.1	1,010.0	1,011.3	1,040.6	1,059.4	1,085.6
62	PWU	113.6	112.8	121.6	121.8	861.6	913.5	812.9	829.5	1,031.4	995.4	994.1	1,051.2	1,146.1	1,180.8	1,256.3	1,261.7	1,291.1
63	Term/ETE/PECO Temporary	0.0	0.0	0.0	0.0	84.6	116.5	144.8	169.6	113.7	49.2	37.4	34.4	1.2	1.3	1.3	0.0	0.0
64	EPSCA	0.0	0.0	0.0	0.0	48.7	80.3	93.9	107.6	112.9	92.0	73.0	46.1	104.4	126.4	118.4	103.4	84.7
65	Unallocated[3]	(4.1)	(3.4)	(10.6)	(8.0)	29.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
66	Total	205.4	210.7	225.6	229.6	1,933.1	2,044.0	1,976.7	2,069.0	2,412.8	2,373.7	2,472.1	2,513.8	2,636.5	2,698.8	2,801.4	2,811.0	2,857.7

[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)

CCC Interrogatory #090

Interrogatory

Reference:
Exhibit F4, Tab 3, Schedule 1, Attachment 2
Exhibit F4, Tab 3, Schedule 1, Attachment 3

Question(s):

Please explain the linkage between the Compensation Philosophy & Peer Groups study (Attachment 2) and the Total Compensation Benchmarking study (Attachment 3). As part of the response, please advise whether the peer group recommendations from Attachment 2 are applied in Attachment 3. In the situation that there are differences between the peer group recommendations, please explain the reason for those differences.

Response

This response was prepared by WTW:

A company's compensation philosophy identifies the talent market and comparator group for assessing the competitiveness of its compensation. As discussed in Ex. L-F4-CCMBC-008, OPG adopted the compensation philosophy recommendations and resulting peer group criteria set out in Ex. L-F4-3-1, Attachment 2, with the exception of the recommendation to eliminate the forced 50:50 weighting between the public sector and private sector to Executive level roles. As detailed in Ex. L-F4-SUP-020, these criteria (Ex. L-F4-3-1, Attachment 2, p.17) were considered by WTW and applied to WTW's survey participants to determine the organizations to include in the Total Excluding Nuclear Authorized comparator group, other than for Executive level roles where a 50% public sector and 50% private sector weighting was applied. In addition, given the nature of pension fund organizations, WTW applied assets under management criteria as a substitute for the revenue criteria ($70 to $250 billion for executive roles and greater than $25 billion for non-executives). This substituted criterion was applied because revenue is not correlated with size and complexity in the pension fund industry.

Refer to L-F4-CCMBC-009 regarding the Nuclear Authorized peer group.

CCC Interrogatory #091

Interrogatory

Reference:
Exhibit F4, Tab 3, Schedule 1, Attachment 2, p. 17
Exhibit F4, Tab 3, Schedule 1, Attachment 3, pp. 14-18

Preamble:

Pages 14 to 18 of the WTW Study provide a summary of results based on various comparisons between OPG and the peer group. The results are provided in percentages that show the difference between OPG's compensation levels relative to the market.

Question(s):

a) Using 2024 actual compensation, please provide the dollar value associated with the percentage differential between OPG and the market, on a total remuneration basis, for each version of the benchmarking analysis (i.e., each of pages 14 to 18 of the study) broken out between PWU, Society, Management and OPG Total. As part of the response, please provide the detailed calculation showing how the impact of OPG's compensation relative to the market (as reflected in percentage terms) is converted to a dollar figure.

b) Using OPG's forecast compensation for each year during the 2027-2031 test period, please provide the dollar value associated with the percentage differential between OPG and the market, on a total remuneration basis, for each version of the benchmarking analysis (i.e., each of pages 14 to 18 of the study) broken out between PWU, Society, Management and OPG Total. As part of the response, please provide the detailed calculation showing how the impact of OPG's compensation relative to the market (as reflected in percentage terms) is converted to a dollar figure.

c) Please provide a revised version of the "Impact of Pension, Benefits & PWU Terms Incumbent Changes since April 2024" results (page 18) inclusive of the Hydro One share grants.

d) Please provide revised summary results of the Total Compensation Benchmarking Study applying each of the following changes to the methodology:
   i. Exclude the 7.5% adjustment for non-authorized nuclear operations roles.

ii. Reflect a 50%/50% weighting of public and private peers, which was the most recent methodology.
iii. Reflect a 25%/75% weighting of public and private peers (as recommended at Attachment 2, p. 17).
iv. Reflect a 50%/50% weighting of public and private peers and exclude the 7.5% adjustment for non-authorized nuclear operations roles.
v. Reflect a 25%/75% weighting of public and private peers (as recommended at Attachment 2, p. 17) and exclude the 7.5% adjustment for non-authorized nuclear operations roles.

Please provide the requested revised summary results inclusive of the Hydro One Share Grants and based on a comparison of Nuclear Authorized at the 50th percentile.

Response

This response was prepared by WTW:

a) As noted at Ex. F4-3-1, Attachment 3, p. 9, total remuneration values in the WTW's benchmarking report should be interpreted with care and used to assess the competitiveness of OPG's total remuneration value relative to the market, rather than the competitiveness of OPG's costs. It is recommended that competitiveness be assessed by determining whether total remuneration levels fall within a reasonable range of market reference values, recommended as a range of +/- 10% of the market reference (refer to Ex. F4-3-1, p. 40 and Attachment 3, p.12), which is intended to reflect normal variation arising from the wide range of factors influencing individual compensation levels (refer to Ex. L-F4-SUP-018). In addition, to the extent the analysis is used in assessing the competitiveness of OPG's compensation costs, total direct compensation should be considered. Charts 1 to 6 below provide an estimate of the dollar difference between each of PWU, Society, and Management employee groups and OPG Total and the market, aligned with the tables in WTW's benchmarking report on pages 14 to 18 (refer to Ex. F4-3-1, Attachment 3, pp. 14-18).

Chart 1 - Estimated Dollar Difference of Total Remuneration Analysis Results (Nuclear Authorized compared to 50th percentile) (reference page 14 of WTW report)

	PWU ($Millions)				Society ($Millions)				Management ($Millions)				Total ($Millions)			
	OPG	Market	% Variance	$ Variance	OPG	Market	% Variance	$ Variance	OPG	Market	% Variance	$ Variance	OPG	Market	% Variance	$ Variance
2024	[redacted]	[redacted]	12.2%	[redacted]	[redacted]	[redacted]	19.2%	[redacted]	[redacted]	[redacted]	-13.8%	[redacted]	[redacted]	[redacted]	8.9%	[redacted]

Note: Table reflects only benchmarked incumbents

Chart 2 - Estimated Dollar Difference of Total Remuneration Analysis Results Including Hydro One Share Grants (Nuclear Authorized compared to 50th percentile) (reference page 15 of WTW report)

	PWU ($Millions)				Society ($Millions)				Management ($Millions)				Total ($Millions)			
	OPG	Market	% Variance	$ Variance	OPG	Market	% Variance	$ Variance	OPG	Market	% Variance	$ Variance	OPG	Market	% Variance	$ Variance
2024	[redacted]	[redacted]	14.0%	[redacted]	[redacted]	[redacted]	20.5%	[redacted]	[redacted]	[redacted]	-13.8%	[redacted]	[redacted]	[redacted]	10.1%	[redacted]

Note: Table reflects only benchmarked incumbents

Chart 3 - Estimated Dollar Difference of Total Remuneration Analysis Results (Nuclear Authorized compared to 75th percentile) (reference page 16 of WTW report)

	PWU ($Millions)				Society ($Millions)				Management ($Millions)				Total ($Millions)			
	OPG	Market	% Variance	$ Variance	OPG	Market	% Variance	$ Variance	OPG	Market	% Variance	$ Variance	OPG	Market	% Variance	$ Variance
2024	[redacted]	[redacted]	11.3%	[redacted]	[redacted]	[redacted]	18.6%	[redacted]	[redacted]	[redacted]	-14.4%	[redacted]	[redacted]	[redacted]	8.1%	[redacted]

Note: Table reflects only benchmarked incumbents

Chart 4 - Estimated Dollar Difference of Total Remuneration Analysis Results Including Hydro One Share Grants (Nuclear Authorized compared to 75th percentile) (reference page 17 of WTW report)

	PWU ($Millions)				Society ($Millions)				Management ($Millions)				Total ($Millions)			
	OPG	Market	% Variance	$ Variance	OPG	Market	% Variance	$ Variance	OPG	Market	% Variance	$ Variance	OPG	Market	% Variance	$ Variance
2024	[redacted]	[redacted]	13.0%	[redacted]	[redacted]	[redacted]	19.8%	[redacted]	[redacted]	[redacted]	-14.3%	[redacted]	[redacted]	[redacted]	9.3%	[redacted]

Note: Table reflects only benchmarked incumbents

Chart 5 - Estimated Dollar Difference of Impact of Pension, Benefits & PWU Terms Incumbent Changes since April 2024 (reference page 18 of WTW report)

	PWU ($Millions)				Society ($Millions)				Management ($Millions)				Total ($Millions)			
	OPG	Market	% Variance	$ Variance	OPG	Market	% Variance	$ Variance	OPG	Market	% Variance	$ Variance	OPG	Market	% Variance	$ Variance
2024	[redacted]	[redacted]	11.4%	[redacted]	[redacted]	[redacted]	18.4%	[redacted]	[redacted]	[redacted]	-13.6%	[redacted]	[redacted]	[redacted]	8.3%	[redacted]

Note: Table reflects only benchmarked incumbents

Chart 6 - Estimated Dollar Difference of Impact of Pension, Benefits & PWU Terms Incumbent Changes since April 2024 with (Nuclear Authorized compared to 75th percentile) (reference page 18 of WTW report)

	PWU ($Millions)				Society ($Millions)				Management ($Millions)				Total ($Millions)			
	OPG	Market	% Variance	$ Variance	OPG	Market	% Variance	$ Variance	OPG	Market	% Variance	$ Variance	OPG	Market	% Variance	$ Variance
2024	[redacted]	[redacted]	10.5%	[redacted]	[redacted]	[redacted]	17.7%	[redacted]	[redacted]	[redacted]	-14.2%	[redacted]	[redacted]	[redacted]	7.5%	[redacted]

Note: Table reflects only benchmarked incumbents

For clarity, OPG's positioning relative to market for each employee group and OPG Total was calculated by comparing the sum of the total dollar value of OPG's compensation of matched incumbents to the corresponding sum of the total dollar value of the market results, as of 2024. The resulting percentage above or below market reflects the variance between the sum of total dollar values (refer to Ex. L-F4-3-1, Attachment 3, p. 10). There is no extrapolation of the result to the entire OPG population (as done in Ex. L-F4-SEC-198).

b) Refer to Ex. L-F4-SEC-198.

c) Chart 7 below provides the version of the "Impact of Pension, Benefits & PWU Terms Incumbent Changes since April 2024" results (from page 18 of the WTW report) inclusive of the Hydro One share grants.

Chart 7 - Impact of Pension, Benefits & PWU Terms Incumbent Changes since April 2024 (including Hydro One shares)

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%	13.2%	14.5%	13.1%
Total Exc. Nuc. Auth	4,694	17.7%	11.8%	13.1%	11.7%
Nuclear Authorized	191	23.5%	34.5%	35.7%	35.2%
Society	3,737	26.2%	15.4%	19.1%	19.6%
Total Exc. Nuc. Auth	3,647	28.2%	17.3%	21.1%	21.6%
Nuclear Authorized	90	-13.2%	-17.4%	-15.1%	-14.5%
Management	1,299	-11.5%	-13.5%	-12.6%	-13.5%
Total Exc. Nuc. Auth	1,239	-10.0%	-11.9%	-11.1%	-12.1%
Nuclear Authorized	60	-27.7%	-26.0%	-24.9%	-25.9%
OPG Total	**9,921**	**15.3%**	**7.8%**	**10.0%**	**9.5%**

For completeness, Charts 8 and 9 below provide the scenarios from Ex. L-F4-SUP-023, part b), Charts 1 and 2, which is based on p. 18 of the WTW benchmarking report excluding PWU Term and Society ETE incumbents, including Hydro One share grants.

Chart 8 - Impact of Pension, Benefits & PWU Terms Incumbent Changes since April 2024 with Nuclear Authorized at P50 and Excluding Terms and ETE Employees (based on Ex. L-F4-SUP-023 part b), Chart 1, including Hydro One shares)

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	4,562	18.4%	13.8%	15.9%	14.7%
Total Exc. Nuc. Auth	4,371	18.1%	12.4%	14.5%	13.3%
Nuclear Authorized	191	23.5%	34.5%	35.7%	35.2%
Society	3,707	26.1%	15.4%	19.2%	19.7%
Total Exc. Nuc. Auth	3,617	28.2%	17.3%	21.1%	21.6%
Nuclear Authorized	90	-13.2%	-17.4%	-15.1%	-14.5%
Management	1,299	-11.5%	-13.5%	-12.6%	-13.5%
Total Exc. Nuc. Auth	1,239	-10.0%	-11.9%	-11.1%	-12.1%
Nuclear Authorized	60	-27.7%	-26.0%	-24.9%	-25.9%
OPG Total	**9,568**	**15.4%**	**7.8%**	**10.4%**	**10.0%**

Chart 9 - Impact of Pension, Benefits & PWU Terms Incumbent Changes since April 2024 with Nuclear Authorized at P75 and Excluding Terms and ETE Employees (based on Ex. L-F4-SUP-023, part b) Chart 2, including Hydro One shares)

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	4,562	17.1%	12.7%	14.8%	13.7%
Total Exc. Nuc. Auth	4,371	18.1%	12.4%	14.5%	13.3%
Nuclear Authorized	191	4.2%	16.4%	18.5%	18.3%
Society	3,707	25.8%	14.7%	18.5%	19.0%
Total Exc. Nuc. Auth	3,617	28.2%	17.3%	21.1%	21.6%
Nuclear Authorized	90	-17.2%	-25.2%	-22.9%	-22.4%
Management	1,299	-11.9%	-14.1%	-13.2%	-14.1%
Total Exc. Nuc. Auth	1,239	-10.0%	-11.9%	-11.1%	-12.1%
Nuclear Authorized	60	-31.6%	-30.4%	-29.7%	-30.2%
OPG Total	**9,568**	**14.6%**	**7.0%**	**9.6%**	**9.2%**

d) The requested calculations are shown in Charts 10-14 below. As all of the interrogatory's bullets i. to v. are inclusive of Hydro One shares and with Nuclear Authorized roles compared to the 50th percentile, only the chart rows impacted by the each bullet's requested changes are provided; that is, Nuclear Authorized segment results do not change and therefore have not been included in the charts below. OPG Total includes the variance for Nuclear Authorized roles.

Notably, for the requested scenarios involving forced weighting (Charts 11-14), this results in fewer matched roles and incumbents (shown in column 2) and would therefore be a less complete analysis (as discussed in Ex. F4-3-1, pp. 42-43) compared to the methodology used by WTW in Ex. F4-3-1, Attachment 3, which aligns with OPG's compensation philosophy for the reasons discussed in Ex. F4-3-1 p. 43, lines 16-22. Also, as discussed in Ex. F4-3-1, Attachment 3, p. 6, non-authorized nuclear operations roles were benchmarked against comparable nuclear positions and adjusted upward by 7.5% to reflect a compensation premium for similar skill sets in the U.S. and for which there were no direct matches in the Canadian market. This approach uses the best available comparable data to address such gaps in the market data, ensuring the assessment of compensation is appropriately aligned with the market value of these specialized skills.

i. **Chart 10 - Excludes the 7.5% adjustment for non-authorized nuclear operations roles**

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	22.6%	17.6%	17.7%	16.0%
Total Exc. Nuc. Auth	4,694	22.5%	16.4%	16.5%	14.7%
Society	3,737	29.0%	18.1%	22.8%	23.2%
Total Exc. Nuc. Auth	3,647	31.2%	20.1%	25.0%	25.3%
Management	1,299	-11.0%	-13.0%	-12.3%	-13.3%
Total Exc. Nuc. Auth	1,239	-9.5%	-11.4%	-10.8%	-11.7%
OPG Total	**9,921**	**18.4%**	**10.5%**	**12.6%**	**11.9%**

ii. **Chart 11 - Reflects a 50%/50% weighting of public and private sector organizations**

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	3,660	26.0%	24.7%	24.5%	22.3%
Total Exc. Nuc. Auth	3,469	26.2%	23.8%	23.3%	21.0%
Society	3,664	25.7%	16.6%	21.1%	21.3%
Total Exc. Nuc. Auth	3,574	27.8%	18.6%	23.2%	23.4%
Management	1,250	-10.0%	-6.8%	-6.7%	-8.1%
Total Exc. Nuc. Auth	1,190	-8.3%	-4.1%	-4.1%	-5.7%
OPG Total	**8,574**	**18.2%**	**13.5%**	**15.5%**	**14.6%**

iii. **Chart 12 - Reflects 25%/75% weighting of public and private sector organization**

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	3,660	23.2%	20.3%	18.4%	17.6%
Total Exc. Nuc. Auth	3,469	23.1%	19.0%	16.8%	16.0%
Society	3,664	26.2%	16.4%	19.5%	20.3%

Total Exc. Nuc. Auth	3,574	28.3%	18.4%	21.6%	22.3%
Management	1,250	-11.8%	-9.8%	-10.0%	-10.6%
Total Exc. Nuc. Auth	1,190	-10.3%	-7.6%	-7.9%	-8.6%
OPG Total	**8,574**	**16.9%**	**11.1%**	**11.9%**	**11.8%**

iv. **Chart 13 - Reflects 50%/50% weighting of public and private sector organizations and excludes the 7.5% adjustment for non-authorized nuclear operations roles**

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	3,660	26.3%	25.0%	24.8%	22.6%
Total Exc. Nuc. Auth	3,469	26.6%	24.1%	23.7%	21.3%
Society	3,664	28.6%	19.2%	23.8%	24.1%
Total Exc. Nuc. Auth	3,574	30.8%	21.5%	26.1%	26.3%
Management	1,250	-9.5%	-6.1%	-6.0%	-7.5%
Total Exc. Nuc. Auth	1,190	-7.8%	-3.3%	-3.4%	-5.0%
OPG Total	**8,574**	**19.6%**	**14.9%**	**16.9%**	**15.9%**

v. **Chart 14 - Reflects 25%/75% weighting of public and private peers and excludes the 7.5% adjustment for non-authorized nuclear operations roles**

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	3,660	23.5%	20.6%	18.7%	17.9%
Total Exc. Nuc. Auth	3,469	23.5%	19.3%	17.2%	16.3%
Society	3,664	29.1%	19.0%	22.2%	23.0%
Total Exc. Nuc. Auth	3,574	31.4%	21.2%	24.5%	25.3%
Management	1,250	-11.3%	-9.4%	-9.5%	-10.1%
Total Exc. Nuc. Auth	1,190	-9.8%	-7.1%	-7.4%	-8.1%
OPG Total	**8,574**	**18.3%**	**12.4%**	**13.2%**	**13.1%**

CCC Interrogatory #092

Interrogatory

Reference:
Exhibit F4, Tab 3, Schedule 1, Attachment 3, pp. 6-7, 20, 35

Question(s):

a) Please further explain the 7.5% adjustment for non-authorized nuclear operations roles at select career levels. As part of the response, please provide the number of OPG incumbents (and the percentage of incumbents relative to total) that are applied this adjustment.

b) WTW notes that "[o]ther 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." Please explain what is included in the long-term incentives (as set out in the market definition data at p. 7 of the report) and how it differs from the Hydro One share grants that are provided to some of OPG's employees.

e) Please provide the percentage of the total peers in the benchmarking study that apply a 1.5x overtime rate.

Response

This response was prepared by WTW:

a) To understand if a pay premium existed for non-authorized roles in nuclear organizations versus the broader utility sector, pay levels for nuclear plan operations roles were compared between US utility and nuclear organizations. It was found that for select non-authorized nuclear operations roles (e.g., technician, supervisory), nuclear organizations provided, on average, a premium of 7.5% relative to the non-nuclear organizations.

   As there are insufficient data (only one directly comparable nuclear operator in Canada participated in WTW's survey), to report for non-authorized roles in nuclear facilities in Canada, the 7.5% premium was applied to the market data from the Canadian Total Sample (excluding Nuclear Authorized), for these select positions. The adjustment was applied to 2,376 OPG incumbents (22% of total OPG employees).

b) Long-term incentives included in the survey include grants of stock options, full-value shares (restricted or performance vesting) and long-term cash plans. Programs similar to OPG's Hydro One share grant are relatively uncommon in the market and distinguishable from typical long-term incentive programs based on program eligibility. The Hydro One share grant program is provided only to those incumbents that were employees at the time the program was implemented. It is not available to new employees, even if the new employee is doing the same or similar work. Long-term incentive plans in the market are provided to eligible employees in each year that they are granted and form part of the compensation and benefits package offered to new employees. As further detailed in Ex. F4-3-1, pp. 41-42, lump-sum awards for the comparators are not captured in WTW's surveys, which makes a direct comparison difficult given the unique nature of OPG's Hydro One share grant program.

c) The overtime analysis is based on the 2024 General Industry Compensation Policies and Practices Survey. Of the energy industry participants in this survey, 50% provide 2x the base rate and 30% provide 1.5x the base rate and 20% provide between 1x and 1.5x the base rate.

CCC Interrogatory #093

Interrogatory

Reference:
Exhibit F4, Tab 3, Schedule 2, pp. 9, 12-13

Question(s):

a) Please further explain the proposed increase in the longer-term salary escalation rate to inflation plus 0.75% (relative to inflation plus 0.5%). As part of the response, please discuss the relationship between the assumption used for pension and OPEB determination purposes and the salary escalation applied for the 2027-2031 period. Please also provide the impact on pension and OPEB costs (for all business units) for the 2027-2031 period of a 0.25% increase in the salary escalation rate.

b) Please further explain the rate of return assumption (6.25%) for the pension fund asset values in the context of the average actual 7% return between 2020-2024. Please provide the 2027-2031 impact on pension and OPEB costs (for all units) of using a 7% rate of return assumption for pension fund asset values (instead of 6.25%).

c) Please advise whether the Canadian Institute of Actuaries has provided its final endorsement of the 2024 Mortality Improvement Scale

Response

a) In accordance with actuarial practice and US GAAP, the longer-term salary escalation rate assumption is included in the actuarial calculations of pension and OPEB costs and obligations in order to ensure that they reasonably capture expectations of a longer-term future salary increase trajectory for plan members over time. This assumption is therefore not a point estimate for a specific year or period of years. As the preamble notes, this assumption for OPG is tied to the long-term inflation assumption.

The increase in the longer-term salary escalation rate to the inflation rate plus 0.75% (and resulting in an assumption of 2.75%), relative to the inflation plus 0.5% (and resulting in an assumption of 2.50%), for the purpose of determining pension and OPEB accrual costs directionally reflects the changes in OPG's overall labour supply and demand environment, collective bargaining landscape and external economic factors, as discussed in Ex. F4-3-1, pp. 3-8 and 49. It falls within the historical range for this assumption used by OPG, ranging from inflation plus 0.50%

to inflation plus 1.0% and has been established in consultation with OPG's external actuary, Aon (Ex. F4-3-2, Attachment 1, p. 7). It is also the same rate as Aon selected for the most recent actuarial valuation of OPG's registered pension plan for funding purposes, as of January 1, 2025 (Ex. F4-3-2, Attachment 4, p. 5).

The longer-term salary escalation rate used for the purposes of determining pension and OPEB costs in the Application [redacted]

Aon, has estimated the impact on the total OPG forecast pension and OPEB accrual costs for each of the years 2027-2031, which underpin these costs of the prescribed facilities shown at Ex. F4-3-2, Charts 1 to 3, of a change in the salary escalation rate assumption requested in the question, holding all other assumptions constant. The change was assumed to take place as at December 31, 2025, with the cumulative effect reflected for each of the subsequent years. The resulting impacts were attributed to the prescribed facilities in the same proportion as the forecast amounts in the pre-filed evidence.

The estimated increases in the proposed revenue requirements resulting from the above calculations are shown in Chart 1. These impacts are determined on the basis of pension and OPEB costs reflected in OM&A expenses and are inclusive of associated income tax impacts (calculated at 25% tax rate / (1-25% tax rate)) for those regulated businesses that are not otherwise in a forecasted regulatory tax loss position.

Chart 1
Impact on Proposed Revenue Requirements to 0.25% Increase in Salary Escalation Rate

(millions of dollars)	**2027**	**2028**	**2029**	**2030**	**2031**
OPG Nuclear					
Pension	8.7	9.7	11.1	12.2	14.7
OPEB	3.5	3.6	3.8	3.9	4.4
Total	12.2	13.3	14.9	16.1	19.1
Regulated Hydroelectric					
Pension	2.5				
OPEB	1.1				
Total	3.6				
DNNP Facilities					
Pension	0.5	0.6	0.6	0.7	0.7
OPEB	0.2	0.2	0.2	0.2	0.2
Total	0.7	0.8	0.8	0.9	0.9

b) As discussed in Ex. F4-3-2, p. 10, lines 18-20, the expected long-term rate of return on the RPP fund assets is 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 as determined by Aon. This the same methodology used to establish the expected long-term rate of return assumption as reflected in OPG's audited financial statements and used consistently in past OPG proceedings, including approval of balances in the pension and OPEB related deferral and variance accounts.

Setting the long-term expected rate of return assumption based on five-year historical returns at a point in time would not be acceptable under US GAAP or generally accepted actuarial practice and is not an approach OPG would apply. The approach would not be acceptable because it does not consider the impact of expected future market conditions and/or any changes in the pension fund asset mix on return expectations. As such, this approach would not constitute the best estimate of the pension fund's future experience.

Aon has estimated the impact of hypothetically using a 7.0% rate of return assumption for pension fund asset values (instead of 6.25%) on the total OPG forecast pension accrual costs for each of the years 2027-2031, which underpin such costs attributed to the prescribed facilities as shown at Ex. F4-3-2, Charts 1 to 3, holding all other assumptions constant. The change is assumed to take place as at December 31, 2025, with the cumulative effect reflected for each of the subsequent years. The resulting impacts were attributed to the prescribed facilities in the same manner as the forecast amounts in the pre-filed evidence.

The estimated increases in the proposed revenue requirements resulting from the above calculations are shown in Chart 2. These results are inclusive of associated income tax impacts (calculated at 25% tax rate /(1-25% tax rate)) for those regulated businesses that are not otherwise in a forecasted regulatory tax loss position.

Chart 2
Impact on Proposed Revenue Requirements of Expected Long-Term Rate of Return on Pension Fund Assets at 7.0%

(millions of dollars)	**2027**	**2028**	**2029**	**2030**	**2031**
OPG Nuclear	(107)	(117)	(129)	(141)	(153)
Regulated Hydroelectric	(28)				
DNNP Facilities	(7)	(7)	(7)	(6)	(6)

c) The Canadian Institute of Actuaries has not yet provided its final endorsement of the 2024 Mortality Improvement Scale.

CCC Interrogatory #094

Interrogatory

Reference:
Exhibit F4, Tab 4, Schedule 1, p. 6

Preamble:

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.

Question(s):

Please explain how BI insurance will operate in the event of an insurable event. For example, how would the insurance operate in the event that OPG lost production at a DRP unit in 2029 as a result of an insurable event? What counts as an insurable event?

Response

In the event of an insurable event, defined as a forced outage at a nuclear generating station that results from 1) any property at the facility damaged due to a nuclear event including unintended radioactive contamination, or 2) damage to property within the Nuclear Island (as defined below) caused by any non-nuclear insured peril (including but not limited to fire, explosion, machinery breakdown, and the like), nuclear business interruption coverage would respond to cover a loss of earnings, subject to policy terms and conditions, including the applicable limits. This coverage would not respond to a loss of earnings due to an outage not caused by physical damage, or for issues of "wear and tear" such as equipment condition degradation.

Like all business interruption insurance, the nuclear business interruption coverage is subject to a waiting period. A waiting period is the minimum amount of time, after an insured event, that must pass before coverage incepts. Similar to a deductible, where any losses below the deductible are not covered, in the case of a nuclear business interruption loss, any loss of earnings below the waiting period is not recoverable. The loss of earnings for the number of days above the waiting period is recoverable, subject to a maximum period (referred to as the indemnity period). The expected waiting period for this coverage is 120 days, which means that the forced outage would need to be at least approximately four months in order to trigger this coverage.

An example of how this coverage could be triggered in 2029 at Darlington is if the station were to experience a forced outage because of a fire that resulted in physical damage to the steam generator. In this scenario, OPG would experience a prolonged outage to repair the damage and return the unit to operation. As the steam generators are included in the definition of Nuclear Island, the nuclear property policy would respond to provide coverage for the direct physical damage to the property. Under the nuclear business interruption coverage, the resulting loss of earnings, because of the forced outage, would be covered by the nuclear business interruption coverage, subject to the limits, including the waiting period and the indemnity period.

Nuclear Island for the purpose of the coverage is defined as the areas of each unit comprising the nuclear reactor containment buildings and its contents; the vacuum building and its contents; that portion of the pressure relief duct work applicable to each unit including equipment therein; the spent fuel storage and its contents; that portion of the fuel handling tunnel and for the unit and any contents thereof; the service auxiliary bays including but not limited to change rooms, health physics department facilities, low activity disposal facilities and the laboratory but not including the control rooms; and any other property that is involved in the process, storage, transportation or handling of nuclear fuel or any radioactive material or heavy water.

CCC Interrogatory #095

Interrogatory

Reference:
Exhibit F4, Tab 4, Schedule 1, p. 10, Table 5b

Preamble:

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.

Question(s):

a) How does OPG forecast IESO non-energy charges?

b) Table 5B exhibits some apparently large variations between OEB approved and actual IESO non-energy charges; what is the driver behind this variances, and are these variances trued up in some fashion, i.e. through a variance account, or are they variances that OPG bears the risk for?

Response

a) The forecast for IESO non-energy charges is based on OPG's future outlook for Global Adjustment (GA) and an estimate of applicable uplifts and fees derived from historical data, applied to OPG's projected energy consumption at a station level. OPG forecasts Global Adjustment using its proprietary modelling tools for forecasting electricity system costs, expected energy production and prices, future capacity additions and costs, as well as the cost of conservation and demand management initiatives. The GA is inversely proportional to energy market prices. As a result, the GA can vary month-to-month and year-to-year.

b) The variance between OEB-approved and actual IESO non-energy charges is mainly driven by differences between OPG's GA forecast and the actual GA rate. Global Adjustment can be impacted by wholesale market prices and their fluctuations due to factors such as demand, weather, fuel prices, and intertie transactions. In 2020 and 2021, actual IESO non-energy charges were greater than OEB-approved due to unforeseen decreases in demand and market prices from

the COVID-19 pandemic. In 2022-2024, actual IESO non-energy charges were lower than the OEB-approved levels due to impacts of the Comprehensive Electricity Plan which removed approximately 85 per cent of the costs from non-hydroelectric renewable contracts from the GA. Variances in non-energy charges expenses are not subject to deferral and variance account treatment or other true-up mechanisms.

CCMBC Interrogatory #004

Interrogatory

Reference:
F4-3-1, Page 48, Figure 13 – Comparison of OPG and Bruce PWU and Society Base Salary

Question(s):

a) Please confirm that Figure 13 does not include pensions and benefits.

b) Please file a figure similar to Figure 13 that compares total compensation including salary, overtime, pensions, and benefits including OPEBs.

Response

This response was prepared by Willis Towers Watson ("WTW"):

a) Confirmed.

b) WTW cannot assess a total compensation comparison between OPG and Bruce Power, as information on the value of Bruce Power's pensions and benefits is not publicly available.

CCMBC Interrogatory #005

Interrogatory

Reference:
F4-3-1, Attachment 1, Page 1, FTE, Compensation and Benefit Information for OPG's Nuclear Regulated Facilities ("Appendix 2k")

Question(s):

Please add a line to the table showing compensation and benefit information per FTE for Nuclear Regulated Facilities.

Response

Refer to Attachment 1.

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 (Regular)	2,015.4	1,923.1	1,829.0	2,070.4	2,375.4	2,954.7	2,550.7	2,492.7	2,461.8	2,429.9	2,413.4	2,395.9
3	Society (Temporary)	255.3	240.6	203.3	152.2	103.6	130.8	232.9	76.5	53.1	46.8	43.8	40.9
4	PWU (Regular)	2,797.4	2,575.6	2,373.7	2,346.1	2,647.7	3,387.9	3,287.6	3,450.2	3,459.1	3,454.3	3,456.6	3,437.5
5	PWU (Temporary)	661.1	717.5	499.4	540.9	558.5	298.1	352.6	201.2	187.3	224.6	183.8	185.6
6	Term	584.2	723.7	830.8	928.1	624.2	240.2	214.2	6.0	6.0	6.0		
7	ETE/PECO Temp	14.7	71.2	97.3	60.5	33.3		1.0	1.0	1.0	1.0		
8	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
9	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												
10	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
11	Society (Regular)	355.7	355.3	390.4	529.3	602.6	727.2	680.8	675.1	665.8	663.0	660.9	648.8
12	Society (Temporary)	30.0	30.0	26.7	35.2	41.1	27.1	9.2	6.5	3.4	2.0	2.0	2.0
13	PWU (Regular)	334.7	295.2	321.3	339.1	372.4	427.3	398.9	440.0	433.6	434.2	437.6	438.9
14	PWU (Temporary)	99.5	109.8	127.6	150.9	116.0	70.9	57.4	49.9	51.7	50.8	51.7	54.9
15	Term	59.6	72.8	74.6	63.2	61.6	39.0	33.3					
16	ETE/PECO Temp	1.0	5.7	5.7	1.4								
17	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
18	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												
19	Management (Regular)	911.5	813.3	823.3	937.9	1078.6	1276.9	1138.6	1042.2	1028.9	1016.2	1007.4	1018.7
20	Society (Regular)	2,371.0	2,278.4	2,219.4	2,599.8	2,977.9	3,681.9	3,231.5	3,167.9	3,127.6	3,092.9	3,074.3	3,044.7
21	Society (Temporary)	285.3	270.6	230.0	187.3	144.8	157.9	242.1	83.1	56.5	48.8	45.8	42.8
22	PWU (Regular)	3,132.1	2,870.8	2,695.0	2,685.2	3,020.1	3,815.3	3,686.5	3,890.1	3,892.7	3,888.5	3,894.2	3,876.4
23	PWU (Temporary)	760.7	827.3	626.9	691.8	674.4	369.0	410.0	251.1	239.1	275.5	235.5	240.5
24	Term	643.7	796.5	905.4	991.3	685.8	279.2	247.5	6.0	6.0	6.0		
25	ETE/PECO Temp	15.7	76.9	103.0	61.9	33.3		1.0	1.0	1.0	1.0		
26	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
27	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**
28	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
29	Society (Regular)	318.2	333.5	315.4	408.0	463.3	580.5	525.1	536.8	545.7	564.6	577.8	593.6
30	Society (Temporary)	34.3	33.0	27.2	22.4	19.3	19.7	29.9	10.8	7.6	6.8	6.3	6.1
31	PWU (Regular)[2]	385.1	391.4	357.9	413.0	503.7	523.5	525.8	574.9	592.7	620.4	636.7	648.6
32	PWU (Temporary)[2]	77.4	88.4	59.9	73.0	76.1	36.8	45.5	24.7	23.6	30.0	24.5	25.4
33	Term[2]	68.0	90.9	105.4	131.5	88.0	32.2	29.8	1.0	1.0	1.0		
34	ETE/PECO Temp	2.7	7.8	14.5	7.8	5.5		0.2	0.2	0.2	0.2		
35	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
36	Unallocated[3]	19.5											
37	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**
38	Society (Regular)	36.8	39.9	43.6	47.9	54.8	42.6	37.4	42.2	39.3	43.5	41.8	40.5
39	Society (Temporary)	2.6	4.3	2.5	1.5	1.3	0.4	0.3	0.0				
40	PWU (Regular)	63.7	64.9	62.1	70.1	83.8	68.8	65.8	96.1	87.3	101.5	95.9	91.4
41	PWU (Temporary)	11.8	16.1	9.2	9.2	10.1	3.0	2.6	0.1	0.1	0.1	0.1	0.1
42	Term	8.6	11.2	15.1	19.8	11.4	3.2	2.5					
43	ETE/PECO Temp	0.2	0.4	1.4	1.2	0.9	0.0						
44	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
45	Unallocated[3]												
46	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**
47	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
48	Society (Regular)	162.4	179.7	174.3	129.0	186.6	216.3	211.0	211.5	215.2	225.1	229.3	236.5
49	Society (Temporary)	3.6	2.4	1.9	1.8	1.7	1.6	2.4	0.9	0.6	0.5	0.5	0.5
50	PWU (Regular)	191.9	203.6	183.0	119.0	186.3	187.2	203.1	218.8	224.8	237.8	243.4	251.7
51	PWU (Temporary)	7.0	6.7	5.1	5.9	6.6	2.8	3.3	1.8	1.7	2.1	1.8	1.9
52	Term	5.1	5.6	7.6	8.9	7.4	2.0	1.8	0.1	0.1	0.1		
53	ETE/PECO Temp	0.0	0.4	0.8	0.5	0.4	0.0	0.0	0.0	0.0	0.0		
54	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
55	Unallocated[3]	7.4											
56	Total	447.7	470.5	446.7	318.0	462.4	490.5	499.703	510.1	521.1	546.5	555.7	573.7
57	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
58	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
59	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**
60	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
61	Society (Regular)	517.4	553.1	533.4	584.9	704.7	839.5	773.5	790.4	800.2	833.2	848.9	870.6
62	Society (Temporary)	40.5	39.8	31.6	25.7	22.2	21.8	32.6	11.7	8.2	7.4	6.8	6.6
63	PWU (Regular)	640.7	659.8	603.0	602.1	773.7	779.6	794.6	889.8	904.8	959.7	976.0	991.7
64	PWU (Temporary)	96.2	111.2	74.2	88.2	92.8	42.6	51.4	26.6	25.4	32.2	26.4	27.3
65	Term	81.7	107.8	128.0	160.1	106.9	37.4	34.2	1.0	1.0	1.1		
66	ETE/PECO Temp	2.9	8.7	16.7	9.5	6.8	0.0	0.2	0.2	0.2	0.2		
67	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
68	Unallocated[3]	26.9											
69	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)

Line No.	Total Compensation $K/FTE Nuclear Facilities (excl DNNP)	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
70	Management	255.4	270.9	277.5	246.5	257.5	257.8	268.5	281.2	289.5	302.2	307.9	316.9
71	Society (Regular)	218.2	242.8	240.3	225.0	236.6	228.0	239.4	249.5	255.9	269.4	276.1	285.9
72	Society (Temporary)	141.9	147.1	137.3	137.4	153.3	138.1	134.7	140.6	145.8	150.9	149.1	153.4
73	PWU (Regular)	204.5	229.8	223.8	224.2	256.2	204.3	215.5	228.7	232.4	246.8	250.6	255.8
74	PWU (Temporary)	126.5	134.4	118.3	127.5	137.5	115.5	125.5	105.9	106.4	117.0	112.0	113.7
75	Term	127.0	135.3	141.4	161.5	155.9	134.0	138.1	169.6	174.1	182.3		
76	ETE/PECO Temp	185.0	112.5	162.5	153.7	205.1		207.9	213.1	218.9	229.2		
77	EPSCA	176.0	200.7	217.2	230.8	246.4	203.8	198.7	240.6	228.9	243.0	257.2	264.7

Line No.	Pension & Benefits as a % of Total Compensation^	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
78	Society & PWU (Regular)	31%	32%	31%	21%	25%	25%	26%	26%	26%	26%	26%	26%
79	Term/ETE/PECO Temp	6%	5%	6%	6%	7%	5%	5%	5%	5%	5%		

^ For Society and PWU regular staff calculated as Benefits (line 48 & 50) divided by Total Compensation (line 61 and 63). For Term/ETE/PECO Temp calculated as Benefits (line 52 & 53) divided by Total Compensation (line 65 & 66)

CCMBC Interrogatory #006

Interrogatory

Reference:
F4-3-1, Attachment 1, Page 2, FTE, Compensation and Benefit Information for OPG's DNNP LP Regulated Facilities ("Appendix 2k")

Question(s):

Please add a line to the table showing compensation and benefit information per FTE for DNNP LP Regulated Facilities.

Response

Refer to Attachment 1.

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 (Regular)	167.1	170.8	123.6	92.4	84.6	79.1
3	Society (Temporary)	10.1	7.6	6.1	3.7	0.2	(0.9)
4	PWU (Regular)	43.5	110.7	169.2	168.6	135.3	132.0
5	PWU (Temporary)	7.4	5.8	5.3	3.4	4.3	1.6
6	EPSCA						
7	Subtotal	296.4	369.9	363.1	313.6	256.8	238.5
	DNNP LP - Allocated						
8	Management	29.9	35.3	37.3	29.9	29.1	19.1
9	Society (Regular)	50.2	57.4	59.0	46.0	45.3	43.0
10	Society (Temporary)	0.3	0.9	1.3	1.1	1.1	1.1
11	PWU (Regular)	13.4	14.4	13.9	13.1	10.6	16.5
12	PWU (Temporary)	6.0	9.1	9.3	9.2	4.4	1.5
13	EPSCA	0.0	0.0	0.0	0.0	0.1	0.2
14	Subtotal	99.8	117.2	120.9	99.5	90.5	81.4
	DNNP LP Facilities						
15	Management	98.3	110.3	96.1	75.3	61.6	45.9
16	Society (Regular)	217.2	228.2	182.6	138.5	129.9	122.2
17	Society (Temporary)	10.4	8.5	7.4	4.9	1.3	0.2
18	PWU (Regular)	56.9	125.1	183.1	181.8	145.9	148.5
19	PWU (Temporary)	13.4	14.9	14.7	12.6	8.7	3.0
20	EPSCA	0.0	0.0	0.0	0.0	0.1	0.2
21	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**
22	Management	20.9	25.3	24.7	21.5	19.5	16.2
23	Society (Regular)	34.7	38.1	32.6	26.5	25.8	25.8
24	Society (Temporary)	1.5	1.3	1.1	0.8	0.2	0.0
25	PWU (Regular)[2]	9.0	21.8	31.4	32.5	26.7	29.5
26	PWU (Temporary)[2]	1.1	1.4	1.4	1.3	1.0	0.2
27	EPSCA[2]	0.0	0.0	0.0	0.0	0.0	0.0
28	Total	67.3	87.8	91.2	82.6	73.2	71.7
	Overtime	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
29	Society (Regular)	1.0	1.0	0.8	0.7	0.7	0.7
30	Society (Temporary)	0.0	0.0	0.0	0.0	0.0	
31	PWU (Regular)	0.2	0.5	0.8	0.8	0.6	3.0
32	PWU (Temporary)	0.0	0.0	0.0	0.0	0.0	0.0
33	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**
34	Management	7.1	8.3	7.4	6.0	4.9	3.7
35	Society (Regular)	13.9	15.0	12.4	9.9	9.3	8.8
36	Society (Temporary)	0.1	0.1	0.1	0.1	0.0	(0.0)
37	PWU (Regular)	3.0	7.5	10.7	11.3	8.8	8.8
38	PWU (Temporary)	0.1	0.1	0.1	0.1	0.1	0.0
39	EPSCA	0.0	0.0	0.0	0.0	0.0	0.0
40	Total	24.2	31.0	30.8	27.3	23.1	21.3
41	Current Benefits (Statutory)	4.2	5.5	5.4	4.8	4.0	3.8
42	Current Benefits (Non-Statutory)	3.3	4.2	4.2	3.8	3.2	2.9
43	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**
44	Management (Regular)	28.0	33.5	32.1	27.5	24.4	19.8
45	Society (Regular)	49.6	54.1	45.9	37.0	35.7	35.3
46	Society (Temporary)	1.7	1.4	1.2	0.8	0.2	0.0
47	PWU (Regular)	12.2	29.9	42.9	44.7	36.1	41.2
48	PWU (Temporary)	1.2	1.5	1.5	1.4	1.0	0.3
49	EPSCA	0.0	0.0	0.0	0.0	0.0	0.0
50	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

Line No.	Total Compensation $K/FTE DNNP LP	2026 Plan	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
51	Management	284.5	303.8	333.7	364.5	395.8	431.7
52	Society (Regular)	228.4	237.0	251.2	267.2	274.9	288.9
53	Society (Temporary)	164.1	164.9	158.5	169.8	169.6	154.6
54	PWU (Regular)	213.8	238.6	234.5	245.7	247.8	277.7
55	PWU (Temporary)	90.8	101.6	104.9	114.6	119.4	85.7
56	EPSCA	148.8	176.1	171.1	178.0	187.0	191.3

CCMBC Interrogatory #007

Interrogatory

Reference:
F4-3-1, Attachment 1, Page 3, FTE, Compensation and Benefit Information for OPG's Hydroelectric Regulated Facilities ("Appendix 2k")

Question(s):

Please add a line to the table showing compensation and benefit information per FTE for Hydroelectric Regulated Facilities.

Response

Refer to Attachment 1.

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 (Regular)	262.1	276.1	309.3	313.6	333.4	334.6	352.6	359.4	417.6	496.0	516.0	528.5	525.0	524.9	527.8	525.0
3	Society (Temporary)	3.7	6.3	11.4	10.9	7.8	12.2	12.0	11.3	5.9	12.0	6.5	7.9	6.2	3.2	3.3	2.3
4	PWU (Regular)	634.0	602.8	630.4	627.7	627.3	622.1	601.4	608.9	650.8	755.8	778.4	778.9	779.2	781.6	783.6	785.3
5	PWU (Temporary)	31.1	36.3	40.0	36.9	40.4	54.4	68.9	93.0	76.5	71.0	105.3	109.7	116.9	127.1	117.6	117.4
6	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																
7	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
8	Society (Regular)	71.2	67.4	73.8	78.5	59.5	54.7	58.0	66.4	78.1	91.9	95.1	98.1	98.0	95.9	95.0	94.1
9	Society (Temporary)	2.9	2.3	3.4	2.9	3.3	3.7	4.2	4.9	4.9	4.8	1.4	0.8	0.6	0.3	0.3	0.3
10	PWU (Regular)	33.3	34.6	35.9	29.6	15.9	13.0	18.8	18.5	20.5	24.5	23.0	21.4	21.1	20.2	20.3	21.0
11	PWU (Temporary)	4.0	4.2	3.5	4.5	2.5	3.5	6.1	6.5	5.6	5.3	4.7	4.5	4.4	4.3	4.3	4.4
12	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																
13	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
14	Society (Regular)	333.2	343.5	383.1	392.1	392.9	389.2	410.6	425.8	495.7	588.0	611.1	626.6	623.0	620.8	622.8	619.1
15	Society (Temporary)	6.5	8.6	14.8	13.8	11.1	15.9	16.1	16.1	10.8	16.8	7.9	8.7	6.8	3.5	3.6	2.6
16	PWU (Regular)	667.3	637.4	666.3	657.3	643.2	635.0	620.2	627.4	671.3	780.3	801.3	800.3	800.3	801.8	803.9	806.3
17	PWU (Temporary)	35.1	40.5	43.5	41.4	42.9	57.9	75.0	99.5	82.2	76.3	110.0	114.2	121.3	131.4	121.9	121.7
18	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**
19	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
20	Society (Regular)	40.8	43.5	48.9	50.3	51.2	54.2	57.2	58.9	71.7	89.7	95.7	101.8	104.1	108.2	112.1	115.6
21	Society (Temporary)	0.6	0.9	1.5	1.5	1.2	1.4	2.0	1.7	1.4	1.9	0.9	1.1	0.9	0.5	0.5	0.4
22	PWU (Regular)[2]	72.6	69.3	72.6	73.2	73.7	79.4	72.8	80.3	95.4	102.6	109.6	112.9	116.3	120.9	125.1	129.8
23	PWU (Temporary)[2]	3.3	4.1	4.0	4.0	4.7	5.7	8.3	10.7	11.7	10.4	15.9	16.8	18.3	20.9	19.3	19.8
24	Unallocated[3]	(3.3)	(2.3)	(8.0)	(6.6)	0.4											
25	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**
26	Society (Regular)	2.2	3.0	3.4	4.1	4.2	4.5	6.0	7.0	6.6	7.1	7.8	8.3	8.5	9.0	9.3	9.8
27	Society (Temporary)	0.0	0.0	0.1	0.1	0.1	(0.1)	0.1	0.1	0.0	0.0	0.0					
28	PWU (Regular)	5.7	8.1	8.7	9.8	8.9	12.8	13.5	16.2	17.1	18.5	18.9	20.2	21.3	22.9	23.2	24.1
29	PWU (Temporary)	0.2	0.4	0.4	0.4	0.5	0.8	1.0	1.5	1.6	1.2	2.0	2.2	2.4	2.9	2.7	2.7
30	Unallocated[3]																
31	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**
32	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
33	Society (Regular)	18.0	18.6	24.0	23.7	26.4	29.3	31.4	18.6	28.4	33.8	39.2	41.2	42.2	44.5	45.8	47.3
34	Society (Temporary)	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.1	0.2	0.1	0.1	0.1	0.0	0.0	0.0
35	PWU (Regular)	31.6	30.6	35.5	34.1	36.5	43.2	39.4	29.6	38.1	38.6	44.2	45.1	46.5	49.2	50.5	52.6
36	PWU (Temporary)	0.3	0.4	0.4	0.3	0.4	0.6	0.7	1.0	0.9	0.7	1.1	1.2	1.3	1.5	1.4	1.4
37	Unallocated[3]	(0.8)	(1.1)	(2.6)	(1.3)	1.7											
38	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
39	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
40	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
41	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**
42	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
43	Society (Regular)	61.0	65.1	76.2	78.1	81.7	88.0	94.5	84.5	106.7	130.5	142.7	151.3	154.8	161.8	167.2	172.7
44	Society (Temporary)	0.7	1.0	1.7	1.7	1.4	1.4	2.3	2.0	1.5	2.1	1.0	1.2	0.9	0.5	0.5	0.4
45	PWU (Regular)	109.9	108.0	116.9	117.1	119.1	135.4	125.7	126.1	150.7	159.6	172.8	178.2	184.0	193.0	198.8	206.6
46	PWU (Temporary)	3.8	4.9	4.7	4.7	5.6	7.1	10.0	13.1	14.2	12.4	19.1	20.2	22.0	25.3	23.3	23.9
47	Unallocated[3]	(4.1)	(3.4)	(10.6)	(8.0)	2.1											
48	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)

Line No.	Total Compensation $K/FTE 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
49	Management	224.3	236.2	249.3	248.5	255.4	258.3	270.6	253.1	270.0	270.2	284.5	297.0	305.9	316.9	323.2	332.2
50	Society (Regular)	183.2	189.7	199.0	199.2	208.0	226.1	230.2	198.6	215.3	222.0	233.5	241.4	248.5	260.6	268.4	279.0
51	Society (Temporary)	104.6	112.8	115.4	123.4	122.3	90.6	139.5	123.1	138.6	126.2	129.7	133.6	138.6	142.2	143.1	144.4
52	PWU (Regular)	164.7	169.4	175.4	178.1	185.2	213.3	202.6	201.0	224.5	204.5	215.6	222.6	230.0	240.7	247.3	256.2
53	PWU (Temporary)	107.0	120.2	108.6	114.6	129.6	122.7	133.6	132.0	172.4	162.1	173.2	176.7	181.2	192.5	191.3	196.6

CCMBC Interrogatory #008

Interrogatory

Reference:
F4-3-1, Attachment 2, Southlea Report, Page 18, Recommendations

Question(s):

Did OPG accept and implement all of Southlea's recommendations. If the answer is no, please list recommendations that OPG rejected and / or did not implement?

Response

No, OPG did not fully implement all of Southlea's recommendations. Specifically, Southlea's recommended peer group ownership structure would have entirely eliminated the forced 50:50 weighting between the public sector and private sector comparators. The recommended approach is intended to enable more robust data and more accurately reflect the market in which OPG competes for talent (Ex. F4-3-1, Attachment 2, p.17). While OPG carefully considered this recommendation and recognizes it would better reflect the competitive talent market, as noted at Ex. F4-3-1, p. 43, lines 22-24, OPG decided to continue to apply the 50:50 public sector/private sector forced weighting for Executives, as a measure of ongoing restraint, notwithstanding that this group continues to benchmark well below the target market range.[1]

[1] Target market range is defined by WTW as +/- 10% of the peer group median or "P50".

CCMBC Interrogatory #009

Interrogatory

Reference:
F4-3-1, Attachment 3, Page 5, Comparator Groups, and page 33 Nuclear Authorized – Executives and Non-Executives and page 34 Pension & Benefits Analysis

Question(s):

a) Why were different comparator organizations selected for Nuclear Authorized – Executives and Non-Executives and Pension & Benefits Analysis?

b) For example, why was Tennessee Valley Authority (TVA) selected as a comparator organization for the Nuclear Authorized – Executives and Non-Executives but not for the Non-Executives and Pension & Benefits Analysis?

c) Is WTW aware that Concentric did not include TVA in its proxy group of utilities (C1-1-1, Attachment 1, Page 14 and Pages 103-109, Concentric Report)?

Response

This response was prepared by WTW:

a) and b)

Different comparator organizations were selected for the Nuclear Authorized comparator group and the Total Excluding Nuclear Authorized comparator group based on the talent market with the nuclear professional body of knowledge required for the Nuclear authorized roles. The Nuclear Authorized comparator group includes Canadian and U.S.-based organizations, including Tennessee Valley Authority (TVA).

A single comparator group of Canadian organizations for pension and benefits market data has been used for all roles, including those roles matched to the Total Excluding Nuclear Authorized sample and the Nuclear Authorized sample because organizations typically offer common pension and benefit plans across all roles and skill sets, and pension and benefits plans vary substantially by country given the differences in regulatory environments. As such, TVA, for example, was excluded from the pension and benefits comparator group

c) No.

CCMBC Interrogatory #010

Interrogatory

Reference:
F4-3-1, Attachment 4, Page 3, 2024 Base Salary Comparison | Society of United Professionals

Question(s):

a) Considering that the base salary for Control Room Shift Supervisor, Training Supervisor is 20% lower at OPG than at Bruce Power, are employees in that category leaving OPG to work for Bruce Power?

b) What is the difference in pension and benefits between OPG and Bruce Power for employees in that category?

c) Are there any differences in job descriptions between OPG and Bruce Power for employees in that category?

Response

a) Refer to Ex. L-F4-CCMBC-003, part (a).

b) Refer to Ex. L-F4-CCMBC-004, part (b).

c) Bruce Power LP's job descriptions are not available to OPG or WTW; therefore, neither OPG nor WTW can comment on any differences between the job descriptions.

CCMBC Interrogatory #011

Interrogatory

Reference:
F4-3-2, Page 1, Pension and Other Post-Employment Benefit Costs

Question(s):

a) Does OPG agree that the vast majority of ratepayers, and in particular younger ratepayers, will never receive pensions and other benefits (if they receive pensions and other benefits at all) anywhere approaching the value of the pensions and other benefits described in this section that are allocated for OPG employees? If OPG does not agree with that statement, please provide evidence to support why OPG believes young ratepayers could expect to receive similar pensions and benefits to OPG employees.

b) How would OPG convince young ratepayers just starting out in their careers that they should accept paying higher rates so that OPG employees can receive lucrative pensions and benefits that these ratepayers are unlikely to receive in their lifetimes?

Response

a) and b)

OPG declines to provide the requested response on the basis of speculation and relevance. With the assumptions and characterizations underlying parts a) and b) of this interrogatory, as well as the broad and general nature of the question, OPG is unable to comment and provide a meaningful or responsive answer that would be relevant. The question seeks information and comment regarding the future personal pension and benefits of ratepayers, particularly younger ratepayers. OPG does not have access to such information, and any such answer would be speculative as it would be entirely dependent on assumptions that have no basis in fact. Furthermore, OPG notes that matters relating to the individual pension and benefit arrangements of ratepayers are outside the scope of and irrelevant to this proceeding.

PWU Interrogatory #010

Interrogatory

Reference:
Ref: Exhibit F4 / Tab 3 / Schedule 1 / Page 48 of 50

Preamble:

The reference states:

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. 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.

Question(s):

a) Please quantify the impact on the test period revenue requirement had OPG wages been equivalent to Bruce Power wages.

b) Please quantify the impact on the test period revenue requirement had OPG's total compensation been equivalent to that of Bruce Power.

Response

a) On average, Bruce Power LP's wage rates are 24% higher than OPG for PWU-represented employees and 9% higher for Society-represented employees as of 2025. For the purposes of quantifying the revenue requirement as if OPG had such wages equivalent to Bruce Power LP's wages, all else equal, the resulting estimated revenue requirement impact of such hypothetical wages and the resulting impact on pension costs is shown in Chart 1 below.

   The pension cost impact represents the hypothetical change in the current service cost assuming the higher wages had been in effect historically. The wage impacts

are determined on the basis of compensation costs reflected in OM&A expenses. The revenue requirement impacts would result in an increase to the OPG and DNNP LP revenue requirements and are inclusive of associated income tax impacts (calculated at 25% tax rate / (1-25% tax rate)) for those regulated businesses that are not otherwise in a forecasted regulatory tax loss position.

Chart 1 -
Estimated Hypothetical Impact of Equivalent Bruce Power Wages on OPG and DNNP LP Revenue Requirements

(millions of dollars)	**2027**	**2028**	**2029**	**2030**	**2031**
OPG Nuclear	133	135	148	148	179
Regulated Hydroelectric	37				
DNNP Facilities	6	6	6	8	11

b) As noted in Ex. L-F4-CCMBC-004, OPG understands that WTW cannot assess a total compensation comparison between OPG and Bruce Power LP, as information on the value of Bruce Power LP's pensions and benefits is not publicly available.

PWU Interrogatory #012

Interrogatory

Reference:
Ref: Exhibit F4 / Tab 3 / Schedule 1 / Page 35 of 50

Preamble:

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%

Question(s):

a) Please quantify the impact on the 2027 revenue requirement specifically, as well as on the revenue requirement for the test period, had the contribution ratio remained at 36%/64% as in 2024 instead of the latest ratio of 50%/50%.

Response

a) If the contribution ratio remained unchanged at 36%/64% from 2026 onwards, the estimated impact on the revenue requirement for 2027 and the remaining IR term is provided in Chart 1 below. These impacts are inclusive of associated income tax impacts (calculated at 25% tax rate / (1-25% tax rate)) for those regulated businesses that are not otherwise in a forecasted regulatory tax loss position.

Chart 1 -
Estimated Hypothetical Impact of 36%/64% Pension Contribution Ratio on OPG and DNNP LP Revenue Requirements

(millions of dollars)	**2027**	**2028**	**2029**	**2030**	**2031**
OPG Nuclear	(11)	(16)	(22)	(29)	(36)
Regulated Hydroelectric	(3)				
DNNP Facilities	(1)	(1)	(1)	(1)	(1)

As noted in Ex. L-F4-SUP-027, the forecasted pension accrual costs for OPG's prescribed facilities over the 2027-2031 period remain lower than the corresponding cash amounts. As discussed in Ex. H1-1-1, Section 5.12, the Pension and OPEB Forecast Accrual versus Actual Cash Differential Variance Account will continue to record interest on the difference between OPG's pension and OPEB accrual costs and cash amounts, asymmetrically in favour of ratepayers.

PWU Interrogatory #014

Interrogatory

Reference:
Ref: Exhibit F4 / Tab 3 / Schedule 1 / Page 11 of 50

Preamble:

The reference states:

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.

Question(s):

a) Please provide the number of actual retirements from 2020 to 2025 and number of employees eligible to retire in each year from 2026 to 2031.

Response

a) Chart 1 shows the actual number of OPG retirements for the period 2020-2025.

Chart 1 – Total OPG Actual Retirements Per Year (2020-2025)

Total OPG Actual Retirements						
Year	2020	2021	2022	2023	2024	2025
	428	308	362	217	233	278

Chart 2 shows the number of OPG employees eligible to retire in each year 2026-2031 respectively.

Chart 2 – Total OPG Employees Eligible to Retire Per Year (2026-2031)

Total OPG Employees Eligible to Retire*						
Year	2026	2027	2028	2029	2030	2031
	80	245	241	294	302	345

*Numbers are not cumulative, and reflect pension rule changes (Ref. Ex. F4-3-1, p. 36, lines 12-19).

SEC Interrogatory #184

Interrogatory

Reference:
F4-1-1, p. 13-14

Question(s):

Please explain why all of these assets that are intended to have service lives "align with the station's post refurbishment life" do not have the same service life.

Response

The referenced assets relate to the results of an internal validation review conducted over 2021-2023 following the return to service of refurbished Darlington Unit 2 as part of the Depreciation Review Committee's ("DRC") ongoing diligence over the estimated service lives for depreciation purposes. As explained in that evidence, the purpose of the review was to confirm if there were individual historical assets within existing asset classes (i.e., other than those comprising the Darlington Refurbishment Program in-service additions) that were tied to Darlington which should have a longer service life in view of the post refurbishment reactor life assumption. The review was conducted as anticipated in EB-2020-0290 Ex. L-F4-01-SEC-138 and Ex. L-F4-01-Staff-269, Attachment 1, page 6, and supported by Concentric Advisors, ULC as part of their assessment of OPG's regulated nuclear life depreciation rates and generating station lives submitted in that proceeding (EB-2020-0290, Ex. F4-1-1, Attachment 1, p. 17).

The service lives of the assets referenced in the preamble were extended as part of the review to better align with the station's post refurbishment life. In aggregate, these changes reduced annual depreciation and amortization expense for OPG's nuclear facilities by approximately $6M. The changes represented a refinement of an earlier asset service life review conducted in relation to the then-expected Darlington refurbishment approximately 15 years ago, when the station's overall life was extended. Based on the review, there are no remaining material assets that are tied to Darlington and have a service life assumption that should, but does not, align to the station's post refurbishment life. The above impacts are reflected in the Application.

Leveraging the experience with the above review, in extending the station life assumption for Pickering Units 5-8 effective December 31, 2023 based on the expectations of the Pickering refurbishment, OPG simultaneous reviewed and as necessary updated the service life assumptions for the material individual assets within each identified asset class (Ex. F4-1-1, Attachment 3, pp. 6-7).

SEC Interrogatory #185

Interrogatory

Reference:
F4-1-1, p. 17

Question(s):

Please provide a table reconciling the increases in depreciation from 2021 to 2031 to "the impact of in-service additions across the fleet".

Response

The table below provides the depreciation and amortization associated with the regulated hydroelectric in-service additions in a given year, beginning with 2021, that accumulate to the change in depreciation and amortization expense from 2020 to 2031 in Ex. F4-1-1, Table 1 related to in-service additions across the fleet.

Year of In-Service	Depreciation and Amortization on In-Service Additions ($M)
2021	6.3
2022	11.2
2023	6.5
2024	10.6
2025	7.2
2026	9.1
2027	14.4
2028	18.9
2029	19.0
2030	16.1
2031	5.5
Total	**126.5**

SEC Interrogatory #186

Interrogatory

Reference:
F4-1-1, Attachment 2, p. 5

Question(s):

Please explain why the end-of-life ("EOL") dates for Bruce A and Bruce B in the table are not December 31, 2064, as described in the text.

Response

The average station EOL dates in the referenced table for the Bruce A and Bruce B nuclear generating stations are correct and remain as December 31, 2061 and December 31, 2052, respectively. These dates represent an average of individual generating unit EOL dates for the respective stations, which are in turn based on such estimated dates specified in the Amended and Restated Bruce Power Refurbishment Implementation Agreement ("ARBPRIA") between the Independent Electricity System Operator and Bruce Power made public in December 2015. Although the ARBPRIA ends on December 31, 2064, such dates specified therein are earlier than December 31, 2064, resulting in the above average station EOL dates. There have been no changes to these dates since they were implemented by OPG for depreciation and amortization purposes effective December 31, 2015.[1]

At Ex. F4-1-1, Attachment 2, p. 5, OPG's Depreciation Review Committee ("DRC") concluded that, notwithstanding the level of technical confidence in the post-refurbishment operation of Bruce Units 3-8 beyond the above noted dates: i) there was insufficient evidence to extend any of such dates beyond the end date of the ARBPRIA; and ii) that while a modest extension of the EOL dates for these units to match December 31, 2064 was possible, such a change was not recommended at that time due to a relatively small impact and as the dates would remain subject to further reassessment until Bruce Power's refurbishment of all six units is completed (and the actual post-refurbishment in-service dates are known).[2] These recommendations are reflected in OPG's financial statements prepared in accordance with US GAAP and the corresponding amounts of Bruce Lease net revenues presented in this Application.

[1] For example, see EB-2016-0152: Ex. F4-1-1, p. 5, lines 8-24 and Attachment 1, p. 4; EB-2020-0290, Ex. F4-1-1, p. 4, Chart 1.
[2] The refurbishment of Bruce Units 1 and 2 was previously completed in 2012 and as such they have a sooner EOL date assumption, resulting in an overall sooner average station EOL date for the Bruce A station.

SEC Interrogatory #187

Interrogatory

Reference:
F4-1-1, Attachment 7

Question(s):

With respect to the Concentric, *Assessment of Regulated Hydroelectric Asset Depreciation Rates* (November 2025) Report:

a) [p.4] Please provide details of the extent, if any, to which the depreciation rates and asset service lives of OPG's regulated hydroelectric assets differ from the depreciation rates and asset service lives of OPG's unregulated hydroelectric assets.

b. [p.8] Please confirm that the information on retirement transactions included full vintage data.

c. [p.10] Please confirm that the "analyses provided to DRC" referred to are on the record in this proceeding, or, if not, provide them.

d. [p.12; Attachment 12 p.14] Given that Concentric has completed depreciation studies on all of the members of the peer group, why is the reliance on "lives in use by peer utilities" throughout the report not circular?

e. [p.17] Please restate Table 1 with original cost and net book value broken out by vintage.

Response

Responses for parts a) and e) are prepared by OPG. Responses for parts b) to d) are provided by Concentric Advisors, ULC ("Concentric").

a) There are no differences between depreciation rates and asset service lives for OPG's regulated and unregulated hydroelectric assets.

b) Concentric confirms that vintage retirement data was provided by OPG.

c) Concentric confirms that the referenced analyses refer to the annual Depreciation Review Committee Recommendations for Regulated Renewable Generation which can be found at Ex. F4-1-1 Attachments 8 to 11.

d) Average Service Life estimates are impacted by a number of factors, which are specific to the utility being studied. Apart from its clients, Concentric does not purport to possess the relevant knowledge necessary to evaluate all the factors and analyses used in the depreciation methodology of its clients' peers. Without understanding the specifics relating to company accounting policy, accounting systems and data retrieval processes, management and operational procedures, and magnitude of large historic retirement events, for example, the relevance of the peer statistics cannot be known. While a detailed review of information related to depreciation studies not completed by Concentric may be publicly available, without access to all relevant information Concentric would not be able to validate that a direct comparison can be made. Additionally, in the specific circumstances of Canadian electric utilities, there is no Canadian-wide uniform system of accounts, resulting in a wide discrepancy in the level of componentization and the types of assets that are capitalized into any specific account. As such, Concentric views that utilities for which it has an understanding of the relevant factors are more relevant peers than those with which Concentric is not as familiar.

Concentric has performed depreciation studies for the majority of the investor owned and crown corporation electric utilities throughout Canada, including utilities in every province and territory, and a number of American states. Ms. Nori herself has extensive knowledge of the accounting, retirement, and management policies that are typical throughout the country. Through this expertise, Ms. Nori is able to match utilities with their best peer comparable utilities to ensure that practices are sufficiently similar to draw reasonable conclusions. This also allows for the consideration of local climate, and physical condition of the assets in service – all of which are important in the selection of the final depreciation parameters.

e) Chart 1 below provides a continuity of the gross hydroelectric assets by year.

Chart 1 – Original Cost and Net Book Value of Hydroelectric Property, Plant, and Equipment by Year as of December 31, 2024 ($M)

Year	Original Cost	Accumulated Depreciation	Net Book Value
April 1, 1999	6,500.5	(2,269.6)	4,230.9
1999[1]	107.6	(57.4)	50.2
2000	99.3	(58.0)	41.3
2001	76.5	(45.9)	30.6
2002	52.9	(32.9)	20.1
2003	49.0	(25.7)	23.3
2004	83.2	(47.8)	35.4
2005	38.9	(17.1)	21.9
2006	66.5	(31.8)	34.6
2007	68.9	(25.5)	43.4
2008	58.3	(26.6)	31.7
2009	83.0	(28.4)	54.7
2010	95.6	(33.1)	62.5
2011	130.5	(39.1)	91.4
2012	65.0	(20.8)	44.2
2013	1,499.8	(202.7)	1,297.1
2014	69.7	(17.4)	52.3
2015	81.4	(19.5)	61.9
2016	49.6	(10.4)	39.3
2017	150.8	(23.3)	127.5
2018	140.4	(22.7)	117.7
2019	260.2	(32.1)	228.1
2020	138.5	(17.0)	121.5
2021	255.4	(23.4)	232.0
2022	531.1	(26.9)	504.2
2023	272.9	(8.6)	264.3
2024	331.7	(3.0)	328.7
Total Plant	**11,357.4**	**(3,166.7)**	**8,190.7**

[1] Reflects establishment of OPG through the purchase of a set of hydroelectric and others assets on April 1, 1999.

SEC Interrogatory #188

Interrogatory

Reference:
F4-1-1, Attachment 12, p. 16-17

Question(s):

With respect to the Concentric, *Assessment of Regulated Hydroelectric Asset Depreciation Rates* (December 2019) Report, please restate Table 1 to include, for each of the four categories, the gross book value and accumulated depreciation each year.

Response

The referenced Table 1 is a listing of multiple asset classes for OPG's regulated hydroelectric facilities. OPG is unable to identify the "four categories" noted in the question and is therefore unable to provide any responsive information.

SEC Interrogatory #189

Interrogatory

Reference:
F4-3-1, p. 21, Figure 4a

Question(s):

Please explain why the percentage of nuclear allocation management – supervisors to total employees has increased as compared to 2020-2023.

Response

Refer to Chart 1 below where the average Management-Supervisory FTEs as a percentage of total regular and non-regular FTEs for the nuclear facilities (refer to Ex. F4-3-1, p.21, Figure 4a) is approximately 10% for the period 2024-2031.

As discussed at Ex. F4-3-1, p.13, lines 14-20, the previously implemented reduction in management positions discussed in EB-2020-0290 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 enable the planning and readiness for execution of these major investments.

OPG continues to leverage the centralization of functions implemented in 2020, including Support Services, to more effectively scale project teams up (or down), using existing organizational structures.

Chart 1 – Nuclear including DNNP facilities FTEs 2020-2031

Figure 4a - Nuclear FTE	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
Total FTE (Regular and Non Regular)	8,396	8,334	8,035	8,621	9,073	9,938	9,589	9,368	9,398	9,249	9,038	8,909
Mgmt-Supervisory % of Total FTE	8.7%	8.0%	8.3%	8.8%	9.8%	10.6%	10.7%	10.3%	10.1%	9.9%	10.0%	10.1%

*Refer to Ex. F4-3-1, Figure 4a

SEC Interrogatory #190

Interrogatory

Reference:
F4-3-1, p. 35

Question(s):

Does the contribution ratio set out in Figure 9 reflect the actual or forecast the overall OPG-wide contribution ratio, or does this reflect only a sub-set of employees (e.g. newer employees)?

Response

The pension contribution ratios in Ex. F4-3-1, Figure 9 reflect the actual and forecast overall OPG-wide contribution ratios.

SEC Interrogatory #191

Interrogatory

Reference:
F4-3-1

Question(s):

With respect to the Ontario Public Sector Salary Disclosure List:

a) For each of the most recent years available, what percentage of OPG's employees were on the Public Sector Disclosure list?

b. For most recent year available, please provide the total number of OPG employees whose salaries are at or above, a) $100,000, and b) $200,000.

Response

a) The percentage of total employees on OPG's payroll listed on the Public Sector Salary Disclosure ("PSSD") was approximately 82% in 2024 and 84% in 2025.

b) The PSSD published in 2026 listed 10,346 OPG employees earning $100,000 or more in 2025, including 1,964 OPG employees earning $200,000 or more.

SEC Interrogatory #192

Interrogatory

Reference:
F4-3-1

Question(s):

Please provide details of all material changes made to the current collective agreement as compared to those in place at the time of the filing of EB-2020-0290.

Response

Details of changes made to the current collective agreements with the PWU and the Society as compared to those in place at the time of the filing of EB-2020-0290 are discussed in Ex. F4-3-1, Section 2.0, Section 6 and Section 7. For ease of reference, material changes, in addition to wage increases and lump-sum payments identified at the above evidence and Ex. L-F4-SEC-194, are summarized below:

- maintained the ability to use PWU represented term-based employees ("Term Employees") and Society-represented extended temporary employees (ETEs);
- agreement that PWU-represented employees may perform certain refurbishment work traditionally performed by the Building Trades Unions (refer to Ex. D2-3-2, pp. 9-10 for additional discussion);
- secured provisions with the PWU and the Society that allow employees to move between positions and locations without triggering disruptive displacement processes (refer to Ex. D2-3-2, pp. 9-10 for additional discussion);
- broadened job classifications for PWU-represented roles, and greater resourcing flexibility in support of maintenance outages for DNNP operations (refer to Ex. F2-4-1, Section 4.2); and
- 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 (refer to Ex. L-F4-Staff-223 for additional discussion).

Refer to Ex. L-F4-SEC-194 for additional details of the material changes described above.

SEC Interrogatory #193

Interrogatory

Reference:
F4-3-1, p. 5

Preamble:

The evidence states notes that the current collective agreement with the PWU expires on March 31, 2027, and the Society collective agreement has expired.

Question(s):

a) For the purpose of the budgets included in the Application for 2027-2031, what assumptions has OPG made regarding the Society's collective agreement?

b) Please quantify the impact, if any, between the response to part (a) and what was decided by way of the Arbitration Decision, dated January 26, 2026. Please provide all calculations.

c) For the purpose of the budgets included in the Application for 2027-2031, what assumptions has OPG made regarding the next PWU collective agreement (beginning April 1, 2027)?

Response

a) Refer to Ex. L-F4-Staff-227.

b) The estimated revenue requirement impact of the differences in wage escalation in the Society Arbitration decision, dated January 26, 2026 relative to the assumptions in Ex. L-F4-Staff-227 for the years 2026-2028 is an increase of approximately $2M for OPG's nuclear facilities in 2027 and less than $1M annually for the remainder of the IR term and for each of the regulated hydroelectric facilities and the DNNP facilities.

c) Refer to Ex. L-F4-Staff-227.

SEC Interrogatory #194

Interrogatory

Reference:
F4-3-1

Question(s):

Please provide a breakdown of the cost impact (additional cost and/or savings) from all changes in the collective agreements with the PWU and the Society since the last application, for each of the following time periods, a) the term of each collective agreement, b) the test period (2027-2031), and c) the total impact if the change extends beyond the test period. Please detail all assumptions made and full calculations. In your response, please provide similar tables included in response to EB-2020-0290, F4-03-SEC-145.

Response

a) - c)

Charts 1 to 5 provide the estimated incremental cost and savings impacts arising from each of the negotiated collective agreements with the Power Workers' Union ("PWU") and the Society of United Professionals ("Society") since EB-2020-0290, for the term of the agreements. As in EB-2016-0152, Ex. L-6.6-15 SEC-072, and EB-2020-0290, Ex. L-F4-SEC-145, cost impact information beyond the current term of the agreements is not detailed in this response, as the agreements may change beyond this timeframe. However, explanations for potential material cost impacts beyond the term of the collective agreements are provided where possible.

Given the greater number of collective agreements covered by this Application as compared to past OPG proceedings, the complexity of OPG's collective bargaining and recognizing the impact of inflation due to the passage of time, OPG has applied a materiality threshold of [redacted] per term of a collective agreement in responding to this interrogatory. This threshold is consistent with [redacted] OPG believes this approach supports a reasonable balance between ensuring the OEB has sufficient information regarding the substantive collective bargaining outcomes, while supporting regulatory efficiency in the proceeding.

As discussed in Ex. F4-3-1, pp. 15-17, OPG has been strategically focused [redacted]

[redacted] Each agreement, provision and planning assumption addresses distinct yet interconnected issues, [redacted]

Negotiated and arbitrated wage outcomes over the historical period have been generally [redacted] (refer to Ex. F4-3-1, p. 25, Chart 1), and cumulative wage increases have been similar to or lesser than organizations with a similar union profile (refer to Ex. F4-3-1, pp. 27-28, Figures 6 and 8). [redacted], OPG secured the continued suspension of the cost-of-living allowance/adjustment provisions in the collective agreements with both unions during this period. [redacted] permanent purchased service agreement provisions with the Society, allows on-going contracting [redacted] and provides OPG with important operational and cost flexibility. These provisions enable the company to access specialized skills, manage workload peaks, and deploy resources more efficiently without permanently increasing the internal workforce, while continuing to meet safety and performance requirements (refer to Ex. L-F4-Staff-223).

[redacted] reflect the operational complexities of OPG's collective agreements as the company approaches a new major refurbishment program that requires significant labour transitions. In particular, a negotiated outcome since EB-2020-0290 supports the ability to [redacted] DNNP operations through broadened job descriptions for PWU-represented employees (refer to Ex. F4-3-1, p. 7, lines 4-11). Furthermore, OPG negotiated agreements that provide flexibility [redacted] enabling the utilization of existing operational staff to work on the PRP. This allows OPG to leverage the critical station-specific expertise, such as radiation protection, maintenance, and fuel handling, to support PRP work. This approach also ensures timely access to qualified labour to meet project schedules in a [redacted] labour [redacted] Refer to Ex. L-F4-Staff-225 for additional details about [redacted] over the IR term.

Specifically, as described above and in Ex. F4-3-1, pp.6-7, and Ex. D2-3-4, pp. 7-8, a jurisdictional tripartite agreement with the PWU and Building Trades Unions provides OPG with the ability to utilize Pickering PWU-represented operational employees for

the PRP instead of using contractors for work that otherwise would fall outside its labour jurisdiction. This strategy, together with the more flexible redeployment provisions for Society-represented employees working in the Durham Region, is expected to [redacted]. This does not take into account [redacted].

The achievement of the above collective bargaining outcomes reflects the responsiveness of OPG's labour relations strategies to shifting business priorities during the historical period. as OPG has used [redacted] ongoing operations and preserves the [redacted]. The financial impacts of these broader agreements over the specific collective agreement terms are provided in each Chart below, as applicable.

Chart 1 -
PWU Collective Agreement Material Impacts
April 1, 2022 to March 31, 2024 Agreement

Item [1,2]	Costs / (Savings) $M
2-Year Wage Increases [3]	[redacted]
One-time lump sum, signing bonus	[redacted]
Nuclear Outage Purchased Services Threshold Renewal [4]	[redacted]
Renewal of Term Employees Category [5]	[redacted]
Total	[redacted]

Numbers may not add due to rounding

Notes for Chart 1:

1. [redacted]
2. [redacted]

[redacted]

3. [redacted]

[redacted]

4. [redacted]

[redacted]

5. [redacted]

Chart 2 -
PWU Collective Agreement Material Impacts
April 1, 2024 to March 31, 2027 Agreement

Item[6]	Costs / (Savings) $M
3-Year Wage Increases [1]	[redacted]
Bill 124 Moderation Period Settlement [2]	[redacted]
Bill 124 One-time Payment (2024)	[redacted]
Nuclear Outage Purchased Services Threshold Renewal [3]	[redacted]
Renewal of Term Employees Category [4]	[redacted]
Ability to redeploy PWU-represented employees to the PRP [5]	[redacted]
Total	[redacted]

Numbers may not add due to rounding

Notes for Chart 2

1. [redacted]

2. [redacted]

3. [redacted]

4. [redacted]

5. [redacted]

6. [redacted]

Chart 3 -
Society Collective Agreement Material Impacts
January 1, 2022 to December 31, 2023 Agreement

Item [3]	Costs / (Savings) $M
2-Year Wage Increases [1]	[redacted]
Bill 124 Moderation Period Award [2]	[redacted]
Purchased Services Agreement (made permanent)	[redacted]
Overtime Amendments[4]	[redacted]
Total	[redacted]

Numbers may not add due to rounding

Notes for Chart 3:

1. [redacted]

2. [redacted]
.
3. [redacted]
.
4. [redacted]

Chart 4 -
Society Collective Agreement Material Impacts
January 1, 2024 to December 31, 2025 Agreement

Item	Costs / (Savings) $M
2-Year Wage Increases [1]	[redacted]
One-time wage grid adjustment [2]	[redacted]
Redeployment provisions supporting transitions [3]	[redacted]
Total	[redacted]

Numbers may not add due to rounding

Notes for Chart 4:

1. [redacted]
2. [redacted]
3. [redacted]
4. [redacted]

Chart 5 -
Society Collective Agreement Material Impacts
January 1, 2026 to December 31, 2028 Agreement

Item [2]	Costs / (Savings) $M
3-Year Wage Increases [1]	[redacted]

Notes for Chart 5:

1. [redacted]

2. [redacted]

SEC Interrogatory #195

Interrogatory

Reference:
F4-3-1, p. 30

Question(s):

With respect to the Stakeholder Return Program ("SRP"):

a) Please provide the percentage applied to forecast corporate earnings before tax ("EBT") for each year 2016 to 2031. Please note if the percentage is different for nuclear and hydroelectric.

b) Please explain how the percentages for 2026-2031 were determined.

Response

a) As noted in Ex. F4-3-1, p. 31, the Applicants adopted a financial results model starting in 2021 for deriving the SRP amounts based on a percentage applied to forecast EBT. A single forecast EBT and a single percentage is used across the corporation and therefore underpins the SRP costs attributed to each of OPG's nuclear facilities and regulated hydroelectric facilities. The percentages applied to forecast EBT for each year from 2021-2026 are shown in Chart 1 below. Refer to Ex. L-F4-AMPCO-123 for the 2027-2031 years.

Chart 1
Stakeholder Return Program - Percentage of Forecast EBT Applied

2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Actual	2026 Plan
[redacted]					

b) As noted in Ex. F4-3-1, p. 31, and Ex. F4-4-1, pp. 7-8, the percentage of forecast EBT for a given year takes into consideration the business objectives for that year and the industry range of 2%-7% of EBT provided by Willis Towers Watson. On average, over both the 2021-2026 period and the 2027-2031 period, approximately 2% has been applied to forecast EBT, which is at the lowest end of the industry range. The percentage applied to the forecast EBT, the corporate balanced scorecard results, and total incentive amounts are subject to approval by OPG's

Board of Directors, with consideration for reasonableness and ensuring adequate funding to effectively drive performance.

SEC Interrogatory #196

Interrogatory

Reference:
F4-3-1, Attachment 1, p. 3

Question(s):

Please provide a revised version of Appendix 2K, that, a) separates Management into executive and non-executive management, b) breakdown compensation between capital and OM&A, and c) include an additional table that includes all employees for hydroelectric, nuclear, and DNNP.

Response

a) and b) Refer to Ex. L-F4-AMPCO-115 Attachment 1

b) Refer to Ex. L-F4-CCC-089 Attachment 1.

SEC Interrogatory #197

Interrogatory

Reference:
F4-3-1, Attachment 3

Question(s):

With respect to the WTW, *Total Compensation Benchmarking Study*:

a) Please detail all methodological changes between the study filed in this application and that filed in EB-2020-0290.

b) Please revise the results of the study so that they provide separate results for each of the general and energy industry.

Response

This response was prepared by WTW:

a) As discussed in Ex. L-F4-CCMBC-008, OPG adopted the compensation philosophy recommendations and resulting peer group criteria set out in Ex. L-F4-3-1, Attachment 2, with the exception of eliminating the forced 50:50 weighting between the public sector and private sector to Executive level roles. As detailed in Ex. L-F4-SUP-020 and Ex. L-F4-CCC-90, these criteria were considered by WTW and applied to WTW's survey participants to determine the organizations to include in the Total Excluding Nuclear Authorized comparator group. This was the only methodological change compared to the compensation study filed in EB-2020-0290.

b) An analysis providing separate results for the general industry and the energy industry cannot be completed in a timely manner, as it would take approximately four to six months and would require a change in the comparator group. We note that in the current comparator group, there are limited general industry organizations (10 to 14 depending on if referencing executive or non-executive Total Excluding Nuclear Authorized comparator group) and this would be insufficient to provide quartile statistics covering the same number of roles as covered in the current benchmarking study. Furthermore, this approach would be inconsistent with the methodology of the study, which applies OPG's compensation philosophy and definition of talent market to the peer comparator group.

This response was prepared by OPG:

OPG's position is that the approach postulated in part b) of the question would also be inconsistent with the EB-2020-0290 OEB-approved settlement proposal, which required OPG to complete its compensation benchmarking study on the current two-segment benchmarking approach only.

SEC Interrogatory #198

Interrogatory

Reference:
F4-3-1, Attachment 3, p. 16-17

Question(s):

With respect to the WTW, *Total Compensation Benchmarking* Study:

a) For each of Management, PWU, and Society, please provide an estimate of the dollar difference between the weighted average total remuneration (including Hydro One Share Grants) for OPG and the P50 median used in the study, and then allocated to each of nuclear, DNNP, and hydroelectric, and to each of capital and OM&A. Please provide the amount for the year the study is representative of and for each year between 2027 and 2031.

b. Please provide a step-by-step explanation of how the estimate was reached, including all supporting calculations so the methodology can be assessed and the calculations verified. In doing so, please also provide a link to what is included in Appendix 2-K (F4-3-1, Attachment 1).

   Please provide the analysis for both Nuclear Authorized at the 50th and 75th percentile.

Response

a) and b)
WTW and OPG have performed the requested analysis to calculate an estimated dollar difference between OPG's total remuneration and the WTW compensation benchmarking results presented in this Application, for the IR term, and provided the associated step-by-step explanations, in a manner consistent with those provided in EB-2020-0290 Ex. L-F4-Staff-149, EB-2020-0290 Ex. JTX 4.18 and EB-2023-0336 Ex. JT 1.8-1.10. Such calculations provided in this response include the scenario requested in the interrogatory (total remuneration including Hydro One share grants, compared to the P50 median), which has been interpreted to reflect OPG's benchmarking position as detailed in the WTW benchmarking study at Ex. F4-3-1, Attachment 3, p. 15. Additionally, provided are the calculations requested in Ex. L-F4-CCC-091, part a) and part b) for all other versions of the results presented in the WTW benchmarking study (refer to Ex. F4-3-1, Attachment 3, pp. 14-18). The calculations in respect of all the above scenarios have been provided in Chart sets 1-6 below.

For completeness with the response to Ex. L-F4-CCC-091 and Ex. L-F4-SUP-023, WTW has also provided the calculations for the benchmarking results outlined in Ex. L-F4-SUP-023 part b) (i.e., no PWU Term and Society ETE employees and with OPG's current pension and benefit provisions), as well as those same scenarios inclusive of Hydro One share grants, the results of which are outlined in Ex. L-F4-CCC-091 part c). These scenarios are more closely aligned to OPG's expected future state (i.e., over the IR term), consistent with the evidence at Ex. F4-3-1, p. 17, pp. 31-32 and pp. 36-37 and Ex. L-F4-CCC-085. The calculations for these scenarios have been provided in Chart sets 7-10 below.

The following summarizes the above noted ten scenarios provided by WTW in Chart sets 1-10 below:

1. OPG Overall and Nuclear Authorized Compared to P50, Excluding Hydro One Shares (p. 14 of WTW report)
2. OPG Overall and Nuclear Authorized Compared to P50 Including Hydro One Shares (p. 15 of WTW report)
3. OPG Overall Compared to P50 and Nuclear Authorized Compared to P75, Excluding Hydro One Shares (p. 16 of WTW report)
4. OPG Overall Compared to P50 and Nuclear Authorized Compared to P75, Including Hydro One Shares (p. 17 of WTW report)
5. OPG Overall Compared to P50 and Nuclear Authorized Compared to P50, Excluding Hydro One Shares, Fewer Term Employees (p. 18 of WTW report)
6. OPG Overall Compared to P50 and Nuclear Authorized Compared to P75, Excluding Hydro One Shares, Fewer Term Employees (p. 18 of WTW report)
7. OPG Overall Compared to P50 and Nuclear Authorized Compared to P50, Excluding Hydro One Shares, No Term and ETE Employees (Chart 1 in Ex. L-F4-SUP-023 part b))
8. OPG Overall Compared to P50 and Nuclear Authorized Compared to P75, Excluding Hydro One Shares No Term and ETE Employees (Chart 2 in Ex. L-F4-SUP-023 part b))
9. OPG Overall Compared to P50 and Nuclear Authorized Compared to P50, Including Hydro One Shares, No Term and ETE Employees (Chart 8 in Ex. L-F4-CCC-091 part c))
10. OPG Overall Compared to P50 and Nuclear Authorized Compared to P75, Including Hydro One Shares, No Term and ETE Employees (Chart 9 in Ex. L-F4-CCC-091 part c)).

As discussed in Ex. F4-3-1, Attachment 3, p. 12, WTW considers the appropriate competitiveness to be within a +/- 10% range of the target market reference point (e.g., the market 50th percentile ("P50") or the market 75th percentile ("P75")) and only amounts outside this range should be the basis of the estimated dollar difference to the market. As such, for each of the ten scenarios, also provided below are the calculations relative to such applicable range of the target market reference point. OPG

notes that in all scenarios over the IR term, OPG's overall benchmarking results are within the +/- 10% range, which results in an estimated dollar difference in respect of OPG's total remuneration of $0.

The calculations provided by WTW for each of the scenarios include the impacts on forecast OM&A costs and capital costs for each of OPG's nuclear facilities, the Darlington New Nuclear Program ("DNNP") facilities and OPG's regulated hydroelectric facilities. The calculations for OPG's nuclear facilities capital costs are shown separately between the Pickering Refurbishment Program ("PRP") and other such capital costs. With respect to capital costs, OPG has computed the associated revenue requirement estimates for the 2027-2031 IR term on the basis of the translation of these costs to capital in-service additions, as this represents the basis of the requested recovery of such costs in this Application. Such translation has been performed by OPG with reference to the information provided in Ex. L-B1-SEC-028. The details of the translation and resulting revenue requirement calculations are provided in Attachment 1. For ease of reference, the end results of the overall analysis undertaken in this response for each of the ten scenarios, by regulated business, year and type of costs, have been summarized by OPG in the respective Charts 1.6, 2.6, 3.6, 4.6, 5.6, 6.6, 7.6, 8.6, 9.6, and 10.6 below.

In providing the calculations in respect of OM&A costs for OPG's regulated hydroelectric facilities for years beyond 2027, OPG maintains that under the proposed regulated hydroelectric rate-setting methodology, while capital-related revenue requirement impacts are required for all years, OM&A costs and certain other revenue requirement elements are relevant for the 2027 test year only (refer to Ex. A1-3-2, Section 2.0). Beyond the 2027 test year, regulated hydroelectric revenue will be determined formulaically by the proposed annual adjustment mechanism outlined in Ex. A1-3-2, Section 2.3.

As detailed in Ex. D2-3-1 and Ex. D2-4-1 and related exhibits, the Applicants have established definitive execution cost estimates and schedules for the PRP and the DNNP, Unit 1. As that evidence demonstrates, these comprehensive release quality estimates have been developed in a rigorous manner that aligns with recommended industry practices and form the basis upon which the Province of Ontario ("Province") has approved the Applicants to proceed with the execution of these programs, as key pillars of the Province's Integrated Energy Plan. They are also the basis upon which the performance of these programs will be measured and underpin OPG's 2025-2031 Business Plan and this Application. As set out in Ex. A1-2-2 and discussed at the above evidence, consistent with the approach adopted for the DRP, the Applicants believe it is appropriate to manage, and have requested the OEB's approval in respect of these large and complex programs, on the basis of a total envelope in-service amount, including labour costs.[1] It is the Applicants' view that only costs in excess of the total

[1] EB-2016-0152, Decision and Order, December 28, 2017, p. 41.

approved in-service amounts would be subject to a future prudence review through the respective deferral and variance accounts.

The following response was prepared by WTW:

As noted in Ex. F4-3-1, Attachment 3, p. 9, total remuneration values in the report should be interpreted with care and used to assess the competitiveness of OPG's total remuneration value relative to the market, rather than the competitiveness of OPG's costs. It is recommended that competitiveness be assessed by determining whether total remuneration levels fall within a reasonable range of market reference values, recommended as a range of +/- 10% of the market reference (refer to Ex. F4-3-1, p. 40 and Attachment 3, p.12), which is intended to reflect normal variation arising from the wide range of factors influencing individual compensation levels (refer to Ex. L-F4-SUP-018). In addition, to the extent the analysis is used in assessing the competitiveness of OPG's compensation costs, total direct compensation should be considered.

Chart sets 1 to 10 below provide an estimate of the dollar difference, by year, between total remuneration for OPG and the market, and then allocated to each of Nuclear, DNNP LP (labelled as DNNP), and Regulated Hydroelectric, and to each of OM&A and capital expenditures, for each version of the analysis in WTW's 2024 Total Compensation Benchmarking Study (Ex. F4-3-1, Attachment 3, pp. 14-18) and for the results in Ex. L-F4-SUP-023 part b) and Ex. L-F4-CCC-091 part c).

Chart 1.1 – Estimated Total Remuneration Dollar Difference – OPG Overall and Nuclear Authorized Compared to P50, Excluding Hydro One Shares (p. 14 of WTW report)

	PWU ($Millions)			Society ($Millions)			Management ($Millions)			Total ($Millions)			Overall +/- Market Range ($Millions)		
	OPG	Market Ref. Point	$ Variance	OPG	Market Ref. Point	$ Variance	OPG	Market Ref. Point	$ Variance	OPG	Market Ref. Point	$ Variance	Market Ref. Point Positioning (%)	% Variance outside +/-10%	$ Variance outside +/-10%
2024	[redacted]		$94.1	[redacted]		$120.9	[redacted]		($53.7)	$1,947.0	$1,785.7	$161.2	9.0%	0%	$0
2027			$103.5			$138.6			($56.7)	$2,367.6	$2,182.3	$185.3	[redacted]	0%	$0
2028			$105.3			$137.3			($58.4)	$2,415.4	$2,231.2	$184.2		0%	$0
2029			$105.7			$136.2			($59.7)	$2,449.5	$2,267.3	$182.1		0%	$0
2030			$105.4			$137.0			($61.8)	$2,495.4	$2,314.9	$180.5		0%	$0
2031			$105.4			$137.2			($64.7)	$2,548.8	$2,370.9	$177.9		0%	$0

Chart 1.2 – Estimated Total Remuneration Dollar Difference – Amounts Allocated to Nuclear and Attributable to OM&A (p.14 of WTW report)

	PWU ($Millions)			Society ($Millions)			Management ($Millions)			Total ($Millions)			Overall +/- Market Range ($Millions)		
	Nuclear			Nuclear			Nuclear			Nuclear			Nuclear		
	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed
2027	$80.7	$44.4	$1.8	$110.8	$46.6	$2.4	($44.8)	($25.5)	($2.4)	$146.7	$65.4	$1.8	$0	$0	$0
2028	$82.1	$44.4	$1.7	$108.4	$45.5	$2.6	($46.1)	($26.8)	($2.6)	$144.4	$63.1	$1.7	$0	$0	$0
2029	$83.5	$45.1	$1.4	$108.9	$45.8	$2.5	($46.6)	($27.5)	($2.7)	$145.8	$63.4	$1.2	$0	$0	$0
2030	$83.2	$45.8	$2.2	$109.6	$47.1	$3.6	($48.2)	($28.9)	($3.2)	$144.6	$64.0	$2.6	$0	$0	$0
2031	$82.2	$54.3	$3.3	$108.4	$55.3	$3.9	($50.5)	($32.8)	($2.9)	$140.1	$76.7	$4.3	$0	$0	$0

Chart 1.3 – Estimated Total Remuneration Dollar Difference – Amounts Allocated to Regulated Hydroelectric Facilities and Attributable to OM&A (p.14 of WTW report)

	PWU ($Millions)		Society ($Millions)		Management ($Millions)		Total ($Millions)		Overall +/- Market Range ($Millions)	
	Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric	
	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed
2027	$15.5	$12.4	$19.4	$11.8	($6.8)	($5.9)	$28.1	$18.3	$0	$0
2028	$15.8	$12.6	$20.6	$12.4	($7.0)	($6.1)	$29.4	$18.9	$0	$0
2029	$15.9	$12.5	$20.4	$12.1	($7.2)	($6.2)	$29.1	$18.3	$0	$0
2030	$15.8	$12.6	$20.5	$12.5	($7.4)	($6.5)	$28.9	$18.6	$0	$0
2031	$16.9	$13.3	$20.6	$13.0	($7.8)	($6.8)	$29.7	$19.5	$0	$0

Chart 1.4 – Estimated Total Remuneration Dollar Difference – Amounts Allocated to Nuclear Facilities and Attributable to Capital Expenditures (p.14 of WTW report)

	PWU ($Millions)				Society ($Millions)				Management ($Millions)				Total ($Millions)				Overall +/- Market Range ($Millions)			
	Nuclear				Nuclear				Nuclear				Nuclear				Nuclear			
	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed
2027	$80.7	$24.2	$0.9	$1.6	$110.8	$34.4	$4.3	$15.5	($44.8)	($9.9)	($2.2)	($2.2)	$146.7	$48.7	$3.0	$14.9	$0	$0	$0	$0
2028	$82.1	$25.5	$2.0	$0.8	$108.4	$33.6	$2.9	$15.2	($46.1)	($10.1)	($1.8)	($2.3)	$144.4	$48.9	$3.1	$13.7	$0	$0	$0	$0
2029	$83.5	$26.7	$2.3	$0.8	$108.9	$34.9	$1.7	$16.3	($46.6)	($10.7)	($1.1)	($2.8)	$145.8	$50.9	$3.0	$14.4	$0	$0	$0	$0
2030	$83.2	$26.6	$0.7	$0.8	$109.6	$35.1	$0.4	$16.4	($48.2)	($10.6)	($0.3)	($2.9)	$144.6	$51.1	$0.9	$14.4	$0	$0	$0	$0
2031	$82.2	$16.4	-	$1.6	$108.4	$26.0	-	$15.2	($50.5)	($9.6)	-	($3.0)	$140.1	$32.9	-	$13.8	$0	$0	$0	$0

Chart 1.5 – Estimated Total Remuneration Dollar Difference – Amounts Allocated to Regulated Hydroelectric Facilities and Attributable to Capital Expenditures (p.14 of WTW report)

	PWU ($Millions)		Society ($Millions)		Management ($Millions)		Total ($Millions)		Overall +/- Market Range ($Millions)	
	Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric	
	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed
2027	$15.5	$3.1	$19.4	$7.6	($6.8)	($0.9)	$28.1	$9.8	$0	$0
2028	$15.8	$3.2	$20.6	$8.2	($7.0)	($0.9)	$29.4	$10.5	$0	$0
2029	$15.9	$3.3	$20.4	$8.4	($7.2)	($0.9)	$29.1	$10.8	$0	$0
2030	$15.8	$3.2	$20.5	$8.0	($7.4)	($0.9)	$28.9	$10.3	$0	$0
2031	$16.9	$3.5	$20.6	$7.6	($7.8)	($0.9)	$29.7	$10.2	$0	$0

Chart 2.1 – Estimated Total Remuneration Dollar Difference – OPG Overall and Nuclear Authorized Compared to P50, Including Hydro One Shares (p. 15 of WTW report)

	PWU ($Millions)			Society ($Millions)			Management ($Millions)			Total ($Millions)			Overall +/- Market Range ($Millions)		
	OPG	Market Ref. Point	$ Variance	OPG	Market Ref. Point	$ Variance	OPG	Market Ref. Point	$ Variance	OPG	Market Ref. Point	$ Variance	Market Ref. Point Positioning (%)	% Variance outside +/-10%	$ Variance outside +/-10%
2024	[redacted]	[redacted]	$107.4	[redacted]	[redacted]	$128.9	[redacted]	[redacted]	($53.4)	$1,968.6	$1,785.7	$182.9	10.2%	0.2%	$4.3
2027	[redacted]	[redacted]	$119.4	[redacted]	[redacted]	$148.6	[redacted]	[redacted]	($56.4)	$2,393.9	$2,182.3	$211.6	[redacted]	0%	$0
2028	[redacted]	[redacted]	$121.9	[redacted]	[redacted]	$147.3	[redacted]	[redacted]	($58.0)	$2,442.4	$2,231.2	$211.2		0%	$0
2029	[redacted]	[redacted]	$122.7	[redacted]	[redacted]	$146.3	[redacted]	[redacted]	($59.4)	$2,477.0	$2,267.3	$209.6		0%	$0
2030	[redacted]	[redacted]	$122.7	[redacted]	[redacted]	$147.3	[redacted]	[redacted]	($61.4)	$2,523.4	$2,314.9	$208.6		0%	$0
2031	[redacted]	[redacted]	$123.2	[redacted]	[redacted]	$147.7	[redacted]	[redacted]	($64.4)	$2,577.4	$2,370.9	$206.5		0%	$0

Chart 2.2 – Estimated Total Remuneration Dollar Difference – Amounts Allocated to Nuclear and Attributable to OM&A (p.15 of WTW report)

	PWU ($Millions)			Society ($Millions)			Management ($Millions)			Total ($Millions)			Overall +/- Market Range ($Millions)		
	Nuclear			Nuclear			Nuclear			Nuclear			Nuclear		
	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed
2027	$93.2	$51.2	$2.0	$118.9	$49.9	$2.6	($44.6)	($25.4)	($2.4)	$167.5	$75.8	$2.3	$0	$0	$0
2028	$95.1	$51.3	$2.0	$116.4	$48.9	$2.8	($45.9)	($26.6)	($2.6)	$165.6	$73.6	$2.2	$0	$0	$0
2029	$97.0	$52.4	$1.6	$117.0	$49.2	$2.7	($46.3)	($27.3)	($2.7)	$167.7	$74.2	$1.7	$0	$0	$0
2030	$97.0	$53.3	$2.5	$117.8	$50.7	$3.9	($47.9)	($28.8)	($3.2)	$166.9	$75.2	$3.2	$0	$0	$0
2031	$96.1	$63.4	$3.8	$116.7	$59.5	$4.2	($50.2)	($32.6)	($2.9)	$162.6	$90.3	$5.1	$0	$0	$0

Chart 2.3 – Estimated Total Remuneration Dollar Difference – Amounts Allocated to Regulated Hydroelectric Facilities and Attributable to OM&A (p.15 of WTW report)

	PWU ($Millions)		Society ($Millions)		Management ($Millions)		Total ($Millions)		Overall +/- Market Range ($Millions)	
	Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric	
	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed
2027	$17.9	$14.3	$20.8	$12.7	($6.8)	($5.9)	$31.9	$21.1	$0	$0
2028	$18.3	$14.6	$22.1	$13.3	($7.0)	($6.1)	$33.4	$21.8	$0	$0
2029	$18.4	$14.5	$21.9	$12.9	($7.1)	($6.2)	$33.2	$21.3	$0	$0
2030	$18.4	$14.7	$22.1	$13.5	($7.4)	($6.5)	$33.1	$21.7	$0	$0
2031	$19.7	$15.6	$22.1	$14.0	($7.7)	($6.8)	$34.1	$22.7	$0	$0

Chart 2.4 – Estimated Total Remuneration Dollar Difference – Amounts Allocated to Nuclear Facilities and Attributable to Capital Expenditures (p.15 of WTW report)

	PWU ($Millions)				Society ($Millions)				Management ($Millions)				Total ($Millions)				Overall +/- Market Range ($Millions)			
	Nuclear				Nuclear				Nuclear				Nuclear				Nuclear			
	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed
2027	$93.2	$27.9	$1.0	$1.9	$118.9	$36.8	$4.6	$16.6	($44.6)	($9.8)	($2.2)	($2.2)	$167.5	$55.0	$3.5	$16.3	$0	$0	$0	$0
2028	$95.1	$29.5	$2.3	$1.0	$116.4	$36.1	$3.1	$16.3	($45.9)	($10.1)	($1.8)	($2.3)	$165.6	$55.5	$3.6	$15.0	$0	$0	$0	$0
2029	$97.0	$31.0	$2.7	$1.0	$117.0	$37.4	$1.9	$17.6	($46.3)	($10.7)	($1.1)	($2.8)	$167.7	$57.8	$3.5	$15.7	$0	$0	$0	$0
2030	$97.0	$31.0	$0.9	$1.0	$117.8	$37.7	$0.5	$17.7	($47.9)	($10.5)	($0.3)	($2.9)	$166.9	$58.2	$1.1	$15.8	$0	$0	$0	$0
2031	$96.1	$19.2	-	$1.9	$116.7	$28.0	-	$16.3	($50.2)	($9.5)	-	($3.0)	$162.6	$37.7	-	$15.2	$0	$0	$0	$0

Chart 2.5 – Estimated Total Remuneration Dollar Difference – Amounts Allocated to Regulated Hydroelectric Facilities and Attributable to Capital Expenditures (p.15 of WTW report)

	PWU ($Millions)		Society ($Millions)		Management ($Millions)		Total ($Millions)		Overall +/- Market Range ($Millions)	
	Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric	
	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed
2027	$17.9	$3.6	$20.8	$8.1	($6.8)	($0.9)	$31.9	$10.8	$0	$0
2028	$18.3	$3.7	$22.1	$8.8	($7.0)	($0.9)	$33.4	$11.6	$0	$0
2029	$18.4	$3.9	$21.9	$9.0	($7.1)	($0.9)	$33.2	$11.9	$0	$0
2030	$18.4	$3.7	$22.1	$8.6	($7.4)	($0.9)	$33.1	$11.4	$0	$0
2031	$19.7	$4.1	$22.1	$8.2	($7.7)	($0.9)	$34.1	$11.4	$0	$0

Chart 3.1 – Estimated Total Remuneration Dollar Difference – OPG Overall Compared to P50 and Nuclear Authorized Compared to P75, Excluding Hydro One Shares (p. 16 of WTW report)

	PWU ($Millions)			Society ($Millions)			Management ($Millions)			Total ($Millions)			Overall +/- Market Range ($Millions)		
	OPG	Market Ref. Point	$ Variance	OPG	Market Ref. Point	$ Variance	OPG	Market Ref. Point	$ Variance	OPG	Market Ref. Point	$ Variance	Market Ref. Point Positioning (%)	% Variance outside +/-10%	$ Variance outside +/-10%
2024	[redacted]		$87.4	[redacted]		$117.4	[redacted]		($56.3)	$1,947.0	$1,798.4	$148.6	8.3%	0%	$0
2027			$95.4			$134.2			($59.7)	$2,367.6	$2,197.8	$169.9	[redacted]	0%	$0
2028			$96.9			$132.9			($61.4)	$2,415.4	$2,247.1	$168.4		0%	$0
2029			$97.0			$131.7			($62.8)	$2,449.5	$2,283.4	$166.0		0%	$0
2030			$96.5			$132.4			($64.9)	$2,495.4	$2,331.3	$164.1		0%	$0
2031			$96.3			$132.6			($67.9)	$2,548.8	$2,387.8	$161.0		0%	$0

Chart 3.2 – Estimated Total Remuneration Dollar Difference – Amounts Allocated to Nuclear and Attributable to OM&A (p. 16 of WTW report)

	PWU ($Millions)			Society ($Millions)			Management ($Millions)			Total ($Millions)			Overall +/- Market Range ($Millions)		
	Nuclear			Nuclear			Nuclear			Nuclear			Nuclear		
	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed
2027	$74.4	$40.9	$1.6	$107.4	$45.1	$2.4	($47.2)	($26.9)	($2.5)	$134.6	$59.1	$1.5	$0	$0	$0
2028	$75.6	$40.8	$1.6	$105.0	$44.1	$2.5	($48.5)	($28.1)	($2.8)	$132.0	$56.8	$1.3	$0	$0	$0
2029	$76.7	$41.4	$1.3	$105.4	$44.3	$2.4	($49.0)	($28.9)	($2.8)	$133.1	$56.8	$0.9	$0	$0	$0
2030	$76.2	$41.9	$2.0	$105.9	$45.6	$3.5	($50.6)	($30.4)	($3.4)	$131.6	$57.1	$2.1	$0	$0	$0
2031	$75.1	$49.6	$3.0	$104.7	$53.4	$3.8	($52.9)	($34.4)	($3.1)	$126.9	$68.6	$3.7	$0	$0	$0

Chart 3.3 – Estimated Total Remuneration Dollar Difference – Amounts Allocated to Regulated Hydroelectric and Attributable to OM&A (p. 16 of WTW report)

	PWU ($Millions)		Society ($Millions)		Management ($Millions)		Total ($Millions)		Overall +/- Market Range ($Millions)	
	Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric	
	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed
2027	$14.3	$11.5	$18.8	$11.5	($7.2)	($6.2)	$25.9	$16.7	$0	$0
2028	$14.5	$11.6	$19.9	$12.0	($7.4)	($6.4)	$27.1	$17.2	$0	$0
2029	$14.6	$11.5	$19.8	$11.7	($7.5)	($6.6)	$26.8	$16.6	$0	$0
2030	$14.5	$11.6	$19.9	$12.1	($7.8)	($6.8)	$26.6	$16.8	$0	$0
2031	$15.4	$12.2	$19.9	$12.5	($8.1)	($7.2)	$27.2	$17.5	$0	$0

Chart 3.4 – Estimated Total Remuneration Dollar Difference – Amounts Allocated to Nuclear Facilities and Attributable to Capital Expenditures (p. 16 of WTW report)

	PWU ($Millions)				Society ($Millions)				Management ($Millions)				Total ($Millions)				Overall +/- Market Range ($Millions)			
	Nuclear				Nuclear				Nuclear				Nuclear				Nuclear			
	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed
2027	$74.4	$22.3	$0.8	$1.5	$107.4	$33.3	$4.2	$15.0	($47.2)	($10.4)	($2.3)	($2.4)	$134.6	$45.2	$2.7	$14.2	$0	$0	$0	$0
2028	$75.6	$23.4	$1.8	$0.8	$105.0	$32.5	$2.8	$14.7	($48.5)	($10.7)	($1.9)	($2.4)	$132.0	$45.3	$2.7	$13.0	$0	$0	$0	$0
2029	$76.7	$24.5	$2.1	$0.8	$105.4	$33.7	$1.7	$15.8	($49.0)	($11.3)	($1.2)	($2.9)	$133.1	$47.0	$2.7	$13.6	$0	$0	$0	$0
2030	$76.2	$24.4	$0.7	$0.8	$105.9	$33.9	$0.4	$15.9	($50.6)	($11.1)	($0.3)	($3.0)	$131.6	$47.2	$0.8	$13.6	$0	$0	$0	$0
2031	$75.1	$15.0	-	$1.5	$104.7	$25.1	-	$14.7	($52.9)	($10.1)	-	($3.2)	$126.9	$30.1	-	$13.0	$0	$0	$0	$0

Chart 3.5 – Estimated Total Remuneration Dollar Difference – Amounts Allocated to Regulated Hydroelectric Facilities and Attributable to Capital Expenditures (p.16 of WTW report)

	PWU ($Millions)		Society ($Millions)		Management ($Millions)		Total ($Millions)		Overall +/- Market Range ($Millions)	
	Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric	
	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed
2027	$14.3	$2.9	$18.8	$7.3	($7.2)	($0.9)	$25.9	$9.3	$0	$0
2028	$14.5	$2.9	$19.9	$8.0	($7.4)	($1.0)	$27.1	$9.9	$0	$0
2029	$14.6	$3.1	$19.8	$8.1	($7.5)	($1.0)	$26.8	$10.2	$0	$0
2030	$14.5	$2.9	$19.9	$7.7	($7.8)	($0.9)	$26.6	$9.7	$0	$0
2031	$15.4	$3.2	$19.9	$7.4	($8.1)	($1.0)	$27.2	$9.6	$0	$0

Chart 4.1 – Estimated Total Remuneration Dollar Difference – OPG Overall Compared to P50 and Nuclear Authorized Compared to P75, Including Hydro One Shares (p. 17 of WTW report)

	PWU ($Millions)			Society ($Millions)			Management ($Millions)			Total ($Millions)			Overall +/- Market Range ($Millions)		
	OPG	Market Ref. Point	$ Variance	OPG	Market Ref. Point	$ Variance	OPG	Market Ref. Point	$ Variance	OPG	Market Ref. Point	$ Variance	Market Ref. Point Positioning (%)	% Variance outside +/-10%	$ Variance outside +/-10%
2024	[redacted]	[redacted]	$100.7	[redacted]	[redacted]	$125.5	[redacted]	[redacted]	($56.0)	$1,968.6	$1,798.4	$170.2	9.5%	0%	$0
2027	[redacted]	[redacted]	$111.4	[redacted]	[redacted]	$144.2	[redacted]	[redacted]	($59.4)	$2,393.9	$2,197.8	$196.2	[redacted]	0%	$0
2028	[redacted]	[redacted]	$113.5	[redacted]	[redacted]	$142.9	[redacted]	[redacted]	($61.1)	$2,442.4	$2,247.1	$195.4	[redacted]	0%	$0
2029	[redacted]	[redacted]	$114.1	[redacted]	[redacted]	$141.9	[redacted]	[redacted]	($62.4)	$2,477.0	$2,283.4	$193.5	[redacted]	0%	$0
2030	[redacted]	[redacted]	$113.9	[redacted]	[redacted]	$142.8	[redacted]	[redacted]	($64.5)	$2,523.4	$2,331.3	$192.1	[redacted]	0%	$0
2031	[redacted]	[redacted]	$114.1	[redacted]	[redacted]	$143.1	[redacted]	[redacted]	($67.5)	$2,577.4	$2,387.8	$189.7	[redacted]	0%	$0

Chart 4.2 – Estimated Total Remuneration Dollar Difference – Amounts Allocated to Nuclear and Attributable to OM&A (p. 17 of WTW report)

	PWU ($Millions)			Society ($Millions)			Management ($Millions)			Total ($Millions)			Overall +/- Market Range ($Millions)		
	Nuclear			Nuclear			Nuclear			Nuclear			Nuclear		
	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed
2027	$86.9	$47.8	$1.9	$115.4	$48.5	$2.5	($46.9)	($26.8)	($2.5)	$155.3	$69.5	$1.9	$0	$0	$0
2028	$88.5	$47.8	$1.9	$112.9	$47.4	$2.7	($48.2)	($28.0)	($2.8)	$153.2	$67.2	$1.8	$0	$0	$0
2029	$90.1	$48.7	$1.5	$113.5	$47.7	$2.6	($48.7)	($28.7)	($2.8)	$154.9	$67.6	$1.3	$0	$0	$0
2030	$90.0	$49.5	$2.3	$114.2	$49.1	$3.8	($50.3)	($30.2)	($3.4)	$153.9	$68.4	$2.7	$0	$0	$0
2031	$89.0	$58.8	$3.6	$113.0	$57.6	$4.1	($52.7)	($34.2)	($3.1)	$149.4	$82.2	$4.6	$0	$0	$0

Chart 4.3 – Estimated Total Remuneration Dollar Difference – Amounts Allocated to Regulated Hydroelectric Facilities and Attributable to OM&A (p. 17 of WTW report)

	PWU ($Millions)		Society ($Millions)		Management ($Millions)		Total ($Millions)		Overall +/- Market Range ($Millions)	
	Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric	
	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed
2027	$16.7	$13.4	$20.2	$12.3	($7.1)	($6.2)	$29.8	$19.5	$0	$0
2028	$17.0	$13.6	$21.4	$12.9	($7.3)	($6.4)	$31.1	$20.1	$0	$0
2029	$17.1	$13.5	$21.3	$12.6	($7.5)	($6.5)	$30.9	$19.6	$0	$0
2030	$17.1	$13.7	$21.4	$13.1	($7.7)	($6.8)	$30.8	$19.9	$0	$0
2031	$18.3	$14.4	$21.5	$13.5	($8.1)	($7.1)	$31.6	$20.8	$0	$0

Chart 4.4 – Estimated Total Remuneration Dollar Difference – Amounts Allocated to Nuclear Facilities and Attributable to Capital Expenditures (p. 17 of WTW report)

	PWU ($Millions)				Society ($Millions)				Management ($Millions)				Total ($Millions)				Overall +/- Market Range ($Millions)			
	Nuclear				Nuclear				Nuclear				Nuclear				Nuclear			
	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed
2027	$86.9	$26.1	$1.0	$1.7	$115.4	$35.8	$4.5	$16.2	($46.9)	($10.3)	($2.3)	($2.3)	$155.3	$51.5	$3.2	$15.5	$0	$0	$0	$0
2028	$88.5	$27.4	$2.1	$0.9	$112.9	$35.0	$3.0	$15.8	($48.2)	($10.6)	($1.9)	($2.4)	$153.2	$51.8	$3.2	$14.3	$0	$0	$0	$0
2029	$90.1	$28.8	$2.5	$0.9	$113.5	$36.3	$1.8	$17.0	($48.7)	($11.2)	($1.2)	($2.9)	$154.9	$54.0	$3.2	$15.0	$0	$0	$0	$0
2030	$90.0	$28.8	$0.8	$0.9	$114.2	$36.5	$0.5	$17.1	($50.3)	($11.1)	($0.3)	($3.0)	$153.9	$54.3	$1.0	$15.0	$0	$0	$0	$0
2031	$89.0	$17.8	-	$1.8	$113.0	$27.1	-	$15.8	($52.7)	($10.0)	-	($3.2)	$149.4	$34.9	-	$14.4	$0	$0	$0	$0

Chart 4.5 – Estimated Total Remuneration Dollar Difference – Amounts Allocated to Regulated Hydroelectric Facilities and Attributable to Capital Expenditures (p.17 of WTW report)

	PWU ($Millions)		Society ($Millions)		Management ($Millions)		Total ($Millions)		Overall +/- Market Range ($Millions)	
	Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric	
	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed
2027	$16.7	$3.3	$20.2	$7.9	($7.1)	($0.9)	$29.8	$10.3	$0	$0
2028	$17.0	$3.4	$21.4	$8.6	($7.3)	($1.0)	$31.1	$11.0	$0	$0
2029	$17.1	$3.6	$21.3	$8.7	($7.5)	($1.0)	$30.9	$11.3	$0	$0
2030	$17.1	$3.4	$21.4	$8.4	($7.7)	($0.9)	$30.8	$10.8	$0	$0
2031	$18.3	$3.8	$21.5	$7.9	($8.1)	($1.0)	$31.6	$10.8	$0	$0

Chart 5.1 – Estimated Total Remuneration Dollar Difference – OPG Overall with Impact of Changes and Nuclear Authorized Compared to P50, Excluding Hydro One Shares (p. 18 of WTW report)

	PWU ($Millions)			Society ($Millions)			Management ($Millions)			Total ($Millions)			Overall +/- Market Range ($Millions)		
	OPG	Market Ref. Point	$ Variance	OPG	Market Ref. Point	$ Variance	OPG	Market Ref. Point	$ Variance	OPG	Market Ref. Point	$ Variance	Market Ref. Point Positioning (%)	% Variance outside +/-10%	$ Variance outside +/-10%
2024	[redacted]		$87.7	[redacted]		$115.5	[redacted]		($52.8)	$1,936.2	$1,785.8	$150.5	8.4%	0%	$0
2027			$95.8			$131.9			($55.6)	$2,354.5	$2,182.4	$172.1	[redacted]	0%	$0
2028			$97.3			$130.6			($57.3)	$2,401.9	$2,231.3	$170.6		0%	$0
2029			$97.5			$129.4			($58.6)	$2,435.7	$2,267.4	$168.3		0%	$0
2030			$97.0			$130.1			($60.7)	$2,481.3	$2,314.9	$166.4		0%	$0
2031			$96.8			$130.2			($63.6)	$2,534.4	$2,371.0	$163.5		0%	$0

Chart 5.2 – Estimated Total Remuneration Dollar Difference – Amounts Allocated to Nuclear and Attributable to OM&A (p. 18 of WTW report)

	PWU ($Millions)			Society ($Millions)			Management ($Millions)			Total ($Millions)			Overall +/- Market Range ($Millions)		
	Nuclear			Nuclear			Nuclear			Nuclear			Nuclear		
	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed
2027	$74.7	$41.1	$1.6	$105.5	$44.3	$2.3	($43.9)	($25.1)	($2.4)	$136.3	$60.4	$1.6	$0	$0	$0
2028	$75.9	$41.0	$1.6	$103.2	$43.3	$2.5	($45.2)	($26.2)	($2.6)	$133.8	$58.1	$1.5	$0	$0	$0
2029	$77.0	$41.6	$1.3	$103.6	$43.5	$2.4	($45.7)	($27.0)	($2.7)	$134.9	$58.1	$1.0	$0	$0	$0
2030	$76.6	$42.1	$2.0	$104.1	$44.8	$3.4	($47.3)	($28.4)	($3.2)	$133.4	$58.5	$2.3	$0	$0	$0
2031	$75.5	$49.9	$3.0	$102.9	$52.5	$3.7	($49.6)	($32.2)	($2.9)	$128.8	$70.1	$3.8	$0	$0	$0

Chart 5.3 – Estimated Total Remuneration Dollar Difference – Amounts Allocated to Regulated Hydroelectric Facilities and Attributable to OM&A (p. 18 of WTW report)

	PWU ($Millions)		Society ($Millions)		Management ($Millions)		Total ($Millions)		Overall +/- Market Range ($Millions)	
	Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric	
	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed
2027	$14.4	$11.5	$18.5	$11.3	($6.7)	($5.8)	$26.2	$17.0	$0	$0
2028	$14.6	$11.7	$19.6	$11.8	($6.9)	($6.0)	$27.3	$17.5	$0	$0
2029	$14.6	$11.6	$19.4	$11.5	($7.0)	($6.1)	$27.0	$16.9	$0	$0
2030	$14.5	$11.6	$19.5	$11.9	($7.3)	($6.4)	$26.8	$17.1	$0	$0
2031	$15.5	$12.2	$19.5	$12.3	($7.6)	($6.7)	$27.4	$17.8	$0	$0

Chart 5.4 – Estimated Total Remuneration Dollar Difference – Amounts Allocated to Nuclear Facilities and Attributable to Capital Expenditures (p. 18 of WTW report)

	PWU ($Millions)				Society ($Millions)				Management ($Millions)				Total ($Millions)				Overall +/- Market Range ($Millions)			
	Nuclear				Nuclear				Nuclear				Nuclear				Nuclear			
	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed
2027	$74.7	$22.4	$0.8	$1.5	$105.5	$32.7	$4.1	$14.8	($43.9)	($9.7)	($2.2)	($2.2)	$136.3	$45.5	$2.8	$14.1	$0	$0	$0	$0
2028	$75.9	$23.5	$1.8	$0.8	$103.2	$32.0	$2.8	$14.4	($45.2)	($10.0)	($1.8)	($2.3)	$133.8	$45.6	$2.8	$12.9	$0	$0	$0	$0
2029	$77.0	$24.6	$2.2	$0.8	$103.6	$33.1	$1.7	$15.5	($45.7)	($10.5)	($1.1)	($2.7)	$134.9	$47.3	$2.7	$13.6	$0	$0	$0	$0
2030	$76.6	$24.5	$0.7	$0.8	$104.1	$33.3	$0.4	$15.6	($47.3)	($10.4)	($0.3)	($2.8)	$133.4	$47.4	$0.8	$13.5	$0	$0	$0	$0
2031	$75.5	$15.1	-	$1.5	$102.9	$24.7	-	$14.4	($49.6)	($9.4)	-	($3.0)	$128.8	$30.4	-	$12.9	$0	$0	$0	$0

Chart 5.5 – Estimated Total Remuneration Dollar Difference – Amounts Allocated to Regulated Hydroelectric Facilities and Attributable to Capital Expenditures (p.18 of WTW report)

	PWU ($Millions)		Society ($Millions)		Management ($Millions)		Total ($Millions)		Overall +/- Market Range ($Millions)	
	Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric	
	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed
2027	$14.4	$2.9	$18.5	$7.2	($6.7)	($0.9)	$26.2	$9.2	$0	$0
2028	$14.6	$2.9	$19.6	$7.8	($6.9)	($0.9)	$27.3	$9.9	$0	$0
2029	$14.6	$3.1	$19.4	$8.0	($7.0)	($0.9)	$27.0	$10.1	$0	$0
2030	$14.5	$2.9	$19.5	$7.6	($7.3)	($0.9)	$26.8	$9.6	$0	$0
2031	$15.5	$3.3	$19.5	$7.2	($7.6)	($0.9)	$27.4	$9.6	$0	$0

Chart 6.1 – Estimated Total Remuneration Dollar Difference – OPG Overall with Impact of Changes and Nuclear Authorized Compared to P75, Excluding Hydro One Shares (p. 18 of WTW report)

	PWU ($Millions)			Society ($Millions)			Management ($Millions)			Total ($Millions)			Overall +/- Market Range ($Millions)		
	OPG	Market Ref. Point	$ Variance	OPG	Market Ref. Point	$ Variance	OPG	Market Ref. Point	$ Variance	OPG	Market Ref. Point	$ Variance	Market Ref. Point Positioning (%)	% Variance outside +/-10%	$ Variance outside +/-10%
2024	[redacted]	[redacted]	$81.1	[redacted]	[redacted]	$112.1	[redacted]	[redacted]	($55.3)	$1,936.2	$1,798.4	$137.8	7.7%	0%	$0
2027	[redacted]	[redacted]	$87.8	[redacted]	[redacted]	$127.6	[redacted]	[redacted]	($58.6)	$2,354.5	$2,197.8	$156.7	[redacted]	0%	$0
2028	[redacted]	[redacted]	$88.9	[redacted]	[redacted]	$126.2	[redacted]	[redacted]	($60.3)	$2,401.9	$2,247.1	$154.8		0%	$0
2029	[redacted]	[redacted]	$88.9	[redacted]	[redacted]	$125.0	[redacted]	[redacted]	($61.6)	$2,435.7	$2,283.5	$152.2		0%	$0
2030	[redacted]	[redacted]	$88.2	[redacted]	[redacted]	$125.6	[redacted]	[redacted]	($63.7)	$2,481.3	$2,331.3	$150.0		0%	$0
2031	[redacted]	[redacted]	$87.8	[redacted]	[redacted]	$125.6	[redacted]	[redacted]	($66.7)	$2,534.4	$2,387.8	$146.6		0%	$0

Chart 6.2 – Estimated Total Remuneration Dollar Difference – Amounts Allocated to Nuclear and Attributable to OM&A (p. 18 of WTW report)

	PWU ($Millions)			Society ($Millions)			Management ($Millions)			Total ($Millions)			Overall +/- Market Range ($Millions)		
	Nuclear			Nuclear			Nuclear			Nuclear			Nuclear		
	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed
2027	$68.5	$37.7	$1.5	$102.0	$42.9	$2.2	($46.3)	($26.4)	($2.5)	$124.2	$54.1	$1.2	$0	$0	$0
2028	$69.4	$37.5	$1.5	$99.7	$41.9	$2.4	($47.6)	($27.6)	($2.7)	$121.4	$51.7	$1.1	$0	$0	$0
2029	$70.2	$37.9	$1.2	$100.0	$42.0	$2.3	($48.1)	($28.4)	($2.8)	$122.1	$51.5	$0.7	$0	$0	$0
2030	$69.6	$38.3	$1.8	$100.5	$43.2	$3.3	($49.7)	($29.8)	($3.3)	$120.4	$51.7	$1.8	$0	$0	$0
2031	$68.5	$45.2	$2.7	$99.2	$50.6	$3.6	($52.1)	($33.8)	($3.0)	$115.6	$61.9	$3.3	$0	$0	$0

Chart 6.3 – Estimated Total Remuneration Dollar Difference – Amounts Allocated to Regulated Hydroelectric Facilities and Attributable to OM&A (p. 18 of WTW report)

	PWU ($Millions)		Society ($Millions)		Management ($Millions)		Total ($Millions)		Overall +/- Market Range ($Millions)	
	Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric	
	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed
2027	$13.2	$10.5	$17.9	$10.9	($7.0)	($6.1)	$24.0	$15.3	$0	$0
2028	$13.3	$10.7	$18.9	$11.4	($7.2)	($6.3)	$25.0	$15.7	$0	$0
2029	$13.3	$10.5	$18.8	$11.1	($7.4)	($6.4)	$24.7	$15.2	$0	$0
2030	$13.2	$10.6	$18.8	$11.5	($7.6)	($6.7)	$24.4	$15.3	$0	$0
2031	$14.0	$11.1	$18.8	$11.9	($8.0)	($7.0)	$24.9	$15.9	$0	$0

Chart 6.4 – Estimated Total Remuneration Dollar Difference – Amounts Allocated to Nuclear Facilities and Attributable to Capital Expenditures (p. 18 of WTW report)

	PWU ($Millions)				Society ($Millions)				Management ($Millions)				Total ($Millions)				Overall +/- Market Range ($Millions)			
	Nuclear				Nuclear				Nuclear				Nuclear				Nuclear			
	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed
2027	$68.5	$20.5	$0.8	$1.4	$102.0	$31.6	$4.0	$14.3	($46.3)	($10.2)	($2.3)	($2.3)	$124.2	$42.0	$2.5	$13.3	$0	$0	$0	$0
2028	$69.4	$21.5	$1.7	$0.7	$99.7	$30.9	$2.7	$14.0	($47.6)	($10.5)	($1.9)	($2.4)	$121.4	$41.9	$2.5	$12.3	$0	$0	$0	$0
2029	$70.2	$22.5	$2.0	$0.7	$100.0	$32.0	$1.6	$15.0	($48.1)	($11.1)	($1.2)	($2.9)	$122.1	$43.4	$2.4	$12.8	$0	$0	$0	$0
2030	$69.6	$22.3	$0.6	$0.7	$100.5	$32.1	$0.4	$15.1	($49.7)	($10.9)	($0.3)	($3.0)	$120.4	$43.5	$0.7	$12.8	$0	$0	$0	$0
2031	$68.5	$13.7	-	$1.4	$99.2	$23.8	-	$13.9	($52.1)	($9.9)	-	($3.1)	$115.6	$27.6	-	$12.1	$0	$0	$0	$0

Chart 6.5 – Estimated Total Remuneration Dollar Difference – Amounts Allocated to Regulated Hydroelectric Facilities and Attributable to Capital Expenditures (p.18 of WTW report)

	PWU ($Millions)		Society ($Millions)		Management ($Millions)		Total ($Millions)		Overall +/- Market Range ($Millions)	
	Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric	
	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed
2027	$13.2	$2.6	$17.9	$7.0	($7.0)	($0.9)	$24.0	$8.7	$0	$0
2028	$13.3	$2.7	$18.9	$7.6	($7.2)	($0.9)	$25.0	$9.3	$0	$0
2029	$13.3	$2.8	$18.8	$7.7	($7.4)	($1.0)	$24.7	$9.5	$0	$0
2030	$13.2	$2.6	$18.8	$7.3	($7.6)	($0.9)	$24.4	$9.1	$0	$0
2031	$14.0	$2.9	$18.8	$7.0	($8.0)	($1.0)	$24.9	$9.0	$0	$0

Chart 7.1 Estimated Total Remuneration Dollar Difference – OPG Overall with Impact of Changes and Nuclear Authorized Compared to P50, Excluding Hydro One Shares, Excluding Terms/ETEs (based on Chart 1 in Ex. L-F4-SUP-023)

	PWU ($Millions)			Society ($Millions)			Management ($Millions)			Total ($Millions)			Overall +/- Market Range ($Millions)		
	OPG	Market Ref. Point	$ Variance	OPG	Market Ref. Point	$ Variance	OPG	Market Ref. Point	$ Variance	OPG	Market Ref. Point	$ Variance	Market Ref. Point Positioning (%)	% Variance outside +/-10%	$ Variance outside +/-10%
2024	[redacted]		$98.4	[redacted]		$115.5	[redacted]		($52.8)	$1,941.5	$1,780.4	$161.2	9.1%	0%	$0
2027			$108.7			$131.9			($55.6)	$2,360.9	$2,175.8	$185.0	[redacted]	0%	$0
2028			$110.8			$130.6			($57.3)	$2,408.6	$2,224.5	$184.1		0%	$0
2029			$111.3			$129.5			($58.6)	$2,442.6	$2,260.4	$182.2		0%	$0
2030			$111.1			$130.1			($60.7)	$2,488.3	$2,307.8	$180.6		0%	$0
2031			$111.3			$130.2			($63.6)	$2,541.6	$2,363.6	$178.0		0%	$0

Chart 7.2 Estimated Total Remuneration Dollar Difference – Amounts Allocated to Nuclear and Attributable to OM&A (based on Chart 1 in Ex. L-F4-SUP-023)

	PWU ($Millions)			Society ($Millions)			Management ($Millions)			Total ($Millions)			Overall +/- Market Range ($Millions)		
	Nuclear			Nuclear			Nuclear			Nuclear			Nuclear		
	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed
2027	$84.8	$46.6	$1.9	$105.5	$44.3	$2.3	($43.9)	($25.1)	($2.4)	$146.4	$65.9	$1.8	$0	$0	$0
2028	$86.4	$46.7	$1.8	$103.2	$43.3	$2.5	($45.2)	($26.2)	($2.6)	$144.3	$63.7	$1.7	$0	$0	$0
2029	$87.9	$47.5	$1.5	$103.6	$43.5	$2.4	($45.7)	($27.0)	($2.7)	$145.8	$64.0	$1.2	$0	$0	$0
2030	$87.8	$48.3	$2.3	$104.1	$44.8	$3.4	($47.3)	($28.4)	($3.2)	$144.6	$64.6	$2.5	$0	$0	$0
2031	$86.8	$57.3	$3.5	$102.9	$52.5	$3.7	($49.6)	($32.2)	($2.9)	$140.1	$77.5	$4.3	$0	$0	$0

Chart 7.3 Estimated Total Remuneration Dollar Difference – Amounts Allocated to Regulated Hydroelectric Facilities and Attributable to OM&A (based on Chart 1 in Ex. L-F4-SUP-023)

	PWU ($Millions)		Society ($Millions)		Management ($Millions)		Total ($Millions)		Overall +/- Market Range ($Millions)	
	Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric	
	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed
2027	$16.3	$13.0	$18.5	$11.3	($6.7)	($5.8)	$28.1	$18.5	$0	$0
2028	$16.6	$13.3	$19.6	$11.8	($6.9)	($6.0)	$29.3	$19.1	$0	$0
2029	$16.7	$13.2	$19.4	$11.5	($7.0)	($6.1)	$29.1	$18.5	$0	$0
2030	$16.7	$13.3	$19.5	$11.9	($7.3)	($6.4)	$28.9	$18.8	$0	$0
2031	$17.8	$14.1	$19.5	$12.3	($7.6)	($6.7)	$29.7	$19.7	$0	$0

Chart 7.4 Estimated Total Remuneration Dollar Difference – Amounts Allocated to Nuclear Facilities and Attributable to Capital Expenditures (based on Chart 1 in Ex. L-F4-SUP-023)

	PWU ($Millions)				Society ($Millions)				Management ($Millions)				Total ($Millions)				Overall +/- Market Range ($Millions)			
	Nuclear				Nuclear				Nuclear				Nuclear				Nuclear			
	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed
2027	$84.8	$25.4	$0.9	$1.7	$105.5	$32.7	$4.1	$14.8	($43.9)	($9.7)	($2.2)	($2.2)	$146.4	$48.5	$2.9	$14.3	$0	$0	$0	$0
2028	$86.4	$26.8	$2.1	$0.9	$103.2	$32.0	$2.8	$14.4	($45.2)	($10.0)	($1.8)	($2.3)	$144.3	$48.8	$3.0	$13.0	$0	$0	$0	$0
2029	$87.9	$28.1	$2.5	$0.9	$103.6	$33.1	$1.7	$15.5	($45.7)	($10.5)	($1.1)	($2.7)	$145.8	$50.8	$3.0	$13.7	$0	$0	$0	$0
2030	$87.8	$28.1	$0.8	$0.9	$104.1	$33.3	$0.4	$15.6	($47.3)	($10.4)	($0.3)	($2.8)	$144.6	$51.0	$0.9	$13.7	$0	$0	$0	$0
2031	$86.8	$17.4	-	$1.7	$102.9	$24.7	-	$14.4	($49.6)	($9.4)	-	($3.0)	$140.1	$32.6	-	$13.2	$0	$0	$0	$0

Chart 7.5 – Estimated Total Remuneration Dollar Difference – Amounts Allocated to Regulated Hydroelectric Facilities and Attributable to Capital Expenditures (based on Chart 1 in Ex. L-F4-SUP-023)

	PWU ($Millions)		Society ($Millions)		Management ($Millions)		Overall ($Millions)		Overall +/- Market Range ($Millions)	
	Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric	
	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed
2027	$16.3	$3.3	$18.5	$7.2	($6.7)	($0.9)	$28.1	$9.6	$0	$0
2028	$16.6	$3.3	$19.6	$7.8	($6.9)	($0.9)	$29.3	$10.3	$0	$0
2029	$16.7	$3.5	$19.4	$8.0	($7.0)	($0.9)	$29.1	$10.6	$0	$0
2030	$16.7	$3.3	$19.5	$7.6	($7.3)	($0.9)	$28.9	$10.1	$0	$0
2031	$17.8	$3.7	$19.5	$7.2	($7.6)	($0.9)	$29.7	$10.1	$0	$0

Chart 8.1 Estimated Total Remuneration Dollar Difference – OPG Overall with Impact of Changes Compared to P50 and Nuclear Authorized Compared to P75, Excluding Hydro One Shares, Excluding Terms/ETEs (based on Chart 2 in Ex. L-F4-SUP-023)

	PWU ($Millions)			Society ($Millions)			Management ($Millions)			Total ($Millions)			Overall +/- Market Range ($Millions)		
	OPG	Market Ref. Point	$ Variance	OPG	Market Ref. Point	$ Variance	OPG	Market Ref. Point	$ Variance	OPG	Market Ref. Point	$ Variance	Market Ref. Point Positioning (%)	% Variance outside +/-10%	$ Variance outside +/-10%
2024	[redacted]	[redacted]	$91.4	[redacted]	[redacted]	$112.1	[redacted]	[redacted]	($55.3)	$1,941.5	$1,793.4	$148.1	8.3%	0%	$0
2027	[redacted]	[redacted]	$100.2	[redacted]	[redacted]	$127.5	[redacted]	[redacted]	($58.6)	$2,360.9	$2,191.7	$169.1	[redacted]	0%	$0
2028	[redacted]	[redacted]	$101.9	[redacted]	[redacted]	$126.2	[redacted]	[redacted]	($60.3)	$2,408.6	$2,240.8	$167.8		0%	$0
2029	[redacted]	[redacted]	$102.2	[redacted]	[redacted]	$125.0	[redacted]	[redacted]	($61.6)	$2,442.6	$2,277.0	$165.6		0%	$0
2030	[redacted]	[redacted]	$101.8	[redacted]	[redacted]	$125.6	[redacted]	[redacted]	($63.7)	$2,488.3	$2,324.7	$163.6		0%	$0
2031	[redacted]	[redacted]	$101.7	[redacted]	[redacted]	$125.6	[redacted]	[redacted]	($66.7)	$2,541.6	$2,381.0	$160.6		0%	$0

Chart 8.2 Estimated Total Remuneration Dollar Difference – Amounts Allocated to Nuclear and Attributable to OM&A (based on Chart 2 in Ex. L-F4-SUP-023)

	PWU ($Millions)			Society ($Millions)			Management ($Millions)			Total ($Millions)			Overall +/- Market Range ($Millions)		
	Nuclear			Nuclear			Nuclear			Nuclear			Nuclear		
	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed
2027	$78.2	$43.0	$1.7	$102.0	$42.9	$2.2	($46.3)	($26.4)	($2.5)	$133.9	$59.4	$1.5	$0	$0	$0
2028	$79.5	$42.9	$1.7	$99.7	$41.9	$2.4	($47.6)	($27.6)	($2.7)	$131.5	$57.2	$1.3	$0	$0	$0
2029	$80.7	$43.6	$1.4	$100.0	$42.0	$2.3	($48.1)	($28.4)	($2.8)	$132.7	$57.2	$0.9	$0	$0	$0
2030	$80.4	$44.2	$2.1	$100.5	$43.2	$3.3	($49.7)	($29.8)	($3.3)	$131.1	$57.6	$2.1	$0	$0	$0
2031	$79.4	$52.4	$3.2	$99.2	$50.6	$3.6	($52.1)	($33.8)	($3.0)	$126.5	$69.1	$3.7	$0	$0	$0

Chart 8.3 Estimated Total Remuneration Dollar Difference – Amounts Allocated to Regulated Hydroelectric Facilities and Attributable to OM&A (based on Chart 2 in Ex. L-F4-SUP-023)

	PWU ($Millions)		Society ($Millions)		Management ($Millions)		Total ($Millions)		Overall +/- Market Range ($Millions)	
	Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric	
	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed
2027	$15.0	$12.0	$17.9	$10.9	($7.0)	($6.1)	$25.9	$16.8	$0	$0
2028	$15.3	$12.2	$18.9	$11.4	($7.2)	($6.3)	$27.0	$17.3	$0	$0
2029	$15.3	$12.1	$18.8	$11.1	($7.4)	($6.4)	$26.7	$16.7	$0	$0
2030	$15.3	$12.2	$18.8	$11.5	($7.6)	($6.7)	$26.5	$17.0	$0	$0
2031	$16.3	$12.9	$18.8	$11.9	($8.0)	($7.0)	$27.1	$17.7	$0	$0

Chart 8.4 Estimated Total Remuneration Dollar Difference – Amounts Allocated to Nuclear Facilities and Attributable to Capital Expenditures (based on Chart 2 in Ex. L-F4-SUP-023)

	PWU ($Millions)				Society ($Millions)				Management ($Millions)				Total ($Millions)				Overall +/- Market Range ($Millions)			
	Nuclear				Nuclear				Nuclear				Nuclear				Nuclear			
	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed
2027	$78.2	$23.5	$0.9	$1.6	$102.0	$31.6	$4.0	$14.3	($46.3)	($10.2)	($2.3)	($2.3)	$133.9	$44.9	$2.6	$13.5	$0	$0	$0	$0
2028	$79.5	$24.6	$1.9	$0.8	$99.7	$30.9	$2.7	$14.0	($47.6)	($10.5)	($1.9)	($2.4)	$131.5	$45.1	$2.7	$12.4	$0	$0	$0	$0
2029	$80.7	$25.8	$2.3	$0.8	$100.0	$32.0	$1.6	$15.0	($48.1)	($11.1)	($1.2)	($2.9)	$132.7	$46.8	$2.7	$12.9	$0	$0	$0	$0
2030	$80.4	$25.7	$0.7	$0.8	$100.5	$32.1	$0.4	$15.1	($49.7)	($10.9)	($0.3)	($3.0)	$131.1	$46.9	$0.8	$12.9	$0	$0	$0	$0
2031	$79.4	$15.9	-	$1.6	$99.2	$23.8	-	$13.9	($52.1)	($9.9)	-	($3.1)	$126.5	$29.8	-	$12.4	$0	$0	$0	$0

Chart 8.5 – Estimated Total Remuneration Dollar Difference – Amounts Allocated to Regulated Hydroelectric Facilities and Attributable to Capital Expenditures (based on Chart 2 in Ex. L-F4-SUP-023)

	PWU ($Millions)		Society ($Millions)		Management ($Millions)		Overall ($Millions)		Overall +/- Market Range ($Millions)	
	Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric	
	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed
2027	$15.0	$3.0	$17.9	$7.0	($7.0)	($0.9)	$25.9	$9.1	$0	$0
2028	$15.3	$3.1	$18.9	$7.6	($7.2)	($0.9)	$27.0	$9.7	$0	$0
2029	$15.3	$3.2	$18.8	$7.7	($7.4)	($1.0)	$26.7	$9.9	$0	$0
2030	$15.3	$3.1	$18.8	$7.3	($7.6)	($0.9)	$26.5	$9.5	$0	$0
2031	$16.3	$3.4	$18.8	$7.0	($8.0)	($1.0)	$27.1	$9.4	$0	$0

Chart 9.1 Estimated Total Remuneration Dollar Difference – OPG Overall with Impact of Changes and Nuclear Authorized Compared to P50, Excluding Terms/ETEs and Including Hydro One Shares (based on Chart 8 in Ex. L-F4-CCC-091)

	PWU ($Millions)			Society ($Millions)			Management ($Millions)			Total ($Millions)			Overall +/- Market Range ($Millions)		
	OPG	Market Ref. Point	$ Variance	OPG	Market Ref. Point	$ Variance	OPG	Market Ref. Point	$ Variance	OPG	Market Ref. Point	$ Variance	Market Ref. Point Positioning (%)	% Variance outside +/-10%	$ Variance outside +/-10%
2024	[redacted]		$112.4	[redacted]		$123.6	[redacted]		($52.5)	$1,963.9	$1,780.4	$183.5	10.3%	0.3%	$5.5
2027			$125.5			$142.0			($55.3)	$2,388.1	$2,175.8	$212.2	[redacted]	0%	$0
2028			$128.2			$140.7			($56.9)	$2,436.5	$2,224.5	$212.0		0%	$0
2029			$129.3			$139.6			($58.3)	$2,471.0	$2,260.4	$210.6		0%	$0
2030			$129.4			$140.5			($60.3)	$2,517.3	$2,307.8	$209.6		0%	$0
2031			$130.1			$140.8			($63.2)	$2,571.2	$2,363.6	$207.6		0%	$0

Chart 9.2 Estimated Total Remuneration Dollar Difference – Amounts Allocated to Nuclear and Attributable to OM&A (based on Chart 8 in Ex. L-F4-CCC-091)

	PWU ($Millions)			Society ($Millions)			Management ($Millions)			Total ($Millions)			Overall +/- Market Range ($Millions)		
	Nuclear			Nuclear			Nuclear			Nuclear			Nuclear		
	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed
2027	$97.9	$53.8	$2.2	$113.6	$47.7	$2.5	($43.7)	($24.9)	($2.4)	$167.8	$76.7	$2.3	$0	$0	$0
2028	$100.0	$54.0	$2.1	$111.1	$46.7	$2.7	($45.0)	($26.1)	($2.6)	$166.2	$74.6	$2.2	$0	$0	$0
2029	$102.1	$55.1	$1.7	$111.7	$46.9	$2.6	($45.5)	($26.8)	($2.6)	$168.4	$75.2	$1.7	$0	$0	$0
2030	$102.2	$56.2	$2.7	$112.4	$48.3	$3.7	($47.0)	($28.2)	($3.2)	$167.6	$76.3	$3.2	$0	$0	$0
2031	$101.5	$67.0	$4.1	$111.2	$56.7	$4.0	($49.3)	($32.1)	($2.9)	$163.4	$91.6	$5.2	$0	$0	$0

Chart 9.3 Estimated Total Remuneration Dollar Difference – Amounts Allocated to Regulated Hydroelectric Facilities and Attributable to OM&A (based on Chart 8 in Ex. L-F4-CCC-091)

	PWU ($Millions)		Society ($Millions)		Management ($Millions)		Total ($Millions)		Overall +/- Market Range ($Millions)	
	Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric	
	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed
2027	$18.8	$15.1	$19.9	$12.1	($6.6)	($5.8)	$32.1	$21.4	$0	$0
2028	$19.2	$15.4	$21.1	$12.7	($6.8)	($5.9)	$33.5	$22.1	$0	$0
2029	$19.4	$15.3	$20.9	$12.4	($7.0)	($6.1)	$33.3	$21.6	$0	$0
2030	$19.4	$15.5	$21.1	$12.9	($7.2)	($6.4)	$33.2	$22.0	$0	$0
2031	$20.8	$16.4	$21.1	$13.3	($7.6)	($6.7)	$34.3	$23.1	$0	$0

Chart 9.4 Estimated Total Remuneration Dollar Difference – Amounts Allocated to Nuclear Facilities and Attributable to Capital Expenditures (based on Chart 8 in Ex. L-F4-CCC-091)

	PWU ($Millions)				Society ($Millions)				Management ($Millions)				Total ($Millions)				Overall +/- Market Range ($Millions)			
	Nuclear				Nuclear				Nuclear				Nuclear				Nuclear			
	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed
2027	$97.9	$29.4	$1.1	$2.0	$113.6	$35.2	$4.4	$15.9	($43.7)	($9.6)	($2.1)	($2.2)	$167.8	$55.0	$3.4	$15.7	$0	$0	$0	$0
2028	$100.0	$31.0	$2.4	$1.0	$111.1	$34.5	$3.0	$15.6	($45.0)	($9.9)	($1.8)	($2.2)	$166.2	$55.6	$3.6	$14.3	$0	$0	$0	$0
2029	$102.1	$32.7	$2.9	$1.0	$111.7	$35.7	$1.8	$16.8	($45.5)	($10.5)	($1.1)	($2.7)	$168.4	$58.0	$3.6	$15.0	$0	$0	$0	$0
2030	$102.2	$32.7	$0.9	$1.0	$112.4	$36.0	$0.4	$16.9	($47.0)	($10.3)	($0.3)	($2.8)	$167.6	$58.3	$1.1	$15.1	$0	$0	$0	$0
2031	$101.5	$20.3	-	$2.0	$111.2	$26.7	-	$15.6	($49.3)	($9.4)	-	($3.0)	$163.4	$37.6	-	$14.6	$0	$0	$0	$0

Chart 9.5 – Estimated Total Remuneration Dollar Difference – Amounts Allocated to Regulated Hydroelectric Facilities and Attributable to Capital Expenditures (based on Chart 8 in Ex. L-F4-CCC-091)

	PWU ($Millions)		Society ($Millions)		Management ($Millions)		Overall ($Millions)		Overall +/- Market Range ($Millions)	
	Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric	
	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed
2027	$18.8	$3.8	$19.9	$7.8	($6.6)	($0.9)	$32.1	$10.7	$0	$0
2028	$19.2	$3.8	$21.1	$8.4	($6.8)	($0.9)	$33.5	$11.4	$0	$0
2029	$19.4	$4.1	$20.9	$8.6	($7.0)	($0.9)	$33.3	$11.7	$0	$0
2030	$19.4	$3.9	$21.1	$8.2	($7.2)	($0.9)	$33.2	$11.2	$0	$0
2031	$20.8	$4.4	$21.1	$7.8	($7.6)	($0.9)	$34.3	$11.3	$0	$0

Chart 10.1 Estimated Total Remuneration Dollar Difference – OPG Overall with Impact of Changes Compared to P50 and Nuclear Authorized Compared to P75, Excluding Terms/ETEs and Including Hydro One Shares (based on Chart 9 in Ex. L-F4-CCC-091)

	PWU ($Millions)			Society ($Millions)			Management ($Millions)			Total ($Millions)			Overall +/- Market Range ($Millions)		
	OPG	Market Ref. Point	$ Variance	OPG	Market Ref. Point	$ Variance	OPG	Market Ref. Point	$ Variance	OPG	Market Ref. Point	$ Variance	Market Ref. Point Positioning (%)	% Variance outside +/-10%	$ Variance outside +/-10%
2024	[redacted]	[redacted]	$105.4	[redacted]	[redacted]	$120.1	[redacted]	[redacted]	($55.1)	$1,963.9	$1,793.4	$170.5	9.5%	0%	$0
2027	[redacted]	[redacted]	$117.0	[redacted]	[redacted]	$137.6	[redacted]	[redacted]	($58.3)	$2,388.1	$2,191.7	$196.3	[redacted]	0%	$0
2028	[redacted]	[redacted]	$119.4	[redacted]	[redacted]	$136.3	[redacted]	[redacted]	($60.0)	$2,436.5	$2,240.8	$195.7		0%	$0
2029	[redacted]	[redacted]	$120.1	[redacted]	[redacted]	$135.2	[redacted]	[redacted]	($61.3)	$2,471.0	$2,277.0	$194.0		0%	$0
2030	[redacted]	[redacted]	$120.1	[redacted]	[redacted]	$135.9	[redacted]	[redacted]	($63.4)	$2,517.3	$2,324.7	$192.6		0%	$0
2031	[redacted]	[redacted]	$120.5	[redacted]	[redacted]	$136.1	[redacted]	[redacted]	($66.4)	$2,571.2	$2,381.0	$190.2		0%	$0

Chart 10.2 Estimated Total Remuneration Dollar Difference – Amounts Allocated to Nuclear and Attributable to OM&A (based on Chart 9 in Ex. L-F4-CCC-091)

	PWU ($Millions)			Society ($Millions)			Management ($Millions)			Total ($Millions)			Overall +/- Market Range ($Millions)		
	Nuclear			Nuclear			Nuclear			Nuclear			Nuclear		
	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed	Nuclear $ Allocated Variance	OM&A | Nuclear Facilities Attributed	OM&A | DNNP Attributed
2027	$91.3	$50.2	$2.0	$110.1	$46.2	$2.4	($46.1)	($26.3)	($2.5)	$155.3	$70.2	$1.9	$0	$0	$0
2028	$93.1	$50.3	$2.0	$107.7	$45.2	$2.6	($47.4)	($27.5)	($2.7)	$153.4	$68.0	$1.8	$0	$0	$0
2029	$94.9	$51.2	$1.6	$108.1	$45.4	$2.5	($47.8)	($28.2)	($2.8)	$155.2	$68.5	$1.3	$0	$0	$0
2030	$94.9	$52.2	$2.5	$108.7	$46.8	$3.6	($49.4)	($29.7)	($3.3)	$154.2	$69.3	$2.7	$0	$0	$0
2031	$94.0	$62.0	$3.8	$107.5	$54.8	$3.9	($51.8)	($33.7)	($3.0)	$149.7	$83.2	$4.6	$0	$0	$0

Chart 10.3 Estimated Total Remuneration Dollar Difference – Amounts Allocated to Regulated Hydroelectric Facilities and Attributable to OM&A (based on Chart 9 in Ex. L-F4-CCC-091)

	PWU ($Millions)		Society ($Millions)		Management ($Millions)		Total ($Millions)		Overall +/- Market Range ($Millions)	
	Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric	
	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed	Hydro Reg $ Allocated Variance	OM&A Attributed
2027	$17.6	$14.0	$19.3	$11.8	($7.0)	($6.1)	$29.8	$19.7	$0	$0
2028	$17.9	$14.3	$20.4	$12.3	($7.2)	($6.3)	$31.2	$20.3	$0	$0
2029	$18.0	$14.2	$20.3	$12.0	($7.4)	($6.4)	$30.9	$19.8	$0	$0
2030	$18.0	$14.4	$20.4	$12.4	($7.6)	($6.7)	$30.8	$20.2	$0	$0
2031	$19.3	$15.2	$20.4	$12.9	($8.0)	($7.0)	$31.7	$21.1	$0	$0

Chart 10.4 Estimated Total Remuneration Dollar Difference – Amounts Allocated to Nuclear Facilities and Attributable to Capital Expenditures (based on Chart 9 in Ex. L-F4-CCC-091)

	PWU ($Millions)				Society ($Millions)				Management ($Millions)				Total ($Millions)				Overall +/- Market Range ($Millions)			
	Nuclear				Nuclear				Nuclear				Nuclear				Nuclear			
	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed	Nuclear $ Allocated Variance	Capital | PRP Attributed	Capital | DNNP Attributed	Remaining Capital Attributed
2027	$91.3	$27.4	$1.0	$1.8	$110.1	$34.1	$4.3	$15.4	($46.1)	($10.1)	($2.3)	($2.3)	$155.3	$51.4	$3.0	$14.9	$0	$0	$0	$0
2028	$93.1	$28.9	$2.2	$0.9	$107.7	$33.4	$2.9	$15.1	($47.4)	($10.4)	($1.9)	($2.4)	$153.4	$51.8	$3.2	$13.6	$0	$0	$0	$0
2029	$94.9	$30.4	$2.7	$0.9	$108.1	$34.6	$1.7	$16.2	($47.8)	($11.0)	($1.1)	($2.9)	$155.2	$54.0	$3.2	$14.3	$0	$0	$0	$0
2030	$94.9	$30.4	$0.9	$0.9	$108.7	$34.8	$0.4	$16.3	($49.4)	($10.9)	($0.3)	($3.0)	$154.2	$54.3	$1.0	$14.3	$0	$0	$0	$0
2031	$94.0	$18.8	-	$1.9	$107.5	$25.8	-	$15.1	($51.8)	($9.8)	-	($3.1)	$149.7	$34.8	-	$13.8	$0	$0	$0	$0

Chart 10.5 – Estimated Total Remuneration Dollar Difference – Amounts Allocated to Regulated Hydroelectric Facilities and Attributable to Capital Expenditures (based on Chart 9 in Ex. L-F4-CCC-091)

	PWU ($Millions)		Society ($Millions)		Management ($Millions)		Overall ($Millions)		Overall +/- Market Range ($Millions)	
	Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric		Hydroelectric	
	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed	Hydro Reg $ Allocated Variance	Capital Attributed
2027	$17.6	$3.5	$19.3	$7.5	($7.0)	($0.9)	$29.8	$10.1	$0	$0
2028	$17.9	$3.6	$20.4	$8.2	($7.2)	($0.9)	$31.2	$10.8	$0	$0
2029	$18.0	$3.8	$20.3	$8.3	($7.4)	($1.0)	$30.9	$11.1	$0	$0
2030	$18.0	$3.6	$20.4	$8.0	($7.6)	($0.9)	$30.8	$10.6	$0	$0
2031	$19.3	$4.0	$20.4	$7.6	($8.0)	($1.0)	$31.7	$10.6	$0	$0

The calculations for Chart sets 1-10 above are outlined in the steps below:

The 2024 total remuneration values for PWU, Society, and Management employee groups are consistent with the results of the WTW Total Compensation Benchmarking Study (Ex. F4-3-1, Attachment 3). In Step 1, these 2024 values are extrapolated to reflect the full OPG population within each representation (PWU, Society, and Management) based on the relative percentage of benchmarked employees.[2] This extrapolation is performed for each version of the analysis presented. The percentage and dollar variance of OPG from the market reference point is then calculated. See Chart 11 below for an example of this calculation. To calculate the dollar value difference outside of the target market range of +/-10%, the formula used is [a – b x (1 +/- 10%)], where the OPG total remuneration dollar value is (a) and the Market reference point dollar value is (b).

[2] As the overall OPG results shown are based on the extrapolated total across all three representations, it may not align to the overall OPG results in the 2024 compensation benchmarking report that was based on benchmarked incumbents.

Chart 11 – Extrapolation of 2024 Total Remuneration for Benchmarked Values to Reflect Full OPG Population (Example for Chart 2)

OPG Group	2024 Total Dollar Values ($MM) OPG Benchmarked Population		% of OPG Matched Incumbents		2024 Total Dollar Values ($MM) Full OPG Population		Variance
	OPG	Market Ref. Point			OPG	Market Ref. Point	%
	(A)	(B)	(C)		(D) = A * (1 + (1 - C))	(E) = B * (1 + (1 - C))	(F) = (D / E) - 1
PWU	[redacted]		90%	[redacted]		14.0%	[redacted]
Society			97%			20.5%	
Management			98%			-13.8%	
Total	**$1,859.9**	**$1,689.5**	**-**	**$1,968.6**	**$1,785.7**	**10.2%**	**$182.9**

*Total for (D) and (E) reflect the sum of the groups and has not been calculated based on the percentage of the OPG matched incumbents.

In Step 2, WTW then calculated the projected headcount year over year changes for each year and employee group based on a percentage change from the 2024 headcount, as provided by OPG (Chart 12 below), derived directly from the 2024 sum of corresponding employee group line items for Nuclear, DNNP LP, and Regulated Hydroelectric in the following:

- Ex. L-F4-CCMBC-005, Attachment 1 (i.e., line 19 for Management, line 20 and line 25 for Society, and line 22 and line 24 for PWU)
- Ex. L-F4-CCMBC-006, Attachment 1 (i.e., line 15 for Management, line 16 for Society, and line 18 for PWU)
- Ex. L-F4-CCMBC-007, Attachment 1 (i.e., line 13 for Management, line 14 for Society, and line 16 for PWU).

Chart 12 – Incorporate Projected OPG Headcount Changes and Calculate the Year-Over-Year % Change for Each Year

OPG Group	OPG Headcount Projections (OPG Full Time Equivalents)									
	2027		2028		2029		2030		2031	
	% change from 2024	Year over Year % change	% change from 2024	Year over Year % change	% change from 2024	Year over Year % change	% change from 2024	Year over Year % change	% change from 2024	Year over Year % change
PWU	110.2%	100.6%	111.5%	101.3%	111.4%	99.9%	110.7%	99.3%	110.4%	99.7%
Society	114.7%	99.1%	112.2%	97.8%	109.9%	97.9%	109.1%	99.3%	108.0%	98.9%
Management	106.5%	93.7%	104.1%	97.8%	101.3%	97.2%	99.6%	98.4%	99.3%	99.7%
OPG Overall	111.4%	99.1%	110.8%	99.4%	109.5%	98.8%	108.6%	99.2%	107.9%	99.4%

In Step 3, WTW determined the wage escalations for each year after 2024, as follows:

- Update the OPG benchmark data based on changes in salary assumed in OPG's business plan, as provided by OPG in Chart 13 below (same as Chart 1 in Ex. L-F4-Staff-227)

Chart 13 – OPG Wage Escalations

Segment	OPG Wage Escalation						
	2025	2026	2027	2028	2029	2030	2031
PWU	3.75%	2.50%	[redacted]				
Society	3.25%	[redacted]					
Management	[redacted]						

- Adjust the market benchmark data based on future wage / salary increases determined by WTW and set out in Chart 14 below, reflecting the following assumptions:
    - Salary increase assumptions for 2025 and 2026 are sourced from WTW's 2025 Canadian Salary Budget Planning Survey.
    - For the remaining years, estimated market increases are based on estimated CPI plus a market-based premium of 1.0%, which represents the average premium of salary increases above CPI over the past ten years.

Chart 14 – Market Wage Increase Projections

	2025 Actual [1]	2026 Forecast [1]	2027 Forecast [2]	2028 Estimate [3]	2029 Estimate [3]	2030 Estimate [3]	2031 Estimate [3]
CPI							
Salary Premium (PWU/Society)							
Salary Premium (Management)							
Market Salary Increase Assumptions							
PWU							
Society							
Management							

[1] Salary increase assumptions sourced from WTW's 2025 Dec Edition Canadian Salary Budget Survey | Natural Resources
[2] [CPI] 2027 forecast based on TD Economics, Quarterly Economic Forecast (December 11, 2025)
[3] [CPI] 2028 to 2031 estimates based on Bank of Canada's inflation-control target

In Step 4, WTW estimated the dollar differentials based on the difference between OPG's total remuneration (as extrapolated) and the market reference point total remuneration for the corresponding employee group for each year[3]. In doing so, for each year, OPG total values and the market reference point were adjusted to reflect the percent changes in headcount from Chart 12 above and expected salary increases at OPG and in the market per Charts 13 and 14 above. These steps are captured in Chart 15 below.

[3] To simplify assumptions, WTW did not account for a decreasing number of employees eligible for Hydro One share grants over the IR term (refer to Ex. F4-3-1, p. 36).

Chart 15 –Calculation of Dollar Difference Incorporating Headcount and Salary Adjustments (Example for Chart 2)

OPG Group	OPG				Market Reference Point				Variance	
	Beginning Total $ Value ($MM)	Headcount Adjustment %	Salary Increase Adjustment %	Ending Total $ Value ($MM)	Beginning Total $ Value ($MM)	Headcount Adjustment %	Salary Increase Adjustment %	Ending Total $ Value ($MM)	%	$MM
	(D) for 2024	(K)	(L)	(M) = D * K * L	(E) for 2024	(K)	(N)	(O) = E * K * N	(P) = (M / O) - 1	(Q) = M - O
PWU										
2024		n/a				n/a			14.0%	$107.4
2024-2025		111%				111%			14.3%	$126.2
2025-2026		98%				98%			13.4%	$120.2
2026-2027		101%				101%			12.8%	$119.4
2027-2028		101%				101%			12.5%	$121.9
2028-2029		100%				100%			12.3%	$122.7
2029-2030		99%				99%			12.0%	$122.7
2030-2031		100%				100%			11.7%	$123.2
Society										
2024		n/a				n/a			20.5%	$128.9
2024-2025		122%				122%			20.2%	$160.1
2025-2026		95%				95%			19.3%	$150.1
2026-2027		99%				99%			18.7%	$148.6
2027-2028		98%				98%			18.4%	$147.3
2028-2029		98%				98%			18.1%	$146.3
2029-2030		99%				99%			17.8%	$147.3
2030-2031		99%				99%			17.5%	$147.7
Management										
2024		n/a				n/a			-13.8%	($53.4)
2024-2025		117%				117%			-13.5%	($63.3)
2025-2026		97%				97%			-13.1%	($61.7)
2026-2027		94%				94%			-12.4%	($56.4)
2027-2028		98%				98%			-12.7%	($58.0)
2028-2029		97%				97%			-12.9%	($59.4)
2029-2030		98%				98%			-13.2%	($61.4)
2030-2031		100%				100%			-13.5%	($64.4)
OPG Total (sum of groups)										
2024									10.2%	$182.9
2024-2025									10.4%	$223.0
2025-2026									9.7%	$208.6
2026-2027									9.7%	$211.6
2027-2028									9.5%	$211.2
2028-2029									9.2%	$209.6
2029-2030									9.0%	$208.6
2030-2031									8.7%	$206.5

In Step 5, WTW allocated the total remuneration differentials to the nuclear (combined OPG and DNNP LP) and regulated hydroelectric businesses based on the percentage of OPG's total compensation cost attributed to the such businesses by employee group, as provided by OPG (refer to Chart 16 and Chart 17). In Step 6, the results were further attributed to OM&A and Capital expenditures on the basis of the percentage of OPG's compensation cost attributed to the nuclear and hydroelectric businesses that are represented by OM&A and Capital expenditures by employee group; these percentages as provided by OPG are set out in Chart 18 and Chart 19 below. An example of the attribution calculations is provided in Chart 20 and 21 below.

Chart 16 – Combined Nuclear (including DNNP) as a % of Total Compensation

	2027	2028	2029	2030	2031
Combined Nuclear % of Total OPG					
Management	79%	79%	78%	78%	78%
Society	80%	79%	80%	80%	79%
PWU	78%	78%	79%	79%	78%

Chart 17 – Regulated Hydroelectric as a % of Total Compensation

	2027	2028	2029	2030	2031
Regulated Hydro % of Total OPG					
Management	12%	12%	12%	12%	12%
Society	14%	15%	15%	15%	15%
PWU	15%	15%	15%	15%	16%

Chart 18 – Allocation to OM&A and Capital Expenditures for OPG Nuclear and DNNP

	2027	2028	2029	2030	2031
Total Nuclear Facilities OM&A % of Combined Nuclear					
Management	57%	58%	59%	60%	65%
Society	42%	42%	42%	43%	51%
PWU	55%	54%	54%	55%	66%
Total DNNP OM&A % of Combined Nuclear					
Management	5%	6%	6%	7%	6%
Society	2%	2%	2%	3%	4%
PWU	2%	2%	2%	3%	4%
Total PRP Capital Expenditures % of Combined Nuclear					
Management	22%	22%	23%	22%	19%
Society	31%	31%	32%	32%	24%
PWU	30%	31%	32%	32%	20%
Total DNNP Capital Expenditures % of Combined Nuclear					
Management	5%	4%	2%	1%	--
Society	4%	3%	2%	0%	--
PWU	1%	2%	3%	1%	--
Total Remaining Capital Expenditures % of Combined Nuclear					
Management	5%	5%	6%	6%	6%
Society	14%	14%	15%	15%	14%
PWU	2%	1%	1%	1%	2%

Chart 19 – Allocation to OM&A and Capital Expenditures for Regulated Hydroelectric

	2027	2028	2029	2030	2031
Total OM&A of Regulated Hydro %					
Management	87%	87%	87%	88%	88%
Society	61%	60%	59%	61%	63%
PWU	80%	80%	79%	80%	79%
Total Capital of Regulated Hydro %					
Management	13%	13%	13%	13%	13%
Society	39%	40%	41%	39%	37%
PWU	20%	20%	21%	20%	21%

Chart 20 – Calculation of Dollar Difference Attributed to Nuclear and Hydroelectric (Example for Chart 2)

OPG Group	OPG $ Variance ($MM)	Nuclear $ Allocation %	Nuclear $ Allocation ($MM)	Hydro $ Allocation %	Hydro $ Allocation ($MM)
	(Q) from step 4	(S)	(T) = Q * S	(U)	(V) = Q * U
PWU					
2027	[redacted]	78%	[redacted]	15%	[redacted]
2028		78%		15%	
2029		79%		15%	
2030		79%		15%	
2031		78%		16%	
Society					
2027	[redacted]	80%	[redacted]	14%	[redacted]
2028		79%		15%	
2029		80%		15%	
2030		80%		15%	
2031		79%		15%	
Management					
2027	[redacted]	79%	[redacted]	12%	[redacted]
2028		79%		12%	
2029		78%		12%	
2030		78%		12%	
2031		78%		12%	
OPG Total (sum of groups)					
2027	$211.6		$167.5		$31.9
2028	$211.2		$165.6		$33.4
2029	$209.6		$167.7		$33.2
2030	$208.6		$166.9		$33.1
2031	$206.5		$162.6		$34.1

Chart 21 – Calculation of Dollar Difference Attributed to OM&A and Capital Expenditures (Example for Chart 2 for Nuclear)

OPG Group	Nuclear $ Variance ($MM)	OM&A | Nuclear Ops (excludes DNNP) Attributed %	OM&A | Nuclear Ops (excludes DNNP) Attributed ($MM)	OM&A | DNNP Attributed %	OM&A | DNNP Attributed ($MM)	Capital | PRP Attributed %	Capital | PRP Attributed ($MM)	Capital | DNNP Attributed %	Capital | DNNP Attributed ($MM)	Remaining Capital Attributed %	Remaining Capital Attributed ($MM)
	(T) from step 5	(W)	(X) = T * W	(Y)	(Z) = T * Y	(AA)	(AB) = T * AA	(AC)	(AD) = T * AC	(AE)	(AF) = T * AE
PWU											
2027	[redacted]	55%	[redacted]	2%	[redacted]	30%	[redacted]	1%	[redacted]	2%	$1.9
2028		54%		2%		31%		2%		1%	$1.0
2029		54%		2%		32%		3%		1%	$1.0
2030		55%		3%		32%		1%		1%	$1.0
2031		66%		4%		20%		-	-	2%	$1.9
Society											
2027	[redacted]	42%	[redacted]	2%	[redacted]	31%	[redacted]	4%	[redacted]	14%	$16.6
2028		42%		2%		31%		3%		14%	$16.3
2029		42%		2%		32%		2%		15%	$17.6
2030		43%		3%		32%		0%		15%	$17.7
2031		51%		4%		24%		-	-	14%	$16.3
Management											
2027	($44.6)	57%	($25.4)	5%	($2.4)	22%	($9.8)	5%	($2.2)	5%	($2.2)
2028	($45.9)	58%	($26.6)	6%	($2.6)	22%	($10.1)	4%	($1.8)	5%	($2.3)
2029	($46.3)	59%	($27.3)	6%	($2.7)	23%	($10.7)	2%	($1.1)	6%	($2.8)
2030	($47.9)	60%	($28.8)	7%	($3.2)	22%	($10.5)	1%	($0.3)	6%	($2.9)
2031	($50.2)	65%	($32.6)	6%	($2.9)	19%	($9.5)	-	-	6%	($3.0)
OPG Total (sum of groups)											
2027	$167.5	-	$75.8	-	$2.3	-	$55.0	-	$3.5	-	$16.3
2028	$165.6	-	$73.6	-	$2.2	-	$55.5	-	$3.6	-	$15.0
2029	$167.7	-	$74.2	-	$1.7	-	$57.8	-	$3.5	-	$15.7
2030	$166.9	-	$75.2	-	$3.2	-	$58.2	-	$1.1	-	$15.8
2031	$162.6	-	$90.3	-	$5.1	-	$37.7	-	-	-	$15.2

The following response was prepared by OPG:

As noted above, with respect to capital costs, OPG has computed such revenue requirement estimates for the 2027-2031 IR term on the basis of the translation of the total estimated capital expenditure differences calculated by WTW for each year of the IR term for each scenario to capital in-service additions, as this represents the basis of the requested recovery of capital costs in this Application.[4] Such translation has been performed with reference to Ex. L-B1-SEC-028, namely by multiplying the capital amounts calculated by WTW by the percentage of such year's capital expenditures forecast to be placed in-service in a given year of the IR term. These percentages are

[4] The percentages provided by OPG in Charts 18 and 19 were derived based on the underlying compensation data in Ex. F4-3-1, Attachment 1 and Ex. L-F4-AMPCO-110 by representation and the cost categories outlined in the charts.

provided in Chart 22 below. OPG's calculations of the resulting estimated revenue requirement impacts for each scenario are detailed in Attachment 1.

The above revenue requirement impacts, together with the estimated OM&A differences calculated by WTW for each year of the IR term for each scenario from the preceding charts, have been summarized by OPG in the respective OPG Charts 1.6, 2.6, 3.6, 4.6, 5.6, 6.6, 7.6, 8.6, 9.6 and 10.6 ("End Results Charts") below, by regulated business, year and type of costs. Based on WTW's analysis of the estimated dollar differences to the target market range (+/- 10% of the P50 or P75 market reference), both the OM&A differences and the capital-related revenue requirement differences, for each of the regulated businesses and years, are $0 for all scenarios.[5]

Chart 22 – Proportion of Capital Placed In-Service By Year*

Total Hydroelectric Capex/ISA Conversion (%)	2027	2028	2029	2030	2031
Hydroelectric Capital Expenditures					
In-Service in 2027	28%				
In-Service in 2028	41%	32%			
In-Service in 2029	20%	39%	40%		
In-Service in 2030	9%	16%	33%	34%	
In-Service in 2031	0%	2%	6%	24%	32%
In-Service in 2032 or later	2%	7%	17%	39%	65%
Total Nuclear Operations Capex/ISA Conversion (%)	**2027**	**2028**	**2029**	**2030**	**2031**
Nuclear Operations Capital Expenditures					
In-Service in 2027	37%				
In-Service in 2028	22%	29%			
In-Service in 2029	18%	22%	38%		
In-Service in 2030	14%	25%	26%	54%	
In-Service in 2031	6%	12%	16%	19%	43%
In-Service in 2032 or later	3%	13%	21%	27%	58%
PRP Capex/ISA Conversion (%)	**2027**	**2028**	**2029**	**2030**	**2031**
PRP Capital Expenditures					
In-Service in 2027	0%				
In-Service in 2028	0%	0%			
In-Service in 2029	0%	0%	0%		
In-Service in 2030	0%	0%	0%	0%	
In-Service in 2031	70%	53%	33%	11%	10%
In-Service in 2032 or later	30%	47%	67%	89%	90%
DNNP Capex/ISA Conversion (%)	**2027**	**2028**	**2029**	**2030**	**2031**
DNNP Capital Expenditures					
In-Service in 2027	0%				
In-Service in 2028	0%	0%			
In-Service in 2029	0%	0%	0%		
In-Service in 2030	87%	100%	100%	100%	
In-Service in 2031	0%	0%	0%	0%	0%
In-Service in 2032 or later	13%	0%	0%	0%	0%

*Calculated based on the dollar amounts for the respective categories as presented in Ex. L-B1-SEC-028, Attachment 1, excluding Reconciling Items rows. As a simplifying assumption, the conversion rates applied in this response do not separately consider

[5] For simplicity of presentation, the End Results Charts display a single set of columns for the Overall +/- Market Range results. However, these results apply to all regulated business and types of costs analyzed.

corporate support projects in Nuclear or Regulated Hydroelectric rate base as these amounts represent only 3% of the total Nuclear and Regulated Hydroelectric in-service amounts.

Chart 1.6 – Estimated Total Remuneration Dollar Difference– Amounts Allocated to Nuclear and Regulated Hydroelectric Facilities and Attributable to OM&A and Capital In-Service Revenue Requirement (p.14 of WTW report)

	Total ($Millions)										Overall +/- Market Range ($Millions)	
	DNNP LP			OPG Nuclear				Hydroelectric			Nuclear	Hydroelectric
	OM&A | DNNP Attributed	Capital In-Service RR | DNNP Attributed	Total OM&A and Capital In-Service RR Attributed	OM&A | Nuclear Facilities Attributed	Capital In-Service RR | PRP Attributed	Remaining Capital In-Service RR Attributed	Total OM&A and Capital In-Service RR Attributed	OM&A Attributed	Capital In-Service RR Attributed	Total OM&A and Capital In-Service RR Attributed	OM&A and Capital in Service RR Attributed	OM&A and Capital in Service RR Attributed
2027	$1.8	$0.0	$1.8	$65.4	$0.0	$0.3	$65.7	$18.3	$0.1	$18.5	$0.0	$0.0
2028	$1.7	$0.0	$1.7	$63.1	$0.0	$1.0	$64.1	$18.9	$0.7	$19.5	$0.0	$0.0
2029	$1.2	$0.0	$1.2	$63.4	$0.0	$2.0	$65.4	$18.3	$1.6	$19.9	$0.0	$0.0
2030	$2.6	$0.2	$2.8	$64.0	$0.0	$3.6	$67.5	$18.6	$2.6	$21.2	$0.0	$0.0
2031	$4.3	$1.0	$5.3	$76.7	$5.1	$5.2	$87.1	$19.5	$3.4	$22.8	$0.0	$0.0

Chart 2.6 – Estimated Total Remuneration Dollar Difference– Amounts Allocated to Nuclear and Regulated Hydroelectric Facilities and Attributable to OM&A and Capital In-Service Revenue Requirement (p.15 of WTW report)

	Total ($Millions)										Overall +/- Market Range ($Millions)	
	DNNP LP			OPG Nuclear				Hydroelectric			Nuclear	Hydroelectric
	OM&A | DNNP Attributed	Capital In-Service RR | DNNP Attributed	Total OM&A and Capital In-Service RR Attributed	OM&A | Nuclear Facilities Attributed	Capital In-Service RR | PRP Attributed	Remaining Capital In-Service RR Attributed	Total OM&A and Capital In-Service RR Attributed	OM&A Attributed	Capital In-Service RR Attributed	Total OM&A and Capital In-Service RR Attributed	OM&A and Capital in Service RR Attributed	OM&A and Capital in Service RR Attributed
2027	$2.3	$0.0	$2.3	$75.8	$0.0	$0.3	$76.1	$21.1	$0.2	$21.3	$0	$0
2028	$2.2	$0.0	$2.2	$73.6	$0.0	$1.1	$74.7	$21.8	$0.7	$22.5	$0	$0
2029	$1.7	$0.0	$1.7	$74.2	$0.0	$2.2	$76.4	$21.3	$1.7	$23.0	$0	$0
2030	$3.2	$0.2	$3.4	$75.2	$0.0	$3.9	$79.1	$21.7	$2.8	$24.6	$0	$0
2031	$5.1	$1.0	$6.1	$90.3	$7.0	$5.7	$103.0	$22.7	$3.7	$26.5	$0	$0

Chart 3.6 – Estimated Total Remuneration Dollar Difference– Amounts Allocated to Nuclear and Regulated Hydroelectric Facilities and Attributable to OM&A and Capital In-Service Revenue Requirement (p.16 of WTW report)

	Total ($Millions)										Overall +/- Market Range ($Millions)	
	DNNP LP			OPG Nuclear				Hydroelectric			Nuclear	Hydroelectric
	OM&A | DNNP Attributed	Capital In-Service RR | DNNP Attributed	Total OM&A and Capital In-Service RR Attributed	OM&A | Nuclear Facilities Attributed	Capital In-Service RR | PRP Attributed	Remaining Capital In-Service RR Attributed	Total OM&A and Capital In-Service RR Attributed	OM&A Attributed	Capital In-Service RR Attributed	Total OM&A and Capital In-Service RR Attributed	OM&A and Capital in Service RR Attributed	OM&A and Capital in Service RR Attributed
2027	$1.5	$0.0	$1.5	$59.1	$0.0	$0.3	$59.4	$16.7	$0.1	$16.8	$0	$0
2028	$1.3	$0.0	$1.3	$56.8	$0.0	$0.9	$57.7	$17.2	$0.6	$17.8	$0	$0
2029	$0.9	$0.0	$0.9	$56.8	$0.0	$1.9	$58.7	$16.6	$1.5	$18.1	$0	$0
2030	$2.1	$0.2	$2.3	$57.1	$0.0	$3.4	$60.5	$16.8	$2.4	$19.3	$0	$0
2031	$3.7	$0.9	$4.6	$68.6	$4.7	$5.0	$78.3	$17.5	$3.2	$20.7	$0	$0

Chart 4.6 – Estimated Total Remuneration Dollar Difference– Amounts Allocated to Nuclear and Regulated Hydroelectric Facilities and Attributable to OM&A and Capital In-Service Revenue Requirement (p.17 of WTW report)

	Total ($Millions)										Overall +/- Market Range ($Millions)	
	DNNP LP			OPG Nuclear				Hydroelectric			Nuclear	Hydroelectric
	OM&A | DNNP Attributed	Capital In-Service RR | DNNP Attributed	Total OM&A and Capital In-Service RR Attributed	OM&A | Nuclear Facilities Attributed	Capital In-Service RR | PRP Attributed	Remaining Capital In-Service RR Attributed	Total OM&A and Capital In-Service RR Attributed	OM&A Attributed	Capital In-Service RR Attributed	Total OM&A and Capital In-Service RR Attributed	OM&A and Capital in Service RR Attributed	OM&A and Capital in Service RR Attributed
2027	$1.9	$0.0	$1.9	$69.5	$0.0	$0.3	$69.8	$19.5	$0.1	$19.6	$0	$0
2028	$1.8	$0.0	$1.8	$67.2	$0.0	$1.0	$68.3	$20.1	$0.7	$20.8	$0	$0
2029	$1.3	$0.0	$1.3	$67.6	$0.0	$2.1	$69.7	$19.6	$1.6	$21.2	$0	$0
2030	$2.7	$0.2	$3.0	$68.4	$0.0	$3.7	$72.1	$19.9	$2.7	$22.6	$0	$0
2031	$4.6	$1.1	$5.7	$82.2	$5.4	$5.5	$93.0	$20.8	$3.6	$24.4	$0	$0

Chart 5.6 – Estimated Total Remuneration Dollar Difference– Amounts Allocated to Nuclear and Regulated Hydroelectric Facilities and Attributable to OM&A and Capital In-Service Revenue Requirement (p.18 of WTW report)

	Total ($Millions)										Overall +/- Market Range ($Millions)	
	DNNP LP			OPG Nuclear				Hydroelectric			Nuclear	Hydroelectric
	OM&A | DNNP Attributed	Capital In-Service RR | DNNP Attributed	Total OM&A and Capital In-Service RR Attributed	OM&A | Nuclear Facilities Attributed	Capital In-Service RR | PRP Attributed	Remaining Capital In-Service RR Attributed	Total OM&A and Capital In-Service RR Attributed	OM&A Attributed	Capital In-Service RR Attributed	Total OM&A and Capital In-Service RR Attributed	OM&A and Capital in Service RR Attributed	OM&A and Capital in Service RR Attributed
2027	$1.6	$0.0	$1.6	$60.4	$0.0	$0.3	$60.7	$17.0	$0.1	$17.1	$0	$0
2028	$1.5	$0.0	$1.5	$58.1	$0.0	$0.9	$59.0	$17.5	$0.6	$18.1	$0	$0
2029	$1.0	$0.0	$1.0	$58.1	$0.0	$1.9	$60.0	$16.9	$1.5	$18.4	$0	$0
2030	$2.3	$0.2	$2.5	$58.5	$0.0	$3.4	$61.9	$17.1	$2.4	$19.6	$0	$0
2031	$3.8	$0.9	$4.8	$70.1	$4.8	$4.9	$79.8	$17.8	$3.2	$21.0	$0	$0

Chart 6.6 – Estimated Total Remuneration Dollar Difference– Amounts Allocated to Nuclear and Regulated Hydroelectric Facilities and Attributable to OM&A and Capital In-Service Revenue Requirement (p.18 of WTW report)

	Total ($Millions)										Overall +/- Market Range ($Millions)	
	DNNP LP			OPG Nuclear				Hydroelectric			Nuclear	Hydroelectric
	OM&A | DNNP Attributed	Capital In-Service RR | DNNP Attributed	Total OM&A and Capital In-Service RR Attributed	OM&A | Nuclear Facilities Attributed	Capital In-Service RR | PRP Attributed	Remaining Capital In-Service RR Attributed	Total OM&A and Capital In-Service RR Attributed	OM&A Attributed	Capital In-Service RR Attributed	Total OM&A and Capital In-Service RR Attributed	OM&A and Capital in Service RR Attributed	OM&A and Capital in Service RR Attributed
2027	$1.2	$0.0	$1.2	$54.1	$0.0	$0.3	$54.4	$15.3	$0.1	$15.4	$0	$0
2028	$1.1	$0.0	$1.1	$51.7	$0.0	$0.9	$52.6	$15.7	$0.6	$16.3	$0	$0
2029	$0.7	$0.0	$0.7	$51.5	$0.0	$1.8	$53.3	$15.2	$1.4	$16.5	$0	$0
2030	$1.8	$0.2	$2.0	$51.7	$0.0	$3.2	$54.8	$15.3	$2.3	$17.6	$0	$0
2031	$3.3	$0.8	$4.1	$61.9	$4.4	$4.7	$71.0	$15.9	$3.0	$18.9	$0	$0

Chart 7.6 – Estimated Total Remuneration Dollar Difference– Amounts Allocated to Nuclear and Regulated Hydroelectric Facilities and Attributable to OM&A and Capital In-Service Revenue Requirement (based on Chart 1 in Ex. L-F4-SUP-023)

	Total ($Millions)										Overall +/- Market Range ($Millions)	
	DNNP LP			OPG Nuclear				Hydroelectric			Nuclear	Hydroelectric
	OM&A | DNNP Attributed	Capital In-Service RR | DNNP Attributed	Total OM&A and Capital In-Service RR Attributed	OM&A | Nuclear Facilities Attributed	Capital In-Service RR | PRP Attributed	Remaining Capital In-Service RR Attributed	Total OM&A and Capital In-Service RR Attributed	OM&A Attributed	Capital In-Service RR Attributed	Total OM&A and Capital In-Service RR Attributed	OM&A and Capital in Service RR Attributed	OM&A and Capital in Service RR Attributed
2027	$1.8	$0.0	$1.8	$65.9	$0.0	$0.3	$66.2	$18.5	$0.1	$18.6	$0	$0
2028	$1.7	$0.0	$1.7	$63.7	$0.0	$1.0	$64.7	$19.1	$0.6	$19.7	$0	$0
2029	$1.2	$0.0	$1.2	$64.0	$0.0	$1.9	$65.9	$18.5	$1.5	$20.1	$0	$0
2030	$2.5	$0.2	$2.8	$64.6	$0.0	$3.4	$68.0	$18.8	$2.5	$21.4	$0	$0
2031	$4.3	$1.0	$5.3	$77.5	$5.1	$5.0	$87.6	$19.7	$3.3	$23.0	$0	$0

Chart 8.6 – Estimated Total Remuneration Dollar Difference– Amounts Allocated to Nuclear and Regulated Hydroelectric Facilities and Attributable to OM&A and Capital In-Service Revenue Requirement (based on Chart 2 in Ex. L-F4-SUP-023)

	Total ($Millions)										Overall +/- Market Range ($Millions)	
	DNNP LP			OPG Nuclear				Hydroelectric			Nuclear	Hydroelectric
	OM&A | DNNP Attributed	Capital In-Service RR | DNNP Attributed	Total OM&A and Capital In-Service RR Attributed	OM&A | Nuclear Facilities Attributed	Capital In-Service RR | PRP Attributed	Remaining Capital In-Service RR Attributed	Total OM&A and Capital In-Service RR Attributed	OM&A Attributed	Capital In-Service RR Attributed	Total OM&A and Capital In-Service RR Attributed	OM&A and Capital in Service RR Attributed	OM&A and Capital in Service RR Attributed
2027	$1.5	$0.0	$1.5	$59.4	$0.0	$0.3	$59.7	$16.8	$0.1	$16.9	$0	$0
2028	$1.3	$0.0	$1.3	$57.2	$0.0	$0.9	$58.1	$17.3	$0.6	$17.9	$0	$0
2029	$0.9	$0.0	$0.9	$57.2	$0.0	$1.8	$59.0	$16.7	$1.4	$18.2	$0	$0
2030	$2.1	$0.2	$2.3	$57.6	$0.0	$3.2	$60.8	$17.0	$2.4	$19.4	$0	$0
2031	$3.7	$0.9	$4.6	$69.1	$4.7	$4.7	$78.6	$17.7	$3.1	$20.8	$0	$0

Chart 9.6 – Estimated Total Remuneration Dollar Difference– Amounts Allocated to Nuclear and Regulated Hydroelectric Facilities and Attributable to OM&A and Capital In-Service Revenue Requirement (based on Chart 8 in Ex. L-F4-CCC-091)

	Total ($Millions)										Overall +/- Market Range ($Millions)	
	DNNP LP			OPG Nuclear				Hydroelectric			Nuclear	Hydroelectric
	OM&A | DNNP Attributed	Capital In-Service RR | DNNP Attributed	Total OM&A and Capital In-Service RR Attributed	OM&A | Nuclear Facilities Attributed	Capital In-Service RR | PRP Attributed	Remaining Capital In-Service RR Attributed	Total OM&A and Capital In-Service RR Attributed	OM&A Attributed	Capital In-Service RR Attributed	Total OM&A and Capital In-Service RR Attributed	OM&A and Capital in Service RR Attributed	OM&A and Capital in Service RR Attributed
2027	$2.3	$0.0	$2.3	$76.7	$0.0	$0.3	$77.0	$21.4	$0.1	$21.6	$0	$0
2028	$2.2	$0.0	$2.2	$74.6	$0.0	$1.0	$75.7	$22.1	$0.7	$22.8	$0	$0
2029	$1.7	$0.0	$1.7	$75.2	$0.0	$2.1	$77.3	$21.6	$1.7	$23.3	$0	$0
2030	$3.2	$0.3	$3.5	$76.3	$0.0	$3.7	$80.1	$22.0	$2.8	$24.8	$0	$0
2031	$5.2	$1.2	$6.4	$91.6	$5.8	$5.5	$102.9	$23.1	$3.7	$26.8	$0	$0

Chart 10.6 – Estimated Total Remuneration Dollar Difference– Amounts Allocated to Nuclear and Regulated Hydroelectric Facilities and Attributable to OM&A and Capital In-Service Revenue Requirement (based on Chart 9 in Ex. L-F4-CCC-091)

	Total ($Millions)										Overall +/- Market Range ($Millions)	
	DNNP LP			OPG Nuclear				Hydroelectric			Nuclear	Hydroelectric
	OM&A | DNNP Attributed	Capital In-Service RR | DNNP Attributed	Total OM&A and Capital In-Service RR Attributed	OM&A | Nuclear Facilities Attributed	Capital In-Service RR | PRP Attributed	Remaining Capital In-Service RR Attributed	Total OM&A and Capital In-Service RR Attributed	OM&A Attributed	Capital In-Service RR Attributed	Total OM&A and Capital In-Service RR Attributed	OM&A and Capital in Service RR Attributed	OM&A and Capital in Service RR Attributed
2027	$1.9	$0.0	$1.9	$70.2	$0.0	$0.3	$70.5	$19.7	$0.1	$19.8	$0.0	$0.0
2028	$1.8	$0.0	$1.8	$68.0	$0.0	$1.0	$69.0	$20.3	$0.7	$21.0	$0.0	$0.0
2029	$1.3	$0.0	$1.3	$68.5	$0.0	$2.0	$70.5	$19.8	$1.6	$21.4	$0.0	$0.0
2030	$2.7	$0.2	$3.0	$69.3	$0.0	$3.5	$72.8	$20.2	$2.7	$22.8	$0.0	$0.0
2031	$4.6	$1.1	$5.7	$83.2	$5.4	$5.2	$93.9	$21.1	$3.5	$24.6	$0.0	$0.0

Scenario 1: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (pg. 14 of WTW report) Nuclear Authorized Compared to 50th percentile, Excluding Hydro One Shares

Pickering Refurbishment Program

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	0.0	0.0	0.0	0.0	1.4
2	**Cost of Capital – Debt**[1]	0.0	0.0	0.0	0.0	1.3
3	**Cost of Capital – ROE**[1]	0.0	0.0	0.0	0.0	2.5
4	**Income Tax**[2]	-	-	-	-	-
5	**Capital-Related Revenue Requirement**	0.0	0.0	0.0	0.0	5.1

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	0.0	0.0	0.0	0.0	52.7
1b	**Weighted Cost of Capital - Debt (%)****	2.21%	2.30%	2.35%	2.38%	2.39%
1c	**Cost of Capital - Debt ($)** (line 1a x line 1b)	0.0	0.0	0.0	0.0	1.3
1d	**Weighted Cost of Capital - ROE (%)*****	4.74%	4.74%	4.74%	4.74%	4.74%
1e	**Cost of Capital - ROE ($)** (line 1a x line 1d)	0.0	0.0	0.0	0.0	2.5

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed** [+]	48.7	48.9	50.9	51.1	32.9
1bb	**Opening Balance**	0.0	0.0	0.0	0.0	0.0
1cc	**In-Service Additions**[++]	0.0	-	-	-	85.6
1dd	**Depreciation**[+++]	0.0	0.0	0.0	0.0	1.4
1ee	**Closing Balance** (line 1bb + line 1cc - line 1dd)	0.0	0.0	0.0	0.0	84.3
1ff	**Net Plant Rate Base Amount** [+++]	0.0	0.0	0.0	0.0	52.7

+ 2027-2031 Capital Attributed obtained from Chart 1.4

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using an in-service date of May 2031 (Ex. D2-3-8, Table 2) and an end of life date of December 31, 2070 (Ex. F4-1-1, Chart 1). The Net Plant Rate Base Amount has been weighted in 2031 to reflect the in-service timing.

** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 4, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 5b, col. (b) x line 5a, col. (c).

[2] No income tax impact is reflected as the OPG's regulated nuclear business is in a forecast regulatory tax loss position.

Scenario 1: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (pg. 14 of WTW report) Nuclear Authorized Compared to 50th percentile, Excluding Hydro One Shares

Darlington New Nuclear Program

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	-	-	-	0.0	0.2
2	**Cost of Capital – Debt**[1]	-	-	-	-	-
3	**Cost of Capital – ROE**[1]	-	-	-	0.2	0.9
4	**Income Tax**[2]	-	-	-	-	-
5	**Capital-Related Revenue Requirement**	-	-	-	0.2	1.0

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	-	-	-	2.0	9.4
1b	**Weighted Cost of Capital - Debt (%)****	0.00%	0.00%	0.00%	0.00%	0.00%
1c	**Cost of Capital - Debt ($)** (line 1a x line 1b)	-	-	-	-	-
1d	**Weighted Cost of Capital - ROE (%)*****	9.11%	9.11%	9.11%	9.11%	9.11%
1e	**Cost of Capital - ROE ($)** (line 1a x line 1d)	-	-	-	0.2	0.9

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed** [+]	3.0	3.1	3.0	0.9	-
1bb	**Opening Balance**	-	-	-	-	9.5
1cc	**In-Service Additions**[++]	-	-	-	9.5	-
1dd	**Depreciation**[+++]	-	-	-	0.0	0.2
1ee	**Closing Balance** (line 1bb + line 1cc - line 1dd)	-	-	-	9.5	9.3
1ff	**Net Plant Rate Base Amount** [+++]	-	-	-	2.0	9.4

+ 2027-2031 Capital Attributed obtained from Chart 1.4

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using an in-service date of October 2030 (Ex. D2-4-8, table 3) and a useful life of 60 years (Ex. F4-1-1, p. 7, line 19). The Net Plant Rate Base Amount has been weighted in 2030 to reflect the in-service timing.

** Calculated as Ex. C1-1-1, Tables 13 to 17 for each respective year, line 3, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 13 to 17 for each respective year, line 5b, col. (b) x col. (c).

[2] No income tax impact is reflected as DNNP LP is in a forecast regulatory tax loss position.

Scenario 1: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (pg. 14 of WTW report) Nuclear Authorized Compared to 50th percentile, Excluding Hydro One Shares

Remaining Nuclear Capital

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	0.1	0.4	0.8	1.4	2.1
2	**Cost of Capital – Debt**[1]	0.1	0.2	0.4	0.7	1.0
3	**Cost of Capital – ROE**[1]	0.1	0.4	0.8	1.4	2.1
4	**Income Tax**[2]	-	-	-	-	-
5	**Capital-Related Revenue Requirement**	0.3	1.0	2.0	3.6	5.2

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	2.7	8.9	17.4	30.4	43.9
1b	**Weighted Cost of Capital - Debt (%)****	2.21%	2.30%	2.35%	2.38%	2.39%
1c	**Cost of Capital - Debt ($)** (line 1a x line 1b)	0.1	0.2	0.4	0.7	1.0
1d	**Weighted Cost of Capital - ROE (%)*****	4.74%	4.74%	4.74%	4.74%	4.74%
1e	**Cost of Capital - ROE ($)** (line 1a x line 1d)	0.1	0.4	0.8	1.4	2.1

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed** [+]	14.9	13.7	14.4	14.4	13.8
1bb	**Opening Balance**	-	5.4	12.3	22.6	38.2
1cc	**In-Service Additions**[++]	5.5	7.3	11.0	17.0	13.5
1dd	**Depreciation**[+++]	0.1	0.4	0.8	1.4	2.1
1ee	**Closing Balance** (line 1bb + line 1cc - line 1dd)	5.4	12.3	22.6	38.2	49.6
1ff	**Net Plant Rate Base Amount** ((line 1bb + line 1ee)/2)	2.7	8.9	17.4	30.4	43.9

+ 2027-2031 Capital Attributed obtained from Chart 1.4

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using a mid-year in-service date and a Darlington end of life of December 31, 2052 (Ex. F4-1-1, Chart 1).

** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 4, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 5b, col. (b) x line 5a, col. (c).

[2] No income tax impact is reflected as the OPG's regulated nuclear business is in a forecast regulatory tax loss position.

Scenario 1: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (pg. 14 of WTW report) Nuclear Authorized Compared to 50th percentile, Excluding Hydro One Shares

Regulated Hydroelectric Capital

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	0.0	0.1	0.3	0.4	0.6
2	**Cost of Capital – Debt**[1]	0.0	0.1	0.4	0.6	0.8
3	**Cost of Capital – ROE**[1]	0.1	0.3	0.7	1.2	1.5
4	**Income Tax**[2]	0.0	0.1	0.2	0.4	0.5
5	**Capital-Related Revenue Requirement**	0.1	0.7	1.6	2.6	3.4

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	1.3	6.3	15.0	24.7	32.4
1b	**Weighted Cost of Capital - Debt (%)****	2.21%	2.30%	2.35%	2.38%	2.39%
1c	**Cost of Capital - Debt ($)** (line 1a x line 1b)	0.0	0.1	0.4	0.6	0.8
1d	**Weighted Cost of Capital - ROE (%)*****	4.74%	4.74%	4.74%	4.74%	4.74%
1e	**Cost of Capital - ROE ($)** (line 1a x line 1d)	0.1	0.3	0.7	1.2	1.5

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed** [+]	9.8	10.5	10.8	10.3	10.2
1bb	**Opening Balance**	-	2.7	9.9	20.1	29.4
1cc	**In-Service Additions**[++]	2.7	7.4	10.4	9.7	6.6
1dd	**Depreciation**[+++]	0.0	0.1	0.3	0.4	0.6
1ee	**Closing Balance** (line 1bb + line 1cc - line 1dd)	2.7	9.9	20.1	29.4	35.4
1ff	**Net Plant Rate Base Amount** ((line 1bb + line 1ee)/2)	1.3	6.3	15.0	24.7	32.4

+ 2027-2031 Capital Attributed obtained from Chart 1.5

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using a mid-year in-service date and a 60 year average useful life.

** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 4, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 5b, col. (b) x line 5a, col. (c).

[2] Calculated as line 3 x 25%/(1-25%). Capital Cost Allowance impacts not computed as a simplifying assumption.

Scenario 2: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (pg. 15 of WTW report) Nuclear Authorized Compared to 50th percentile, Including Hydro One Shares

Pickering Refurbishment Program

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	0.0	0.0	0.0	0.0	1.6
2	**Cost of Capital – Debt**[1]	0.0	0.0	0.0	0.0	1.4
3	**Cost of Capital – ROE**[1]	0.0	0.0	0.0	0.0	2.8
4	**Income Tax**[2]	-	-	-	-	-
5	**Capital-Related Revenue Requirement**	0.0	0.0	0.0	0.0	5.8

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	0.0	0.0	0.0	0.0	59.7
1b	**Weighted Cost of Capital - Debt (%)****	2.21%	2.30%	2.35%	2.38%	2.39%
1c	**Cost of Capital - Debt ($)** (line 1a x line 1b)	0.0	0.0	0.0	0.0	1.4
1d	**Weighted Cost of Capital - ROE (%)*****	4.74%	4.74%	4.74%	4.74%	4.74%
1e	**Cost of Capital - ROE ($)** (line 1a x line 1d)	0.0	0.0	0.0	0.0	2.8

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed** [+]	55.0	55.5	57.8	58.2	37.7
1bb	**Opening Balance**	0.0	0.0	0.0	0.0	0.0
1cc	**In-Service Additions**[++]	0.0	-	-	-	97.0
1dd	**Depreciation**[+++]	0.0	0.0	0.0	0.0	1.6
1ee	**Closing Balance** (line 1bb + line 1cc - line 1dd)	0.0	0.0	0.0	0.0	95.5
1ff	**Net Plant Rate Base Amount** [+++]	0.0	0.0	0.0	0.0	59.7

+ 2027-2031 Capital Attributed obtained from Chart 2.4

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using an in-service date of May 2031 (Ex. D2-3-8, Table 2) and an end of life date of December 31, 2070 (Ex. F4-1-1, Chart 1). The Net Plant Rate Base Amount has been weighted in 2031 to reflect the in-service timing.

** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 4, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 5b, col. (b) x line 5a, col. (c).

[2] No income tax impact is reflected as the OPG's regulated nuclear business is in a forecast regulatory tax loss position.

Scenario 2: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (pg. 15 of WTW report) Nuclear Authorized Compared to 50th percentile, Including Hydro One Shares

Darlington New Nuclear Program

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	-	-	-	0.0	0.2
2	**Cost of Capital – Debt**[1]	-	-	-	-	-
3	**Cost of Capital – ROE**[1]	-	-	-	0.2	1.0
4	**Income Tax**[2]	-	-	-	-	-
5	**Capital-Related Revenue Requirement**	-	-	-	0.2	1.2

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	-	-	-	2.3	11.0
1b	**Weighted Cost of Capital - Debt (%)****	0.00%	0.00%	0.00%	0.00%	0.00%
1c	**Cost of Capital - Debt ($)** (line 1a x line 1b)	-	-	-	-	-
1d	**Weighted Cost of Capital - ROE (%)*****	9.11%	9.11%	9.11%	9.11%	9.11%
1e	**Cost of Capital - ROE ($)** (line 1a x line 1d)	-	-	-	0.2	1.0

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed** [+]	3.5	3.6	3.5	1.1	-
1bb	**Opening Balance**	-	-	-	-	11.1
1cc	**In-Service Additions**[++]	-	-	-	11.1	-
1dd	**Depreciation**[+++]	-	-	-	0.0	0.2
1ee	**Closing Balance** (line 1bb + line 1cc - line 1dd)	-	-	-	11.1	10.9
1ff	**Net Plant Rate Base Amount** [+++]	-	-	-	2.3	11.0

+ 2027-2031 Capital Attributed obtained from Chart 2.4

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using an in-service date of October 2030 (Ex. D2-4-8, table 3) and a useful life of 60 years (Ex. F4-1-1, p. 7, line 19). The Net Plant Rate Base Amount has been weighted in 2030 to reflect the in-service timing.

** Calculated as Ex. C1-1-1, Tables 13 to 17 for each respective year, line 3, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 13 to 17 for each respective year, line 5b, col. (b) x col. (c).

[2] No income tax impact is reflected as DNNP LP is in a forecast regulatory tax loss position.

Scenario 2: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (pg. 15 of WTW report) Nuclear Authorized Compared to 50th percentile, Including Hydro One Shares

Remaining Nuclear Capital

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	0.1	0.4	0.8	1.5	2.3
2	**Cost of Capital – Debt**[1]	0.1	0.2	0.4	0.8	1.1
3	**Cost of Capital – ROE**[1]	0.1	0.5	0.9	1.6	2.3
4	**Income Tax**[2]	-	-	-	-	-
5	**Capital-Related Revenue Requirement**	0.3	1.1	2.2	3.9	5.7

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	3.0	9.7	19.1	33.2	48.1
1b	**Weighted Cost of Capital - Debt (%)****	2.21%	2.30%	2.35%	2.38%	2.39%
1c	**Cost of Capital - Debt ($)** (line 1a x line 1b)	0.1	0.2	0.4	0.8	1.1
1d	**Weighted Cost of Capital - ROE (%)*****	4.74%	4.74%	4.74%	4.74%	4.74%
1e	**Cost of Capital - ROE ($)** (line 1a x line 1d)	0.1	0.5	0.9	1.6	2.3

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed** [+]	16.3	15.0	15.7	15.8	15.2
1bb	**Opening Balance**	-	5.9	13.5	24.7	41.8
1cc	**In-Service Additions**[++]	6.0	7.9	12.1	18.6	14.8
1dd	**Depreciation**[+++]	0.1	0.4	0.8	1.5	2.3
1ee	**Closing Balance** (line 1bb + line 1cc - line 1dd)	5.9	13.5	24.7	41.8	54.3
1ff	**Net Plant Rate Base Amount** [+++] ((line 1bb + line 1ee)/2)	3.0	9.7	19.1	33.2	48.1

+ 2027-2031 Capital Attributed obtained from Chart 2.4

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using a mid-year in-service date and a Darlington end of life of December 31, 2052 (Ex. F4-1-1, Chart 1).

** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 4, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 5b, col. (b) x line 5a, col. (c).

[2] No income tax impact is reflected as the OPG's regulated nuclear business is in a forecast regulatory tax loss position.

Scenario 2: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (pg. 15 of WTW report) Nuclear Authorized Compared to 50th percentile, Including Hydro One Shares

Regulated Hydroelectric Capital

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	0.0	0.1	0.3	0.5	0.6
2	**Cost of Capital – Debt**[1]	0.0	0.2	0.4	0.7	0.9
3	**Cost of Capital – ROE**[1]	0.1	0.3	0.8	1.3	1.7
4	**Income Tax**[2]	0.0	0.1	0.3	0.4	0.6
5	**Capital-Related Revenue Requirement**	0.2	0.7	1.7	2.8	3.7

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	1.5	7.0	16.6	27.4	35.9
1b	**Weighted Cost of Capital - Debt (%)****	2.21%	2.30%	2.35%	2.38%	2.39%
1c	**Cost of Capital - Debt ($)** (line 1a x line 1b)	0.0	0.2	0.4	0.7	0.9
1d	**Weighted Cost of Capital - ROE (%)*****	4.74%	4.74%	4.74%	4.74%	4.74%
1e	**Cost of Capital - ROE ($)** (line 1a x line 1d)	0.1	0.3	0.8	1.3	1.7

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed** [+]	10.8	11.6	11.9	11.4	11.4
1bb	**Opening Balance**	-	3.0	11.0	22.2	32.5
1cc	**In-Service Additions**[++]	3.0	8.1	11.5	10.7	7.4
1dd	**Depreciation**[+++]	0.0	0.1	0.3	0.5	0.6
1ee	**Closing Balance** (line 1bb + line 1cc - line 1dd)	3.0	11.0	22.2	32.5	39.3
1ff	**Net Plant Rate Base Amount** [+++] ((line 1bb + line 1ee)/2)	1.5	7.0	16.6	27.4	35.9

+ 2027-2031 Capital Attributed obtained from Chart 2.5

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using a mid-year in-service date and a 60 year average useful life.

** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 4, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 5b, col. (b) x line 5a, col. (c).

[2] Calculated as line 3 x 25%/(1-25%). Capital Cost Allowance impacts not computed as a simplifying assumption.

Scenario 3: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (pg. 16 of WTW report)
Nuclear Authorized Compared to 75th percentile, Excluding Hydro One Shares

Pickering Refurbishment Program

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	0.0	0.0	0.0	0.0	1.3
2	**Cost of Capital – Debt**[1]	0.0	0.0	0.0	0.0	1.2
3	**Cost of Capital – ROE**[1]	0.0	0.0	0.0	0.0	2.3
4	**Income Tax**[2]	-	-	-	-	-
5	**Capital-Related Revenue Requirement**	0.0	0.0	0.0	0.0	4.7

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	0.0	0.0	0.0	0.0	48.8
1b	**Weighted Cost of Capital - Debt (%)****	2.21%	2.30%	2.35%	2.38%	2.39%
1c	**Cost of Capital - Debt ($)** (line 1a x line 1b)	0.0	0.0	0.0	0.0	1.2
1d	**Weighted Cost of Capital - ROE (%)*****	4.74%	4.74%	4.74%	4.74%	4.74%
1e	**Cost of Capital - ROE ($)** (line 1a x line 1d)	0.0	0.0	0.0	0.0	2.3

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed** +	45.2	45.3	47.0	47.2	30.1
1bb	**Opening Balance**	0.0	0.0	0.0	0.0	0.0
1cc	**In-Service Additions**++	0.0	-	-	-	79.3
1dd	**Depreciation**+++	0.0	0.0	0.0	0.0	1.3
1ee	**Closing Balance** (line 1bb + line 1cc - line 1dd)	0.0	0.0	0.0	0.0	78.0
1ff	**Net Plant Rate Base Amount** +++	0.0	0.0	0.0	0.0	48.8

+ 2027-2031 Capital Attributed obtained from Chart 3.4

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using an in-service date of May 2031 (Ex. D2-3-8, Table 2) and an end of life date of December 31, 2070 (Ex. F4-1-1, Chart 1). The Net Plant Rate Base Amount has been weighted in 2031 to reflect the in-service timing.

** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 4, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 5b, col. (b) x line 5a, col. (c).

[2] No income tax impact is reflected as the OPG's regulated nuclear business is in a forecast regulatory tax loss position.

Scenario 3: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (pg. 16 of WTW report) Nuclear Authorized Compared to 75th percentile, Excluding Hydro One Shares

Darlington New Nuclear Program

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	-	-	-	0.0	0.1
2	**Cost of Capital – Debt**[1]	-	-	-	-	-
3	**Cost of Capital – ROE**[1]	-	-	-	0.2	0.8
4	**Income Tax**[2]	-	-	-	-	-
5	**Capital-Related Revenue Requirement**	-	-	-	0.2	0.9

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	-	-	-	1.8	8.4
1b	**Weighted Cost of Capital - Debt (%)****	0.00%	0.00%	0.00%	0.00%	0.00%
1c	**Cost of Capital - Debt ($)** (line 1a x line 1b)	-	-	-	-	-
1d	**Weighted Cost of Capital - ROE (%)*****	9.11%	9.11%	9.11%	9.11%	9.11%
1e	**Cost of Capital - ROE ($)** (line 1a x line 1d)	-	-	-	0.2	0.8

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed** +	2.7	2.7	2.7	0.8	-
1bb	**Opening Balance**	-	-	-	-	8.5
1cc	**In-Service Additions**++	-	-	-	8.5	-
1dd	**Depreciation**+++	-	-	-	0.0	0.1
1ee	**Closing Balance** (line 1bb + line 1cc - line 1dd)	-	-	-	8.5	8.3
1ff	**Net Plant Rate Base Amount** +++	-	-	-	1.8	8.4

+ 2027-2031 Capital Attributed obtained from Chart 3.4

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using an in-service date of October 2030 (Ex. D2-4-8, table 3) and a useful life of 60 years (Ex. F4-1-1, p. 7, line 19). The Net Plant Rate Base Amount has been weighted in 2030 to reflect the in-service timing.

** Calculated as Ex. C1-1-1, Tables 13 to 17 for each respective year, line 3, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 13 to 17 for each respective year, line 5b, col. (b) x col. (c).

[2] No income tax impact is reflected as DNNP LP is in a forecast regulatory tax loss position.

Scenario 3: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (pg. 16 of WTW report) Nuclear Authorized Compared to 75th percentile, Excluding Hydro One Shares

Remaining Nuclear Capital

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	0.1	0.4	0.7	1.3	2.0
2	**Cost of Capital – Debt**[1]	0.1	0.2	0.4	0.7	1.0
3	**Cost of Capital – ROE**[1]	0.1	0.4	0.8	1.4	2.0
4	**Income Tax**[2]	-	-	-	-	-
5	**Capital-Related Revenue Requirement**	0.3	0.9	1.9	3.4	5.0

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	2.6	8.4	16.6	28.9	41.7
1b	**Weighted Cost of Capital - Debt (%)****	2.21%	2.30%	2.35%	2.38%	2.39%
1c	**Cost of Capital - Debt ($)** (line 1a x line 1b)	0.1	0.2	0.4	0.7	1.0
1d	**Weighted Cost of Capital - ROE (%)*****	4.74%	4.74%	4.74%	4.74%	4.74%
1e	**Cost of Capital - ROE ($)** (line 1a x line 1d)	0.1	0.4	0.8	1.4	2.0

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed** [+]	14.2	13.0	13.6	13.6	13.0
1bb	**Opening Balance**	-	5.2	11.7	21.5	36.3
1cc	**In-Service Additions**[++]	5.3	6.9	10.5	16.1	12.8
1dd	**Depreciation**[+++]	0.1	0.4	0.7	1.3	2.0
1ee	**Closing Balance** (line 1bb + line 1cc - line 1dd)	5.2	11.7	21.5	36.3	47.1
1ff	**Net Plant Rate Base Amount** [+++] ((line 1bb + line 1ee)/2)	2.6	8.4	16.6	28.9	41.7

+ 2027-2031 Capital Attributed obtained from Chart 3.4

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using a mid-year in-service date and a Darlington end of life of December 31, 2052 (Ex. F4-1-1, Chart 1).

** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 4, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 5b, col. (b) x line 5a, col. (c).

[2] No income tax impact is reflected as the OPG's regulated nuclear business is in a forecast regulatory tax loss position.

Scenario 3: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (pg. 16 of WTW report) Nuclear Authorized Compared to 75th percentile, Excluding Hydro One Shares

Regulated Hydroelectric Capital

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	0.0	0.1	0.2	0.4	0.5
2	**Cost of Capital – Debt**[1]	0.0	0.1	0.3	0.6	0.7
3	**Cost of Capital – ROE**[1]	0.1	0.3	0.7	1.1	1.5
4	**Income Tax**[2]	0.0	0.1	0.2	0.4	0.5
5	**Capital-Related Revenue Requirement**	0.1	0.6	1.5	2.4	3.2

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	1.3	6.0	14.2	23.4	30.6
1b	**Weighted Cost of Capital - Debt (%)****	2.21%	2.30%	2.35%	2.38%	2.39%
1c	**Cost of Capital - Debt ($)** (line 1a x line 1b)	0.0	0.1	0.3	0.6	0.7
1d	**Weighted Cost of Capital - ROE (%)*****	4.74%	4.74%	4.74%	4.74%	4.74%
1e	**Cost of Capital - ROE ($)** (line 1a x line 1d)	0.1	0.3	0.7	1.1	1.5

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed** [+]	9.3	9.9	10.2	9.7	9.6
1bb	**Opening Balance**	-	2.5	9.4	19.0	27.8
1cc	**In-Service Additions**[++]	2.6	7.0	9.8	9.2	6.2
1dd	**Depreciation**[+++]	0.0	0.1	0.2	0.4	0.5
1ee	**Closing Balance** (line 1bb + line 1cc - line 1dd)	2.5	9.4	19.0	27.8	33.5
1ff	**Net Plant Rate Base Amount** [+++] ((line 1bb + line 1ee)/2)	1.3	6.0	14.2	23.4	30.6

+ 2027-2031 Capital Attributed obtained from Chart 3.5

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using a mid-year in-service date and a 60 year average useful life.

** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 4, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 5b, col. (b) x line 5a, col. (c).

[2] Calculated as line 3 x 25%/(1-25%). Capital Cost Allowance impacts not computed as a simplifying assumption.

Scenario 4: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (pg. 17 of WTW report) Nuclear Authorized Compared to 75th percentile, Including Hydro One Shares

Pickering Refurbishment Program

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	0.0	0.0	0.0	0.0	1.5
2	**Cost of Capital – Debt**[1]	0.0	0.0	0.0	0.0	1.3
3	**Cost of Capital – ROE**[1]	0.0	0.0	0.0	0.0	2.6
4	**Income Tax**[2]	-	-	-	-	-
5	**Capital-Related Revenue Requirement**	0.0	0.0	0.0	0.0	5.4

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	0.0	0.0	0.0	0.0	55.8
1b	**Weighted Cost of Capital - Debt (%)****	2.21%	2.30%	2.35%	2.38%	2.39%
1c	**Cost of Capital - Debt ($)** (line 1a x line 1b)	0.0	0.0	0.0	0.0	1.3
1d	**Weighted Cost of Capital - ROE (%)*****	4.74%	4.74%	4.74%	4.74%	4.74%
1e	**Cost of Capital - ROE ($)** (line 1a x line 1d)	0.0	0.0	0.0	0.0	2.6

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed** [+]	51.5	51.8	54.0	54.3	34.9
1bb	**Opening Balance**	0.0	0.0	0.0	0.0	0.0
1cc	**In-Service Additions**[++]	0.0	-	-	-	90.7
1dd	**Depreciation**[+++]	0.0	0.0	0.0	0.0	1.5
1ee	**Closing Balance** (line 1bb + line 1cc - line 1dd)	0.0	0.0	0.0	0.0	89.3
1ff	**Net Plant Rate Base Amount** [+++]	0.0	0.0	0.0	0.0	55.8

+ 2027-2031 Capital Attributed obtained from Chart 4.4

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using an in-service date of May 2031 (Ex. D2-3-8, Table 2) and an end of life date of December 31, 2070 (Ex. F4-1-1, Chart 1). The Net Plant Rate Base Amount has been weighted in 2031 to reflect the in-service timing.

** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 4, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 5b, col. (b) x line 5a, col. (c).

[2] No income tax impact is reflected as the OPG's regulated nuclear business is in a forecast regulatory tax loss position.

Scenario 4: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (pg. 17 of WTW report) Nuclear Authorized Compared to 75th percentile, Including Hydro One Shares

Darlington New Nuclear Program

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	-	-	-	0.0	0.2
2	**Cost of Capital – Debt**[1]	-	-	-	-	-
3	**Cost of Capital – ROE**[1]	-	-	-	0.2	0.9
4	**Income Tax**[2]	-	-	-	-	-
5	**Capital-Related Revenue Requirement**	-	-	-	0.2	1.1

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	-	-	-	2.1	10.0
1b	**Weighted Cost of Capital - Debt (%)****	0.00%	0.00%	0.00%	0.00%	0.00%
1c	**Cost of Capital - Debt ($)** (line 1a x line 1b)	-	-	-	-	-
1d	**Weighted Cost of Capital - ROE (%)*****	9.11%	9.11%	9.11%	9.11%	9.11%
1e	**Cost of Capital - ROE ($)** (line 1a x line 1d)	-	-	-	0.2	0.9

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed** [+]	3.2	3.2	3.2	1.0	-
1bb	**Opening Balance**	-	-	-	-	10.1
1cc	**In-Service Additions**[++]	-	-	-	10.1	-
1dd	**Depreciation**[+++]	-	-	-	0.0	0.2
1ee	**Closing Balance** (line 1bb + line 1cc - line 1dd)	-	-	-	10.1	9.9
1ff	**Net Plant Rate Base Amount** [+++]	-	-	-	2.1	10.0

+ 2027-2031 Capital Attributed obtained from Chart 4.4

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using an in-service date of October 2030 (Ex. D2-4-8, table 3) and a useful life of 60 years (Ex. F4-1-1, p. 7, line 19). The Net Plant Rate Base Amount has been weighted in 2030 to reflect the in-service timing.

** Calculated as Ex. C1-1-1, Tables 13 to 17 for each respective year, line 3, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 13 to 17 for each respective year, line 5b, col. (b) x col. (c).

[2] No income tax impact is reflected as DNNP LP is in a forecast regulatory tax loss position.

Scenario 4: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (pg. 17 of WTW report) Nuclear Authorized Compared to 75th percentile, Including Hydro One Shares

Remaining Nuclear Capital

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	0.1	0.4	0.8	1.5	2.2
2	**Cost of Capital – Debt**[1]	0.1	0.2	0.4	0.8	1.1
3	**Cost of Capital – ROE**[1]	0.1	0.4	0.9	1.5	2.2
4	**Income Tax**[2]	-	-	-	-	-
5	**Capital-Related Revenue Requirement**	0.3	1.0	2.1	3.7	5.5

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	2.8	9.3	18.2	31.7	45.8
1b	**Weighted Cost of Capital - Debt (%)****	2.21%	2.30%	2.35%	2.38%	2.39%
1c	**Cost of Capital - Debt ($)** (line 1a x line 1b)	0.1	0.2	0.4	0.8	1.1
1d	**Weighted Cost of Capital - ROE (%)*****	4.74%	4.74%	4.74%	4.74%	4.74%
1e	**Cost of Capital - ROE ($)** (line 1a x line 1d)	0.1	0.4	0.9	1.5	2.2

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed** +	15.5	14.3	15.0	15.0	14.4
1bb	**Opening Balance**	-	5.7	12.8	23.6	39.9
1cc	**In-Service Additions**++	5.8	7.6	11.5	17.8	14.1
1dd	**Depreciation**+++	0.1	0.4	0.8	1.5	2.2
1ee	**Closing Balance** (line 1bb + line 1cc - line 1dd)	5.7	12.8	23.6	39.9	51.8
1ff	**Net Plant Rate Base Amount** +++ ((line 1bb + line 1ee)/2)	2.8	9.3	18.2	31.7	45.8

+ 2027-2031 Capital Attributed obtained from Chart 4.4

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using a mid-year in-service date and a Darlington end of life of December 31, 2052 (Ex. F4-1-1, Chart 1).

** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 4, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 5b, col. (b) x line 5a, col. (c).

[2] No income tax impact is reflected as the OPG's regulated nuclear business is in a forecast regulatory tax loss position.

Scenario 4: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (pg. 17 of WTW report) Nuclear Authorized Compared to 75th percentile, Including Hydro One Shares

Regulated Hydroelectric Capital

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	0.0	0.1	0.3	0.4	0.6
2	**Cost of Capital – Debt**[1]	0.0	0.2	0.4	0.6	0.8
3	**Cost of Capital – ROE**[1]	0.1	0.3	0.7	1.2	1.6
4	**Income Tax**[2]	0.0	0.1	0.2	0.4	0.5
5	**Capital-Related Revenue Requirement**	0.1	0.7	1.6	2.7	3.6

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	1.4	6.6	15.8	26.0	34.1
1b	**Weighted Cost of Capital - Debt (%)****	2.21%	2.30%	2.35%	2.38%	2.39%
1c	**Cost of Capital - Debt ($)** (line 1a x line 1b)	0.0	0.2	0.4	0.6	0.8
1d	**Weighted Cost of Capital - ROE (%)*****	4.74%	4.74%	4.74%	4.74%	4.74%
1e	**Cost of Capital - ROE ($)** (line 1a x line 1d)	0.1	0.3	0.7	1.2	1.6

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed** [+]	10.3	11.0	11.3	10.8	10.8
1bb	**Opening Balance**	-	2.8	10.5	21.1	30.9
1cc	**In-Service Additions**[++]	2.8	7.7	11.0	10.2	7.0
1dd	**Depreciation**[+++]	0.0	0.1	0.3	0.4	0.6
1ee	**Closing Balance** (line 1bb + line 1cc - line 1dd)	2.8	10.5	21.1	30.9	37.3
1ff	**Net Plant Rate Base Amount** [+++] ((line 1bb + line 1ee)/2)	1.4	6.6	15.8	26.0	34.1

+ 2027-2031 Capital Attributed obtained from Chart 4.5

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using a mid-year in-service date and a 60 year average useful life.

** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 4, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 5b, col. (b) x line 5a, col. (c).

[2] Calculated as line 3 x 25%/(1-25%). Capital Cost Allowance impacts not computed as a simplifying assumption.

Scenario 5: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (pg. 18 of WTW report)

Impact of Pension, Benefits & PWU Terms Incumbent Changes Nuclear Authorized Compared to 50th percentile, Excluding Hydro One Shares

Pickering Refurbishment Program

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	0.0	0.0	0.0	0.0	1.3
2	**Cost of Capital – Debt**[1]	0.0	0.0	0.0	0.0	1.2
3	**Cost of Capital – ROE**[1]	0.0	0.0	0.0	0.0	2.3
4	**Income Tax**[2]	-	-	-	-	-
5	**Capital-Related Revenue Requirement**	0.0	0.0	0.0	0.0	4.8

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	0.0	0.0	0.0	0.0	49.0
1b	**Weighted Cost of Capital – Debt (%)****	2.21%	2.30%	2.35%	2.38%	2.39%
1c	**Cost of Capital – Debt ($)** (line 1a x line 1b)	0.0	0.0	0.0	0.0	1.2
1d	**Weighted Cost of Capital – ROE (%)*****	4.74%	4.74%	4.74%	4.74%	4.74%
1e	**Cost of Capital – ROE ($)** (line 1a x line 1d)	0.0	0.0	0.0	0.0	2.3

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed** [+]	45.5	45.6	47.3	47.4	30.4
1bb	**Opening Balance**	0.0	0.0	0.0	0.0	0.0
1cc	**In-Service Additions**[++]	0.0	-	-	-	79.7
1dd	**Depreciation**[+++]	0.0	0.0	0.0	0.0	1.3
1ee	**Closing Balance** (line 1bb + line 1cc – line 1dd)	0.0	0.0	0.0	0.0	78.5
1ff	**Net Plant Rate Base Amount** [+++]	0.0	0.0	0.0	0.0	49.0

+ 2027-2031 Capital Attributed obtained from Chart 5.4

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using an in-service date of May 2031 (Ex. D2-3-8, Table 2) and an end of life date of December 31, 2070 (Ex. F4-1-1, Chart 1). The Net Plant Rate Base Amount has been weighted in 2031 to reflect the in-service timing.

** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 4, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 5b, col. (b) x line 5a, col. (c).

[2] No income tax impact is reflected as the OPG's regulated nuclear business is in a forecast regulatory tax loss position.

Scenario 5: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (pg. 18 of WTW report)

Impact of Pension, Benefits & PWU Terms Incumbent Changes Nuclear Authorized Compared to 50th percentile, Excluding Hydro One Shares

Darlington New Nuclear Program

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	-	-	-	0.0	0.1
2	**Cost of Capital – Debt**[1]	-	-	-	-	-
3	**Cost of Capital – ROE**[1]	-	-	-	0.2	0.8
4	**Income Tax**[2]	-	-	-	-	-
5	**Capital-Related Revenue Requirement**	-	-	-	0.2	0.9

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	-	-	-	1.8	8.7
1b	**Weighted Cost of Capital - Debt (%)****	0.00%	0.00%	0.00%	0.00%	0.00%
1c	**Cost of Capital - Debt ($)** (line 1a x line 1b)	-	-	-	-	-
1d	**Weighted Cost of Capital - ROE (%)*****	9.11%	9.11%	9.11%	9.11%	9.11%
1e	**Cost of Capital - ROE ($)** (line 1a x line 1d)	-	-	-	0.2	0.8

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed** +	2.8	2.8	2.7	0.8	-
1bb	**Opening Balance** ++	-	-	-	-	8.7
1cc	**In-Service Additions**++	-	-	-	8.8	-
1dd	**Depreciation**	-	-	-	0.0	0.1
1ee	**Closing Balance** (line 1bb + line 1cc - line 1dd)	-	-	-	8.7	8.6
1ff	**Net Plant Rate Base Amount** +++	-	-	-	1.8	8.7

+ 2027-2031 Capital Attributed obtained from Chart 5.4

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using an in-service date of October 2030 (Ex. D2-4-8, table 3) and a useful life of 60 years (Ex. F4-1-1, p. 7, line 19). The Net Plant Rate Base Amount has been weighted in 2030 to reflect the in-service timing.

** Calculated as Ex. C1-1-1, Tables 13 to 17 for each respective year, line 3, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 13 to 17 for each respective year, line 5b, col. (b) x col. (c).

[2] No income tax impact is reflected as DNNP LP is in a forecast regulatory tax loss position.

Scenario 5: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (pg. 18 of WTW report)

Impact of Pension, Benefits & PWU Terms Incumbent Changes Nuclear Authorized Compared to 50th percentile, Excluding Hydro One Shares

Remaining Nuclear Capital

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	0.1	0.4	0.7	1.3	2.0
2	**Cost of Capital – Debt**[1]	0.1	0.2	0.4	0.7	1.0
3	**Cost of Capital – ROE**[1]	0.1	0.4	0.8	1.4	2.0
4	**Income Tax**[2]	-	-	-	-	-
5	**Capital-Related Revenue Requirement**	0.3	0.9	1.9	3.4	4.9

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	2.6	8.4	16.5	28.7	41.4
1b	**Weighted Cost of Capital - Debt (%)****	2.21%	2.30%	2.35%	2.38%	2.39%
1c	**Cost of Capital - Debt ($)** (line 1a x line 1b)	0.1	0.2	0.4	0.7	1.0
1d	**Weighted Cost of Capital - ROE (%)*****	4.74%	4.74%	4.74%	4.74%	4.74%
1e	**Cost of Capital - ROE ($)** (line 1a x line 1d)	0.1	0.4	0.8	1.4	2.0

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed** +	14.1	12.9	13.6	13.5	12.9
1bb	**Opening Balance** ++	-	5.1	11.6	21.3	36.1
1cc	**In-Service Additions**++	5.2	6.9	10.4	16.0	12.7
1dd	**Depreciation** +++	0.1	0.4	0.7	1.3	2.0
1ee	**Closing Balance** (line 1bb + line 1cc - line 1dd)	5.1	11.6	21.3	36.1	46.8
1ff	**Net Plant Rate Base Amount** ((line 1bb + line 1ee)/2)	2.6	8.4	16.5	28.7	41.4

+ 2027-2031 Capital Attributed obtained from Chart 5.4

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using a mid-year in-service date and a Darlington end of life of December 31, 2052 (Ex. F4-1-1, Chart 1).

** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 4, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 5b, col. (b) x line 5a, col. (c).

[2] No income tax impact is reflected as the OPG's regulated nuclear business is in a forecast regulatory tax loss position.

Scenario 5: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (pg. 18 of WTW report)

Impact of Pension, Benefits & PWU Terms Incumbent Changes
Nuclear Authorized Compared to 50th percentile, Excluding Hydro One Shares

Regulated Hydroelectric Capital

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	0.0	0.1	0.2	0.4	0.5
2	**Cost of Capital – Debt**[1]	0.0	0.1	0.3	0.6	0.7
3	**Cost of Capital – ROE**[1]	0.1	0.3	0.7	1.1	1.4
4	**Income Tax**[2]	0.0	0.1	0.2	0.4	0.5
5	**Capital-Related Revenue Requirement**	0.1	0.6	1.5	2.4	3.2

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	1.3	5.9	14.1	23.3	30.4
1b	**Weighted Cost of Capital - Debt (%)****	2.21%	2.30%	2.35%	2.38%	2.39%
1c	**Cost of Capital - Debt ($)** (line 1a x line 1b)	0.0	0.1	0.3	0.6	0.7
1d	**Weighted Cost of Capital - ROE (%)*****	4.74%	4.74%	4.74%	4.74%	4.74%
1e	**Cost of Capital - ROE ($)** (line 1a x line 1d)	0.1	0.3	0.7	1.1	1.4

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed**	9.2	9.9	10.1	9.6	9.6
1bb	**Opening Balance** +	-	2.5	9.4	18.9	27.6
1cc	**In-Service Additions**++	2.5	6.9	9.8	9.1	6.2
1dd	**Depreciation** +++	0.0	0.1	0.2	0.4	0.5
1ee	**Closing Balance** (line 1bb + line 1cc - line 1dd)	2.5	9.4	18.9	27.6	33.3
1ff	**Net Plant Rate Base Amount** ((line 1bb + line 1ee)/2)	1.3	5.9	14.1	23.3	30.4

+ 2027-2031 Capital Attributed obtained from Chart 5.5

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using a mid-year in-service date and a 60 year average useful life.

** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 4, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 5b, col. (b) x line 5a, col. (c).

[2] Calculated as line 3 x 25%/(1-25%). Capital Cost Allowance impacts not computed as a simplifying assumption.

Scenario 6: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (pg. 18 of WTW report) Impact of Pension, Benefits & PWU Terms Incumbent Changes Nuclear Authorized Compared to 75th percentile, Excluding Hydro One Shares

Pickering Refurbishment Program

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	0.0	0.0	0.0	0.0	1.2
2	**Cost of Capital – Debt**[1]	0.0	0.0	0.0	0.0	1.1
3	**Cost of Capital – ROE**[1]	0.0	0.0	0.0	0.0	2.1
4	**Income Tax**[2]	-	-	-	-	-
5	**Capital-Related Revenue Requirement**	0.0	0.0	0.0	0.0	4.4

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	0.0	0.0	0.0	0.0	45.1
1b	**Weighted Cost of Capital - Debt (%)****	2.21%	2.30%	2.35%	2.38%	2.39%
1c	**Cost of Capital - Debt ($)** (line 1a x line 1b)	0.0	0.0	0.0	0.0	1.1
1d	**Weighted Cost of Capital - ROE (%)*****	4.74%	4.74%	4.74%	4.74%	4.74%
1e	**Cost of Capital - ROE ($)** (line 1a x line 1d)	0.0	0.0	0.0	0.0	2.1

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed** [+]	42.0	41.9	43.4	43.5	27.6
1bb	**Opening Balance**	0.0	0.0	0.0	0.0	0.0
1cc	**In-Service Additions**[++]	0.0	-	-	-	73.4
1dd	**Depreciation**[+++]	0.0	0.0	0.0	0.0	1.2
1ee	**Closing Balance** (line 1bb + line 1cc - line 1dd)	0.0	0.0	0.0	0.0	72.2
1ff	**Net Plant Rate Base Amount** [+++]	0.0	0.0	0.0	0.0	45.1

+ 2027-2031 Capital Attributed obtained from Chart 6.4

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using an in-service date of May 2031 (Ex. D2-3-8, Table 2) and an end of life date of December 31, 2070 (Ex. F4-1-1, Chart 1). The Net Plant Rate Base Amount has been weighted in 2031 to reflect the in-service timing.

** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 4, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 5b, col. (b) x line 5a, col. (c).

[2] No income tax impact is reflected as the OPG's regulated nuclear business is in a forecast regulatory tax loss position.

Scenario 6: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (pg. 18 of WTW report) Impact of Pension, Benefits & PWU Terms Incumbent Changes Nuclear Authorized Compared to 75th percentile, Excluding Hydro One Shares

Darlington New Nuclear Program

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	-	-	-	0.0	0.1
2	**Cost of Capital – Debt**[1]	-	-	-	-	-
3	**Cost of Capital – ROE**[1]	-	-	-	0.1	0.7
4	**Income Tax**[2]	-	-	-	-	-
5	**Capital-Related Revenue Requirement**	-	-	-	0.2	0.8

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	-	-	-	1.6	7.6
1b	**Weighted Cost of Capital - Debt (%)****	0.00%	0.00%	0.00%	0.00%	0.00%
1c	**Cost of Capital - Debt ($)** (line 1a x line 1b)	-	-	-	-	-
1d	**Weighted Cost of Capital - ROE (%)*****	9.11%	9.11%	9.11%	9.11%	9.11%
1e	**Cost of Capital - ROE ($)** (line 1a x line 1d)	-	-	-	0.1	0.7

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed** +	2.5	2.5	2.4	0.7	-
1bb	**Opening Balance** ++	-	-	-	-	7.7
1cc	**In-Service Additions**++	-	-	-	7.7	-
1dd	**Depreciation**	-	-	-	0.0	0.1
1ee	**Closing Balance** (line 1bb + line 1cc - line 1dd)	-	-	-	7.7	7.6
1ff	**Net Plant Rate Base Amount** +++	-	-	-	1.6	7.6

+ 2027-2031 Capital Attributed obtained from Chart 6.4

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using an in-service date of October 2030 (Ex. D2-4-8, table 3) and a useful life of 60 years (Ex. F4-1-1, p. 7, line 19). The Net Plant Rate Base Amount has been weighted in 2030 to reflect the in-service timing.

** Calculated as Ex. C1-1-1, Tables 13 to 17 for each respective year, line 3, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 13 to 17 for each respective year, line 5b, col. (b) x col. (c).

[2] No income tax impact is reflected as DNNP LP is in a forecast regulatory tax loss position.

Scenario 6: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (pg. 18 of WTW report) Impact of Pension, Benefits & PWU Terms Incumbent Changes Nuclear Authorized Compared to 75th percentile, Excluding Hydro One Shares

Remaining Nuclear Capital

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	0.1	0.3	0.7	1.2	1.9
2	**Cost of Capital – Debt**[1]	0.1	0.2	0.4	0.6	0.9
3	**Cost of Capital – ROE**[1]	0.1	0.4	0.7	1.3	1.9
4	**Income Tax**[2]	-	-	-	-	-
5	**Capital-Related Revenue Requirement**	0.3	0.9	1.8	3.2	4.7

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	2.4	7.9	15.6	27.2	39.2
1b	**Weighted Cost of Capital - Debt (%)****	2.21%	2.30%	2.35%	2.38%	2.39%
1c	**Cost of Capital - Debt ($)** (line 1a x line 1b)	0.1	0.2	0.4	0.6	0.9
1d	**Weighted Cost of Capital - ROE (%)*****	4.74%	4.74%	4.74%	4.74%	4.74%
1e	**Cost of Capital - ROE ($)** (line 1a x line 1d)	0.1	0.4	0.7	1.3	1.9

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed** +	13.3	12.3	12.8	12.8	12.1
1bb	**Opening Balance** ++	-	4.9	11.0	20.2	34.1
1cc	**In-Service Additions**++	5.0	6.5	9.9	15.2	12.0
1dd	**Depreciation** +++	0.1	0.3	0.7	1.2	1.9
1ee	**Closing Balance** (line 1bb + line 1cc - line 1dd)	4.9	11.0	20.2	34.1	44.2
1ff	**Net Plant Rate Base Amount** ((line 1bb + line 1ee)/2)	2.4	7.9	15.6	27.2	39.2

+ 2027-2031 Capital Attributed obtained from Chart 6.4

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using a mid-year in-service date and a Darlington end of life of December 31, 2052 (Ex. F4-1-1, Chart 1).

** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 4, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 5b, col. (b) x line 5a, col. (c).

[2] No income tax impact is reflected as the OPG's regulated nuclear business is in a forecast regulatory tax loss position.

Scenario 6: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (pg. 18 of WTW report) Impact of Pension, Benefits & PWU Terms Incumbent Changes Nuclear Authorized Compared to 75th percentile, Excluding Hydro One Shares

Regulated Hydroelectric Capital

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	0.0	0.1	0.2	0.4	0.5
2	**Cost of Capital – Debt**[1]	0.0	0.1	0.3	0.5	0.7
3	**Cost of Capital – ROE**[1]	0.1	0.3	0.6	1.0	1.4
4	**Income Tax**[2]	0.0	0.1	0.2	0.3	0.5
5	**Capital-Related Revenue Requirement**	0.1	0.6	1.4	2.3	3.0

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	1.2	5.6	13.3	21.9	28.7
1b	**Weighted Cost of Capital - Debt (%)****	2.21%	2.30%	2.35%	2.38%	2.39%
1c	**Cost of Capital - Debt ($)** (line 1a x line 1b)	0.0	0.1	0.3	0.5	0.7
1d	**Weighted Cost of Capital - ROE (%)*****	4.74%	4.74%	4.74%	4.74%	4.74%
1e	**Cost of Capital - ROE ($)** (line 1a x line 1d)	0.1	0.3	0.6	1.0	1.4

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed**	8.7	9.3	9.5	9.1	9.0
1bb	**Opening Balance** +	-	2.4	8.8	17.8	26.0
1cc	**In-Service Additions**++	2.4	6.5	9.2	8.6	5.8
1dd	**Depreciation** +++	0.0	0.1	0.2	0.4	0.5
1ee	**Closing Balance** (line 1bb + line 1cc - line 1dd)	2.4	8.8	17.8	26.0	31.3
1ff	**Net Plant Rate Base Amount** ((line 1bb + line 1ee)/2)	1.2	5.6	13.3	21.9	28.7

+ 2027-2031 Capital Attributed obtained from Chart 6.5

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using a mid-year in-service date and a 60 year average useful life.

** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 4, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 5b, col. (b) x line 5a, col. (c).

[2] Calculated as line 3 x 25%/(1-25%). Capital Cost Allowance impacts not computed as a simplifying assumption.

Scenario 7: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (based on Chart 1 in Ex. L-F4-SUP-023) Excluding Terms and ETEs
Nuclear Authorized Compared to 50th percentile, Excluding Hydro One Shares

Pickering Refurbishment Program

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	0.0	0.0	0.0	0.0	1.4
2	**Cost of Capital – Debt**[1]	0.0	0.0	0.0	0.0	1.3
3	**Cost of Capital – ROE**[1]	0.0	0.0	0.0	0.0	2.5
4	**Income Tax**[2]	-	-	-	-	-
5	**Capital-Related Revenue Requirement**	0.0	0.0	0.0	0.0	5.1

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	0.0	0.0	0.0	0.0	52.5
1b	**Weighted Cost of Capital - Debt (%)****	2.21%	2.30%	2.35%	2.38%	2.39%
1c	**Cost of Capital - Debt ($)** (line 1a x line 1b)	0.0	0.0	0.0	0.0	1.3
1d	**Weighted Cost of Capital - ROE (%)*****	4.74%	4.74%	4.74%	4.74%	4.74%
1e	**Cost of Capital - ROE ($)** (line 1a x line 1d)	0.0	0.0	0.0	0.0	2.5

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed** +	48.5	48.8	50.8	51.0	32.6
1bb	**Opening Balance**	0.0	0.0	0.0	0.0	0.0
1cc	**In-Service Additions**++	0.0	-	-	-	85.4
1dd	**Depreciation**+++	0.0	0.0	0.0	0.0	1.4
1ee	**Closing Balance** (line 1bb + line 1cc - line 1dd)	0.0	0.0	0.0	0.0	84.0
1ff	**Net Plant Rate Base Amount** +++	0.0	0.0	0.0	0.0	52.5

+ 2027-2031 Capital Attributed obtained from Chart 7.4

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using an in-service date of May 2031 (Ex. D2-3-8, Table 2) and an end of life date of December 31, 2070 (Ex. F4-1-1, Chart 1). The Net Plant Rate Base Amount has been weighted in 2031 to reflect the in-service timing.

** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 4, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 5b, col. (b) x line 5a, col. (c).

[2] No income tax impact is reflected as the OPG's regulated nuclear business is in a forecast regulatory tax loss position.

Scenario 7: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (based on Chart 1 in Ex. L-F4-SUP-023) Excluding Terms and ETEs
Nuclear Authorized Compared to 50th percentile, Excluding Hydro One Shares

Darlington New Nuclear Program

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	-	-	-	0.0	0.2
2	**Cost of Capital – Debt**[1]	-	-	-	-	-
3	**Cost of Capital – ROE**[1]	-	-	-	0.2	0.9
4	**Income Tax**[2]	-	-	-	-	-
5	**Capital-Related Revenue Requirement**	-	-	-	0.2	1.0

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	-	-	-	1.6	7.6
1b	**Weighted Cost of Capital - Debt (%)****	-	-	-	2.0	9.4
1c	**Cost of Capital - Debt ($)** (line 1a x line 1b)	0.00% -	0.00% -	0.00% -	0.00% -	0.00% -
1d	**Weighted Cost of Capital - ROE (%)*****					
1e	**Cost of Capital - ROE ($)** (line 1a x line 1d)	9.11% -	9.11% -	9.11% -	9.11% 0.2	9.11% 0.9

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed** +	2.9	3.0	3.0	0.9	-
1bb	**Opening Balance** ++	-	-	-	-	9.5
1cc	**In-Service Additions**++	-	-	-	9.5	-
1dd	**Depreciation**	-	-	-	0.0	0.2
1ee	**Closing Balance** (line 1bb + line 1cc - line 1dd)	-	-	-	9.5	9.3
1ff	**Net Plant Rate Base Amount** +++	-	-	-	2.0	9.4

+ 2027-2031 Capital Attributed obtained from Chart 7.4

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using an in-service date of October 2030 (Ex. D2-4-8, table 3) and a useful life of 60 years (Ex. F4-1-1, p. 7, line 19). The Net Plant Rate Base Amount has been weighted in 2030 to reflect the in-service timing.

** Calculated as Ex. C1-1-1, Tables 13 to 17 for each respective year, line 3, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 13 to 17 for each respective year, line 5b, col. (b) x col. (c).

[2] No income tax impact is reflected as DNNP LP is in a forecast regulatory tax loss position.

Scenario 7: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (based on Chart 1 in Ex. L-F4-SUP-023) Excluding Terms and ETEs
Nuclear Authorized Compared to 50th percentile, Excluding Hydro One Shares

Remaining Nuclear Capital

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	0.1	0.4	0.7	1.3	2.0
2	**Cost of Capital – Debt**[1]	0.1	0.2	0.4	0.7	1.0
3	**Cost of Capital – ROE**[1]	0.1	0.4	0.8	1.4	2.0
4	**Income Tax**[2]	-	-	-	-	-
5	**Capital-Related Revenue Requirement**	0.3	1.0	1.9	3.4	5.0

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	2.6	8.5	16.7	29.0	41.9
1b	**Weighted Cost of Capital - Debt (%)****	2.21%	2.30%	2.35%	2.38%	2.39%
1c	**Cost of Capital - Debt ($)** (line 1a x line 1b)	0.1	0.2	0.4	0.7	1.0
1d	**Weighted Cost of Capital - ROE (%)*****	4.74%	4.74%	4.74%	4.74%	4.74%
1e	**Cost of Capital - ROE ($)** (line 1a x line 1d)	0.1	0.4	0.8	1.4	2.0

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed** +	14.3	13.0	13.7	13.7	13.2
1bb	**Opening Balance** ++	-	5.2	11.8	21.6	36.4
1cc	**In-Service Additions**++	5.3	6.9	10.5	16.2	12.9
1dd	**Depreciation** +++	0.1	0.4	0.7	1.3	2.0
1ee	**Closing Balance** (line 1bb + line 1cc - line 1dd)	5.2	11.8	21.6	36.4	47.3
1ff	**Net Plant Rate Base Amount** ((line 1bb + line 1ee)/2)	2.6	8.5	16.7	29.0	41.9

+ 2027-2031 Capital Attributed obtained from Chart 7.4

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using a mid-year in-service date and a Darlington end of life of December 31, 2052 (Ex. F4-1-1, Chart 1).

** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 4, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 5b, col. (b) x line 5a, col. (c).

[2] No income tax impact is reflected as the OPG's regulated nuclear business is in a forecast regulatory tax loss position.

Scenario 7: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (based on Chart 1 in Ex. L-F4-SUP-023) Excluding Terms and ETEs
Nuclear Authorized Compared to 50th percentile, Excluding Hydro One Shares

Regulated Hydroelectric Capital

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	0.0	0.1	0.2	0.4	0.5
2	**Cost of Capital – Debt**[1]	0.0	0.1	0.3	0.6	0.8
3	**Cost of Capital – ROE**[1]	0.1	0.3	0.7	1.1	1.5
4	**Income Tax**[2]	0.0	0.1	0.2	0.4	0.5
5	**Capital-Related Revenue Requirement**	0.1	0.6	1.5	2.5	3.3

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	1.3	6.2	14.7	24.2	31.8
1b	**Weighted Cost of Capital - Debt (%)****	2.21%	2.30%	2.35%	2.38%	2.39%
1c	**Cost of Capital - Debt ($)** (line 1a x line 1b)	0.0	0.1	0.3	0.6	0.8
1d	**Weighted Cost of Capital - ROE (%)*****	4.74%	4.74%	4.74%	4.74%	4.74%
1e	**Cost of Capital - ROE ($)** (line 1a x line 1d)	0.1	0.3	0.7	1.1	1.5

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed**	9.6	10.3	10.6	10.1	10.1
1bb	**Opening Balance** +	-	2.6	9.7	19.7	28.8
1cc	**In-Service Additions**++	2.7	7.2	10.2	9.5	6.5
1dd	**Depreciation** +++	0.0	0.1	0.2	0.4	0.5
1ee	**Closing Balance** (line 1bb + line 1cc - line 1dd)	2.6	9.7	19.7	28.8	34.7
1ff	**Net Plant Rate Base Amount** ((line 1bb + line 1ee)/2)	1.3	6.2	14.7	24.2	31.8

+ 2027-2031 Capital Attributed obtained from Chart 7.5

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using a mid-year in-service date and a 60 year average useful life.

** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 4, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 5b, col. (b) x line 5a, col. (c).

[2] Calculated as line 3 x 25%/(1-25%). Capital Cost Allowance impacts not computed as a simplifying assumption.

Scenario 8: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (based on Chart 2 in Ex. L-F4-SUP-023) Excluding Terms and ETEs
Nuclear Authorized Compared to 75th percentile, Excluding Hydro One Shares

Pickering Refurbishment Program

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	0.0	0.0	0.0	0.0	1.3
2	**Cost of Capital – Debt**[1]	0.0	0.0	0.0	0.0	1.2
3	**Cost of Capital – ROE**[1]	0.0	0.0	0.0	0.0	2.3
4	**Income Tax**[2]	-	-	-	-	-
5	**Capital-Related Revenue Requirement**	0.0	0.0	0.0	0.0	4.7

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	0.0	0.0	0.0	0.0	48.5
1b	**Weighted Cost of Capital - Debt (%)****	2.21%	2.30%	2.35%	2.38%	2.39%
1c	**Cost of Capital - Debt ($)** (line 1a x line 1b)	0.0	0.0	0.0	0.0	1.2
1d	**Weighted Cost of Capital - ROE (%)*****	4.74%	4.74%	4.74%	4.74%	4.74%
1e	**Cost of Capital - ROE ($)** (line 1a x line 1d)	0.0	0.0	0.0	0.0	2.3

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed** +	44.9	45.1	46.8	46.9	29.8
1bb	**Opening Balance**	0.0	0.0	0.0	0.0	0.0
1cc	**In-Service Additions**++	0.0	-	-	-	78.8
1dd	**Depreciation**+++	0.0	0.0	0.0	0.0	1.3
1ee	**Closing Balance** (line 1bb + line 1cc - line 1dd)	0.0	0.0	0.0	0.0	77.5
1ff	**Net Plant Rate Base Amount** +++	0.0	0.0	0.0	0.0	48.5

+ 2027-2031 Capital Attributed obtained from Chart 8.4

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using an in-service date of May 2031 (Ex. D2-3-8, Table 2) and an end of life date of December 31, 2070 (Ex. F4-1-1, Chart 1). The Net Plant Rate Base Amount has been weighted in 2031 to reflect the in-service timing.

** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 4, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 5b, col. (b) x line 5a, col. (c).

[2] No income tax impact is reflected as the OPG's regulated nuclear business is in a forecast regulatory tax loss position.

Scenario 8: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (based on Chart 2 in Ex. L-F4-SUP-023) Excluding Terms and ETEs
Nuclear Authorized Compared to 75th percentile, Excluding Hydro One Shares

Darlington New Nuclear Program

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	-	-	-	0.0	0.1
2	**Cost of Capital – Debt**[1]	-	-	-	-	-
3	**Cost of Capital – ROE**[1]	-	-	-	0.2	0.8
4	**Income Tax**[2]	-	-	-	-	-
5	**Capital-Related Revenue Requirement**	-	-	-	0.2	0.9

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	-	-	-	1.8	8.4
1b	**Weighted Cost of Capital - Debt (%)****	0.00%	0.00%	0.00%	0.00%	0.00%
1c	**Cost of Capital - Debt ($)** (line 1a x line 1b)	-	-	-	-	-
1d	**Weighted Cost of Capital - ROE (%)*****	9.11%	9.11%	9.11%	9.11%	9.11%
1e	**Cost of Capital - ROE ($)** (line 1a x line 1d)	-	-	-	0.2	0.8

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed** +	2.6	2.7	2.7	0.8	-
1bb	**Opening Balance** ++	-	-	-	-	8.4
1cc	**In-Service Additions**++	-	-	-	8.5	-
1dd	**Depreciation**	-	-	-	0.0	0.1
1ee	**Closing Balance** (line 1bb + line 1cc - line 1dd)	-	-	-	8.4	8.3
1ff	**Net Plant Rate Base Amount** +++	-	-	-	1.8	8.4

+ 2027-2031 Capital Attributed obtained from Chart 8.4

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using an in-service date of October 2030 (Ex. D2-4-8, table 3) and a useful life of 60 years (Ex. F4-1-1, p. 7, line 19). The Net Plant Rate Base Amount has been weighted in 2030 to reflect the in-service timing.

** Calculated as Ex. C1-1-1, Tables 13 to 17 for each respective year, line 3, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 13 to 17 for each respective year, line 5b, col. (b) x col. (c).

[2] No income tax impact is reflected as DNNP LP is in a forecast regulatory tax loss position.

Scenario 8: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (based on Chart 2 in Ex. L-F4-SUP-023) Excluding Terms and ETEs
Nuclear Authorized Compared to 75th percentile, Excluding Hydro One Shares

Remaining Nuclear Capital

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	0.1	0.3	0.7	1.3	1.9
2	**Cost of Capital – Debt**[1]	0.1	0.2	0.4	0.7	0.9
3	**Cost of Capital – ROE**[1]	0.1	0.4	0.7	1.3	1.9
4	**Income Tax**[2]	-	-	-	-	-
5	**Capital-Related Revenue Requirement**	0.3	0.9	1.8	3.2	4.7

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	2.5	8.0	15.8	27.5	39.6
1b	**Weighted Cost of Capital - Debt (%)****	2.21%	2.30%	2.35%	2.38%	2.39%
1c	**Cost of Capital - Debt ($)** (line 1a x line 1b)	0.1	0.2	0.4	0.7	0.9
1d	**Weighted Cost of Capital - ROE (%)*****	4.74%	4.74%	4.74%	4.74%	4.74%
1e	**Cost of Capital - ROE ($)** (line 1a x line 1d)	0.1	0.4	0.7	1.3	1.9

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed** +	13.5	12.4	12.9	12.9	12.4
1bb	**Opening Balance** ++	-	4.9	11.2	20.4	34.5
1cc	**In-Service Additions**++	5.0	6.6	10.0	15.3	12.1
1dd	**Depreciation** +++	0.1	0.3	0.7	1.3	1.9
1ee	**Closing Balance** (line 1bb + line 1cc - line 1dd)	4.9	11.2	20.4	34.5	44.7
1ff	**Net Plant Rate Base Amount** ((line 1bb + line 1ee)/2)	2.5	8.0	15.8	27.5	39.6

+ 2027-2031 Capital Attributed obtained from Chart 8.4

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using a mid-year in-service date and a Darlington end of life of December 31, 2052 (Ex. F4-1-1, Chart 1).

** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 4, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 5b, col. (b) x line 5a, col. (c).

[2] No income tax impact is reflected as the OPG's regulated nuclear business is in a forecast regulatory tax loss position.

Scenario 8: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (based on Chart 2 in Ex. L-F4-SUP-023) Excluding Terms and ETEs
Nuclear Authorized Compared to 75th percentile, Excluding Hydro One Shares

Regulated Hydroelectric Capital

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	0.0	0.1	0.2	0.4	0.5
2	**Cost of Capital – Debt**[1]	0.0	0.1	0.3	0.5	0.7
3	**Cost of Capital – ROE**[1]	0.1	0.3	0.7	1.1	1.4
4	**Income Tax**[2]	0.0	0.1	0.2	0.4	0.5
5	**Capital-Related Revenue Requirement**	0.1	0.6	1.4	2.4	3.1

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	1.2	5.8	13.9	22.9	29.9
1b	**Weighted Cost of Capital - Debt (%)****	2.21%	2.30%	2.35%	2.38%	2.39%
1c	**Cost of Capital - Debt ($)** (line 1a x line 1b)	0.0	0.1	0.3	0.5	0.7
1d	**Weighted Cost of Capital - ROE (%)*****	4.74%	4.74%	4.74%	4.74%	4.74%
1e	**Cost of Capital - ROE ($)** (line 1a x line 1d)	0.1	0.3	0.7	1.1	1.4

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed**	9.1	9.7	9.9	9.5	9.4
1bb	**Opening Balance** +	-	2.5	9.2	18.6	27.1
1cc	**In-Service Additions**++	2.5	6.8	9.6	8.9	6.1
1dd	**Depreciation** +++	0.0	0.1	0.2	0.4	0.5
1ee	**Closing Balance** (line 1bb + line 1cc - line 1dd)	2.5	9.2	18.6	27.1	32.7
1ff	**Net Plant Rate Base Amount** ((line 1bb + line 1ee)/2)	1.2	5.8	13.9	22.9	29.9

+ 2027-2031 Capital Attributed obtained from Chart 8.5

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using a mid-year in-service date and a 60 year average useful life.

** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 4, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 5b, col. (b) x line 5a, col. (c).

[2] Calculated as line 3 x 25%/(1-25%). Capital Cost Allowance impacts not computed as a simplifying assumption.

Scenario 9: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (based on Chart 8 in Ex. L-F4-CCC-091) Excluding Terms and ETEs
Nuclear Authorized Compared to 50th percentile, Including Hydro One Shares

Pickering Refurbishment Program

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	0.0	0.0	0.0	0.0	1.6
2	**Cost of Capital – Debt**[1]	0.0	0.0	0.0	0.0	1.4
3	**Cost of Capital – ROE**[1]	0.0	0.0	0.0	0.0	2.8
4	**Income Tax**[2]	-	-	-	-	-
5	**Capital-Related Revenue Requirement**	0.0	0.0	0.0	0.0	5.8

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	0.0	0.0	0.0	0.0	59.7
1b	**Weighted Cost of Capital - Debt (%)****	2.21%	2.30%	2.35%	2.38%	2.39%
1c	**Cost of Capital - Debt ($)** (line 1a x line 1b)	0.0	0.0	0.0	0.0	1.4
1d	**Weighted Cost of Capital - ROE (%)*****	4.74%	4.74%	4.74%	4.74%	4.74%
1e	**Cost of Capital - ROE ($)** (line 1a x line 1d)	0.0	0.0	0.0	0.0	2.8

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed** [+]	55.0	55.6	58.0	58.3	37.6
1bb	**Opening Balance**	0.0	0.0	0.0	0.0	0.0
1cc	**In-Service Additions**[++]	0.0	-	-	-	97.1
1dd	**Depreciation**[+++]	0.0	0.0	0.0	0.0	1.6
1ee	**Closing Balance** (line 1bb + line 1cc - line 1dd)	0.0	0.0	0.0	0.0	95.6
1ff	**Net Plant Rate Base Amount** [+++]	0.0	0.0	0.0	0.0	59.7

+ 2027-2031 Capital Attributed obtained from Chart 9.4

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using an in-service date of May 2031 (Ex. D2-3-8, Table 2) and an end of life date of December 31, 2070 (Ex. F4-1-1, Chart 1). The Net Plant Rate Base Amount has been weighted in 2031 to reflect the in-service timing.

** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 4, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 5b, col. (b) x line 5a, col. (c).

[2] No income tax impact is reflected as the OPG's regulated nuclear business is in a forecast regulatory tax loss position.

Scenario 9: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (based on Chart 8 in Ex. L-F4-CCC-091) Excluding Terms and ETEs
Nuclear Authorized Compared to 50th percentile, Including Hydro One Shares

Darlington New Nuclear Program

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	-	-	-	0.0	0.2
2	**Cost of Capital – Debt**[1]	-	-	-	-	-
3	**Cost of Capital – ROE**[1]	-	-	-	0.2	1.0
4	**Income Tax**[2]	-	-	-	-	-
5	**Capital-Related Revenue Requirement**	-	-	-	0.3	1.2

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	-	-	-	2.3	11.0
1b	**Weighted Cost of Capital - Debt (%)****	0.00%	0.00%	0.00%	0.00%	0.00%
1c	**Cost of Capital - Debt ($)** (line 1a x line 1b)	-	-	-	-	-
1d	**Weighted Cost of Capital - ROE (%)*****	9.11%	9.11%	9.11%	9.11%	9.11%
1e	**Cost of Capital - ROE ($)** (line 1a x line 1d)	-	-	-	0.2	1.0

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed** +	3.4	3.6	3.6	1.1	-
1bb	**Opening Balance** ++	-	-	-	-	11.1
1cc	**In-Service Additions**++	-	-	-	11.2	-
1dd	**Depreciation**	-	-	-	0.0	0.2
1ee	**Closing Balance** (line 1bb + line 1cc - line 1dd)	-	-	-	11.1	10.9
1ff	**Net Plant Rate Base Amount** +++	-	-	-	2.3	11.0

+ 2027-2031 Capital Attributed obtained from Chart 9.4

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using an in-service date of October 2030 (Ex. D2-4-8, table 3) and a useful life of 60 years (Ex. F4-1-1, p. 7, line 19). The Net Plant Rate Base Amount has been weighted in 2030 to reflect the in-service timing.

** Calculated as Ex. C1-1-1, Tables 13 to 17 for each respective year, line 3, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 13 to 17 for each respective year, line 5b, col. (b) x col. (c).

[2] No income tax impact is reflected as DNNP LP is in a forecast regulatory tax loss position.

Scenario 9: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (based on Chart 8 in Ex. L-F4-CCC-091) Excluding Terms and ETEs
Nuclear Authorized Compared to 50th percentile, Including Hydro One Shares

Remaining Nuclear Capital

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	0.1	0.4	0.8	1.5	2.2
2	**Cost of Capital – Debt**[1]	0.1	0.2	0.4	0.8	1.1
3	**Cost of Capital – ROE**[1]	0.1	0.4	0.9	1.5	2.2
4	**Income Tax**[2]	-	-	-	-	-
5	**Capital-Related Revenue Requirement**	0.3	1.0	2.1	3.7	5.5

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	2.9	9.3	18.3	31.9	46.1
1b	**Weighted Cost of Capital - Debt (%)****	2.21%	2.30%	2.35%	2.38%	2.39%
1c	**Cost of Capital - Debt ($)** (line 1a x line 1b)	0.1	0.2	0.4	0.8	1.1
1d	**Weighted Cost of Capital - ROE (%)*****	4.74%	4.74%	4.74%	4.74%	4.74%
1e	**Cost of Capital - ROE ($)** (line 1a x line 1d)	0.1	0.4	0.9	1.5	2.2

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed** +	15.7	14.3	15.0	15.1	14.6
1bb	**Opening Balance** ++	-	5.7	12.9	23.7	40.1
1cc	**In-Service Additions**++	5.8	7.6	11.6	17.8	14.2
1dd	**Depreciation** +++	0.1	0.4	0.8	1.5	2.2
1ee	**Closing Balance** (line 1bb + line 1cc - line 1dd)	5.7	12.9	23.7	40.1	52.1
1ff	**Net Plant Rate Base Amount** ((line 1bb + line 1ee)/2)	2.9	9.3	18.3	31.9	46.1

+ 2027-2031 Capital Attributed obtained from Chart 9.4

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using a mid-year in-service date and a Darlington end of life of December 31, 2052 (Ex. F4-1-1, Chart 1).

** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 4, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 5b, col. (b) x line 5a, col. (c).

[2] No income tax impact is reflected as the OPG's regulated nuclear business is in a forecast regulatory tax loss position.

Scenario 9: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (based on Chart 8 in Ex. L-F4-CCC-091) Excluding Terms and ETEs
Nuclear Authorized Compared to 50th percentile, Including Hydro One Shares

Regulated Hydroelectric Capital

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	0.0	0.1	0.3	0.5	0.6
2	**Cost of Capital – Debt**[1]	0.0	0.2	0.4	0.6	0.8
3	**Cost of Capital – ROE**[1]	0.1	0.3	0.8	1.3	1.7
4	**Income Tax**[2]	0.0	0.1	0.3	0.4	0.6
5	**Capital-Related Revenue Requirement**	0.1	0.7	1.7	2.8	3.7

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	1.5	6.9	16.4	26.9	35.3
1b	**Weighted Cost of Capital - Debt (%)****	2.21%	2.30%	2.35%	2.38%	2.39%
1c	**Cost of Capital - Debt ($)** (line 1a x line 1b)	0.0	0.2	0.4	0.6	0.8
1d	**Weighted Cost of Capital - ROE (%)*****	4.74%	4.74%	4.74%	4.74%	4.74%
1e	**Cost of Capital - ROE ($)** (line 1a x line 1d)	0.1	0.3	0.8	1.3	1.7

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed**	10.7	11.4	11.7	11.2	11.3
1bb	**Opening Balance** +	-	2.9	10.8	21.9	32.0
1cc	**In-Service Additions**++	2.9	8.0	11.3	10.6	7.3
1dd	**Depreciation** +++	0.0	0.1	0.3	0.5	0.6
1ee	**Closing Balance** (line 1bb + line 1cc - line 1dd)	2.9	10.8	21.9	32.0	38.7
1ff	**Net Plant Rate Base Amount** ((line 1bb + line 1ee)/2)	1.5	6.9	16.4	26.9	35.3

+ 2027-2031 Capital Attributed obtained from Chart 9.5

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using a mid-year in-service date and a 60 year average useful life.

** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 4, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 5b, col. (b) x line 5a, col. (c).

[2] Calculated as line 3 x 25%/(1-25%). Capital Cost Allowance impacts not computed as a simplifying assumption.

Scenario 10: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (based on Chart 9 in Ex. L-F4-CCC-091) Excluding Terms and ETEs
Nuclear Authorized Compared to 75th percentile, Including Hydro One Shares

Pickering Refurbishment Program

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	0.0	0.0	0.0	0.0	1.5
2	**Cost of Capital – Debt**[1]	0.0	0.0	0.0	0.0	1.3
3	**Cost of Capital – ROE**[1]	0.0	0.0	0.0	0.0	2.6
4	**Income Tax**[2]	-	-	-	-	-
5	**Capital-Related Revenue Requirement**	0.0	0.0	0.0	0.0	5.4

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	0.0	0.0	0.0	0.0	55.7
1b	**Weighted Cost of Capital - Debt (%)****	2.21%	2.30%	2.35%	2.38%	2.39%
1c	**Cost of Capital - Debt ($)** (line 1a x line 1b)	0.0	0.0	0.0	0.0	1.3
1d	**Weighted Cost of Capital - ROE (%)*****	4.74%	4.74%	4.74%	4.74%	4.74%
1e	**Cost of Capital - ROE ($)** (line 1a x line 1d)	0.0	0.0	0.0	0.0	2.6

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed** [+]	51.4	51.8	54.0	54.3	34.8
1bb	**Opening Balance**	0.0	0.0	0.0	0.0	0.0
1cc	**In-Service Additions**[++]	0.0	-	-	-	90.6
1dd	**Depreciation**[+++]	0.0	0.0	0.0	0.0	1.5
1ee	**Closing Balance** (line 1bb + line 1cc - line 1dd)	0.0	0.0	0.0	0.0	89.1
1ff	**Net Plant Rate Base Amount** [+++]	0.0	0.0	0.0	0.0	55.7

+ 2027-2031 Capital Attributed obtained from Chart 10.4

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using an in-service date of May 2031 (Ex. D2-3-8, Table 2) and an end of life date of December 31, 2070 (Ex. F4-1-1, Chart 1). The Net Plant Rate Base Amount has been weighted in 2031 to reflect the in-service timing.

** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 4, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 5b, col. (b) x line 5a, col. (c).

[2] No income tax impact is reflected as the OPG's regulated nuclear business is in a forecast regulatory tax loss position.

Scenario 10: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (based on Chart 9 in Ex. L-F4-CCC-091) Excluding Terms and ETEs
Nuclear Authorized Compared to 75th percentile, Including Hydro One Shares

Darlington New Nuclear Program

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	-	-	-	0.0	0.2
2	**Cost of Capital – Debt**[1]	-	-	-	-	-
3	**Cost of Capital – ROE**[1]	-	-	-	0.2	0.9
4	**Income Tax**[2]	-	-	-	-	-
5	**Capital-Related Revenue Requirement**	-	-	-	0.2	1.1

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	-	-	-	2.1	10.0
1b	**Weighted Cost of Capital - Debt (%)****	0.00%	0.00%	0.00%	0.00%	0.00%
1c	**Cost of Capital - Debt ($)** (line 1a x line 1b)	-	-	-	-	-
1d	**Weighted Cost of Capital - ROE (%)*****	9.11%	9.11%	9.11%	9.11%	9.11%
1e	**Cost of Capital - ROE ($)** (line 1a x line 1d)	-	-	-	0.2	0.9

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed** +	3.0	3.2	3.2	1.0	-
1bb	**Opening Balance** ++	-	-	-	-	10.1
1cc	**In-Service Additions**++	-	-	-	10.1	-
1dd	**Depreciation**	-	-	-	0.0	0.2
1ee	**Closing Balance** (line 1bb + line 1cc - line 1dd)	-	-	-	10.1	9.9
1ff	**Net Plant Rate Base Amount** +++	-	-	-	2.1	10.0

+ 2027-2031 Capital Attributed obtained from Chart 10.4

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using an in-service date of October 2030 (Ex. D2-4-8, table 3) and a useful life of 60 years (Ex. F4-1-1, p. 7, line 19). The Net Plant Rate Base Amount has been weighted in 2030 to reflect the in-service timing.

** Calculated as Ex. C1-1-1, Tables 13 to 17 for each respective year, line 3, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 13 to 17 for each respective year, line 5b, col. (b) x col. (c).

[2] No income tax impact is reflected as DNNP LP is in a forecast regulatory tax loss position.

Scenario 10: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (based on Chart 9 in Ex. L-F4-CCC-091) Excluding Terms and ETEs
Nuclear Authorized Compared to 75th percentile, Including Hydro One Shares

Remaining Nuclear Capital

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	0.1	0.4	0.8	1.4	2.1
2	**Cost of Capital – Debt**[1]	0.1	0.2	0.4	0.7	1.0
3	**Cost of Capital – ROE**[1]	0.1	0.4	0.8	1.4	2.1
4	**Income Tax**[2]	-	-	-	-	-
5	**Capital-Related Revenue Requirement**	0.3	1.0	2.0	3.5	5.2

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	2.7	8.9	17.4	30.3	43.8
1b	**Weighted Cost of Capital - Debt (%)****	2.21%	2.30%	2.35%	2.38%	2.39%
1c	**Cost of Capital - Debt ($)** (line 1a x line 1b)	0.1	0.2	0.4	0.7	1.0
1d	**Weighted Cost of Capital - ROE (%)*****	4.74%	4.74%	4.74%	4.74%	4.74%
1e	**Cost of Capital - ROE ($)** (line 1a x line 1d)	0.1	0.4	0.8	1.4	2.1

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed** +	14.9	13.6	14.3	14.3	13.8
1bb	**Opening Balance** ++	-	5.4	12.3	22.6	38.1
1cc	**In-Service Additions**++	5.6	7.3	11.0	16.9	13.5
1dd	**Depreciation** +++	0.1	0.4	0.8	1.4	2.1
1ee	**Closing Balance** (line 1bb + line 1cc - line 1dd)	5.4	12.3	22.6	38.1	49.5
1ff	**Net Plant Rate Base Amount** ((line 1bb + line 1ee)/2)	2.7	8.9	17.4	30.3	43.8

+ 2027-2031 Capital Attributed obtained from Chart 10.4

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using a mid-year in-service date and a Darlington end of life of December 31, 2052 (Ex. F4-1-1, Chart 1).

** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 4, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 5b, col. (b) x line 5a, col. (c).

[2] No income tax impact is reflected as the OPG's regulated nuclear business is in a forecast regulatory tax loss position.

Scenario 10: Calculation of Estimated Total Remuneration Dollar Difference of Revenue Requirement Impact on Capital In-Service (based on Chart 9 in Ex. L-F4-CCC-091) Excluding Terms and ETEs
Nuclear Authorized Compared to 75th percentile, Including Hydro One Shares

Regulated Hydroelectric Capital

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1	**Depreciation & Amortization**	0.0	0.1	0.3	0.4	0.6
2	**Cost of Capital – Debt**[1]	0.0	0.1	0.4	0.6	0.8
3	**Cost of Capital – ROE**[1]	0.1	0.3	0.7	1.2	1.6
4	**Income Tax**[2]	0.0	0.1	0.2	0.4	0.5
5	**Capital-Related Revenue Requirement**	0.1	0.7	1.6	2.7	3.5

[1] Cost of Capital calculations are as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1a	**Net Plant Rate Base***	1.4	6.5	15.5	25.6	33.5
1b	**Weighted Cost of Capital - Debt (%)****	2.21%	2.30%	2.35%	2.38%	2.39%
1c	**Cost of Capital - Debt ($)** (line 1a x line 1b)	0.0	0.1	0.4	0.6	0.8
1d	**Weighted Cost of Capital - ROE (%)*****	4.74%	4.74%	4.74%	4.74%	4.74%
1e	**Cost of Capital - ROE ($)** (line 1a x line 1d)	0.1	0.3	0.7	1.2	1.6

*Net Plant Rate Base calculated as follows:

Line No.	Description	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
1aa	**Capital Attributed**	10.1	10.8	11.1	10.6	10.6
1bb	**Opening Balance** +	-	2.8	10.3	20.8	30.3
1cc	**In-Service Additions**++	2.8	7.6	10.8	10.0	6.9
1dd	**Depreciation** +++	0.0	0.1	0.3	0.4	0.6
1ee	**Closing Balance** (line 1bb + line 1cc - line 1dd)	2.8	10.3	20.8	30.3	36.7
1ff	**Net Plant Rate Base Amount** ((line 1bb + line 1ee)/2)	1.4	6.5	15.5	25.6	33.5

+ 2027-2031 Capital Attributed obtained from Chart 10.5

++ A given year's in-service additions calculated as the sum of the portions of the line 1aa amounts obtained by multiplying the line 1aa amounts by the percentage of each year's respective capital expenditures forecast to be placed in-service in such given year per Chart 22.

+++ Depreciation calculated using a mid-year in-service date and a 60 year average useful life.

** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 4, col. (b) x col. (c).

*** Calculated as Ex. C1-1-1, Tables 1 to 5 for each respective year, line 5b, col. (b) x line 5a, col. (c).

[2] Calculated as line 3 x 25%/(1-25%). Capital Cost Allowance impacts not computed as a simplifying assumption.

SEC Interrogatory #199

Interrogatory

Reference:
F4-2-1, p. 3, 8

Preamble:

OPG proposes that the announced extension of the accelerated investment incentive program ("AIIP") during the bridge year and IR term be captured through variance accounts including the Income & Other Taxes Variance Account. If the impacts were included in the revenue requirement sought for approval, please provide the impact on the income tax expense for each year.

Question(s):

Please provide all calculations.

Response

Refer to Ex. L-F4-CCC-084.

SEC Interrogatory #200

Interrogatory

Reference:
F4-2-1

Question(s):

Please provide an estimate of the weighted average capital cost allowance ("CCA") rate for each of, a) nuclear operations capital, b) support services capital, and c) regulated hydroelectric capital, each year between 2022 and 2031, excluding the impact of the AIIP.

Response

The chart below provides the estimated weighted average CCA rates for OPG's nuclear facilities and OPG's regulated hydroelectric facilities for each year between 2022 and 2031, inclusive of the associated Support Services capital expenditures, based on the information provided at Ex. F4-2-1, Tables 11-20 (regulated hydroelectric) and Ex. F4-2-1 Tables 23-32 (nuclear). The rates are calculated by dividing total CCA for the year by the average of undepreciated capital cost ("UCC") at the beginning of that year and the UCC at the end of that year. OPG does not track this information separately for Support Services. The weighted average CCA rates have been calculated with reference to actual information for the 2022-2024 period and forecast information for the 2025-2031 period based on the pre-filed evidence.

As the existing accelerated incentive investment property ("AIIP") program in effect since November 2018 is not elective and automatically applies when computing CCA under the Income Tax Act and Regulations (Canada), consistent with the Application, its impact is excluded from the calculation of the weighted average CCA rate after the scheduled phase-out at the end of 2027.

For clarity, this analysis does not include the effects of the reinstatement of the AIIP (referred to as RIIP) that was enacted, for qualifying property acquired on or after January 1, 2025, by the *Budget 2025 Implementation Act, No. 1* in March 2026. As discussed at Ex. F4-2-1, p. 8, lines 20-24, the Application does not reflect these provisions, which were proposed but not legislated at the time.

OPG Weighted Average Capital Cost Allowance Rates

	OPG Nuclear Facilities	Regulated Hydroelectric Facilities
2022	10.2%	7.9%
2023	10.3%	10.7%
2024	9.9%	6.9%
2025	9.7%	7.4%
2026	10.2%	9.9%
2027	11.2%	12.5%
2028	9.8%	9.1%
2029	9.5%	8.5%
2030	9.0%	7.9%
2031	8.9%	7.5%

Board Staff Interrogatory #192

Interrogatory

Reference:
Ref 1: Exhibit F4 / Tab 3 / Schedule 1 / Attachment 1, p. 1
Ref 2: Exhibit F2 / Tab 1 / Schedule 1 / Table 1a
Ref 3: Exhibit F2 / Tab 1 / Schedule 1 / Table 1b

Preamble:

Reference 1 shows nuclear facilities, DNNP LP, and hydroelectric regulated facilities FTEs for 2020-2031, broken down according to direct vs allocated.

Question(s):

a) For each of nuclear facilities, DNNP LP, and hydroelectric regulated facilities, please show how many of the allocated FTEs are treated as capital vs. OM&A for 2026-2031.

Response

a) The forecast Allocated FTEs by Capital and OM&A for 2026-2031 for each of OPG's nuclear facilities, DNNP LP, and OPG's regulated hydroelectric facilities are shown in Charts 1-3 below, respectively.

Chart 1 – OPG Nuclear Facilities Allocated FTEs
OM&A vs Capital for 2026-2031

Nuclear Facilities (excluding DNNP LP)	2026 Plan	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
Nuclear - Allocated	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**
OM&A	1,254.6	1,076.6	1,071.7	1,072.3	1,081.0	1,140.2
Capital	288.9	420.2	406.1	408.9	399.3	327.8

Chart 2 – DNNP LP Allocated FTEs
OM&A vs Capital for 2026-2031

	2026 Plan	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
DNNP LP Allocated	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**
OM&A	59.3	74.4	82.5	76.9	76.7	71.2
Capital	40.5	42.8	38.4	22.6	13.8	10.2

Chart 3 – OPG Regulated Hydroelectric Facilities Allocated FTEs
OM&A vs Capital for 2026-2031

	2026 Plan	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
Hydroelectric Facilities Allocated	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**
OM&A	164.0	153.6	150.8	146.1	146.6	151.5
Capital	29.9	36.8	37.6	38.1	37.3	33.9

Board Staff Interrogatory #219

Interrogatory

Reference:
Ref 1: Exhibit F4 / Tab 2 / Schedule 1 / p. 5

Preamble:

OPG states that for 2020-2026, regulatory income taxes for the prescribed facilities are presented on a combined nuclear and hydroelectric basis, with total taxes before scientific research and experimental development (SR&ED) investment technology credits (ITCs) allocated based on each business' regulatory taxable income, while 2027-2031 are presented on a standalone basis, i.e. hydroelectric and nuclear are separate.

Question(s):

a) Please provide a bridge from the 2026 combined prescribed-facilities tax calculation to the separate 2027 standalone hydroelectric and nuclear tax calculations, showing separately:
   i. Changes arising from the move away from the combined calculation
   ii. Changes in tax loss utilization
   iii. Changes in SR&ED ITC attribution
   iv. Any changes in reference amounts used for tax-related deferral and variance accounts.

Response

a) i. and ii.

Attachment 1 provides a breakout of the forecast standalone regulatory taxable income for the year 2026 presented at Ex. F4-2-1, Table 3, col. (g) between OPG's prescribed nuclear and regulated hydroelectric facilities in a manner comparable to the respective standalone regulatory taxable income calculations for years 2027-2031 presented at Ex. F4-2-1, Tables 3b and 3d.

In addition, Chart 1 below shows a breakdown of the forecast regulatory income taxes for the two regulated businesses for the year 2026, comprised of regulatory income taxes before SR&ED ITCs and the SR&ED ITCs. In determining regulatory income taxes before SR&ED ITCs for each of the businesses in the historical and bridge periods, such regulatory income taxes for the prescribed facilities as a whole

(for 2026, at Ex. F4-2-1, Table 3, line 28 plus line 29) are allocated to each of the two business proportionately to their regulatory income before taxes, unless there is a negative regulatory taxable income for one of the businesses, in which case the negative regulatory taxable income of the applicable business reduces or eliminates the regulatory income tax expense of the other business.

iii. There are no differences in SR&ED ITC attribution as between the combined and stand-alone regulatory income tax calculations referenced. SR&ED ITCs are predominantly directly attributed to each business based on the underlying expenditures giving rise to the ITCs.

iv. The appliable reference amounts for all of OPG's deferral and variance accounts in effect during 2026 are determined in accordance with the EB-2020-0290 Payment Amounts Order and are not subject to change.

Chart 1 – Breakdown of OPG's 2026 Forecast Regulatory Income Taxes ($M)

	2026		
	Regulated		
	Nuclear	Hydroelectric	Total
Income Taxes Before SR&ED ITC	(20.3)	0.0	(20.3)
SR&ED ITC	(16.6)	(3.3)	(19.9)
Total Regulatory Income Taxes	(36.9)	(3.3)	(40.2)

Numbers may not add due to rounding

Filed: 2026-04-22
EB-2025-0297
Exhibit L
F4-Staff-219
Attachment 1
Table 1

Table 1
Calculation of Regulatory Taxable Income for OPG Prescribed Nuclear and Regulated Hydroelectric Facilities ($M)
Year Ending December 31, 2026

Line No.	Particulars	Nuclear Facilities	Regulated Hydroelectric	Total OPG Regulated
		(a)	(b)	(c)
	Determination of Regulatory Taxable Income			
1	**Regulatory Earnings Before Tax**	179.0	411.0	590.0
	Additions for Regulatory Tax Purposes:			
2	**Depreciation and Amortization**	553.8	173.1	726.9
3	**Nuclear Waste Management Expenses**	30.1	0.0	30.1
4	**Receipts from Nuclear Segregated Funds**	534.2	0.0	534.2
5	**Pension and OPEB Accrual**	182.5	42.1	224.6
6	**Regulatory Asset Amortization - Bruce Lease Net Revenues Variance Account**	21.8	0.0	21.8
7	**Regulatory Asset Amortization - Pension & OPEB Cash Versus Accrual Differential Deferral Account**	174.8	28.3	203.1
8	**Regulatory Liability Amortization - Income and Other Taxes Variance Account**	(3.7)	(4.6)	(8.3)
9	**Adjustment Related to Financing Cost for Nuclear Liabilities**	(7.5)	0.0	(7.5)
10	**Restricted Net Interest and Financing Expenses**	0.0	0.0	0.0
11	**Disallowance of Heavy Water Storage and Drum Handling Facility ("D2O") Project Expenditures**	0.0	0.0	0.0
12	**Taxable SR&ED Investment Tax Credits**	16.6	3.3	19.9
13	**Nuclear fuel Expense Half Charge Adjustment**	0.6	0.0	0.6
14	**Other**	102.6	6.6	109.2
15	**Total Additions**	1,605.7	248.9	1,854.6
	Deductions for Regulatory Tax Purposes:			
16	**CCA**	988.0	383.5	1,371.5
17	**Cash Expenditures for Nuclear Waste Management & Decommissioning**	653.5	0.0	653.5
18	**Contributions to Nuclear Segregated Funds**	39.2	0.0	39.2
19	**Pension Plan Contributions**	100.4	19.5	119.9
20	**OPEB/SPP Payments**	114.1	22.1	136.2
21	**Reversal of Return on Rate Base Recorded in Deferral and Variance Accounts**	42.9	46.2	89.2
22	**Deductible SR&ED Qualifying Expenditures**	81.4	25.0	106.4
23	**Other**	9.7	0.0	9.8
24	**Total Deductions**	2,029.2	496.4	2,525.6
25	**Regulatory Taxable Income / (Loss)**	(244.5)	163.5	(81.0)

Board Staff Interrogatory #220

Interrogatory

Reference:
Ref 1: Exhibit F4 / Tab 2 / Schedule 1 / p. 1
Ref 2: Exhibit H1 / Tab 1 / Schedule 1 / p. 15
Ref 3: Exhibit F4 / Tab 2 / Schedule 1 / Table 3b

Preamble:

OPG states that hydroelectric income taxes are embedded in the hydroelectric capital-related revenue requirement and C-factor because those taxes are predominantly (although not entirely) capital-related.

In Reference 2, OPG states that as of the effective date of the payment amounts order, the Income and Other Taxes Variance Account (OPG) reference amounts for hydro will be the corresponding 2027-2031 annual income tax provisions in Exhibit F4-02-01 Table 3b of the evidence. The Income and Other Taxes Variance Account shows that for hydroelectric, the account has a 2024 balance of ($17.3 million), with ($9.2 million) already approved for 2025-2026 amortization, and ($8.1 million) proposed for disposition in this application over 36 months.

Question(s):

a) Please provide, for each year of 2027-2031:
   i. The hydroelectric income tax amount embedded in the capital-related revenue requirement/C- factor
   ii. The portion OPG considers capital-related versus non-capital-related
   iii. An explanation of how OPG avoids duplication between recovery through the C-factor and additions to the Income and Other Taxes Variance Account (OPG) and any related hydro capital variance accounts.

b) For the Income and Other Taxes Variance Account – Hydroelectric,
   i. Please provide a reconciliation from the 2024 audited balance of ($17.3 million) to the ($8.1 million) proposed for disposition in this application, identifying each component by vintage, driver and amount.
   ii. Reconcile which amounts were previously approved for amortization in EB-2023-0336 and explain the derivation of the ($9.2 million) shown in Reference 2.
   iii. Reconcile the annual ($2.7 million) amortization amounts in 2027-2029 to the tax model line “Regulatory Liability Amortization – Income and Other Taxes Variance Account” in Reference 3.

iv. Confirm whether the account balance already includes the associated income tax impacts, i.e. gross-up, for each component.

Response

a)

i. The hydroelectric income tax amounts embedded in the forecast capital-related revenue requirement ("CRRR") underpinning the C-factor calculation are found at Ex. I1-2-1, Table 2, line 4 and Ex. F4-2-1, Table 3b, line 23.

ii. For purposes of determining the forecast CRRR underpinning the C-factor, as referred to at Ex. A1-3-2, p. 18, Note *, OPG has reflected the full amount of forecast regulatory income tax expense for the regulated hydroelectric facilities, calculated at Ex. F4-2-1, Table 3b, line 23, as capital related. This simplified approach recognizes that the large majority of such regulatory income tax expense is capital related, including in relation to regulatory earnings before tax that are tied to the return on equity amounts and most of the adjustments to regulatory earnings before tax. For example, between the addition for depreciation and amortization expense at Ex. F4-2-1, Table 3b, line 2 and the deduction for capital cost allowance at such line 10, these adjustments comprise over 90% of the net additions/deductions across such lines 9 and 16. For purposes of calculating the actual CRRR to determine entries into the Global Hydroelectric Capital Variance Account ("GHCVA"), OPG will only capture income tax impacts that are specific to capital related items.

iii. The interaction between the GHCVA, the Capacity Refurbishment Variance Account and various income tax-related accounts is discussed at Ex. A1-3-2, pp. 23-26. The process described in that evidence would ensure no duplication of recovery across these accounts. There would be no duplication possible between the forecast CRRR underpinning the C-factor and the income-tax related accounts because such accounts would only record differences relative to the forecasts underpinning the payment amounts, not the forecasts themselves.

b)

i. The requested continuity can be found at Ex. H1-2-1, Table 1, line 5, cols. (a) to (d).

ii. The ($9.2M) is the sum of, and is therefore fully addressed, by the OEB-approved amortization for 2025 of ($4.6M) and for 2026 of ($4.6M) from EB-2023-0336 Decision and Order, Appendix A, Table 1, line 5, cols. (h) and (i), respectively.

iii. Refer to Ex. F4-2-1, Table 3b, line 5, cols. (a) to (c), where the annual amounts for 2027 to 2029 are equal to the corresponding annual amortization amounts of ($2.7M) found at Ex. H1-2-1, Table 1, line 5.

iv. The underlying balance of the Income and Other Taxes Variance Account (OPG), and therefore the associated annual amortization amounts at Ex. F4-2-1, Table 3b, line 5, do contain certain income tax impacts, namely as part of Entry (i) into the account as shown at Ex. H1-1-1, Table 6. Specifically, these impacts stem from lines 3 and 4 of that table by virtue of the "gross-up" calculation contained in such line 5. These impacts total approximately ($1.5M), translating into ($0.5M) per year as part of the proposed ($2.7M) annual amortization amount for the 2027-2029 period.[1] OPG does not propose to adjust the approvals sought in the Application on account of the resulting duplication of ($0.5M) per year to the benefit of ratepayers, having acknowledged such potential outcome at Ex. F4-2-1, p. 15, footnote 12. At that reference, the Application explains that, given the modest balances sought for disposition in respect of the account, a simplified approach was taken to base the associated adjustment to regulatory earnings before tax on the full account balance, rather than isolating the portion that was not already "grossed-up". As that evidence also notes, going forward, OPG will ensure that all components of the account consistently reflect the income tax impacts, eliminating the need for this adjustment to earnings before tax altogether. The Applicants intend to apply this approach to entries into the Income and Other Taxes Variance Account (OPG) and the proposed Income and Other Taxes Variance Account (DNNP), effective January 1, 2027.

[1] The ($1.5M) amount is calculated as (Ex. H1-1-1, Table 6: line 3, col. (c) plus line 4, col. (f)) multiplied by (1 / (1-25%) minus 1).

Board Staff Interrogatory #221

Interrogatory

Reference:
Ref 1: Exhibit F4 / Tab 3 / Schedule 1 / p. 5

Preamble:

At Reference 1, OPG states that OPG was able to reach agreements with both the Power Workers' Union (PWU) and the Society of United Professionals (the Society) on more efficient downsizing provisions for a partial or total Pickering closure during the first rounds of bargaining after EB-2020-0290.

Reference 1 also states that the new provisions cover a potential downsizing related to the completion of the Darlington Refurbishment Program.

Question(s):

a) Please clarify whether there are any new workforce planning provisions in the agreements with the PWU or the Society related to the Pickering Refurbishment Program since 2024.

Response

a) OPG interprets "workforce planning provisions" as any provisions or agreements that impact the ability to plan for workforce changes such as redeployment or downsizing. There have been no new provisions negotiated with the PWU or Society since 2024 related to organizational downsizing. However, during negotiations for the Society renewal collective agreement term from January 1, 2026 through December 31, 2028, OPG and the Society jointly agreed to renew the provisions agreed to in previous rounds of negotiations.

With respect to other provisions related to staff redeployments and transitions, there are two notable provisions that were either negotiated or successfully awarded through interest arbitration. As discussed in Ex. F4-3-1, p. 6, 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. In September 2024, the Society challenged OPG's practical application of this agreement through the grievance process, ending in an arbitration hearing. In February 2025, OPG received a favourable arbitration award allowing OPG to maintain the right to redeploy staff. This permits OPG to make staffing changes and transitions related to the conclusion of the DRP and advancement of the PRP using the aforementioned provisions.

Refer to Ex. L-F4-SEC-194 for additional information on the cost savings related to the above provisions.

Board Staff Interrogatory #222

Interrogatory

Reference:
Ref 1: Exhibit F4 / Tab 3 / Schedule 1 / pp. 5-6
Ref 2: Exhibit F4 / Tab 3 / Schedule 1 / Attachment 1

Preamble:

At Reference 1, the Applicants state that OPG also succeeded in maintaining the ability to use the Power Workers' Union (PWU)-represented term-based employees (Term Employees) and the Society of United Professionals (the Society)-represented extended temporary employees (ETEs). The Applicants state that this was a critical strategy in mitigating the impacts of a Pickering shutdown.

Reference 2 provides FTE, Compensation and Benefit information for OPG nuclear, OPG hydroelectric, DNNP LP. The Applicants' workforce classifications include Management, Society, PWU, Term/ETE/PECO Temporary, and Electrical Power Systems Construction Association (EPSCA).

Question(s):

a) Please show the number of Society ETE and PWU Term employees within each of the workforce classifications at Reference 2.

b) If Society ETE and PWU Term employees do not account for all employees in the Term/ETE/PECO Temporary classification, please explain.

c) Please explain how EPSCA employees' compensation is determined, given that those employees do not belong to the unions or management.

Response

a) Refer to Ex. L-F4-CCMBC-005, Attachment 1 for breakdown of PWU Term and Society ETE/PECO Temporary employees at Reference 2.

b) Society ETE and PWU Term employees account for all employees within the Term/ETE/PECO Temporary classification.

For clarity, the terms “ETE” and “ETE/PECO” are used interchangeably in OPG’s pre-filed evidence 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.

c) Electrical Power Systems Construction Association ("EPSCA") category of employees are unionized. The EPSCA is the employer association which negotiates and administers collective agreements directly with Building Trades Unions ("BTU") on behalf of employers in the electrical construction sector (including OPG). The BTU have exclusive labour jurisdiction to represented individuals in the province’s skilled trades labour workforce. When these employees are directly hired by OPG, they continue to be represented by the BTU and are compensated in accordance with the collective agreement(s) negotiated between the EPSCA and the BTU.

Board Staff Interrogatory #223

Interrogatory

Reference:
Ref 1: Exhibit F4 / Tab 3 / Schedule 1 / p. 7

Preamble:

At Reference 1, OPG states that it 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."

Question(s):

a) Please compare the cost effectiveness of contracting out professional services to the use of temporary and term employees.

Response

a) Given the general nature of the question, this response provides a broad perspective on the use of contracted professional services and temporary employees at OPG. For clarity, Term Employees are the exclusive labour jurisdiction of the PWU and cannot be used in place of the professional services that may be contracted out to perform work that falls under the labour jurisdiction of the Society.

   The purpose of the provision referenced is to preserve and secure the ongoing ability to determine the appropriate resourcing approach in circumstances involving temporary or peak workload requirements. Without this flexibility, peak or specialized, intermittent work needs would have to be met through regular or temporary employees, which may be unsuitable to the work as well as entail incremental recruitment, onboarding, supervision, potential severance and other employee-related costs. Refer to Ex. L-F4-SEC-194 for additional information on the cost differential of using contracted resources relative to Regular employees.

   For example, peak volumes in the recruitment function are commonly addressed through temporary staffing, given labour market availability of the labour and the transferability of the skillset. On the other hand, OPG may engage contracted professional services for specialized engineering work performed on a periodic basis, such as a Periodic Safety Review for a nuclear station that is conducted

every ten years, or periodic Fire Hazard Analysis assessments required every five years under CSA N293-17. In these cases, specialized expertise and tools are required and are more efficiently sourced through a qualified vendor, with OPG maintaining appropriate oversight.

Having the ability to contract out professional services where necessary provides greater flexibility to meet business needs and ensures the appropriate resource type can be secured, contributing to the overall cost effectiveness of OPG's operations.

Board Staff Interrogatory #224

Interrogatory

Reference:
Ref 1: Exhibit F4 / Tab 3 / Schedule 1 / p. 8
Ref 2: Exhibit F4 / Tab 3 / Schedule 1 / Attachment 1

Preamble:

At Reference 1, OPG states that at the end of 2024, it employed 10,332 Regular, Term and Extended Temporary Employees.

Reference 2 provides FTE totals by business. The 2024 value is 9,073 (p. 1 line 18) for OPG's nuclear business and 1,415.6 (p. 3 line 12) for OPG's hydroelectric business. The sum of these values is 10,488.6.

Question(s):

a) Please reconcile the difference between the value at Reference 1 and the sum using Reference 2 calculated by OEB staff in the preamble.

Response

a) The two References are not equivalent and cannot be reconciled.

Reference 1 includes total OPG headcount for Regular, Term and Extended Temporary Employees for both regulated and non-regulated businesses and represents the number of employees planned. It does not include other temporary resources such as EPSCA resources.

Reference 2 refers to Full Time Equivalent ("FTE") for Nuclear and regulated Hydroelectric businesses, including all temporary resources. Refer to Ex. L-F4-AMPCO-127 for a detailed definition of FTE.

Board Staff Interrogatory #225

Interrogatory

Reference:
Ref 1: Exhibit F4 / Tab 3 / Schedule 1 / p. 11
Ref 2: Exhibit F4 / Tab 3 / Schedule 1 / pp. 15-17

Preamble:

At Reference 1, OPG states that 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.

Reference 2 describes OPG's redeployment strategy. The strategy begins with redeploying 1,300 employees from the Pickering station to other areas of OPG Nuclear.

Question(s):

a) Please describe and explain how OPG Nuclear's redeployment strategy will affect the FTE counts of departments within Pickering Refurbishment, the Darlington generating station, and the DNNP. Please include an explanation of FTE trends in each of the described departments in the 2027-2031 period.

b) Does OPG allow for a period of overlap for the purpose of knowledge transfer between retiring employees and their replacements? How are overlaps of this kind reflected in the 2026-2031 compensation costs and FTE counts?

Response

a) Nuclear redeployments – for example a change in an employee's job, location, or reporting organization – are being grouped and timed in such a way as to ensure that as certain work programs cease at Pickering and the station moves into the Pickering Refurbishment Program ("PRP") and as the Darlington Refurbishment Program ("DRP") reaches completion, employees are redeployed according to business need. It is expected that approximately 1,500 employees will be redeployed, including approximately 1,300 employees from Pickering Operations and approximately 200 employees from the DRP. Of these, about 1,200 employees are planned to move to the PRP, approximately 150 to Darlington Operations, approximately 30 to the DNNP, and the remainder to other parts of the organization. In addition to redeployments, approximately 200 employees previously supporting the DRP are expected to be reassigned to different project work.

Exhibit F2-1-1, Table 2a, line 6 (as corrected in Ex. L-F2-Staff-199) shows Nuclear Facilities OM&A FTEs (i.e., Pickering and Darlington) decline by 1,163 FTEs between 2026 and 2027 as the employees are redeployed per above, followed by a generally stable trend between 2027 and 2030 and then increasing by 615 in 2031 with the expected Pickering Unit 5 return to service and the redeployment of employees back to Pickering.

Exhibit F2-1-1, Table 2a, line 24 shows an increase of 1,209 PRP FTEs between 2026 and 2027, as the employees are redeployed per above, followed by a generally stable trend between 2027 and 2030, before declining by 724 in 2031 as Pickering Unit 5 returns to service and the majority of the employees are redeployed back to operate Pickering.

Exhibit F2-1-1, Table 2b, line 6 and line 1 show DNNP Facilities FTEs increasing for OM&A and declining for Capital over the 2027-2031 period, as the DNNP Unit 1 approaches and reaches completion in 2030.

Exhibit F2-1-1, Table 2a, line 18 shows a decline of approximately 620 FTEs for the DRP between 2025 and 2026 and then a further decline to none over the 2027-2031 period, due to the completion of the DRP.

Note that although the two are directionally aligned, the redeployment values in the first part of this response represent the number of Regular employees, whereas the FTE values in the second part of this response represent charged labour hours divided by scheduled hours, including Non-Regular FTEs.

b) OPG does not prohibit overlaps between a retiring employee and their replacement for purposes of knowledge transfer, where it is necessary. These instances are managed operationally. Overlaps between retiring employees and their replacements are not reflected in the 2026-2031 forecast compensation costs and FTE counts.

Board Staff Interrogatory #226

Interrogatory

Reference:
Ref 1: Exhibit F4 / Tab 3 / Schedule 1 / p. 14

Preamble:

At Reference 1, the Applicants state that 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.

Question(s):

a) Are project managers' compensation costs capitalized to projects, expensed to OM&A, or a mix of both? Please explain.

Response

a) The compensation costs of project managers assigned to capital projects are capitalized, as such amounts represent expenditures directly attributable to such projects. The compensation costs of project managers not assigned to capital or nuclear liability (i.e., nuclear provision) projects are expensed to OM&A costs.

Board Staff Interrogatory #227

Interrogatory

Reference:
Ref 1: Exhibit F4 / Tab 3 / Schedule 1 / p. 18

Preamble:

At Reference 1, OPG states that the increases in compensation 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.

Question(s):

a) Please provide the annual wage escalation assumptions for 2025-2031 for the Power Workers' Union (PWU), the Society of United Professionals (the Society), and management.

Response

a) The annual wage escalation assumptions for 2025-2031 as reflected in OPG's 2025-2031 Business Plan and the Application are provided in Chart 1 below. The escalation is effective January 1 of a given year, unless otherwise noted.

Chart 1 – Annual Wage Escalation by Employee Group (2025-2031)

	2025	2026	2027	2028	2029	2030	2031
PWU (Effective April 1)	3.75%	2.50%					
Society	3.25%						
Management	3.82%						

Board Staff Interrogatory #228

Interrogatory

Reference:
Ref 1: Exhibit F4 / Tab 3 / Schedule 1 / p. 20

Preamble:

At Reference 1, OPG states that as of 2022, Nuclear base OM&A 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.

Question(s):

a) Please provide the planned vs. actual Nuclear Base OM&A FTE numbers and compensation costs in 2022 and 2023.

Response

a) The EB-2020-0290 plan and actual Nuclear Base OM&A FTEs and compensation costs for 2022 and 2023 are provided in Chart 1 below. In response to Ex. L-F4-SUP-017, 2025 actuals are included.

Chart 1 –
2022, 2023 and 2025 Nuclear Base OM&A FTEs and Compensation Costs

	EB-2020-0290	EB-2025-0297	EB-2020-0290	EB-2025-0297	EB-2025-0297
Nuclear Facilities (excluding DNNP LP) Base OM&A	**2022 Plan**	**2022 Actual**	**2023 Plan**	**2023 Actual**	**2025 Actual**
Direct FTEs	4,984.2	4,764.6	4,865.0	4,909.5	4,352.7
Allocated FTEs	1,104.5	1,127.0	1,048.2	1,294.0	1,187.6
Total FTEs	**6,088.7**	**5,891.6**	**5,913.2**	**6,203.6**	**5,540.3**
Total Compensation Costs $M	1,179.5	1,202.4	1,175.5	1,391.8	1,294.2

Board Staff Interrogatory #229

Interrogatory

Reference:
Ref 1: Exhibit F4 / Tab 3 / Schedule 1 / p. 21
Ref 2: Exhibit F4 / Tab 3 / Schedule 1 / Figure 4b

Preamble:

At Reference 1, OPG states that the FTEs for the regulated hydroelectric facilities were 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.

Reference 2 shows that there are no Term employees or Extended Temporary Employees (ETE) in the regulated hydroelectric business.

Question(s):

a) Please confirm that none of the increase in regulated hydroelectric FTE count in 2024 and 2025 is due to the hiring of Term employees or ETEs. If not confirmed, please reconcile with Reference 2.

b) Did OPG consider using Term employees or ETEs to support its hydroelectric major capital projects? Please explain.

c) Does OPG expect its FTE complement to decline following the completion of its major capital projects? Please explain.

Response

a) Confirmed.

b) As described in Ex. F4-3-1, p. 17, lines 12-14, in accordance with collective agreement provisions, Term and ETE employees can only be hired instead of regular staff in the Nuclear business, in circumstances where employees are likely to be laid off as a result of the planned shutdown of Pickering. Instead, as described in Ex. F1-2-1, p. 4, lines 16-21, the hydroelectric regional operations groups make use of incremental short-term labour resources that are primarily temporary staff with a start and end date, where appropriate. These resources are deployed to

address peak workload demands, seasonal operational requirements, and to provide coverage for short-duration staff absences or vacancies.

c) The expected future size of OPG's regulated FTE complements at the completion of its major capital projects presented in this Application, which extend beyond the IR term, is not currently known and will depend on a range of factors including future business needs and project requirements.

Board Staff Interrogatory #230

Interrogatory

Reference:
Ref 1: Exhibit F4 / Tab 3 / Schedule 1 / pp. 27-28

Preamble:

The text in the four figures at Reference 1 is not readable.

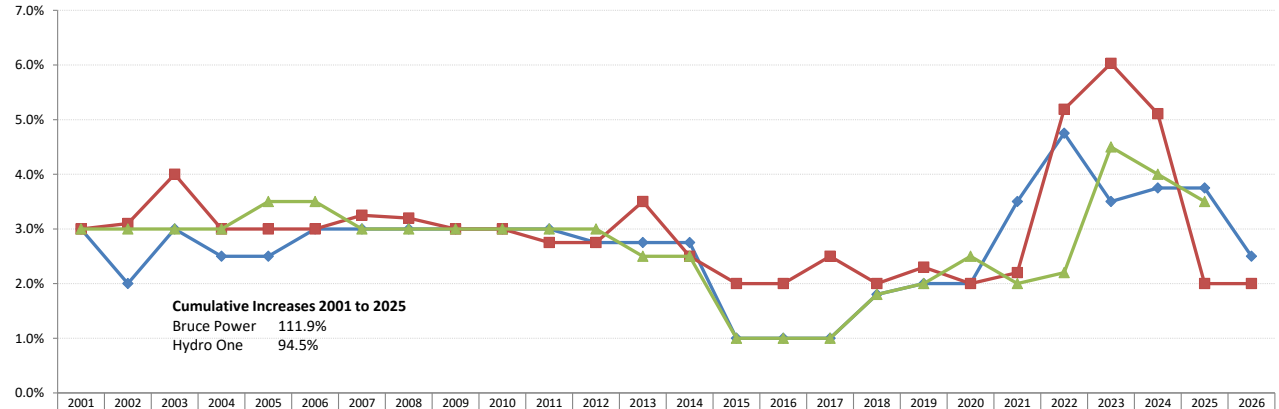
Question(s):

a) Please provide searchable, high-resolution versions of the figures at Reference 1

Response

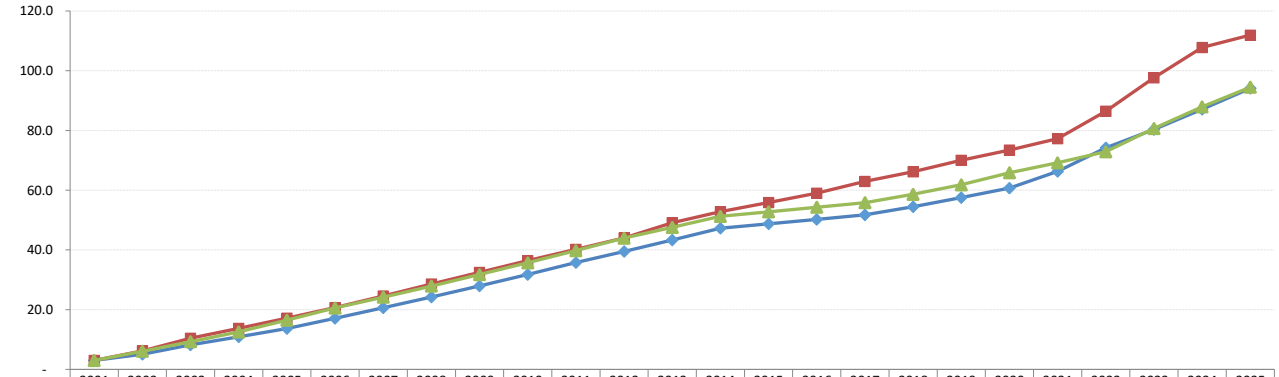
a) A searchable version of Figures 5 to 8 at Reference 1 is provided in Attachment 1.

Figure 5 - PWU Annual Salary Increases



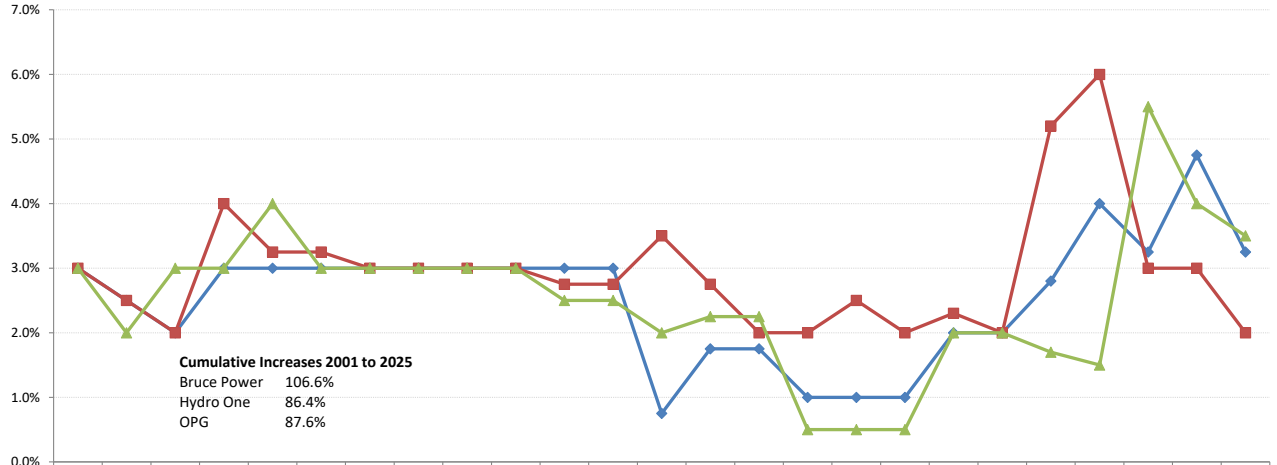
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
OPG	3.0%	2.0%	3.0%	2.5%	2.5%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	2.75%	2.75%	2.75%	1.0%	1.0%	1.0%	1.8%	2.0%	2.0%	3.50%	4.75%	3.50%	3.75%	3.75%	2.50%
Bruce Power	3.0%	3.1%	4.0%	3.0%	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



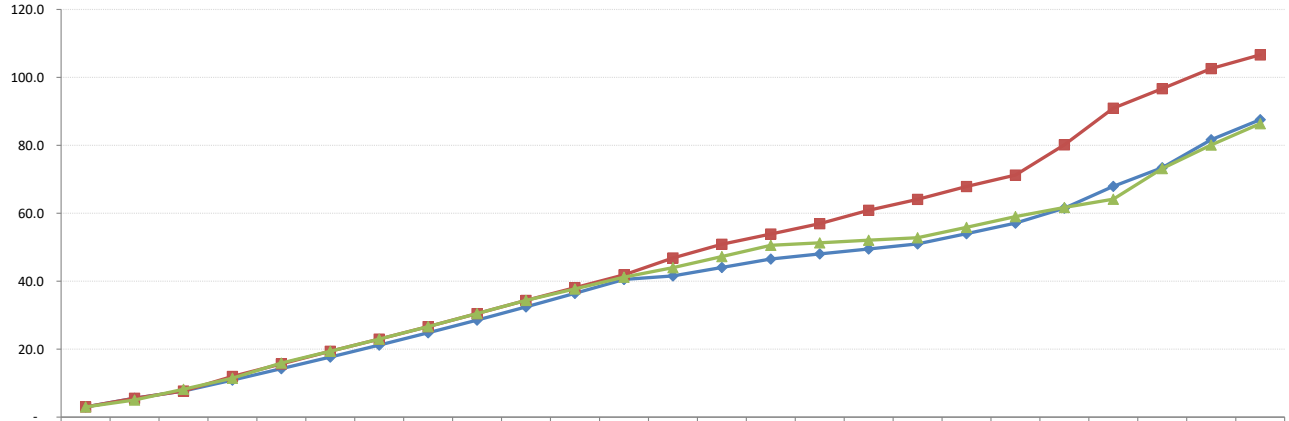
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
OPG	3.0	5.1	8.2	10.9	13.7	17.1	20.6	24.2	28.0	31.8	35.8	39.5	43.3	47.3	48.7	50.2	51.7	54.5	57.5	60.7	66.3	74.2	80.3	87.1	94.1
Bruce Power	3.0	6.2	10.4	13.8	17.2	20.7	24.6	28.6	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

Board Staff Interrogatory #231

Interrogatory

Reference:
Ref 1: Exhibit F4 / Tab 3 / Schedule 1 / pp. 30-31
Ref 2: Exhibit F4 / Tab 3 / Schedule 1 / Attachment 3

Preamble:

At Reference 1, OPG states that the Stakeholder Return Program 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. Since 2021, OPG has used a financial results model for deriving the amounts based on a percentage applied to forecast corporate earnings before tax.

Reference 2 is a Total Compensation Benchmarking Study conducted by Willis Towers Watson.

Question(s):

a) Please describe any changes to the Stakeholder Performance Program since EB-2020-0290.

b) Please confirm that the Stakeholder Performance Program costs are equivalent to the “Target Incentive” included under Total Direct Compensation in Reference 2.

Response

a) There have been no changes to the Stakeholder Return Program (“SRP”) since EB-2020-0290.

b) In the Total Compensation Benchmarking Study conducted by Willis Towers Watson, the “Target Incentive” included under Total Direct Compensation in Reference 2 includes the SRP at target, and other incentive plans as applicable.

Board Staff Interrogatory #232

Interrogatory

Reference:
Ref 1: Exhibit F4 / Tab 3 / Schedule 1 / p. 33

Preamble:

At Reference 1, OPG states that its registered pension plan has Available Actuarial Surplus. In March 2025, OPG's Board of Directors approved a reduction in OPG's contributions to match the level of employee contributions over the 2025-2027 period, effective March 2025.

Reference 1 further states that the Available Actuarial Surplus is forecasted to continue throughout the IR term and that OPG's 2025-2031 Business Plan and the Application assume that OPG's employer contributions will continue to match employee contributions over this period.

Question(s):

a) By how much did OPG reduce its employer contribution in 2025 and 2026, relative to what would be required if the pension plan had not been in a funding surplus?

b) Please provide the estimated compensation cost savings in 2027-2031 arising from the assumption that employer contributions will continue to be lower than what would be required if the pension plan was not in a funding surplus?

Response

a) OPG reduced its registered pension plan contribution by approximately $58M in 2025 and forecasts reducing it by approximately $74M in 2026, relative to what would otherwise be required based on the January 1, 2025 actuarial valuation of the pension plan for funding purposes, on account of the funding surplus as discussed in Ex. F4-3-1, Section 7.0.1.

b) Refer to Ex. L-F4-SUP-027.

Board Staff Interrogatory #233

Interrogatory

Reference:
Ref 1: Exhibit F4 / Tab 3 / Schedule 2 / pp. 1-2

Preamble:

OPG states that the forecast 2027-2031 pension and other post-employment benefit costs (OPEB) for OPG's regulated facilities and the Darlington New Nuclear Program (DNNP) facilities included in the proposed revenue requirement are determined in accordance with US Generally Accepted Accounting Principles (GAAP). As in prior applications, OPG's accrual costs for pension and OPEB include several components.

Question(s):

a) Please confirm whether the pension and OPEB amounts included in the 2027-2031 revenue requirement are based on total annual accrual costs determined under OPG's US GAAP accounting treatment.

b) Please provide a breakdown for each forecast year showing the components of annual pension and OPEB cost reflected in the forecast revenue requirement, by major plan.

c) Please identify any components of annual pension and OPEB cost determined for financial reporting purposes that are not included in the forecast revenue requirement and explain why they are excluded.

d) Please confirm if OPG's accrual costs for pension and OPEB includes a component related to the amortized actuarial gains or losses (which is allowed under US GAAP). If so, please provide the figures for historical periods and also 2027-2031 related to the amortized actuarial gains or losses.

Response

a) Confirmed.

b) Provided below is the breakdown for the components of the forecasted annual pension and OPEB accrual costs for years 2027-2031 as attributed to each of OPG's nuclear facilities, OPG's regulated hydroelectric facilities and the DNNP LP's facilities in the manner described in Ex. F4-3-2, Section 4.2. The current service cost components shown correspond to Ex. F4-3-2, Chart 12, Chart 13 and Chart 14, respectively.

Chart 1
Pension and OPEB Cost Components for 2027-2031 – OPG Nuclear

(millions of dollars)	**2027**	**2028**	**2029**	**2030**	**2031**
Pension					
Current Service Cost	250.6	255.3	267.3	272.7	282.1
Interest Cost	603.0	612.3	629.8	645.9	659.2
Expected Return on Assets	(831.0)	(853.8)	(886.0)	(911.5)	(932.7)
Amortization of Past Service Cost	0.0	0.0	0.1	0.7	0.7
Amortization of Actuarial Losses (Gains)	0.0	0.0	0.0	0.0	0.0
Total	22.6	13.8	11.2	7.8	9.3
OPEB					
Current Service Cost	92.0	94.2	98.9	102.3	106.7
Interest Cost	117.3	120.6	125.6	130.2	134.4
Expected Return on Assets	0.0	0.0	0.0	0.0	0.0
Amortization of Past Service Cost	2.7	2.7	2.7	2.8	3.3
Amortization of Actuarial Losses (Gains)	(8.9)	(7.4)	(6.2)	(5.2)	(3.8)
Immediate Recognition of LTD Losses (Gains)	0.9	0.9	1.0	1.1	1.1
Total	204.0	211.0	222.0	231.2	241.7
Total					
Current Service Cost	342.6	349.5	366.2	375.0	388.8
Interest Cost	720.3	732.9	755.4	776.1	793.6
Expected Return on Assets	(831.0)	(853.8)	(886.0)	(911.5)	(932.7)
Amortization of Past Service Cost	2.7	2.7	2.8	3.5	4.0
Amortization of Actuarial Losses (Gains)	(8.9)	(7.4)	(6.2)	(5.2)	(3.8)
Immediate Recognition of LTD Losses (Gains)	0.9	0.9	1.0	1.1	1.1
Total	226.6	224.8	233.2	239.0	251.0

* Numbers may not add due to rounding.

Chart 2
Pension and OPEB Cost Components for 2027-2031 – Regulated Hydroelectric

(millions of dollars)	**2027**	**2028**	**2029**	**2030**	**2031**
Pension					
Current Service Cost	48.8	49.8	52.4	53.8	55.8
Interest Cost	116.9	119.4	123.4	127.8	131.2
Expected Return on Assets	(161.1)	(166.5)	(173.6)	(180.2)	(185.5)
Amortization of Past Service Cost	0.0	0.0	0.0	0.1	0.1
Amortization of Actuarial Losses (Gains)	0.0	0.0	0.0	0.0	0.0
Total	4.6	2.7	2.2	1.5	1.6
OPEB	OPEB				
Current Service Cost	17.9	18.4	19.4	20.2	21.2
Interest Cost	22.8	23.6	24.6	25.7	26.7
Expected Return on Assets	0.0	0.0	0.0	0.0	0.0
Amortization of Past Service Cost	0.5	0.5	0.5	0.6	0.7
Amortization of Actuarial Losses (Gains)	(1.8)	(1.5)	(1.2)	(1.0)	(0.8)
Immediate Recognition of LTD Losses (Gains)	0.2	0.2	0.2	0.2	0.2
Total	39.6	41.2	43.5	45.7	48.0
Total	Total				
Current Service Cost	66.7	68.2	71.8	74.0	77.0
Interest Cost	139.7	143.0	148.0	153.5	157.9
Expected Return on Assets	(161.1)	(166.5)	(173.6)	(180.2)	(185.5)
Amortization of Past Service Cost	0.5	0.5	0.5	0.7	0.8
Amortization of Actuarial Losses (Gains)	(1.8)	(1.5)	(1.2)	(1.0)	(0.8)
Immediate Recognition of LTD Losses (Gains)	0.2	0.2	0.2	0.2	0.2
Total	44.2	43.9	45.7	47.2	49.6

* Numbers may not add due to rounding.

Chart 3
Pension and OPEB Cost Components for 2027-2031 – DNNP Facilities

(millions of dollars)	2027	2028	2029	2030	2031
Pension					
Current Service Cost	15.6	15.4	13.6	11.5	10.6
Interest Cost	37.4	38.3	32.7	27.9	25.5
Expected Return on Assets	(51.6)	(53.4)	(45.9)	(39.2)	(35.8)
Amortization of Past Service Cost	0.0	0.0	0.0	0.0	0.0
Amortization of Actuarial Losses (Gains)	0.0	0.0	0.0	0.0	0.0
Total	1.4	0.3	0.4	0.2	0.3
OPEB					
Current Service Cost	5.7	5.7	5.1	4.4	3.9
Interest Cost	7.2	7.4	6.5	5.7	5.3
Expected Return on Assets	0.0	0.0	0.0	0.0	0.0
Amortization of Past Service Cost	0.2	0.2	0.1	0.1	0.1
Amortization of Actuarial Losses (Gains)	(0.5)	(0.4)	(0.3)	(0.2)	(0.1)
Immediate Recognition of LTD Losses (Gains)	0.1	0.1	0.1	0.0	0.0
Total	12.7	13.0	11.5	10.0	9.2
Total					
Current Service Cost	21.3	21.1	18.7	15.9	14.5
Interest Cost	44.6	45.7	39.2	33.6	30.8
Expected Return on Assets	(51.6)	(53.4)	(45.9)	(39.2)	(35.8)
Amortization of Past Service Cost	0.2	0.2	0.1	0.1	0.1
Amortization of Actuarial Losses (Gains)	(0.5)	(0.4)	(0.3)	(0.2)	(0.1)
Immediate Recognition of LTD Losses (Gains)	0.1	0.1	0.1	0.0	0.0
Total	14.1	13.3	11.9	10.2	9.5

* Numbers may not add due to rounding.

c) No components of annual pension and OPEB costs identified for financial reporting purposes in accordance with US GAAP are excluded from the proposed revenue requirements.

d) Confirmed. The figures for the forecast amortization of actuarial gains and losses for the 2027-2031 period, as attributed to each of OPG's nuclear facilities, OPG's regulated hydroelectric facilities and DNNP LP's facilities, can be found in the response to part b) in the Total sections, under the lines "Amortization of Actuarial Losses (Gains)". Provided below are the figures for the historical periods as attributed to each of OPG's nuclear facilities and OPG's regulated hydroelectric facilities (DNNP LP was not then in existence).

Chart 4
Pension and OPEB Amortization of Actuarial Losses (Gains) for Historical Years – OPG Nuclear

(millions of dollars)	**2020**	**2021**	**2022**	**2023**	**2024**
Pension	129.0	211.5	93.5	0.0	0.0
OPEB	5.7	12.1	5.6	(40.0)	(19.9)
Total	134.7	223.6	99.1	(40.0)	(19.9)

Chart 5
Pension and OPEB Amortization of Actuarial Losses (Gains) for Historical Years – Regulated Hydroelectric

(millions of dollars)	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Pension	24.7	22.8	25.6	21.1	21.4	39.4	17.8	0.0	0.0
OPEB	3.0	0.7	1.6	0.7	0.9	2.3	1.1	(7.2)	(3.4)
Total	27.7	23.5	27.2	21.8	22.3	41.7	18.9	(7.2)	(3.4)

Board Staff Interrogatory #234

Interrogatory

Reference:
Ref 1: Exhibit F4 / Tab 3 / Schedule 2 / pp. 9-10, 26

Preamble:

OPG states that its pension and other post-retirement benefits (OPEB) costs are determined annually by an independent actuary using management's best estimate assumptions, both economic and demographic, and that many of the pension assumptions used for accounting purposes are the same as those used in the actuarial valuations for funding purposes.

OPG also states that the expected long-term rate of return on the registered pension plan (RPP) fund assets continues to be calculated by its independent actuary, Aon, based on the pension fund asset mix and capital market expectations of future risk and return for each class. OPG states that 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.

Question(s):

a) Please identify the material assumptions and methodologies used to determine the annual pension and OPEB accrual costs included in revenue requirement, including any material plan asset-related assumptions.
   i. Please identify which of those assumptions and methodologies differ from those used in the actuarial valuations for funding purposes, as discussed in Reference 1.
   ii. For each material difference identified, please briefly explain the nature of the difference, and whether the difference affects the forecast revenue requirement, cash funding requirements, or both.
   iii. Please quantify, to the extent possible, the impact on forecast revenue requirement of each material difference identified in part a.
   iv. Please quantify the impact on forecast revenue requirement of changes in the most material plan asset-related assumption(s), using reasonable sensitivity ranges.

Response

a) The material assumptions and methodologies used to determine the annual pension and OPEB accrual costs are described in Ex. F4-3-2, Sections 4.0 and 4.1. In particular, Ex. F4-3-2, Chart 8, presents key assumptions used to determine OPG's 2025-2031 projected pension and OPEB accrual costs in accordance with US GAAP, which are attributed to the prescribed facilities in the manner described in Ex. F4-3-2, Section 4.2.

i. and ii.

As key assumptions for solvency valuations of registered pension plans (for funding purposes) are prescribed under the *Pension Benefits Act* (Ontario) and as there are no forecast contribution requirements pursuant to a solvency valuation for OPG's registered pension plan, OPG interprets the question to be in relation to actuarial assumptions and methodologies for the registered pension plan as used for US GAAP purposes compared to those used for going concern valuations (for funding purposes). As discussed below, such material differences applicable to OPG relate to the discount rate, expected rate of return and provision for adverse deviation ("PfAD") set of assumptions, as well as certain asset valuation methodologies.

The discount rate used to determine the current service cost and interest cost components of the registered pension plan accrual costs is based on AA corporate bond yield curve as required by US GAAP and as provided by an independent actuary. US GAAP also requires that accrual costs include an expected return on assets component, which utilizes an expected long-term rate of return on the pension fund assets. This expected long-term rate of return is based on calculations prepared by Aon, OPG's external actuary, and is further discussed in Ex. L-F4-CCC-093. Furthermore, for purposes of determining accrual costs, the pension fund assets are valued using a market-related value of assets, which recognizes gains and losses on equity assets relative to a 6% assumed real return over a five-year period. This market-related value is used in the calculation of the expected return on assets and the amortization of actuarial gains and losses components of the accrual costs.

The going concern benefit obligation and associated funding requirements for the registered pension plan are determined using a discount rate representing Aon's best estimate expected long-term rate of return on pension plan assets. This discount rate is therefore typically close to the rate used to calculate the expected return on assets component of the accrual costs, with some differences possible to the treatment of passive investment management fees or other technical factors based on the applicable actuarial or accounting

standards. In this proceeding, the accounting assumption for the expected long-term rate of return of 6.25% used to determine the forecasted accrual costs is the same as the going concern valuation discount rate.

The going concern valuation incorporates a PfAD as required by the *Pension Benefits Act* (Ontario), which serves to increase funding requirements. 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 the Government of Canada bonds yields. There is no similar construct applicable under US GAAP.

For purposes of determining the annual pension plan contributions under the going concern valuation, the pension fund assets are valued using an actuarial value of assets. The actuarial value of assets recognizes asset gains and losses based on the difference between the actual investment return and the expected investment return based on the going concern valuation discount rate over a five-year period.

The above assumptions and methods that are used for US GAAP purposes impact the determination of forecast pension accrual costs and therefore the requested revenue requirements; they do not impact the forecast pension plan contributions presented in the Application. The above assumptions and methods that are used for going concern valuation purposes could impact the forecast registered pension plan contributions presented in the Application, depending on their impact on the projected available actuarial surplus that informs the company's expected ability to reduce employer contributions to match the level of employee contributions (discussed at Ex. F4-3-2, p. 27, line 5, to p. 28, line 4). Changes in forecast pension plan contributions could in turn affect the requested revenue requirements through their effects on the regulatory income tax calculations, where pension contributions are treated as deductible for tax purposes (refer to Ex. F4-2-1, Section 3.2.5), depending on whether the associated regulated business is in a forecasted regulatory taxable income or regulatory tax loss position.

iii. OPG understands the question to be asking to quantify, where possible, the impact on the forecast accrual costs for the registered pension plan as determined in accordance with US GAAP of the differences discussed in part i) above. For the reasons outlined below, OPG does not believe it is possible or practical to quantify such impacts while remaining in compliance with US GAAP and therefore has not done so.

With respect to the discount rate used to determine the current service cost and interest cost components of the accrual costs, as noted, it must be based on AA

corporate bond yield curve as required by US GAAP. US GAAP does not permit this discount rate to be based on an expected rate of return on pension plan assets, such as the one used for going concern valuation purposes. With respect to the application of PfAD required for use in going concern valuations, as noted, there is no similar construct applicable under US GAAP.

With respect to the expected long-term rate of return used to determine the expected return on assets component of the accrual costs, as noted, that rate in this proceeding is equal to the discount rate used for going concern valuation purposes.

With respect to the asset valuation method used for the calculation of the expected return on assets and the amortization of actuarial gains and losses components of the accrual costs compared to the method used to determine the actuarial value of assets for going concern valuation purposes, for accounting purposes, a method change would represent a change in accounting policy under US GAAP that would require retrospective application. Such retrospective application would require a recalculation and restatement of financial information for a period of over 25 years, as well as significant assumptions around how such a retrospective change would be treated from a revenue requirement standpoint. It would be practical to undertake such an extensive analysis and OPG has not done so.

iv. The expected long-term rate of return on the pension plan assets is the most material plan asset-related assumption. Aon has estimated the impact of a change in this assumption on the total OPG forecast pension accrual costs for each of the years 2027-2031, which underpin such costs attributed to the prescribed facilities as shown at Ex. F4-3-2, Charts 1 to 3, holding all other assumptions constant. The change was assumed to take place as at December 31, 2025, with the cumulative effect reflected for each of the subsequent years. The resulting impacts were attributed to the prescribed facilities in the same manner as the forecast amounts in the pre-filed evidence.

The estimated increases (decreases) in the proposed revenue requirements resulting from the above calculations are shown in Charts 1. These results are inclusive of associated income tax impacts (calculated at 25% tax rate /(1-25% tax rate)) for those regulated businesses that are not otherwise in a forecasted regulatory tax loss position.

Chart 1 – Sensitivities of Proposed Revenue Requirements to Changes in Expected Rate of Return on Pension Plan Assets

(millions of dollars)	**2027**	**2028**	**2029**	**2030**	**2031**
OPG Nuclear					
0.25% increase	(35)	(39)	(42)	(46)	(50)
0.25% decrease	35	38	42	45	49
Regulated Hydroelectric					
0.25% increase	(9)				
0.25% decrease	9				
DNNP Facilities					
0.25% increase	(2)	(2)	(2)	(2)	(2)
0.25% decrease	2	2	2	2	2
OPG Nuclear					
0.50% increase	(71)	(78)	(85)	(93)	(101)
0.50% decrease	70	76	83	90	97
Regulated Hydroelectric					
0.50% increase	(18)				
0.50% decrease	18				
DNNP Facilities					
0.50% increase	(4)	(5)	(4)	(4)	(4)
0.50% decrease	4	5	4	4	4

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Interrogatory

Reference:
Ref 1: Exhibit F4 / Tab 3 / Schedule 2 / pp. 11-13, 18

Preamble:

OPG states that forecasting pension and other post-retirement benefits (OPEB) accrual costs requires projections of the actual pension fund performance as well as projections of assumptions that will be used to determine the actual obligations. OPG further states that the forecast 2026-2031 costs use assumptions determined as of the end of December 2024, as updated, effective December 31, 2026, to reflect the 2024 Mortality Improvement Scale (MI-2024). The forecast 2025-2031 costs also reflect previously negotiated pension reform measures effective in 2025. OPG also states that pension costs increased from 2023 to 2024 due in part to updated salary increase assumptions and that 2026 to 2027 forecast costs increase due to the expected adoption of MI-2024.

Question(s):

a) Please identify all material changes in pension and OPEB assumptions or other forecast inputs reflected in the 2025 to 2031 forecast relative to the assumptions and inputs used in OPG's last payment amounts proceeding.
   i. For each material change identified, please explain the reason for the change.
   ii. For each material change, please quantify the impact on the forecast revenue requirement for each affected year.

b) Please provide a sensitivity analysis, in table form, showing the impact on the 2027-2031 pension and OPEB-related revenue requirement of an increase and decrease in the discount rate assumption of 25 basis points, and 50 basis points.

Response

a) The material changes in OPG's pension and OPEB assumptions and forecast inputs between EB-2020-0290 and this Application are as follows:

Chart 1
Changes in Key Pension and OPEB Assumptions from EB-2020-0290

Assumptions	EB-2020-0290	EB-2025-0297
Discount rate for Pension	Current service cost – 3.02% Interest cost – 2.37%	Current service cost – 4.80% Interest cost – 4.39%
Discount rate for OPRB*	Current service cost - 3.08% Interest cost – 2.56%	Current service cost – 4.81% Interest cost – 4.47%
Discount rate for LTD*	Current service cost – 2.21% Interest cost – 1.67%	Current service cost – 4.37% Interest cost – 3.98%
Inflation rate	1.75%	2.00%
Expected long-term rate of return on pension fund assets ("EROA")	6.00%	6.25%
Longer-term salary schedule escalation rate	2.25% (Inflation rate + 50 bps)	2.75% (Inflation rate + 75 bps)
Mortality improvement scale	2017 Mortality Improvement Scale ("MI-2017")	2024 Mortality Improvement Scale ("MI-2024")

*OPRB = other post retirement benefits; LTD = long term disability plan

Additionally, there have been changes to plan membership data and other inputs into the pension and OPEB actuarial calculations, as discussed further below.

i. and ii.

Below OPG discusses the reasons for each material assumption or input change with respect to the determination of its pension and OPEB costs, between EB-2020-0290 and this Application.

OPG's approach to determining key assumptions for pension and OPEB costs is outlined at Ex. F4-3-2, Section 4.0 and is unchanged from EB-2020-0290. These assumptions are determined in the same manner as reflected in OPG's consolidated financial statements and, in accordance with US GAAP, must be reviewed and as necessary updated annually to ensure they continue to represent the best estimate of future event. OPG's pension and OPEB costs and obligations are determined annually by an external actuary. OPG follows the recommendations of the external actuary, Aon and does not adopt any assumptions with which Aon, does not agree. Aon's report on OPG's forecast pension and OPEB costs including the key assumptions reflected in this Application is found at Ex. F4-3-2. Attachment 1.

The forecast 2021-2026 costs in EB-2020-0290 reflected projections of benefit obligations and pension fund assets at the end of each year in the 2020-2025 period using the assumptions determined as of the end of June 2020. The forecast 2025 costs in this Application 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. The forecast 2026-2031 costs in this Application 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 December 31, 2026, to reflect MI-2024 as recommended by Aon.

The discount rates used to forecast pension and OPEB costs in the Application have been determined by an external actuary based on the yield curve as at December 31, 2024, and the EB-2020-0290 discount rates were determined based on the yield curve at the time. OPG continues to follow the same full yield curve approach to determining pension and OPEB costs as it did in EB-2020-0290, described at Ex. F4-3-1, p. 10, lines 1-9. As noted in that evidence, there has been no new authoritative guidance issued since EB-2020-0290 with respect to the selection of such discount rates.

The long-term inflation assumption continues to be set 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 and spreads between nominal and real interest rates. While historically the assumption was set at 2.0%, in consultation with OPG's external actuary, it was lowered to 1.75% in recognition of observed narrowing between nominal and real interest rates around the time of EB-2020-0290.[1] This was also Aon's best estimate assumption in the January 1, 2020 actuarial valuation for funding purposes. The long-term inflation assumption was subsequently restored to 2.0% to reflect updated long-term economic expectations and evolving macroeconomic conditions, and is also Aon's best estimate assumption in the January 1, 2025 actuarial valuation of OPG's registered pension plan for funding purposes.

The longer-term salary escalation rate builds on the long-term inflation assumption. Determined in consultation with Aon, the longer-term salary escalation rate is equal to the long-term inflation rate plus 0.75% in this Application, an increase from plus 0.50% used in EB-2020-0290.[2] This change is explained in Ex. L-F4-CCC-093.

The expected long-term rate of return on pension plan assets reflects calculations prepared by Aon, based on the pension fund asset mix and capital market

[1] See Ex. EB-2020-0290, L-F4-03-Staff-306.
[2] The near-term salary growth assumptions continue to reflect known short-term expectations based on collective agreement provisions and other expectations of salary growth.

expectations of future risk and return for each asset class within the fund portfolio as determined by Aon. The increase in the expected long-term rate of return from 6.00% in EB-2020-0290 to 6.25% in this Application reflects higher longer-term inflation assumptions and expected fixed income returns. Aon continues to use the same approach to these calculations, as described further at Ex. F4-3-2, Attachment 1, p. 7. As discussed in Ex. L-F4-Staff-234, part a), the expected long-term rate of return in this Application is the same as the going concern valuation discount rate determined by Aon in the January 1, 2025 actuarial valuation of OPG's registered pension plan for funding purposes.

As discussed in Ex. F4-3-2, p. 11, line 26 to p. 12, line 8, Aon also recommended an update, effective as of the end of 2026, to the mortality improvement scale assumption to reflect recently released Mortality Improvement Scale ("MI-2024") from the Canadian Institute of Actuaries. Aon advised OPG that it expects MI-2024 to be widely adopted by pension plan sponsors in Canada, as a best estimate of mortality improvement assumption for the Canadian pensioner population (Ex. F4-3-2, Attachment 1, p. 7).

Additionally, there are differences in the underlying pension and benefit plan membership data to reflect changes in the demographic characteristics of the OPG population over time; the forecast OPG headcount and associated employee retirement assumptions between EB-2020-0290 and this Application due in large part to the Pickering station no longer expected to end commercial operation in the near term; and the health care benefit costs (referred to as "claims costs") underpinning the OPEB costs, which are periodically updated by Aon in the normal course based on OPG's actual historical experience.

OPG's external actuary, Aon, has estimated the impact on the total OPG forecast pension and OPEB accrual costs for each of the years 2027-2031, which underpin such costs attributed to the prescribed facilities as shown at Ex. F4-3-2, Charts 1 to 3, of a change in the material assumptions from EB-2020-2090 as requested in the question, holding all other assumptions constant as each of the material assumptions changes. The change was assumed to take place as at December 31, 2025, with the cumulative effect reflected for each of the subsequent years. The resulting impacts were attributed to the prescribed facilities in the same proportion as the forecast amounts in the pre-filed evidence.

The estimated increases (decreases) in the proposed revenue requirements resulting from the above calculations are shown in Chart 2. These results are determined on the basis of pension and OPEB costs reflected in OM&A expenses and are inclusive of associated income tax impacts (calculated at 25% tax rate / (1-25% tax rate)) for those regulated businesses that are not otherwise in a forecasted regulatory tax loss position.

Chart 2
Impact on Proposed Revenue Requirements to Changes in Material Pension/OPEB Assumptions Since EB-2020-0290

(millions of dollars)	**2027**	**2028**	**2029**	**2030**	**2031**
OPG Nuclear					
EB-2020 Yield Curve (discount rate)	(223)	(204)	(194)	(183)	(206)
Inflation – 1.75%	34	36	39	42	47
MI2017	27	28	31	32	35
EROA – 6.00%	(35)	(38)	(42)	(45)	(49)
Salary Scale	25	26	28	31	35
2020 Claims Costs	(20)	(19)	(19)	(19)	(18)
Regulated Hydroelectric					
EB2020 yield curve	(66)				
Inflation – 1.75%	9				
MI2017	7				
EROA – 6.00%	(9)				
Salary Scale	6				
2020 Claims Costs	(5)				
DNNP Facilities					
EB2020 yield curve	(13)	(11)	(10)	(11)	(11)
Inflation – 1.75%	2	2	2	2	2
MI2017	1	1	1	1	1
EROA – 6.00%	(2)	(2)	(2)	(2)	(2)
Salary Scale	1	1	1	1	1
2020 Claims Costs	(1)	(1)	(1)	(1)	(1)

Aon has indicated that it is not feasible to isolate the impact of the changes in the plan membership data, forecast headcounts or retirement assumptions since the EB-2020-0290 forecasts.

b) Aon has estimated the impact on the total OPG forecast pension and OPEB costs for each of the years 2027-2031, which underpin such costs attributed to the prescribed facilities as shown at Ex. F4-3-2, Charts 1 to 3, of a change in the discount rate assumption requested in the question, holding all other assumptions constant. The change was assumed to take place as at December 31, 2025, with the cumulative effect reflected for each of the subsequent years. The resulting impacts were attributed to the prescribed facilities in the same proportion as the forecast amounts in the pre-filed evidence.

The estimated increases (decreases) in the proposed revenue requirements resulting from the above calculations are shown in Chart 3. These impacts are determined on the basis of pension and OPEB costs reflected in OM&A expenses and are inclusive of associated income tax impacts (calculated at 25% tax rate /(1-25% tax rate)) for those regulated businesses that are not otherwise in a forecasted regulatory tax loss position.

Chart 3
Sensitivities of Proposed Revenue Requirements to Changes in Discount Rate – Pension and OPEB

(millions of dollars)	**2027**	**2028**	**2029**	**2030**	**2031**
OPG Nuclear					
0.25% increase	(7)	(7)	(7)	(7)	(9)
0.25% decrease	13	7	8	7	9
Regulated Hydroelectric					
0.25% increase	(3)				
0.25% decrease	4				
DNNP Facilities					
0.25% increase	0	0	0	0	0
0.25% decrease	0	0	0	0	0
OPG Nuclear					
0.5% increase	15	12	9	8	4
0.5% decrease	34	25	20	20	26
Regulated Hydroelectric					
0.5% increase	3				
0.5% decrease	10				
DNNP Facilities					
0.5% increase	1	1	1	0	0
0.5% decrease	2	1	1	0	0

Board Staff Interrogatory #236

Interrogatory

Reference:
Ref 1: Exhibit F4 / Tab 3 / Schedule 2 / pp. 1, 3, 5-8
Ref 2: Exhibit H1 / Tab 1 / Schedule 1

Preamble:

Reference 1 presents both forecast accrual costs and forecast cash amounts, as well as the differential between the accrual costs and cash amounts. The exhibit also supports the request for disposition of balances in the various pension and other post-retirement benefits (OPEB) deferral and variance accounts (DVAs).

OPG notes that the operation of these DVAs is discussed in Reference 2, including the continued application of the account that records interest on the difference between pension and OPEB accrual costs and cash amounts.

Question(s):

a) For each historical year for which amounts have been recorded in the applicable pension and OPEB DVAs and are relevant to the balances requested for disposition in this proceeding, please provide a reconciliation of:
   i. The pension and OPEB amounts included in revenue requirement
   ii. the actual accrual costs
   iii. the actual cash funding or cash payment amounts
   iv. the actual amounts recorded in each applicable pension and OPEB variance and deferral account.

b) For each forecast year of 2026-2031, please provide a bridge between:
   i. The pension and OPEB amounts included in the revenue requirement
   ii. The forecast cash funding or cash payment amounts
   iii. The forecast amounts expected to be recorded in the applicable pension and OPEB DVAs.

c) Please explain the key reasons for the differences among the amounts in question a and b, including the extent to which the differences related to accounting treatment, funding valuation methodology, or timing.

d) Please confirm whether the same cost components reflected in forecast revenue requirement are also the basis for determining the actual or forecast amounts recorded in the applicable accounts. If not, please explain the differences.

Response

a) Refer to Ex. H1-1-1, Tables 7, 7a, and 7b that show the calculations of the amounts recorded to OPG's pension and OPEB related deferral and variance accounts (for 2023 and 2024) that are requested for disposition in this proceeding, with reference to the relevant accrual costs and cash amounts. The entries to these accounts have been made in accordance with the EB-2020-0290 Payment Amounts Order.

b) Attachment 1, Tables 1, 1a, and 1b provide the details of the forecast additions to OPG's pension and OPEB related deferral and variance accounts for 2026 in the same manner as Ex. H1-1-1, Tables 7, 7a, and 7b for the actual 2023 and 2024 additions. These 2026 forecast additions are as shown in the continuity schedule for year 2026 forecast deferral and variance account activity provided at Ex. L-H1-Staff-260, Attachment 2, Table 2. Additionally, the details of such actual 2025 additions can be found at Ex. L-H1-Staff-260, Attachment 1, Tables 7, 7a, and 7b. The account entries recorded in 2025 and forecast to be recorded in 2026 in accordance with the EB-2020-0290 Payment Amounts Order.

OPG does not have projections of likely amounts to be recorded in the pension and OPEB related deferral and variance accounts over the 2027-2031 IR term, and is unable to assess a potential range of such amounts at this time, as variances would depend on a host of variables that are outside of OPG's control and are very difficult to predict.

c) With respect to the pension and OPEB accrual costs, which differences are relevant for additions to OPG's Pension and OPEB Cost Variance Account, the key drivers can be found at Ex. F4-3-2, Section 4.3.1.

With respect to the pension and OPEB cash amounts, which differences are relevant for additions to the Pension & OPEB Cash Payment Variance Account, the key driver is the difference in registered pension plan contributions relative to the higher reference amounts that are based on the January 1, 2014 actuarial valuation (for funding purposes) of the registered pension plan that underpinned the regulated hydroelectric revenue requirements approved in the EB-2013-0321 proceeding.

With respect to the differences between pension and OPEB accrual costs and cash amounts, which are relevant for additions to the Pension & OPEB Cash Versus

Accrual Differential Deferral Account and the Pension and OPEB Forecast Accrual versus Actual Cash Payment Differential Variance Account, the key driver is the inherent difference in the constructs that each of these amounts represent. Pension and OPEB accrual costs represent the cost of future benefits earned by employees for providing service in a given period as determined in accordance with US GAAP. The various components of these costs and the key methods and assumptions used to derive them are discussed in Ex. F4-3-2, Section 4.0. Pension and OPEB cash amounts represent, for the registered pension plan, the estimated employer pension plan contributions in accordance with the *Pension Benefits Act* (Ontario) and, for the other benefit plans, amounts paid to retirees, dependents and other beneficiaries in accordance with the provisions of these plans. The components of the registered pension plan contributions and the key methods and assumptions used to derive them are discussed in Ex. F4-3-2, Section 5.0. A further discussion of the differences in material assumptions and methodologies used to determine accrual costs and funding contributions for the registered pension plan can be found at Ex. L-F4-Staff-234. For the other plans, benefit payments in a particular year bear no relationship to the accrual costs for that year.

d) Confirmed.

Numbers may not add due to rounding.

Filed: 2026-04-22
EB-2025-0297
Exhibit L
F4-Staff-236
Attachment 1
Table 1

Table 1
Pension & OPEB Cash Payment Variance Account and Pension & OPEB Cash Versus Accrual Differential Deferral Account
Projected Summary of Account Transactions - 2026 ($M)

Line No.	Particulars	Note	Budget 2026		
			Regulated Hydroelectric	Nuclear[4]	(a)+(b) Total
			(a)	(b)	(c)
1	**Forecast Pension Contributions**	1	45.1	0.0	45.1
2	**Forecast OPEB Payments**	1	12.8	0.0	12.8
3	**Total Forecast Pension and OPEB Cash Amounts** (line 1 + line 2)		58.0	0.0	58.0
4	**Projected Pension Contributions**	2	19.5	0.0	19.5
5	**Projected OPEB Payments**	2	22.1	0.0	22.1
6	**Total Projected Pension and OPEB Cash Amounts** (line 4 + line 5)		41.6	0.0	41.6
7	**Total Addition to Pension & OPEB Cash Payment Variance Account** (line 6 - line 3)		(16.4)	0.0	(16.4)
8	**Projected Pension - Registered Pension Plan (RPP) Accrual Costs**	3	1.7	0.0	1.7
9	**Projected OPEB - Non-RPP Accrual Costs**	3	36.8	0.0	36.8
10	**Total Projected Pension and OPEB Accrual** (line 8 + line 9)		38.5	0.0	38.5
11	**Addition to Pension & OPEB Cash Versus Accrual Differential Deferral Account - RPP** (line 8 - line 4)		(17.8)	0.0	(17.8)
12	**Addition to Pension & OPEB Cash Versus Accrual Differential Deferral Account - Non-RPP** (line 9 - line 5)		14.7	0.0	14.7
13	**Total Addition to Pension & OPEB Cash Versus Accrual Differential Deferral Account** (line 11 + line 12)		(3.0)	0.0	(3.0)

Notes:

1 Col. (a) per EB-2020-0290 Payment Amounts Order, App. E, p. 12.

2 Col. (a) from Ex. F4-3-2, Chart 5.

3 Col. (a) from Ex. F4-3-2, Chart 2.

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.

Filed: 2026-04-22
EB-2025-0297
Exhibit L
F4-Staff-236
Attachment 1
Table 1a

Table 1a
Pension & OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance Account - Primary, Contra and Carrying Charges Sub-Accounts
Projected Summary of Account Transactions - 2026 ($M)

Line No.	Particulars	Note	Budget 2026		
			Regulated Hydroelectric	Nuclear	(a)+(b) Total
			(a)	(b)	(c)
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
2	**Amortization of Pension & OPEB Cash Versus Accrual Differential Deferral - Non-RPP - EB-2018-0243 Approved**	1	0.0	0.0	0.0
3	**Amortization of Pension & OPEB Cash Versus Accrual Differential Deferral - Post-2017 Additions - EB-2020-0290 Approved**	1	8.8	55.6	64.5
4	**Amortization of Pension & OPEB Cash Versus Accrual Differential Deferral - Post-2019 Additions**	2	11.2	65.9	77.2
5	**Projected Pension and OPEB Accrual Costs - Nuclear**	3	0.0	200.5	200.5
6	**Projected Pension and OPEB Cash Amounts - Nuclear**	4	0.0	214.5	214.5
7	**Total Addition to Primary Sub-Account Tracking Balance** (line 1 + line 2 + line 3 + line 4 + line 5 - line 6)		28.3	160.9	189.2
8	**Total Addition to Contra Sub-Account Tracking Balance** (line 7 x -1)		(28.3)	(160.9)	(189.2)
9	**Net Total Addition to Primary and Contra Sub-Accounts Tracking Balances**		0.0	0.0	0.0
10	**Primary Sub-Account Tracking Credit Balance - Opening**	5	127.1	572.5	699.6
11	**Primary Sub-Account Tracking Credit Balance - Closing** (line 7 + line 10)		155.4	733.4	888.8
12	**Total Addition to Carrying Charges Sub-Account**	6	(5.9)	(27.1)	(33.0)

Notes:

1 Col. (a) per EB-2020-0290 Payment Amounts Order, App. C, Table 1, lines 10-12, col. (l).
Col. (b) per EB-2020-0290 Payment Amounts Order, App. D, Table 1, lines 15-17, col. (l).

2 Col. (a) per EB-2023-0336 Decision and Order, App. A, Table 1, line 12, cols. (i).
Col. (b) per EB-2023-0336 Decision and Order, App. A, Table 2, line 16, cols. (i).

3 Col. (b) from Ex. L-F4-Staff-236, Table 1b, line 6, col. (a).

4 Col. (b) from Ex. F4-3-2, Chart 4.

5 Cols. (a) and (b) from Ex. L-H1-Staff-260, Attachment 1, Table 7a, line 11, cols. (g) and (h), respectively.

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 at Q4 2025 of 4.23%.

Numbers may not add due to rounding.

Table 1b
Pension and OPEB Cost Variance Account - Nuclear
Projected Summary of Account Transactions - 2026 ($M)

Line No.	Particulars	Note	Budget 2026
			(a)
1	**Forecast Accrual Pension Costs**	1	36.7
2	**Forecast Accrual OPEB Costs**	1	146.8
3	**Total Forecast Accrual Pension and OPEB Costs** (line 1 + line 2)	2	183.5
4	**Projected Accrual Pension Costs**	3	10.0
5	**Projected Accrual OPEB Costs**	3	190.5
6	**Total Projected Accrual Pension and OPEB Costs** (line 4 + line 5)		200.5
7	**Addition to Variance Account - Pension Costs** (line 4 - line 1)		(26.7)
8	**Addition to Variance Account - OPEB Costs** (line 5 - line 2)		43.7
9	**Addition to Variance Account - Income Tax Impact**	4	9.9
10	**Total Addition to Variance Account** (line 7 + line 8 + line 9)		27.0

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 28.

3 From Ex. F4-3-2, Chart 1.

4 The income tax impact of the pension and OPEB cost additions to the account is calculated as follows ($M):

Line No.		Note	Budget 2026
			(a)
1a	Forecast Income Tax Impact	*	(14.6)
	Projected Additions to / Deductions from Regulatory Earnings Before Tax:		
2a	Projected Accrual Pension Costs (line 4)		10.0
3a	Projected Accrual OPEB Costs (line 5)		190.5
4a	Less: Projected Pension Contributions	**	100.4
5a	Less: Projected OPEB Payments	**	114.1
6a	Net Additions to Regulatory Earnings Before Tax (line 2a + line 3a - line 4a - line 5a)		(13.9)
7a	Projected Income Tax Impact (line 6a x 25% / (1 - 25%))		(4.6)
8a	Addition to Variance Account - Income Tax Impact (line 7a - line 1a)		9.9

* From EB-2020-0290 Payment Amounts Order, App. E, p. 11, line 2.

** From Ex. F4-3-2, Chart 4.

Board Staff Interrogatory #237

Interrogatory

Reference:
Ref 1: Exhibit F4 / Tab 4 / Schedule 1 / Table 1
Ref 2: Exhibit F4 / Tab 4 / Schedule 1 / pp. 3-7

Preamble:

At Reference 1, the table shows that nuclear insurance costs are flat from 2020 ($19.5 million) to 2026 ($18.1 million). Then, over the IR term, those costs are forecast by OPG to more than double to $40.7 million by 2031.

At Reference 2, OPG identified two reasons for the forecast increase:

1. An anticipated increase in the current nuclear insurance liability limit under the Nuclear Liability and Compensation Act (NLCA). OPG states, effective 2027, subject to final confirmation by NRCan, the nuclear liability limit is expected to increase from $1 billion to $1.2 billion, for each of Pickering and Darlington, following a five-year NRCan review of the limit.

2. OPG plans to purchase nuclear Business Interruption (BI) insurance for Darlington beginning in 2027 to mitigate the potential loss of earnings and potential impact on OPG's credit ratings in the event of physical damage to the station from a nuclear peril. OPG notes it has not historically procured this coverage.

OPG further notes the BI coverage is not necessary for Pickering until the first unit returns to service and Darlington New Nuclear Program (DNNP) will be insured separately.

In relation to the potential change to the NLCA liability limit, OEB staff reviewed NRCan's Summary of Findings from its Five-Year Review document which notes the following: (1) "An inflation considered value would bring the nuclear third party liability limit to C$1.1 billion."; (2) "Any increase to the liability limit should be phased in gradually …"; and (3) "Internationally the liability limit is increasing with the entry into force of the Amended Paris Convention (2004) in January 2022. This amendment will require that operators in signatory States hold over ~C$1.04 billion." NRCan indicated the current $1 billion was implemented over a three-year phase in period (from $650 million).

Question(s):

a) Please provide a table that shows the forecast increase in costs for each year of 2027 to 2031 attributable to the NLCA and the BI coverage separately.

b) Given NRCan's findings (inflation adjustment to $1.1 billion, gradual phase in, etc.) on the potential change to the NLCA liability limit and the prior phase in to increase it to $1 billion, please explain OPG's anticipated immediate increase to $1.2 billion.

c) In relation to the new BI coverage, please explain why OPG did not consider it to be necessary in the past, but believes it is necessary going forward.

d) Please identify how many times the new BI coverage would have been triggered over the past decade.

e) OPG has indicated its intent to have the BI coverage for all of its nuclear facilities – Darlington, Pickering, DNNP – as they come into service. Table 1 is limited to Darlington and therefore does not reflect what the ultimate full impact would be on consumers. Please provide a table that reflects the cost associated with a hypothetical scenario whereby all the units are in service and have the BI coverage during this IR term (with Darlington, Pickering, and DNNP shown separately). Alternatively, provide a forecast of the cost for when OPG expects all those nuclear units will be in service.

Response

a) The forecasted annual increase in cost for nuclear liability insurance for OPG's nuclear facilities attributed to the expected increase in the nuclear liability limit from $1.0B to $1.2B under the NLCA for each of the Pickering and Darlington stations is as follows from 2027-2031 ($M):

Re: NLCA Limit Increase	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Year-over-Year Incremental Premium Increase	0.0	2.3	0.0	0.1	0.0	0.1
Cumulative Premium Increase Since 2026	0.0	2.3	2.3	2.4	2.4	2.5

The forecasted annual increase in cost attributed to purchasing nuclear business interruption ("BI") insurance coverage for OPG's nuclear facilities is as follows from 2027-2031 ($M):

Re: Addition of Nuclear BI	2026	2027	2028	2029	2030	2031
Year-over-Year Incremental Premium Increase	0.0	8.0	0.2	0.1	0.2	1.2
Cumulative Premium Increase Since 2026	0.0	8.0	8.2	8.3	8.5	9.7

b) OPG, along with the other Canadian nuclear operators, has been in communication with Natural Resources Canada ("NRCan") as NRCan has been completing its five-year review of the nuclear liability limits under the NLCA. NRCan has confirmed to OPG and the other Canadian nuclear operators that the new limit, applicable to each of the Pickering and Darlington stations, is expected to be $1.2B effective January 1, 2027.

c) As stated at Ex. F4-4-1, p. 6, lines 12-18 with respect to nuclear business interruption insurance, "[w]hile 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 [nuclear] BI event occur, having the appropriate insurance coverage will be important to mitigating the impact to OPG's funding profile and therefore credit ratings."

The Company's plan to obtain such coverage is also informed by expectations that it would experience a greater revenue loss should an insurable nuclear BI event occur in the absence of such coverage, compared to past periods, due to a higher revenue rate anticipated for nuclear generation as a result of recovering a return of and on the significant investments being made at these facilities. Based on advice received from its insurance broker, OPG understands that other nuclear power generators in Canada specifically purchase nuclear BI coverage.

As noted in part e) below, in addition to the Darlington station, the Applicants have forecasted and plan to purchase nuclear BI for the Pickering station upon the first unit returning to service from refurbishment as well as for the DNNP facilities beginning with the first unit once it is online, for the same reasons as above.

d) Nuclear business interruption insurance provides coverage if there is physical damage from a nuclear incident and to the nuclear island property that results in a business interruption loss. In the past decade, there has not been such an incident at OPG's facilities that OPG expects would have resulted in an insurance recovery had this coverage been in place.

For clarity, OPG's history in the above regard is not a significant consideration in its plans to procure this coverage. Given the high severity of such an insurable event and the operational and safety measures in place at the nuclear plants, both from the standpoint of an insurer and a nuclear operator such as OPG, these incidents are expected to have a low frequency. This is consistent with the general theory of insurance that provides protection against high impact, low likelihood events. If this were a high frequency event, insurers could not provide such coverage.

e) In addition to the Darlington station, the Applicants have forecasted and plan to purchase nuclear BI insurance for the Pickering station upon the first unit returning to service from refurbishment as well as for the DNNP facilities beginning with the first unit once it is online. As such, in addition to the four units at the Darlington station, the requested nuclear revenue requirements reflect the forecasted insurance expense for such coverage for Pickering Unit 5 for the period from May 2031 onwards and for DNNP Unit 1 from October 2030 onwards.

The chart below provides an indicative estimate of the incremental cost associated with nuclear BI insurance for a hypothetical scenario in 2031 where, in addition to the four Darlington units and the one DNNP unit, all four Pickering Units 5-8 are in service for a full year.

Entity	Number of Operating Units	Forecast Cost of Nuclear BI Coverage in 2031 ($M)
OPG	Darlington – 4 Pickering – 4 (hypothetical)	12.6[1] (hypothetical)
DNNP LP	DNNP – 1	3.3

[1] On a standalone basis, the premium expected to be payable for Darlington's nuclear BI coverage represents a minimum premium requirement. As Pickering Units 5-8 return to service from refurbishment and are added to the nuclear BI coverage, the cost of the coverage per unit is expected to reduce.

Society Interrogatory #014

Interrogatory

Reference:
(1) Exhibit F4-3-1, Attachment 1, "Appendix 2K"
(2) EB-2013-0321Decision With Reasons dated November 20, 2014 pps71,72,82
(3) Exhibit F4-3-1, Attachment 3, "Total Compensation Benchmarking Study prepared by Willis Towers Watson" p2 The total OPG count in 2024 is stated to be PWU 5407, Society 3866, Mgmt Group 1328 and OPG Total 10601.

Question(s):

a) Please update Reference (1) to show 2025 Actuals, and the latest projections for 2026 [if the 2025 Actuals are not immediately available, please update and provide them when available]. Also please provide an excel version of this update.

b) Please verify or update the values in the provided table below which are extracted from Appendix 2K.

c) Please update this table referred to in b) above to show 2025 Actuals, and the latest projections for 2026 [if the 2025 Actuals are not immediately available, please update and provide them when available]. Also please provide an excel version of this update.

d) In the OEB's Decision with Reasons in OPG's EB-2013-0321 application, the Board noted that "the percentage of employees that are managers has increased from approximately 10.5% in 2010 to 11.5% in 2015" (p71) and found that "OPG has not sufficiently justified the number of its management positions" (p72). As a consequence, the Board reduced OPG's OM&A costs to reflect a reduction to 10.5% management in total staffing (p.82).
   i. Please explain why Nuclear Facilities management staff are over 12% of total regular staff in each of 2027 to 2031.
   ii. What would the impact be on OM&A costs in each of 2027 to 2031 if Nuclear Facilities management staff were reduced to 10.5% of total regular staff?
   iii. Please explain why DNNP management staff are over 20% of total regular staff in each of 2027 and 2028 and between 19 and 18% in 2028 to 2031.
   iv. What would the impact be on OPG costs in each of 2027 to 2031 if DNNP management staff were reduced to 10.5% of total regular staff?
   v. How would OPG go about eliminating management staff in order to reach a management staff level of 10.5% of total regular staff?

e) For Nuclear Facilities, please provide the year over year reductions in SUP staff between year end 2025 and 2031 in absolute numbers as well as in percentage terms.

f) For Nuclear Facilities, please explain how OPG intends to go about eliminating roughly 750 SUP staff (a 20% reduction) over this six year period between year end 2025 and 2031? Will OPG offer severance packages to these staff whose employment will be terminated?

g) Please reconcile the difference between the value for 2024 OPG total staff provided in answer to b) above and Reference (3).

		Source:	Appendix 2k	F4-3-1 Attachment 1					
		2024	2025	2026	2027	2028	2029	2030	2031
Nuclear Facilities									
Management		1078.6	1276.9	1138.6	1042.2	1028.9	1016.2	1007.4	1018.7
SUP		3122.7	3639.7	3473.6	3250.9	3184.1	3141.7	3120.1	3087.5
PWU		3694.6	4184.3	4096.5	4141.2	4131.8	4164	4129.8	4116.9
Term/ETE/PECO Temp		719.1	279.2	248.5	7	7	7	0	0
EPSCA		458	358.2	231.8	433.9	551.9	487.3	402	320
	Total	9073	9938.3	9189	8875.2	8903.7	8816.2	8659.3	8543.1
	Total Reg	7895.9	9300.9	8708.7	8434.3	8344.8	8321.9	8257.3	8223.1
	Mgmt % Reg	13.66%	13.73%	13.07%	12.36%	12.33%	12.21%	12.20%	12.39%
	SUP % Reg	39.55%	41.28%	39.89%	38.54%	38.16%	37.75%	37.79%	37.55%
	PWU%Reg	46.79%	44.99%	47.04%	49.10%	49.51%	50.04%	50.01%	50.07%
DNNP									
Management		0	0	100	113.2	100.6	83.7	75.4	66.4
SUP		0	0	228.9	239.3	194.4	152.1	145.4	142.9
PWU		0	0	70.7	140.6	198.9	196.6	158.1	156
Term/ETE/PECO Temp		0	0	0	0	0	0	0	0
EPSCA		0	0	0	0	0	0	0.1	0.2
	Total	0	0	399.6	493.1	493.9	432.4	379	365.5
	Total Reg	0	0	399.6	493.1	493.9	432.4	378.9	365.3
	Mgmt % Reg	0.00%	0.00%	25.03%	22.96%	20.37%	19.36%	19.90%	18.18%
	SUP % Reg	0.00%	0.00%	57.28%	48.53%	39.36%	35.18%	38.37%	39.12%
	PWU%Reg	0.00%	0.00%	17.69%	28.51%	40.27%	45.47%	41.73%	42.70%
HydoElectric Facilities									
Management		155.6	164.5	165.9	162.1	160.4	158.4	160.7	161.3
SUP		506.5	604.8	619	635.3	629.8	624.4	626.4	621.7
PWU		753.5	856.6	911.4	914.5	921.6	933.2	925.8	928.1
Term/ETE/PECO Temp		0	0	0	0	0	0	0	0
EPSCA		0	0	0	0	0	0	0	0
	Total	**1415.6**	**1625.9**	**1696.3**	**1711.9**	**1711.8**	**1716**	**1712.9**	**1711.1**
	Total Reg	1415.6	1625.9	1696.3	1711.9	1711.8	1716	1712.9	1711.1
	Mgmt % Reg	10.99%	10.12%	9.78%	9.47%	9.37%	9.23%	9.38%	9.43%
	SUP % Reg	35.78%	37.20%	36.49%	37.11%	36.79%	36.39%	36.57%	36.33%
	PWU%Reg	53.23%	52.68%	53.73%	53.42%	53.84%	54.38%	54.05%	54.24%
OPG TOTAL									
Management		1234.2	1441.4	1404.5	1317.5	1289.9	1258.3	1243.5	1246.4
SUP		3629.2	4444.5	4321.5	4125.5	4008.3	3918.2	3891.9	3852.1
PWU		4448.1	5040.9	5078.6	5196.3	5252.3	5293.8	5213.7	5201
Term/ETE/PECO Temp		719.1	279.2	248.5	7	7	7	0	0
EPSCA		458	358.2	231.8	433.9	551.9	487.3	402.1	320.2
	Total	10488.6	11564.2	11284.9	11080.2	11109.4	10964.6	10751.2	10619.7
	Total Reg	9311.5	10926.8	10804.6	10639.3	10550.5	10470.3	10349.1	10299.5
	Mgmt % Reg	13.25%	13.19%	13.00%	12.38%	12.23%	12.02%	12.02%	12.10%
	SUP % Reg	38.98%	40.68%	40.00%	38.78%	37.99%	37.42%	37.61%	37.40%
	PWU%Reg	47.77%	46.13%	47.00%	48.84%	49.78%	50.56%	50.38%	50.50%

Response

a) Refer to Ex. L-F4-AMPCO-110, Attachment 1 for an excel version, including 2025 actuals. The latest 2026 projections available in the Appendix 2K level of detail are per the budget included in the pre-filed evidence.

b) and c)

Refer to Ex. L-F4-AMPCO-110, Attachment 1 for updated values and 2025 actuals. The latest 2026 projections available in the "Appendix 2K" level of detail are per the budget included in the pre-filed evidence.

d)

i. Nuclear Facilities management and supervisory staff are not over 12% of total Regular staff. Management Supervisory roles are, on average, approximately 10.0% of total Regular staff over the IR term. Refer to Ex. F4-3-1 Figure 4a and Ex. L- F4-SEC-189.

ii. It is not possible to determine the requested impact on OM&A costs in each of 2027 to 2031 absent additional specificity. A determinative response for any reduced OM&A costs would require elimination of work programs and would necessitate the Applicants to carefully assess impacts to production, safety, performance and delays to project execution, among other priorities.

iii. DNNP staffing requirements reflect project execution and transition from project execution toward a steady state operating Unit 1. As discussed at Ex. F2-2-1, pp. 3-4, overall, the BWRX-300 design, digital technology and managed systems are designed to optimize resource needs, with staff trained and qualified on a wider scope of tasks and disciplines. As such, represented positions comprise a proportionately smaller percentage of the total FTE complement.

iv. It is not possible to determine the requested impact on costs in each of 2027 - 2031 absent additional specificity. A determinative response for any reduced costs would require elimination of work programs and would necessitate the Applicants to carefully assess impacts to production delay and delays to project execution (schedule or scope) among other priorities.

v. OPG declines to comment on this speculative question. A determinative response for any reduced OM&A costs would require elimination of work programs and would necessitate the Applicants to carefully assess impacts to production, safety, performance and delays to project execution, among other priorities.

e) Refer to Chart 1 below.

Chart 1 - Nuclear Facilities (excluding DNNP LP) Society Regular and Non-Regular FTEs 2025-2031

Nuclear Facilities (excluding DNNP LP)	**2025 Actual**	**2026 Plan**	**2027 Plan**	**2028 Plan**	**2029 Plan**	**2030 Plan**	**2031 Plan**
Staff (Regular and Non-Regular)		**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**
Society	3,251.4	3,473.6	3,250.9	3,184.1	3,141.7	3,120.1	3,087.5
YOY Change		222.2	(222.7)	(66.9)	(42.4)	(21.6)	(32.6)
YOY % Change		6.8%	-6.4%	-2.1%	-1.3%	-0.7%	-1.0%

f) OPG does not expect a need to terminate employment for Society-represented employees supporting OPG's nuclear facilities and the DNNP facilities. FTEs related to both OPG's nuclear facilities and the DNNP facilities should be combined to assess any FTE trends over the IR term. On this basis, Society-represented Regular FTEs reduce by approximately 80 from 2025 to 2031.

g) The two references are not equivalent and cannot be reconciled.

Attachment 1 refers to FTEs for OPG's nuclear facilities and the DNNP facilities. Refer to Ex. L-F4-AMPCO-127 for a detailed definition of FTE.

Reference 3 includes OPG Regular and Term Employee incumbents in role as of April 1, 2024.

Regulated Facilities - Regular FTE as a percentage of Total Regular and Non-Regular FTE

Nuclear Facilities (Excl DNNP)	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
	FTE	**FTE**	**FTE**	**FTE**	**FTE**	**FTE**	**FTE**	**FTE**
Staff (Regular and Non-Regular)	**Actual**	**Actual**	**Plan**	**Plan**	**Plan**	**Plan**	**Plan**	**Plan**
Management	1,078.6	1,135.8	1,138.6	1,042.2	1,028.9	1,016.2	1,007.4	1,018.7
Society	3,122.7	3,251.4	3,473.6	3,250.9	3,184.1	3,141.7	3,120.1	3,087.5
PWU	3,694.6	3,863.9	4,096.5	4,141.2	4,131.8	4,164.0	4,129.8	4,116.9
Term/ETE/PECO Temporary	719.1	319.8	248.5	7.0	7.0	7.0	-	-
EPSCA	458.0	407.9	231.8	433.9	551.9	487.3	402.0	320.0
Total (Regular and Non-Regular)	9,073.0	8,978.8	9,189.0	8,875.1	8,903.6	8,816.2	8,659.2	8,543.2
Total Regular	7,044.3	7,531.2	8,023.5	8,089.9	8,040.6	7,989.1	7,966.4	7,930.4
Mgmt % Reg	15.3%	15.1%	14.2%	12.9%	12.8%	12.7%	12.6%	12.8%
Society % Reg	44.3%	43.2%	43.3%	40.2%	39.6%	39.3%	39.2%	38.9%
PWU % Reg	52.4%	51.3%	51.1%	51.2%	51.4%	52.1%	51.8%	51.9%
DNNP LP	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
	FTE	**FTE**	**FTE**	**FTE**	**FTE**	**FTE**	**FTE**	**FTE**
Staff (Regular and Non-Regular)	**Actual**	**Actual**	**Plan**	**Plan**	**Plan**	**Plan**	**Plan**	**Plan**
Management			98.3	110.3	96.1	75.3	61.6	45.9
Society			227.6	236.7	190.0	143.4	131.2	122.3
PWU			70.3	140.0	197.8	194.3	154.6	151.6
Term/ETE/PECO Temporary								
EPSCA			0.0	0.0	0.0	0.0	0.1	0.2
Total (Regular and Non-Regular)			396.2	487.1	484.0	413.1	347.3	319.9
Total Regular			371.9	463.2	461.4	395.1	336.6	316.1
Mgmt % Reg			26.4%	23.8%	20.8%	19.1%	18.3%	14.5%
Society % Reg			61.2%	51.1%	41.2%	36.3%	39.0%	38.7%
PWU % Reg			18.9%	30.2%	42.9%	49.2%	45.9%	48.0%
Hydroelectric Facilities	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
	FTE	**FTE**	**FTE**	**FTE**	**FTE**	**FTE**	**FTE**	**FTE**
Staff (Regular and Non-Regular)	**Actual**	**Actual**	**Plan**	**Plan**	**Plan**	**Plan**	**Plan**	**Plan**
Management	155.6	155.7	165.9	162.1	160.4	158.4	160.7	161.3

Society		506.5	548.9	619.0	635.3	629.8	624.4	626.4	621.7
PWU		753.5	801.8	911.4	914.5	921.6	933.2	925.8	928.1
Term/ETE/PECO Temporary									
EPSCA									
	Total (Regular and Non-Regular)	1,415.6	1,506.5	1,696.3	1,711.9	1,711.9	1,716.0	1,712.9	1,711.1
	Total Regular	1,317.8	1,406.5	1,575.1	1,586.7	1,581.6	1,579.0	1,584.8	1,585.1
	Mgmt % Reg	11.8%	11.1%	10.5%	10.2%	10.1%	10.0%	10.1%	10.2%
	Society % Reg	38.4%	39.0%	39.3%	40.0%	39.8%	39.5%	39.5%	39.2%
	PWU % Reg	57.2%	57.0%	57.9%	57.6%	58.3%	59.1%	58.4%	58.5%
OPG Regulated Facilities Total		**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
		FTE	**FTE**	**FTE**	**FTE**	**FTE**	**FTE**	**FTE**	**FTE**
Staff (Regular and Non-Regular)		**Actual**	**Actual**	**Plan**	**Plan**	**Plan**	**Plan**	**Plan**	**Plan**
Management		1,234.3	1,291.5	1,402.8	1,314.6	1,285.4	1,250.0	1,229.6	1,225.9
Society		3,629.2	3,800.3	4,320.2	4,122.9	4,003.9	3,909.4	3,877.7	3,831.5
PWU		4,448.0	4,665.7	5,078.2	5,195.6	5,251.2	5,291.5	5,210.1	5,196.6
Term/ETE/PECO Temporary		719.1	319.8	248.5	7.0	7.0	7.0	-	-
EPSCA		458.0	407.9	231.8	433.9	551.9	487.4	402.0	320.2
	Total (Regular and Non-Regular)	10,488.5	10,485.2	11,281.5	11,074.0	11,099.4	10,945.2	10,719.4	10,574.2
	Total Regular	8,362.0	8,937.7	9,970.5	10,139.8	10,083.6	9,963.2	9,887.8	9,831.5
	Mgmt % Reg	14.8%	14.5%	14.1%	13.0%	12.7%	12.5%	12.4%	12.5%
	Society % Reg	43.4%	42.5%	43.3%	40.7%	39.7%	39.2%	39.2%	39.0%
	PWU % Reg	53.2%	52.2%	50.9%	51.2%	52.1%	53.1%	52.7%	52.9%

Society Interrogatory #015

Interrogatory

Reference:
(1) OEB staff interrogatory F2-Staff-222 ie split Term/ETE/PECO Temporary FTE's into Society ETE, PWU term and Other fte's
(2) OPG reply to F4-SUP-14 a) ie update Exhibit F4-3-1, Attachment 1, "Appendix 2K" with 2025 actuals and an updated 2026 forecast.

Question(s):

a) Please update Reference (1) to show 2025 Actuals, and the latest projections for 2026 [if the 2025 Actuals are not immediately available, please update and provide them when available].

b) Update reference (2) with the FTE data provided in a) as well as the corresponding split in compensation for such.

Response

a) and b)

Refer to Ex. L-F4-AMPCO-110 Attachment 1. The latest 2026 projections available in the "Appendix 2K" level of detail are per the budget included in the pre-filed evidence.

Society Interrogatory #016

Interrogatory

Reference:
(1) OEB staff interrogatory F2-Staff-224 ie reconciliation of Exhibit F4-3-1, Attachment 1 staff total for 2024 with Exhibit F4-3-1p8 total for 2024
(2) OPG reply to F4-SUP-14 a) ie update Exhibit F4-3-1, Attachment 1, "Appendix 2K" with 2025 actuals and an updated 2026 forecast.

Question(s):

a) If OPG's reply to reference (1) requires an update to the 2024 data in Exhibit F4-3-1, Attachment 1, please update OPG's reply to reference (2).

Response

a) As explained in Ex. L-F4-Staff-224, the two referenced sources are not equivalent and cannot be reconciled.

Society Interrogatory #017

Interrogatory

Reference:
(1) OEB staff interrogatory F2-Staff-228 ie provide planned vs. actual Nuclear Base OM&A FTE numbers and compensation costs in 2022 and 2023
(2) OPG reply to F4-SUP-14 a) ie update Exhibit F4-3-1, Attachment 1, "Appendix 2K" with 2025 actuals and an updated 2026 forecast.

Question(s):

a) Please update reference (2) with data for 2022 and 2023 based on OPG's reply to reference (1).

Response

a) Refer to Ex. L-F4-Staff-228 for planned and actual Nuclear Base OM&A FTE and compensation costs in 2022 and 2023. 2025 Actuals are also provided. The latest 2026 projections available in the Appendix 2K level of detail are per the budget included in the pre-filed evidence.

Society Interrogatory #018

Interrogatory

Reference:
Exhibit F4-3-1, Attachment 3, "Total Compensation Benchmarking Study prepared by Willis Towers Watson" p12

Preamble:

"Willis Towers Watson, consistent with standard methodologies, defines competitive market positioning as +/-10% of the target market position"

Question(s):

a) Is the definition of competitive market positioning as +/-10% of the target market position a definition unique to WTW or is this an industry standard definition?

b) If +/-10% is an industry standard definition please list examples of other companies which use it.

Response

This response was prepared by WTW:

a) The use of a market range when defining compensation competitiveness is consistent with standard methodologies for compensation benchmarking purposes. WTW's standard for position and total organization benchmarking is +/- 10%. Given the limitations inherent in market data sources and the wide range of factors influencing individual compensation levels, it is important to keep in mind that market data reflect an approximation of the overall market for a job. The specific range may vary depending on the circumstances, including the underlying variability in the market data. For example, WTW at times uses a wider range (+/- 15% to +/- 20%) for total direct compensation at executive levels where the underlying variability of the data can be wider. Comparatively, +/- 10% is considered to be a reasonable range, appropriate to the range of positions included in OPG's compensation benchmarking study.

b) Publicly available examples of other companies using +/- 10% of the target market positioning include:
   i. ATCO Electric 2022 Total Remuneration Review prepared by Mercer[1]

[1] 2023-2025 General Tariff Application, Section 1, Appendix 1-B.

ii. Enbridge Gas Inc., 2022 Compensation Benchmarking Review prepared by Mercer[2]
iii. EPCOR Utilities Inc., 2025 Competitive Compensation and Benefits Analysis prepared by WTW[3]
iv. Hydro Ottawa Mercer's Market Compensation Review benchmarking analysis[4].

[2] EB-2022-0200, Exhibit 4, Tab 4, Schedule 3, Attachment 1
[3] 2026-2027 General Tariff Application, Appendix G-1
[4] EB-2024-0115, Exhibit 1, Tab 3, Schedule 3, Attachment F

Society Interrogatory #019

Interrogatory

Reference:
Exhibit F4-3-1, Attachment 3, "Total Compensation Benchmarking Study prepared by Willis Towers Watson" p7

Question(s):

a) The WTW study report is dated November 2025. Please explain why April 2024 data was used rather than more current information as of April 2025. Would not 2025 data be more relevant to this study and its purpose in this proceeding?

b) When was the April 2024 data available and how many months afterwards did it take for WTW to essentially complete the referenced study? How does this compare to the largely identical WTW study prepared for OPG's EB-2020-0290 evidence?

Response

This response was prepared by WTW:

a) WTW's compensation surveys are conducted from April to August, with an April effective date, and results released in September of the same year. As the report had to be finalized by December 2025 for filing in this proceeding, the 2025 survey results would not have been available with sufficient lead time to complete the required benchmarking, validation, and documentation activities. Accordingly, the study relied on the most recent complete WTW dataset available at the time the analysis was undertaken

b) WTW's 2024 compensation survey results were published and available in September 2024. From that point, WTW required approximately 6 months to complete the analysis and prepare the final report. This overall timing is consistent with the approach applied in the comparable WTW study filed in OPG's EB-2020-0290 proceeding, which similarly relied on the April 2019 survey effective date and the subsequent publication cycle for OPG's payment amounts application filed in December 2020.

Society Interrogatory #020

Interrogatory

Reference:
(1) Exhibit F4-3-1, Attachment 3, "Total Compensation Benchmarking Study prepared by Willis Towers Watson" p32 Comparator Organizations Non-Executives
(2) EB-2013-0321Decision With Reasons dated November 20, 2014 p75
"The Board finds that Group 2 is the most appropriate comparator for OPG. Group 2 is a small cohort of nuclear related comparators: Atomic Energy of Canada Limited, Bruce Power, Candu Energy Inc., Hydro Quebec, and New Brunswick Power. All are unionized and have or had, in the case of Hydro Quebec nuclear operations."

Question(s):

a) Regarding reference (1), please explain in detail the basis of the selection of these comparator organizations, including why rather than focus on OPG peers in the electricity, nuclear generation and nuclear generation services industries, WTW choose a vast majority of entities in completely unrelated industries. In detail, also please explain why WTW self selected comparator organizations in the:
   i. Transportation industry such as Air Canada, CNR and CPKG.
   ii. Mining industry such as Alcoa, Barrick Gold and Kinross Gold.
   iii. Fossil fuel industry such as Imperial Oil, Irving Oil, Strathcona Resources and Suncor Energy.
   iv. Public Sector organizations focused in totally unrelated areas and services to OPG such as the Business Development Bank of Canada, Export Development Canada, Investment Management Corporation of Ontario, OMERS, Ontario Teachers' Pension Plan Board, OPSEU Pension Trust, Workplace Safety and Insurance Board.

b) Further to reference (1), the majority of OPG staff work in the Greater Toronto Area which has a far greater cost of living than the regions where most of these comparator organizations are located. Did WTW normalize compensation to take into the differing regional costs of living amongst study participants. If not, why not?

c) With regard to reference (2), please explain why WTW choose:
   i. To not include Atomic Energy of Canada Limited and New Brunswick Power in OPG's comparator peer group despite the OEB panel in EB-2013-0321 deciding that they were appropriate comparators.

ii. To include Atkins Realis rather than its subsidiary Candu Energy Inc., which the OEB panel in EB-2013-0321 decided was an appropriate nuclear related comparator for OPG.

Response

This response was prepared by WTW:

a) As part of its updated compensation philosophy, OPG adopted the recommendations regarding peer group criteria outlined at Ex. F4-3-1, Attachment 2, p. 17, as further discussed in Ex. L-F4-CCMBC-008. To determine the organizations to include in the Total Excluding Nuclear Authorized comparator group, WTW applied these criteria against the participants in its 2024 Canadian compensation surveys. The criteria include ownership (corporate structure), size (revenue, assets under management[1]), industry, geography, and complexity. WTW's approach is to take the full list of participants in the survey and apply the comparator group criteria to the organizations. This methodological approach avoids any biased selection of organizations. The organizations included in the comparator group met the comparator group criteria and reflect OPG's market for talent.

i. and ii. These transportation and mining industry organizations have been included based on meeting size, corporate structure and complexity criteria. These organizations also have significant workforces in Ontario with similar skill set requirements (e.g., engineering, project management).

iii. These organizations meet WTW's definition of energy industry organizations and also meet the size, ownership and complexity criteria.

iv. These public sector organizations meet the size criteria and are significant Ontario based organizations, and have been included to meet the 25% general industry weighting criteria, aligned with OPG's compensation philosophy (as outlined in Ex. F4-3-1, Attachment 2, p. 17).

b) Market compensation levels have not been adjusted to reflect regional differences in the cost of living, which is consistent with standard benchmarking methodologies. The comparator groups used in the report reflect the organizations within OPG's talent market and capture the range of companies (in terms of industry and region) from which OPG recruits or loses talent. To the extent that OPG draws talent from a broader labour market (i.e., national), then the market competitive cost of labour

[1] Refer to Ex. L-F4-CCC-090 for discussion of when assets under management criterion is applied instead of revenue.

is national in scope regardless of where the employee is located and / or the specific cost of living in each region.

i. Atomic Energy of Canada Limited and New Brunswick Power Corporation did not participate in WTW's 2024 compensation surveys.

ii. AtkinsRéalis participated in WTW's 2024 compensation survey and provided compensation data for their employees in Candu Energy Inc. as part of their submission.

Society Interrogatory #021

Interrogatory

Reference:
(1) Exhibit F4-3-1, Attachment 3, "Total Compensation Benchmarking Study prepared by Willis Towers Watson" p32 Comparator Organizations Non-Executives
(2) EB-2021-0110 Exhibit E-6-1 Attachment 1 "Mercer Compensation Benchmarking Study Hydro One Networks" dated 8 July 2021
p3 Table 1 Benchmarking study results
p11 Table 3 Participating Organizations

Preamble:

Comparing the comparator organizations in References 1 and 2, WTW has excluded the following nine companies in the Canadian electricity industry from its study: ATCO Ltd, Toronto Hydro Corporation, Alectra Utilities, SaskPower, Manitoba Hydro, Nalcor Energy, New Brunswick Power, Hydro Ottawa, Elexicon Energy. Note that several of the above companies operate hydroelectric or nuclear generating facilities.

WTW has included 11 companies which were also included in the Reference (2) study along with 44 organizations in completely unrelated industries.

Question(s):

a) Please explain why WTW did not include in its peer group provided in Reference (1) the nine Canadian electricity industry companies listed above which were included in the Reference (2) study.

b) In place of the nine Canadian electricity industry companies listed above which were included in the Reference (2) study, please explain why did WTW substitute in the 44 organizations in completely unrelated industries in its reference (1) study?

c) What would the ballpark impact be on the WTW study in Reference (1) if the 44 organizations in completely unrelated industries mentioned in b) above were eliminated from the results?

Response

This response was prepared by WTW:

a) We note that the Reference (2) study in this question was not a study conducted by WTW, and it was not a study pertaining to OPG. Rather we understand, it was a custom study conducted by Mercer for Hydro One Networks Inc. in connection with its prior rate application and particular to the circumstances of that utility and application. WTW is not familiar with the details of this study. For purposes of the WTW study in this Application, Reference (1) above, please see our response to Ex. L-F4-SUP-020 for details regarding the selection of peer group comparator organizations. Regarding the nine Canadian electricity industry companies listed in this question, they did not participate in WTW's 2024 compensation surveys.

b) Please see our response to part (a) above, and Ex. L-F4-SUP-020 for details regarding the selection of peer group comparator organizations. WTW did not "substitute" companies in place of organizations in the Reference (2) study and we do not agree with the characterization of the organizations in this question. As noted in the response to part (a) above, the Reference (2) study was not conducted by WTW and it was not a study for OPG.

c) WTW disagrees with the characterization of the organizations in this question. The impact of excluding the 44 organizations from the comparator group cannot be accurately estimated. Completing the required analysis would take approximately four to six months, and removing these organizations would substantially reduce the size of the comparator group, resulting in insufficient data for many benchmark roles.

Society Interrogatory #022

Interrogatory

Reference:
(1) Exhibit F4-3-1, Attachment 3, "Total Compensation Benchmarking Study prepared by Willis Towers Watson" p33 Comparator Organizations Nuclear Authorized- Executives and Non-Executives

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*

(2) Exhibit F4-3-1, Attachment 3, "Total Compensation Benchmarking Study prepared by Willis Towers Watson" p5 Comparator Groups - Nuclear Authorized:
- 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

Question(s):

a) Please explain why Bruce Power was included in the WTW study but not Point Lepreau who have equivalent Canadian nuclear authorized staff and are an ideal comparator for OPG.

b) In reference (2), WTW asserts that the "comparator group reflects a sample of 10 large nuclear organizations of a comparable size to OPG". However, in terms of size, OPG is in the bottom quartile of this group. How would the study results change if the relatively huge top quartile organizations were eliminated?

c) Please explain why only nuclear organizations of allegedly "comparable size" were used when nuclear authorized staff have similar requirements regardless of size of the organization?

d) Please explain why mainly U.S.-based nuclear organizations were used when there are nuclear authorized staff around the world that could have been used as comparators. Does WTW not have ready access to such information?

Response

This response was prepared by WTW:

a) Bruce Power LP participated in WTW's 2024 compensation surveys. New Brunswick Power Corporation, the operator of the Point Lepreau Nuclear Generating Station, did not participate in WTW's 2024 compensation surveys.

b) and c) These nuclear organizations were selected for consistency with the previous studies in EB-2016-0152 and EB-2020-0290 and therefore the comparator group is unchanged. In 2015, companies for this peer group were selected based on the nuclear generating capacity and not based on revenue, as nuclear generating capacity is a good indicator of organization size and complexity. A minimum of ten organizations is required for a comparator group to conduct a competitive benchmarking analysis. Reducing the size of the organizations (either based on revenue and / or nuclear generating capacity) in the comparator group while maintaining the requisite ten organizations is expected to have a minimal impact on the study results.

c) and d) The comparator group reflects the primary talent market from which OPG recruits and retains nuclear-authorized staff, which is predominantly North America. While WTW conducts compensation surveys globally, combining non-North American data would introduce significant complexity and reduce comparability due to differences in compensation structures, pay levels and mix across jurisdictions.

Society Interrogatory #023

Interrogatory

Reference:
(1) Exhibit F4-3-1, Attachment 3, "Total Compensation Benchmarking Study prepared by Willis Towers Watson" p14 Total Remuneration Analysis Results (Nuclear Authorized compared to 50th percentile)

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.

(2) Exhibit F4-3-1, Section 5.1.1 PWU and Society-represented Term-Based Employees, p17 lines 28-29

Preamble:

"Pursuant to collective agreement provisions, OPG will have substantially no Term Employees or ETEs in its workforce after 2026."

Question(s):

a) Regarding Reference (1), please explain why Society total remuneration rose 5.4% above total direct compensation whereas PWU and Management did not when they have similar pension and health and dental benefits?

b) Per Reference (2), OPG will substantially have no Term Employees or ETEs in its workforce after 2026. How does this impact the total remuneration provided in Reference (1)?

Response

This response was prepared by WTW:

a) WTW determines the value of pension and benefit programs using a consistent methodology and a common set of assumptions for each employee profile. These profiles reflect the underlying demographics of the OPG employees represented by that profile including factors such as average age, tenure, salary, and gender. In addition to any differences in the employer provided values of the pension and benefits under the respective collective agreements with the PWU and the Society, the demographics differ between the PWU and the Society segments. As a result, the calculated pension and benefit values (and therefore total remuneration positioning) differ between segments.

b) Reference (2) refers to the expectation that OPG will not have Term Employees or ETEs after 2026. Since the benchmarking study results in Reference (1) are as of 2024 – using 2024 data, including Term Employees at the time – whether there are Term Employees or ETEs after 2026 does not impact the 2024 study results (and the 2024 employees should not be removed from the study).

In an effort to be of assistance, WTW has prepared information in Chart 1 and 2 below, on the basis of the Impact of Pension, Benefits & PWU Terms Incumbent Changes since April 2024 Analysis Results (refer to Ex. F4-3-1, Attachment 3, p.18), excluding the PWU Term and Society ETE incumbents. In this analysis, OPG Total Remuneration overall positioning would be 8.8% with Nuclear Authorized at P50 and 8.0% with Nuclear Authorized at P75.

Chart 1
Impact of Pension, Benefits & PWU Terms Incumbent Changes since April 2024 Analysis Results (p. 18 of WTW report with Nuclear Authorized at P50) - Excluding Terms and ETEs

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	4,562	18.4%	11.4%	13.8%	12.9%
Total Exc. Nuc. Auth	4,371	18.1%	10.1%	12.5%	11.6%
Nuclear Authorized	191	23.5%	30.9%	32.6%	32.4%
Society	3,707	26.1%	13.7%	17.7%	18.4%
Total Exc. Nuc. Auth	3,617	28.2%	15.6%	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	**9,568**	**15.4%**	**6.3%**	**9.1%**	**8.8%**

Chart 2
Impact of Pension, Benefits & PWU Terms Incumbent Changes since April 2024 Analysis Results (p. 18 of WTW report with Nuclear Authorized at P75) - Excluding Terms and ETEs

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	4,562	17.1%	10.3%	12.8%	11.9%
Total Exc. Nuc. Auth	4,371	18.1%	10.1%	12.5%	11.6%
Nuclear Authorized	191	4.2%	13.2%	15.8%	15.9%
Society	3,707	25.8%	13.1%	17.1%	17.7%
Total Exc. Nuc. Auth	3,617	28.2%	15.6%	19.7%	20.3%
Nuclear Authorized	90	-17.2%	-26.7%	-24.2%	-23.6%
Management	1,299	-11.9%	-14.2%	-13.3%	-14.2%
Total Exc. Nuc. Auth	1,239	-10.0%	-12.0%	-11.2%	-12.1%
Nuclear Authorized	60	-31.6%	-30.5%	-29.8%	-30.3%
OPG Total	**9,568**	**14.6%**	**5.5%**	**8.3%**	**8.0%**

Society Interrogatory #024

Interrogatory

Reference:
(1) Exhibit A1-03-01, Section 3.5 Workforce and Resource Strategy, p15 lns12-18 "OPG's regular headcount is forecast to increase by approximately 30% from 2021- 2027, then remain stable through the IR term. This is in contrast to the context of EB-2020-0290, at which time OPG was preparing to downsize as a result of then-planned end of commercial operations at Pickering in 2025. With growing external labour market pressures and a shrinking pool of skilled workers, competition for talent, especially for energy project professionals, has intensified".
(2) Exhibit F4-03-01, Section 3.2 Work Locations and Employees, p9 lns20,21 p10 lns1,2 "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".
(3) Exhibit F4-03-01, Section 3.3 Demographics, p11 lns2-4 "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."

Question(s):

a) Further to references (1), (2) and (3), skilled labour availability is a recognized execution risk for nuclear projects. Please describe how this experience profile is factored into the nuclear projects' risk management and execution planning.

Response

a) Yes, skilled labour availability is a recognized execution risk for nuclear projects that requires ongoing management and has been factored into the projects planning through appropriate strategies, including greater use of OPG labour in the case of the PRP and/or contingencies for labour supply disruption. Given the active risk mitigation described below and leveraging the strategies that worked for the DRP, the risk is expected to be manageable.

   OPG is committed to building capacity and the development of a robust supply of skilled labour and talent in the energy sector (refer to Ex. F4-3-1, p.3 and pp. 13-17). Collaborating with other sector partners, trade unions and contractors, OPG supports the development and advancement of skilled workers, strengthening their

supply. Additionally, OPG remains focused on ways to increase the level of interest by Indigenous Peoples in the skilled trades, by leading the Indigenous Opportunities Network program, which includes Building Trades Unions ("BTUs"), vendor partners and local Indigenous employment offices. More recently, OPG has been focused on direct outreach and building relationships with local educational institutions, supporting early education to advance interest in the trades and the future pipeline of talent. For example, OPG supported over 75 outreach events in 2024 and 2025 to raise awareness for energy sector jobs, including skilled trades.

OPG also continues to advance its strategies for the skilled trades pipeline, including proactively understanding signals related to demand and supply gaps in the labour market. Working with the Ontario Tripartite Labour Resource Council, these demand profiles are also communicated to the BTUs to provide confidence in the level of apprenticeship intakes and to proactively mitigate shortage risks.

In managing the risks, OPG is building on the success of the trades supply strategies applied for projects such as the Darlington Refurbishment Program ("DRP"). This included actions to address skilled trades availability through early risk identification, review of supply and demand modelling with trade unions, and sharing of critical skills information with the trade unions. OPG, together with its vendor partners, put together formal mitigation plans to address areas of need through outreach and advocacy initiatives and strategies that included utilizing permit trades and traveler resources. OPG also coordinated with Bruce Power LP to ensure resources were available for projects by sharing demand data and jointly discussing areas of risk. An example of this collaboration was a vendor partner's utilization of trained resources at Darlington who had also executed refurbishment work at the Bruce stations, minimizing training and reducing the number of trades needed.

Internally, OPG uses a robust enterprise risk management process to identify, classify, quantify, and mitigate risks. Through risk management practices, the status of challenges with trades availability is monitored and partnerships with the respective unions can respond to help build supply where needed. An example with the DRP was the Boilermaker Helper program, where an additional 100 temporary boilermakers were hired and trained to support lower-skilled demolition work so that higher skilled Boilermakers were available for the critical parts of the project.

Other strategies are leveraged through workforce planning. As discussed in Ex. F4-3-1, pp. 6-7 and Ex. D2-3-2, p.10, the resourcing flexibility negotiated between OPG, the BTU and the PWU enables work historically performed by the BTUs to be assigned to members of the PWU, which will help optimize the execution of the project and enable cost efficiencies (refer to Ex. L-F4-SEC-194). This workforce

planning approach entails redeploying existing PWU-represented employees to perform certain work on the project, allowing skilled, knowledgeable and site-experienced labour to execute the work. In addition, the parties have agreed to the potential use of composite/blended crews to better utilize the combined capabilities of the PWU and BTU represented resources, where appropriate (refer to Ex. D2-3-2, p.10). This overall approach to redeployment and resourcing the PRP will support the timely availability of the necessary skilled labour for the program, as well as to the Pickering station itself once the refurbished units begin to return to service.

Society Interrogatory #025

Interrogatory

Reference:
(1) Exhibit F4-3-1, Section 2.0 Overview, p4 lns23-26
"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."
(2) Exhibit F4-3-1, Section 6.2.2 Management Salaries, p29 lns8,9
"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."

Question(s):

a) OPG states that wage compression makes it more difficult to attract experienced employees into management positions. Please provide summary information on the experience profile of individuals appointed to management roles from 2021 through 2025, including:
   i. The average and median years of relevant nuclear industry experience at the time of appointment;
   ii. Whether these roles were filled through internal promotion or external recruitment; and
   iii. The current number of filled and unfilled Band H positions (first level above the Society of United Professionals), and how these vacancies relate to the Company's stated challenges in attracting experienced managers.
   iv. In addition to wage compression, please explain whether other factors affect the ability to attract experienced employees into Band H management positions, including job security, exposure to termination risk, and proximity to retirement, and how these factors have been considered in the Company's management staffing and compensation approach.

Response

a)
   i. Recruitment and selection of candidates is based on the best qualified basis for both internal and external hires. As OPG does not permanently collect such data on an employee's personal work history, the information is not available for aggregation and averaging.

ii. Over the 2021-2025 period, approximately 34% of Band H positions were filled through promotions of internal employees and approximately 25% through external hiring, with the remaining positions filled through other means such as lateral movements.

iii. Currently, there are approximately 25 Band H unfilled vacancies. These vacancies are primarily in project management and IT roles, areas where OPG competes for management talent with companies across Canada and the US.

iv. As outlined at Ex. F4-3-1, p. 30, there have been both non-compensation and compensation-related initiatives implemented to help retain and attract qualified management employees. As a result, there has been an approximately 30% increase in Society-represented employees moving into management roles over the 2021-2025 period. However, externally, compensation remains the top reason offers are declined. OPG recognizes that each employee has their own evolving personal goals as it relates to career and skill development and is not able to infer as to what each individual might consider.

Society Interrogatory #026

Interrogatory

Reference:
Exhibit F4-3-1, Section 5.1 Workforce Planning and Redeployments, p15 lns 29-31, p16 ln1

Preamble:

"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."

Question(s):

a) OPG has indicated that approximately 1,500 staff are being redeployed to other areas of the organization. For the purpose of assessing the prudence and reasonableness of costs proposed for recovery through rates, please describe the training required to support these redeployments, including:
   i. The types of training provided (e.g., technical, safety, regulatory, management, or role specific);
   ii. The estimated total training costs associated with the redeployments, by year;
   iii. Whether these training costs are included in the OM&A forecast in this application; and
   iv. The expected duration over which redeployed staff are anticipated to reach full productivity in their new roles along with the total annual cost of this lower productivity.

Response

a)
   i. Central to the redeployment strategy, as discussed in Ex. F4-3-1, OPG successfully secured agreements with the PWU and the Society that permit the movement of employees between locations where they are performing the same or similar work. These agreements support optimal resourcing for the PRP, ensuring the expedited availability of proficient skilled labour required to meet project demands and schedules. OPG has been able to rely on and utilize employees already trained, knowledgeable in their work, and familiar with the station(s), to support such timely transitions. As a result, the required training is

limited. This strategy, as it relates to the PRP, is discussed further in Ex. D2-3-4. Where employees are redeployed to roles outside of their base position to address business needs, OPG has prioritized coordination of knowledge, skill and capability, aligning the employees' new assignments with their pre-existing core competencies. This ensures that OPG maximizes specialized knowledge, while minimizing the potential training time, for the efficient execution of required work.

ii. and iii.

Training costs as a result of redeployment are expected to be minimal given most employees being redeployed perform the same or similar job functions and are not separately identified in OPG's 2025-2031 Business Plan. OPG notes that, as detailed in Ex. L-F4-SEC-194, the redeployment strategy and workforce plan for resourcing the PRP will avoid significant incremental training and other costs compared to severing and subsequently re-hiring such otherwise PWU redeployed employees.

iv. The utilization of already proficient skilled labour in order to meet project demands and schedules is a primary objective of OPG's redeployment strategy. As most employees will be performing the same or similar job functions, there is not an expectation of lower productivity.

Society Interrogatory #027

Interrogatory

Reference:
Exhibit F4-3-2 Pension and OPEB Costs

Question(s):

a) OPG uses an accrual basis for including its pension costs in rates, either as OM&A or capex. Please discuss any impacts on customers of OPG's decision to reduce its pension contributions, including the impact on its financing costs and intergenerational equity.

Response

a) OPG understands the question to refer to its decision to reduce registered pension plan contributions on account of the funding surplus, as discussed in Ex. F4-3-1, Section 7.0.1. As discussed in Ex. F4-3-2, Section 2.0, pension and OPEB costs for the regulated facilities have been calculated on an accrual basis of accounting for the purposes of the proposed revenue requirements.

The reduction in pension contributions has a small impact on customers, resulting in an estimated average increase of less than 0.1% in the impact of the Application on a typical monthly residential customer bill. The estimated revenue requirement impacts underpinning this calculation can be found in Ex. L-F4-PWU-012. The impacts reflect forecasted lower earnings on the pension asset component of the pension accrual costs as a result of the lower contributions over the IR term, together with the effects of such lower contributions on the regulatory income tax calculations

OPG has not identified any meaningful intergenerational equity considerations for customers with respect to its reduced pension contributions, as the payment amounts are proposed to reflect the accrual basis of accounting. As shown at Ex. F4-3-2, Chart 6 and Chart 7, taking into account the impact of the reduced pension contributions on account of the funding surplus, the forecasted pension accrual costs for OPG's prescribed facilities over the 2027-2031 period remain lower than the corresponding cash amounts. As discussed in Ex. H1-1-1, Section 5.12, the Pension and OPEB Forecast Accrual versus Actual Cash Differential Variance Account will continue to record interest on the difference between OPG's pension and OPEB accrual costs and cash amounts, asymmetrically in favour of ratepayers.

Society Interrogatory #028

Interrogatory

Reference:
Exhibit F4-3-2 Pension and OPEB Costs

Question(s):

a) Should OPG be required to increase its pension contributions as a result of the next pension actuarial assessment, please explain what, if any, the impacts would be to customers or to established variance accounts.

Response

a) This question is effectively the inverse of the one posed at Ex. L-F4-SUP-027. For the same reasons as discussed in Ex. L-F4-SUP-027, should OPG be required to increase its pension contributions during the 2027-2031 IR term relative to the forecast amounts underpinning the payment amounts approved in this proceeding, there would be a small reduction in the revenue requirement impacts associated with the pension and OPEB costs for OPG and DNNP LP's prescribed facilities and these amounts would be recorded in the respective Pension and OPEB Cost Variance Account as a future refund to customers.

As noted in Ex. L-F4-SUP-027, the forecasted pension accrual costs for OPG's prescribed facilities over the 2027-2031 period remain lower than the corresponding cash amounts. As discussed in Ex. H1-1-1, Section 5.12, the Pension and OPEB Forecast Accrual versus Actual Cash Differential Variance Account will continue to record interest on the difference between OPG's pension and OPEB accrual costs and cash amounts, asymmetrically in favour of ratepayers.