AMPCO Interrogatory #125

Interrogatory

Reference:
I1-1-1

Question(s):

Please provide the following Tables on the basis of the following assumptions: current capital structure remains, current Stretch Factor for nuclear remains: Table 1, Table 2, Table 3a, Table 3b, Table 4 and Table 5.

Response

Refer to Attachment 1 for versions of Ex. I1-1-1, Table 1, Table 2, Table 3a, and Table 3b hypothetically reflective of the deemed capital structure and nuclear stretch factor approved in EB-2020-0290.

Exhibit I1-1-1, Table 4 (Determination of 2025 Forecast Return on Equity) and Table 5 (Determination of 2026 Forecast Return on Equity) are reflective of the 2022-2026 deemed capital structure, and the nuclear payment amounts in place in those years were reflective of the stretch factors approved in EB-2020-0290. As such, updated versions of those tables are not provided.

Table 1
Summary of Revenue Requirement - Regulated Hydroelectric - Hypothetical EB-2020-0290 Assumptions ($M)
Year Ending December 31, 2027

Line No.	Description	Note	2027
			(a)
	Rate Base		
1	**Net Fixed Assets**	1	9,115.6
2	**Working Capital**	1	0.3
3	**Cash Working Capital**	1	19.3
4	**Total Rate Base**		9,135.1
	Capitalization		
5	**Short-Term Debt**	2	152.4
6	**Long-Term Debt**	2	4,871.9
7	**Common Equity**	2	4,110.8
8	**Total Capital**		9,135.1
	Cost of Capital		
9	**Short-Term Debt**	3	7.7
10	**Long-Term Debt**	3	223.1
11	**Common Equity**	3	374.5
12	**Total Cost of Capital**		605.3
	Expenses:		
13	**OM&A**	4	498.9
14	**GRC**	5	352.2
15	**Depreciation & Amortization**	6	215.4
16	**Property Tax**	7	2.1
17	**Total Expenses**		1,068.5
	Less:		
	Other Revenues		
18	**Ancillary and Other Revenue**	8	62.2
19	**Total Other Revenues**		62.2
20	**Income Tax**	9	7.9
21	**Revenue Requirement** (line 12 + line 17 - line 19 + line 20)		1,619.5
22	**Amortization of Variance & Deferral Account Amounts**	10	(37.9)
23	**Revenue Requirement Plus Variance & Deferral Account Amounts** (line 21 + line 22)		1,581.5

Notes:
1 Per Ex. B1-1-1 Table 1.
2 Total capital cost unchanged from pre-filed evidence. Portion deemed to be financed by long-term debt and common equity based on 45% equity and 55% debt structure.
3 Regulated hydroelectric portion of totals from Ex. C1-1-1 Table 5, (col. (d) - recalculated using 45% equity and 55% debt structure). 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. Change from pre-filed evidence due to deemed capital structure in Asset Service Fees.
5 Per Ex. F1-1-1, Table 1, line 7.
6 Per Ex. F4-1-1, Table 1, line 10.
7 Per Ex. F4-2-1, Table 1, line 5.
8 Per Ex. G1-1-1, Table 1, line 7.
9 Per Ex. F4-2-1, Table 1, line 1. Change from pre-filed evidence due to change in return on equity resulting from deemed capital structure of 45% equity and 55% debt.
10 Per Ex. H1-2-1 Table 1, col. (h), line 19.

Numbers may not add due to rounding.

Table 2
Summary of Revenue Requirement - OPG Nuclear Facilities - Hypothetical EB-2020-0290 Assumptions ($M)
Years Ending December 31, 2027 to 2031

Line No.	Description	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
	Rate Base						
1	**Net Fixed Assets**	1	14,920.0	15,375.4	15,247.3	15,769.2	22,435.9
2	**Working Capital**	1	897.1	975.3	1,040.2	1,120.8	1,174.5
3	**Cash Working Capital**	1	(22.5)	(22.4)	(22.5)	(22.5)	(22.5)
4	**Total Rate Base**		15,794.7	16,328.3	16,265.0	16,867.5	23,587.9
	Capitalization						
5	**Short-Term Debt**	2	261.9	259.9	248.9	246.6	274.6
6	**Long-Term Debt**	2	8,370.1	8,708.0	8,696.9	9,030.5	12,698.8
7	**Common Equity**	2	6,988.7	7,271.3	7,259.6	7,536.5	10,564.9
7a	**EB-2020-0290 Settlement Adjustment for Equity at Long-Term Debt Rate**	13	73.9	66.1	59.6	53.9	49.6
8	**Adjustment for Lesser of UNL or ARC**	2	100.1	23.0	0.0	0.0	0.0
9	**Total Capital**		15,794.7	16,328.3	16,265.0	16,867.5	23,587.9
	Cost of Capital						
10	**Short-Term Debt**	3	13.3	12.2	12.0	11.4	13.2
11	**Long-Term Debt**	3	383.2	416.6	426.2	448.5	632.7
12	**Common Equity**	3	636.7	662.4	661.4	686.6	962.5
12a	**EB-2020-0290 Settlement Adjustment for Equity at Long-Term Debt Rate**	13	3.4	3.2	2.9	2.7	2.5
13	**Adjustment for Lesser of UNL or ARC**	3	4.7	1.1	0.0	0.0	0.0
14	**Total Cost of Capital**		1,041.3	1,095.5	1,102.6	1,149.2	1,610.9
	Expenses:						
15	**OM&A**	4	1,863.0	1,755.6	1,916.7	1,855.5	2,152.5
16	**Fuel**	5	150.9	221.7	223.6	261.2	306.1
17	**Depreciation & Amortization**	6	663.3	708.5	730.3	779.8	992.6
18	**Property Tax**	7	14.0	14.2	14.5	14.8	15.0
19	**Total Expenses**		2,691.2	2,700.0	2,885.0	2,911.4	3,466.3
	Less:						
	Other Revenues						
20	**Bruce Lease Revenues Net of Direct Costs**	8	(5.2)	11.5	(18.1)	7.3	(17.1)
21	**Ancillary and Other Revenue**	9	6.3	32.7	13.8	13.5	23.6
22	**Total Other Revenues**		1.1	44.2	(4.3)	20.8	6.5
22a	**Concurrent Cost Recovery - Pickering Refurbishment Program**	14	297.6	479.9	667.7	832.0	646.2
23	**Income Tax**	10	(16.6)	(16.6)	(16.6)	(16.6)	(16.6)
24	**Revenue Requirement Before Stretch Factor** (line 14 + line 19 - line 22 + Line 22a + line 23)		4,012.3	4,214.6	4,642.9	4,855.1	5,700.2
25	**Cumulative Nuclear Stretch Dollars**	11	0.0	13.8	28.9	44.4	53.6
26	**Revenue Requirement Net of Stretch Factor** (line 24 - line 25)		4,012.3	4,200.8	4,614.1	4,810.7	5,646.7
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)		4,146.8	4,335.3	4,748.6	4,878.5	5,714.4

Notes:
1 Per Ex. B1-1-1 Table 2.
2 Total capital cost unchanged from pre-filed evidence. Portion deemed to be financed by long-term debt and common equity based on 45% equity and 55% debt structure.
3 OPG's nuclear facilities portion of totals from Ex. C1-1-1 Table 5, (col. (d) - recalculated using 45% equity and 55% debt structure). 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. Change from pre-filed evidence due to deemed capital structure in Asset Service Fees.
5 Per Ex. F2-1-1, Table 1a, line 17.
6 Per Ex. F4-1-1, Table 2, line 11.
7 Per Ex. F4-2-1, Table 2, line 4.
8 Per Ex. G2-2-1, Table 1, line 3.
9 Per Ex. G2-1-1, Table 1, line 7.
10 Per Ex. F4-2-1, Table 2, line 1.
11 Recalculated using stretch factor percentages approved in EB-2020-0290: 0.6% for 2023-2025 and 0.3% for 2026. For this hypothetical response, these percentage are applied as 0.6% for 2028-2030 and 0.3% for 2031.
12 Per Ex. H1-2-1 Table 2, col. (h)-(l), line 32.
13 Per Ex. C1-1-1, Tables 1-5, line 5. Represents the portion of rate base financed by common equity that is subject to return at the long-term debt rate until 2036 per the OEB-approved settlement proposal in EB-2020-0290 (Settlement Proposal, p. 23).
14 Per Ex. I1-1-1, Table 7, line 7.

Table 3a
Summary of Revenue Deficiency - Regulated Hydroelectric - Hypothetical EB-2020-0290 Assumptions
January 1, 2027 to December 31, 2027

Line No.	Description	Note	2027
			(a)
1	**Forecast Production (TWh)**	1	32.5
2	**2026 Payment Amount per EB-2020-0290 ($/MWh)**	2	43.88
3	**Indicated Production Revenue ($M)** (line 1 x line 2)		1,424.4
4	**Revenue Requirement ($M)**	3	**1,619.5**
5	**Revenue Requirement Deficiency ($M)** (line 4 - line 3)		**195.0**

Notes:
1 Ex. E1-1-1, Table 1, line 4.
2 EB-2020-0290 Payment Amounts Order, p. 4.
3 Ex. L-I1-AMPCO-125, Table 1, line 21.

Table 3b
Summary of Revenue Deficiency - OPG Nuclear Facilities - Hypothetical EB-2020-0290 Assumptions
January 1, 2027 to December 31, 2031

Line No.	Description	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
1	**Forecast Production (TWh)**	1	18.7	26.7	25.1	26.8	28.9
2	**2026 Payment Amount per EB-2020-0290 ($/MWh)**	2	111.33	111.33	111.33	111.33	111.33
3	**Indicated Production Revenue ($M)** (line 1 x line 2)		2,081.0	2,971.6	2,790.6	2,986.3	3,222.2
4	**Revenue Requirement Net of Stretch Factor ($M)**	3	**4,012.3**	**4,200.8**	**4,614.1**	**4,810.7**	**5,646.7**
5	**Revenue Requirement Deficiency ($M)** (line 4 - line 3)		**1,931.3**	**1,229.2**	**1,823.4**	**1,824.4**	**2,424.4**

Notes:
1 Ex. E2-1-1, Table 1, line 3.
2 EB-2020-0290 Payment Amounts Order, App. B, Table 1, line 3, col. (e).
3 Ex. L-I1-AMPCO-125, Table 2, line 26.

AMPCO Interrogatory #126

Interrogatory

Reference:
I1-1-2

Question(s):

a) Please provide the bill impacts (and show the calculation) for a typical Class A customers (10 MW) associated with:
   i. Nuclear revenue requirements
   ii. Hydroelectric revenue requirements
   iii. Clearance of deferral and variance accounts

b) Please provide the bill impacts for the following customer classes (Residential, GS<50 kW, GS >50 kW, Large User (1,000-4,999 kw) associated with:
   iv. Nuclear revenue requirements
   v. Hydroelectric revenue requirements
   vi. Clearance of deferral and variance accounts

Response

a) and b)
Refer to Ex. L-I1-SEC-215.

CCC Interrogatory #109

Interrogatory

Reference:
Exhibit I1, Tab 3, Schedule 2, p. 5

Question(s):

Please provide a revised version of Chart 3 that shows the WAPA and residential bill impacts in a single table based on the shaping proposal.

Response

The requested information is presented in Chart 1, below.

Chart 1 – Ex. I1-3-2, Chart 3 –
Reproduced with Proposed Weighted Average Payment Amount

Line No	Description	2027	2028	2029	2030	2031
1	BNPA ($/MWh)	206.70	192.42	202.74	199.16	219.60
2	BNPR ($/MWh)	7.19	5.04	5.36	2.48	2.19
3	TNPF (TWh)	18.69	26.69	25.07	27.32	30.87
4	HPA ($/MWh)	51.39	54.97	59.20	62.02	64.21
5	HPR ($/MWh)	(1.17)	(1.17)	(1.17)	0.00	0.00
6	HPF (TWh)	32.46	32.46	32.46	32.46	32.46
7	WAPA ($/MWh)	110.03	118.62	123.42	125.83	141.02
8	WAPA (% y/y change)	41.5%	7.8%	4.0%	2.0%	12.1%
9	Typical Residential Monthly Bill Impact (%)	5.6%	1.7%	0.9%	0.5%	3.3%

SEC Interrogatory #215

Interrogatory

Reference:
I1-1-2, p. 6, Table 1

Question(s):

Please provide a revised version of Table 1 that shows bill impacts for all major rate classes (i.e. not just residential but also GS<50, GS>50, Large Use).

Response

As discussed in Ex. I1-1-2, the Applicants estimated monthly consumer bill impacts using typical consumer data based on the average electricity distributor bill information provided on the OEB's website at:
https://www.oeb.ca/consumer-information-and-protection/bill-calculator

The Applicants are unaware of a similar tool for typical customers in all major rate classes across all OEB-regulated distributors and, thus, cannot perform the requested analysis for all major rate classes. However, they provide Attachment 1 that contains a bill impact analysis for medium and large volume customers using data from Toronto Hydro, Alectra (PowerStream rate zone) and Hydro One Networks. This analysis is consistent with information provided in prior OPG applications dating back to EB-2016-0152.[1]

[1] The origin of this analysis is discussed in EB-2016-0152, Ex. J20.1, Attachment 1.

Numbers may not add due to rounding.

Table 1
Annualized Bill Impact for Typical Alectra (PowerStream) Consumers 2027-2031

Line No.	Description	Note	2027		2028		2029		2030		2031	
			Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	**Typical Consumer Usage (kWh/Month)**	1	82,952	2,840,600	82,952	2,840,600	82,952	2,840,600	82,952	2,840,600	82,952	2,840,600
2	**Total Forecast Production (TWh)**	2	51.2	51.2	59.2	59.2	57.5	57.5	59.8	59.8	63.3	63.3
3	**OPG Portion of Consumer Usage**	3	31.2%	31.2%	36.1%	36.1%	35.1%	35.1%	36.5%	36.5%	38.6%	38.6%
4	**Consumer Usage of OPG Generation (kWh/Month)**		25,885	886,414	29,933	1,025,029	29,111	996,860	30,253	1,035,967	32,049	1,097,483
	(line 1 x line 3)											
5	**Typical Monthly Consumer Bill ($)**	1	19,554	623,417	19,554	623,417	19,554	623,417	19,554	623,417	19,554	623,417
	EB-2020-0290/EB-2023-0336 to EB-2025-0297:											
6	**Increase in OPG Weighted Average Total Payments ($/MWh)**	4	32.30	32.30	8.62	8.62	4.95	4.95	2.58	2.58	15.35	15.35
7	**Percentage Increase in Consumer Bills**		4.28%	4.59%	1.32%	1.42%	0.74%	0.79%	0.40%	0.43%	2.52%	2.70%
	(line 6 x (line 4/1000) / line 5)											
8	**Dollar Increase in Consumer Bills ($)** (line 5 x line 7)		836.10	28,631.18	258.02	8,835.75	144.10	4,934.46	78.05	2,672.80	491.95	16,846.36

Notes:
1 Current Approved Rates and Usage (adjusted for line losses) are taken from the Alectra EB-2025-0055 proceeding, Excel File: Final rate order_Alectra_RGM PRZ_20251222
GS > 50 customer, consumption 80,000 kWh, loss factor 3.69%
Large User customer, consumption 2,800,000 kWh, loss factor 1.45%
2 Per Ex. I1-1-2, Table 2, line 3 and line 6.
3 Per Ex. I1-1-2, Table 1, line 11.
4 Per Ex. I1-1-2, Table 1, line 8.

Numbers may not add due to rounding.

Table 2
Annualized Bill Impact for Typical Hydro One Networks Consumers 2027-2031

Line No.	Description	Note	2027 Medium/Large Business	2027 Large Industrial	2028 Medium/Large Business	2028 Large Industrial	2029 Medium/Large Business	2029 Large Industrial	2030 Medium/Large Business	2030 Large Industrial	2031 Medium/Large Business	2031 Large Industrial
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	**Typical Consumer Usage (kWh/Month)**	1	38,306	1,655,471	38,306	1,655,471	38,306	1,655,471	38,306	1,655,471	38,306	1,655,471
2	**Total Forecast Production (TWh)**	2	51.2	51.2	59.2	59.2	57.5	57.5	59.8	59.8	63.3	63.3
3	**OPG Portion of Consumer Usage**	3	31.2%	31.2%	36.1%	36.1%	35.1%	35.1%	36.5%	36.5%	38.6%	38.6%
4	**Consumer Usage of OPG Generation (kWh/Month)**		11,953	516,593	13,823	597,376	13,443	580,959	13,970	603,751	14,800	639,601
	(line 1 x line 3)											
5	**Typical Monthly Consumer Bill ($)**	1	8,413	269,489	8,413	269,489	8,413	269,489	8,413	269,489	8,413	269,489
	EB-2020-0290/EB-2023-0336 to EB-2025-0297:											
6	**Increase in OPG Weighted Average Total Payments ($/MWh)**	4	32.30	32.30	8.62	8.62	4.95	4.95	2.58	2.58	15.35	15.35
7	**Percentage Increase in Consumer Bills**		4.59%	6.19%	1.42%	1.91%	0.79%	1.07%	0.43%	0.58%	2.70%	3.64%
	(line 6 x (line 4/1000) / line 5)											
8	**Dollar Increase in Consumer Bills ($)** (line 5 x line 7)		386.10	16,685.94	119.15	5,149.38	66.54	2,875.75	36.04	1,557.68	227.18	9,817.88

Notes:
1 Current Approved Rates and Usage (adjusted for line losses) are taken from EB-2021-0110, Excel file: HONI_JRAP_Settlement Proposal_Attachment Update_Attachment 2_Schedule 7.1_20221116
Medium/Large Business: GSd_Avg customer, consumption 34,334 kWh, loss factor 6.1%
Large Industrial: ST_Avg customer, consumption 1,373,443 kWh, loss factor 3.4%
2 Per Ex. I1-1-2, Table 2, line 3 and line 6.
3 Per Ex. I1-1-2, Table 1, line 11.
4 Per Ex. I1-1-2, Table 1, line 8.

Numbers may not add due to rounding.

Table 3
Annualized Bill Impact for Typical Toronto Hydro Consumers 2027-2031

Line No.	Description	Note	2027 Medium/Large Business	2027 Large Industrial	2028 Medium/Large Business	2028 Large Industrial	2029 Medium/Large Business	2029 Large Industrial	2030 Medium/Large Business	2030 Large Industrial	2031 Medium/Large Business	2031 Large Industrial
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	**Typical Consumer Usage (kWh/Month)**	1	81,331	3,967,080	81,331	3,967,080	81,331	3,967,080	81,331	3,967,080	81,331	3,967,080
2	**Total Forecast Production (TWh)**	2	51.2	51.2	59.2	59.2	57.5	57.5	59.8	59.8	63.3	63.3
3	**OPG Portion of Consumer Usage**	3	31.2%	31.2%	36.1%	36.1%	35.1%	35.1%	36.5%	36.5%	38.6%	38.6%
4	**Consumer Usage of OPG Generation (kWh/Month)**		25,379	1,237,934	29,348	1,431,519	28,542	1,392,179	29,661	1,446,795	31,423	1,532,705
	(line 1 x line 3)											
5	**Typical Monthly Consumer Bill ($)**	1	14,446	694,406	14,446	694,406	14,446	694,406	14,446	694,406	14,446	694,406
	EB-2020-0290/EB-2023-0336 to EB-2025-0297:											
6	**Increase in OPG Weighted Average Total Payments ($/MWh)**	4	32.30	32.30	8.62	8.62	4.95	4.95	2.58	2.58	15.35	15.35
7	**Percentage Increase in Consumer Bills**		5.67%	5.76%	1.75%	1.78%	0.98%	0.99%	0.53%	0.54%	3.34%	3.39%
	(line 6 x (line 4/1000) / line 5)											
8	**Dollar Increase in Consumer Bills ($)** (line 5 x line 7)		819.76	39,985.27	252.98	12,339.69	141.28	6,891.29	76.53	3,732.73	482.34	23,527.02

Notes:
1 Current Approved Rates and Usage (adjusted for line losses) are taken from EB-2023-0195, excel file THESL_DRO_Schedule 8_OEB_Appendix_2-W_Bill Impacts_20241126
Medium/Large Business: GS 50-999 customer, consumption 79,000 kWh, loss factor 2.95%
Large Industrial : Large Use customer, consumption 3,900,000 kWh, loss factor 1.72%
2 Per Ex. I1-1-2, Table 2, line 3 and line 6.
3 Per Ex. I1-1-2, Table 1, line 11.
4 Per Ex. I1-1-2, Table 1, line 8.

SEC Interrogatory #216

Interrogatory

Reference:
I1-3-2, p. 6, Attachment 1, p. 19

Question(s):

With respect to rate shaping:

a) Please confirm the amounts included in Approaches A, B and C, were provided to Innovative by OPG.

b) Please explain why OPG (or Innovative if (a) it is not confirmed) did not consider an approach where payment amounts or bill impacts increased at the same rate each year between 2027 and 2031.

c) Please provide the annual revenue requirement deferrals required to have the same annual percentage increase for each of, i) payment amounts, and ii) bill impact, for each year between 2027 and 2031.

d) What would be the incremental interest costs if the approaches discussed in part (c) were implemented. Please provide all supporting calculations.

Response

a) OPG confirms that the Approach A, B and C amounts included in the chart at Ex. I1-3-2, Attachment 1, p. 19 were provided by OPG.

b) OPG did not pursue an approach where weighted average payment amounts ("WAPA") or typical residential customer bill impacts increased at the same rate in each year between 2027 and 2031 because such an approach would fail the financial viability criterion of not adversely affecting OPG's credit metrics (Ex. I1-3-1, Section 4.1). Additionally, as demonstrated in parts (c) and (d), below, a shaping proposal that results in increasing WAPA at the same rate each year would require deferring $1,528M of OPG's proposed nuclear revenue requirement in 2027 and result in interest costs of $328M; and a shaping proposal that results in increasing typical residential customer bill impacts at the same rate each year would require deferring $1,300M in 2027, and results in interest costs of $228M.

c) The requested information is summarized in Chart 1 and Chart 2 below.

Chart 1
Payment Amount Shaping Hypothetical Scenario: Constant Rate Increase (WAPA)

	2027	2028	2029	2030	2031
Proposed Combined Revenue Requirement Before Shaping ($M)	4,363.8	4,636.2	5,081.9	5,441.7	6,779.6
Hypothetical Revenue Requirement Shaping Adjustment ($M)	(1,527.8)	(362.9)	(176.6)	800.1	1,267.7
Hypothetical Shaped Combined Revenue Requirement ($M)	2,836.0	4,273.3	4,905.2	6,241.8	8,047.3
Total Nuclear Production Forecast (TWh)	18.7	26.7	25.1	27.3	30.9
Hypothetical Blended Nuclear Payment Amount After Shaping ($/MWh)	151.72	160.09	195.69	228.44	260.66
Year-over-year Change in Hypothetical WAPA (%)	15.7%	15.7%	15.7%	15.7%	15.7%
Typical Residential Consumer Bill Impact (%)*	2.1%	2.8%	3.2%	3.8%	4.7%

* The bill impact analysis reflects the format, methodology and applicable inputs used to produce Ex. I1-1-2, Table 1 that determines the estimated typical residential consumer impacts of the Application.

Chart 2
Payment Amount Shaping Hypothetical Scenario: Constant Rate Increase (Bill Impact)

	2027	2028	2029	2030	2031
Proposed Combined Revenue Requirement Before Shaping ($M)	4,363.8	4,636.2	5,081.9	5,441.7	6,779.6
Hypothetical Revenue Requirement Shaping Adjustment ($M)	(1,299.5)	(81.2)	10.2	718.9	651.2
Hypothetical Shaped Combined Revenue Requirement ($M)	3,064.3	4,555.0	5,098.8	6,160.6	7,430.9
Total Nuclear Production Forecast (TWh)	18.7	26.7	25.1	27.3	30.9
Hypothetical Blended Nuclear Payment Amount After Shaping ($/MWh)	163.93	170.65	203.17	225.47	240.69
Year-over-year Change in Hypothetical WAPA (%)	21.4%	15.3%	13.6%	11.5%	9.8%
Typical Residential Consumer Bill Impact (%)*	2.9%	2.9%	2.9%	2.9%	2.9%

* The bill impact analysis reflects the format, methodology and applicable inputs used to produce Ex. I1-1-2, Table 1 that determines the estimated typical residential consumer impacts of the Application.

d) An estimate of interest costs associated with the scenarios requested in part (c) is presented in Charts 3 and 4, below. The total estimated interest under a scenario with payment amounts increasing at a constant rate is $328M (sum of interest row in Chart 3). The total estimated interest under a scenario with bill impacts increasing at a constant rate is $228M (sum of interest row in Chart 4).

Chart 3
Interest Cost for Payment Amount Shaping Hypothetical Scenario: Constant Rate Increase (WAPA)

	2027	2028	2029	2030	2031
Opening (before interest)	-	1,528	1,891	2,067	1,267
Transactions (per part c)	1,528	363	177	(800)	(1,267)
Closing (before interest)	1,528	1,891	2,067	1,267	-
Estimated Annual Interest*	35	82	97	83	32

*The interest estimate is calculated by multiplying the average of the opening and closing balance by OPG's proposed long-term debt rates in Ex. C1-1-1, Tables 1-5.

Chart 4
Interest Cost for Payment Amount Shaping Hypothetical Scenario: Constant Rate Increase (Bill Impact)

	2027	2028	2029	2030	2031
Opening (before interest)	-	1,300	1,381	1,370	651
Transactions (per part c)	1,300	81	(11)	(719)	(651)
Closing (before interest)	1,300	1,381	1,370	651	-
Estimated Annual Interest*	30	64	67	50	16

*The interest estimate is calculated by multiplying the average of the opening and closing balance by OPG's proposed long-term debt rates in Ex. C1-1-1, Tables 1-5.

Board Staff Interrogatory #258

Interrogatory

Reference:
Ref 1: Exhibit A1 / Tab 2 / Schedule 2 / p. 7
Ref 2: Exhibit I1 / Tab 1 / Schedule 3 / pp.8-9

Preamble:

Reference 1 outlines that OPG is seeking approval of an annual process to recover balances recorded in the Darlington New Nuclear Project (DNNP) Variance Account re Capital Cost Amounts and the Pickering B Refurbishment Project (PRP) Variance Account, beginning with recovery of 2026 balances during 2027. OPG also notes that pursuant to O. Reg 53/05, recovery is to occur in the year following the year in which amounts are recorded, to the extent the OEB is satisfied the amounts are accurately recorded.

Reference 2 outlines the Applicants' proposal for this annual recovery.

Question(s):

a) Please explain whether the Applicants plan to dispose of the PRP and DNNP concurrent cost recovery (CCR) variance account amounts on an audited or forecast basis.

b) Please describe the proposed review and true-up mechanism for any forecast to actual differences, corrections, or audit adjustments identified after the year-end and how they would be treated.

c) Please describe the evidence OPG expects to provide each year to enable the OEB to be satisfied that the balances are accurately recorded, including at minimum, confirmation of:
   i. A continuity schedule with the opening balance, transactions, interest, closing balance;
   ii. A reconciliation to audited source records;
   iii. Supporting details for capital expenditures and in-service amounts, as applicable;
   iv. A demonstration that no duplication has occurred with amounts otherwise reflected in payment amounts or other DVAs.

d) Please describe the proposed interest calculation methodology, including the applicable interest rate, and period over which interest accrued.

e) Please explain whether the Applicants propose to set the associated payment amount ride on the basis of an already OEB-approved production forecast or a new production forecast provided through that application. Please include the rationale for this proposal.

f) Please explain whether and how the Applicants considered combining this application to recover CCR amounts with other annual applications from either OPG, DNNP LP, or the Applicants.

Response

a) The Applicants propose to clear the year-end balances in the Darlington New Nuclear Project Variance Account re Capital Cost Amounts and the Pickering B Refurbishment Project Variance Account (collectively, "CCR DVA") on an audited, actual basis.

b) The Applicants expect that any adjustments identified as a result of the audit of the CCR DVA balances in respect of a given year would be reflected in the balances submitted in such year's annual clearance application. Any adjustments or corrections identified thereafter the approval of the annual balances could be addressed in the following year's annual clearance application.

c) The Applicants confirm that an annual continuity schedule with the opening balance, transactions, interest and closing balance for each of the CCR DVAs will be filed as part of the annual clearance application. The Applicants will also file a table showing the calculation of the additions to each of the accounts in a format similar to Ex. I1-1-1, Tables 6 and 7 in order to demonstrate the underlying calculations, including the variances relative to the forecast amounts reflected in the payment amounts. As the Applicants will also file an auditor's report with respect to the balances to be cleared, they do not believe that any additional supporting details for the capital expenditures or in-service amounts, or other evidence, is necessary to enable the OEB to be satisfied that the balances are accurately recorded.

d) The interest calculation methodology for the CCR DVAs, including the applicable interest rate and period over which interest is to be recorded, is established by O. Reg. 53/05, as summarized in Ex. I1-1-3, Section 3.0. Specifically, the regulation specifies the use of an interest rate equal to "Ontario Power Generation Inc.'s long-term debt rate", with "long-term debt rate" defined as "the long-term debt rate reflecting the generator's cost of long-term borrowing that is determined or approved by the Board". Pursuant to O. Reg. 53/05, interest will be recorded until such time as all respective capital expenditures have been placed in service (or, in the case of the DNNP, the associated small modular reactor has been abandoned), and the account balance itself will attract interest at the rate specified above.

OPG's proposed 2027-2031 long-term debt rates in this Application, and therefore, if approved, those that would be used in the above interest calculations, are as set out in Ex. C1-1-1, Tables 1-5, line 2, col. (c) for 2027 to 2031, respectively. For 2026, the Applicants will apply OPG's long-term debt rate of 3.65% as reflected in the EB-2020-0290 Payment Amounts Order, App. A, Table 15, line 2, col. (c). For the purpose of determining the actual CCR amounts and therefore the monthly entries into the CCR DVAs, the Applicants will apply the interest rate to the corresponding monthly opening construction work-in-progress balance (i.e., the cumulative capital costs incurred less amounts placed in service).

e) For simplicity and regulatory effectiveness, the Applicants expect that they would propose to set the payment amount rider associated with the disposition of the CCR DVAs using an already OEB-approved production forecast.

f) The Applicants expect that annual clearance applications for CCR DVAs could be combined with their other annual applications, unless doing so would cause unreasonable delays in the disposition of the CCR DVAs.

Board Staff Interrogatory #265

Interrogatory

Reference:
Ref 1: Exhibit I1 / Tab 1 / Schedule 1 / Attachment 1, Sheet 11
Ref 2: Exhibit I1 / Tab 3 / Schedule 2 / Attachment 1

Preamble:

At Reference 1, OPG presents a 2027 Bill Impact. In the Production and Demand section, OPG presents its forecast production as 51.2 TWh and the IESO forecast provincial demand as 163.9 TWh. The Bill Impact assessment shows OPG's proportion of Consumer usage as 31.2%.

At page 16 of Reference 2, Innovative Research Group states that OPG is responsible for about half of Ontario's electricity.

Question(s):

a) Noting the Customer Engagement Report identifies field dates in November 2025, please explain the discrepancy between stating to participants that OPG is responsible for about half of Ontario's electricity while the Bill Impact assessment in Reference 1 shows OPG's proportion as 31.2%.

b) Please explain and provide the calculation of the following statements made at page 16 of Reference 2:
   i. The hydroelectric fleet account for 30% of OPG's 2027-2031 plan
   ii. The nuclear fleet account for 65% of OPG's 2027-2031 plan
   iii. Roughly 5% of OPG's proposed 2027-2031 budget will fund development of the first grid-scale small modular reactor project in North America

c) For the figures referenced in part b), please confirm, and if not confirmed explain, the following:
   i. That the "2027-2031 plan" and "2027-2031 budget" are the same
   ii. That the plan/budget referenced to the participants of the survey are the same as the revenue requirements brought forward in this proceeding
   iii. That the plan/budget referenced to the participants of the survey include both OPG's and DNNP LP's requested revenue requirements

Response

a) The reference to "about half" of electricity used in Ontario is consistent with the 2025 "OPG Proportion of Consumer Usage" percentages publicly reported in EB-2020-0290 and EB-2023-0336 (47.4% and 46.0%).[1] As the study was being conducted in 2025, OPG felt this was a reasonable representation. The 31.2% proportion is determined as described in the preamble.

b) The quoted figures are approximations calculated at a point-in-time prior to finalizing the Application. The purpose of these statements was to give customers a general understanding of OPG's business. The calculations are as follows using the final revenue requirements and indicative revenue amounts included in the Application.

- 2027-2031 OPG Nuclear Facilities Revenue Requirement (Ex. I1-1-1, Table 2: sum of cols. (a) to (e), line 26) **= $23.6B**
- 2027-2031 DNNP Facilities Revenue Requirement (Ex. I1-1-1, Table 2a: sum of cols. (a) to (e) line 22) **= $2.7B**
- 2027-2031 Hydroelectric Indicative Revenue (payment amounts at Ex. I1-2-1, Table 1, line 11, multiplied by forecast production of 32.5TWh) **= $9.5B**

Using the above information results in the following percentages, which are directionally in line with the percentages used in the customer engagement process:
OPG Nuclear Facilities **= 66%**
DNNP Facilities **= 7.5%**
Regulated Hydroelectric **= 26.5%**

c)
i. OPG confirms that the references to "plan" and "budget" are intended to have the same meaning in the customer engagement study.
ii. and iii. Not confirmed. The customer engagement process necessarily used preliminary revenue requirement and indicative revenue information as the Application was not yet final at the time of preparing such supporting materials. This information included both OPG and DNNP LP.

[1] See EB-2020-0290 Payment Amounts Order, App. B, Table 2A, line 11 and EB-2023-0336 Decision and Order, App. A, Table 3, line 10.

Board Staff Interrogatory #266

Interrogatory

Reference:
Ref 1: Exhibit I1 / Tab 1 / Schedule 1 / Chart 1
Ref 2: 2024 EBT Estimate Prescribed RRR Final_Non-Confidential.pdf

Preamble:

At Reference 1, OPG presents actual and forecast return on equity for 2022-2026. Reference 2 is the 2024 Annual Regulatory Return reported to the OEB.

Question(s):

a) Please reproduce Reference 2 to show 2025 and 2026 forecast return on equity, including all supplementary notes and sub-tables, as per Reference 1.

Response

a) With OPG's 2025 audited consolidated financial statements issued on March 12, 2026 (refer to Ex. L-A2-Staff-010, Attachment 1), OPG provides its preliminary actual return on equity for 2025 in the requested format in Attachment 1 (Confidential). The return on equity for 2025 is preliminary, pending, among others, completion of the 2025 income tax return by June 30, 2026 and an update to cash working capital calculations. Attachment 2 (Confidential) provides OPG's 2026 forecast return on equity, reproduced to match Reference 2, in the format requested.

Table 1
Summary of Preliminary Actual Capitalization and Cost of Capital
Year Ended December 31, 2025

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, 2	475.6	2.3%	2.92%	18.5
2	**Existing Long-term Debt**	1	5,912.7	28.1%	4.03%	238.1
3	**Other Long-term Debt Provision**	1, 3	5,198.5	24.7%	4.03%	209.4
4	**Total Debt**	4	11,586.8	55.0%	4.02%	466.0
5	**Common Equity**	4,5	9,480.1	45.0%	13.02%	1,234.1
6	**Rate Base Financed by Capital Structure**	4	21,067.0	98.2%	8.07%	1,700.1
7	**Adjustment for Lesser of UNL or ARC**	1	375.4	1.8%	4.72%	17.7
8	**Rate Base**	1	21,442.4	100.0%	8.01%	1,717.8

Notes:
1 Amounts in cols. (a) and (d) and the cost rates in col. (c) are determined using the same methodologies as applied in EB-2020-0290.
2 The cost of short-term debt includes interest at the cost rate shown in col. (c) plus an allocation of the actual credit facility cost.
3 Debt required to balance capital structure with actual rate base.
4 Capital structure as approved by the OEB in EB-2020-0290.
5 Preliminary actual regulatory return on equity in col. (d) from Table 2, line 13, col. (c).

Numbers may not add due to rounding.

Highlighted for redaction

Table 2
Preliminary Actual Regulatory Return on Equity ($M)
Year Ended December 31, 2025

Line No.	Description	Note	Regulated Hydroelectric	Nuclear	Total
			(a)	(b)	(c)
1	**Accounting EBIT (includes rounding)**	1	590.8	1,422.0	2,012.8
Accounting Expenses/Revenues not Included in Regulatory EBIT:					
2	**Add: Accretion on Nuclear Fixed Asset Removal and Nuclear Waste Management Liabilities**	1	N/A	[redacted]	[redacted]
3	**Deduct: Earnings/(Losses) on Nuclear Fixed Asset Removal and Nuclear Waste Management Funds**	1	N/A	[redacted]	[redacted]
Differences Between Accounting and Regulatory Treatment:					
4	**Deduct: Shareholder Portion of Hydroelectric Incentive Mechanism Revenue**	2	[redacted]	N/A	[redacted]
5	**Deduct: Shareholder Portion of Heavy Water Sales Net of Costs**	3	N/A	[redacted]	[redacted]
6	**Deduct: Amortization of Return on Equity Components of Variance and Deferral Account Balances**	4	6.6	13.7	20.3
7	**Regulatory EBIT** (lines 1+2-3-4-5-6)		584.2	1,393.7	1,977.9
Deemed Cost of Capital:					
8	**Deduct: Cost of Deemed Debt for Regulated Assets**	5	183.2	282.7	466.0
9	**Deduct: Cost Related to UNL/ARC Adjustment**	5	N/A	17.7	17.7
10	**Add: Cost of Capital Variance and Deferral Account Additions**	6	57.8	42.8	100.6
11	**Regulatory EBT** (line 7 - line 8 - line 9 + line 10)		458.8	1,136.1	1,594.8
Determination of Regulatory Return on Equity:					
12	**Deduct: Regulatory Income Taxes on Regulated Assets**	7	103.2	257.5	360.7
13	**Regulatory Return on Equity** (line 11 - line 12)		355.6	878.6	1,234.1

See Table 2a for notes

Table 2a
Preliminary Actual Regulatory Return on Equity ($M)
Year Ended December 31, 2025
Notes to Table 2

Notes:

1 Preliminary actual amounts on lines 1, 2, and 3 are determined in accordance with US GAAP, as approved by the OEB for use by OPG for regulatory accounting, reporting and rate-making purposes. These amounts are determined using the same methodology as reflected in the 2019/2018 audited financial statements for OPG's prescribed facilities filed in EB-2020-0290 Ex. A2-1-1, Attachment 2.

2 During 2025, hydroelectric incentive mechanism (HIM) revenue was earned pursuant to the mechanism approved by the OEB in EB-2013-0321, EB-2016-0152 and continued in EB-2020-0290.

[redacted]

[redacted]

3 Heavy water sales net of costs are applied by the OEB as a reduction to OPG's nuclear revenue requirement. In EB-2010-0008, the OEB approved a sharing mechanism for heavy water sales net of costs between OPG and ratepayers. The shareholder portion of heavy water sales net of costs represents the excess, if any, of the actual sales net of costs in 2025 reflected in the EB-2020-0290 Payment Amounts Order.

4 Amounts represent differences between the cost of capital additions recognized in the variance and deferral accounts, and the corresponding regulatory assets reflected in the US GAAP financial statements. In accordance with US GAAP, OPG limits the portion of cost of capital additions recognized as a regulatory asset in the financial statements to amounts calculated using the average rate of capitalized interest applied by OPG to construction and development in progress balances.

5 Costs related to deemed debt and UNL/ARC adjustment for 2025 are allocated to Regulated Hydroelectric and Nuclear based on actual rate base, using the same methodology applied in EB-2020-0290, as follows:

Table to Note 5 ($M)

Line No.	Item	Regulated Hydroelectric	Nuclear
		(a)	(b)
1a	Interest Rate (Table 1, line 4, col. (c))	4.02%	4.02%
2a	Actual Rate Base (Table 1, line 8, col. (a))	8,283.7	13,158.7
3a	ARC / UNL Adjustment (Table 1, line 7, col. (a))	N/A	375.4
4a	Rate Base Financed by Capital Structure	8,283.7	12,783.3
	(line 2a - line 3a)		
5a	Debt Ratio (Table 1, line 4, col. (b))	55.0%	55.0%
6a	Deemed Debt (line 4a x line 5a)	4,556.0	7,030.8
7a	Cost of Deemed Debt for Regulated Assets	183.2	282.7
	(line 1a x line 6a)		
8a	Cost Related to UNL/ARC Adjustment	N/A	17.7
	(Table 1, line 7, col. (c) x line 3a)		

6 The amounts represent the cost of capital additions to the Capacity Refurbishment Variance Account, the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account, the Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account, and the Nuclear Liability Deferral Account recorded in 2025.

7 The amount of regulatory income taxes is determined based on Regulatory EBT at line 11, using the methodology for calculating regulatory income taxes applied in EB-2020-0290, as adjusted to reflect the inclusion of income tax amounts in certain deferral and variance accounts (i.e. the impact of tax additions and deductions that represent items for which the tax cost or benefit is being passed on to ratepayers through deferral and variance accounts) and to exclude the benefit of tax losses forecasted in EB-2020-0290 to be carried forward beyond the 2022-2026 period. The amount of regulatory income taxes herein reflects the 2025 tax provision at the time of filing this interrogatory response. These amounts will be updated to reflect the 2025 income tax return, to be completed in June 2026, at the time of the annual filing in July 2026.

Numbers may not add due to rounding.
Highlighted for redaction

Table 3
Comparison of Preliminary Actual Regulatory Return on Equity to Board Approved for Nuclear ($M)
Year Ended December 31, 2025

Line No.	Description	Note	OEB Approved	Preliminary Actual	(b) - (a) Variance
			(a)	(b)	(c)
	Revenues:				
1	**Revenue Requirement**	1	3,197.6		
2	**Ancillary and Other Revenue**	1	[redacted]		
3	**Bruce Lease Revenues Net of Direct Costs**	1	(46.5)		
4	**Amortization of Variance & Deferral Account Amounts**	11	214.1		
4a	**Income Tax Impact from Amortization of Pension & OPEB Cash Versus Accrual Differential Deferral Account**	12	58.3		
5	**Total Revenues** (lines 1 through 4a)	2	[redacted]	[redacted]	[redacted]
	Expenses:				
6	**OM&A**	1, 3	1,803.3	1,911.1	107.8
7	**Fuel**	1	189.9	271.0	81.1
8	**Depreciation & Amortization, including Amortization of Variance & Deferral Account Amounts**	4	722.0	726.0	4.0
9	**Property Taxes**	1	12.7	14.6	1.9
10	**Total Expenses** (lines 6 through 9)		2,727.8	2,922.7	194.9
11	**Other Losses/(Gains)**		0.0	14.0	14.0
	Cost of Capital Excluding Return on Equity:				
12	**Cost of Deemed Debt for Regulated Assets**	5	246.8	282.7	36.0
13	**Adjustment for Lesser of UNL or ARC**	1, 6	0.0	17.7	17.7
14	**Cost of Capital Variance and Deferral Account Additions**	7	0.0	(42.8)	(42.8)
15	**Total Cost of Capital Excluding Return on Equity** (lines 12 through 14)		246.8	257.6	10.9
16	**Income Tax**	1	[redacted]		
16a	**Income Tax Impact from Amortization of Pension & OPEB Cash Versus Accrual Differential Deferral Account**	12	58.3		
16b	**Total Income Tax** (line 16 + line 16a)	8	[redacted]	257.5	[redacted]
17	**Reporting Adjustment**	9	N/A	[redacted]	N/A
17a	**Cumulative Nuclear Stretch Dollars**	1	40.0		
18	**Regulatory Return on Equity** (line 5 - line 10 - line 11 - line 15 - line 16b + line 17 + line 17a)	1, 10	470.8	878.6	407.8

Notes:

1 OEB-approved amounts are the sum of corresponding amounts in EB-2020-0290 Payment Amounts Order, App. A, Table 4 (2025 Nuclear).

2 Preliminary actual amounts in col. (b) includes the adjustment to remove the revenue component of the shareholder portion of heavy water sales net of costs for Nuclear shown in Table 2, line 5.

3 Preliminary actual amount in col. (b) includes the adjustment to remove the cost component of the shareholder portion of heavy water sales net of costs shown in Table 2, line 5.

4 OEB-approved amount in col. (a) is calculated as the sum of line 17, col. (c) in EB-2020-0290 Payments Amount Order, App. A, Table 4, plus line 4, col. (a) above. Preliminary actual amounts in col. (b) include the amortization adjustment shown in Table 2, line 6.

5 OEB-approved amounts are the sum of short-term debt cost and long-term debt cost from the EB-2020-0290 Payment Amounts Order (App. A, Table 4, lines 10 and 11). Actual amounts are from Table 2, line 8, col. (b).

6 Preliminary actual amount in col. (b) from Table 2, line 9, col. (b).

7 Preliminary actual amount in col. (b) from Table 2, line 10, col. (b).

8 Preliminary actual amount in col. (b) from Table 2, line 12, col. (b).

9 The Reporting Adjustment line is included solely to maintain the confidentiality of the amount of actual heavy water sales net of costs.

10 Preliminary actual amount in col. (b) is as shown in Table 2, line 13, col. (b).

11 OEB-approved amount is the sum of EB-2020-0290 PAO, App. D, Table 1, lines 25 and 29, col. (k) and EB-2023-0336 Decision and Order, Attachment A, Table 2, lines 26 and 28, col. (h).

12 OEB-approved amount is the sum of EB-2020-0290 PAO, App. D, Table 1, lines 26 - 28, col. (k) and EB-2023-0336 Decision and Order, Attachment A, Table 2, line 27, col. (h).

Appendix 1 ($M)
Year Ended December 31, 2025

Line No.	Item	Regulated Hydroelectric	Nuclear
		(a)	(b)
1	Rate Base Financed by Capital Structure (Table 2a, Note 5, line 4a)	8,283.7	12,783.3
2	Equity Ratio (Table 1, line 5, col. (b))	45%	45%
3	Common Equity (line 1 x line 2)	3,727.7	5,752.5
4	Preliminary Actual Regulatory Return on Equity (Table 2, line 13)	355.6	878.6
5	Preliminary Actual Regulatory Return on Equity Divided by 45% of Rate Base (line 4 / line 3) [1]	0.0954	0.1527

Note:

1 Per EB-2020-0290 Decision and Order, Schedule A, Appendix A, Page 1, OPG agreed to provide, as part of its annual reporting, "a calculation equivalent to dividing the actual dollar regulatory return for each of the regulated nuclear and hydroelectric business segments by 45% of the corresponding rate base for each of these segments, where 45% is the equity thickness in the agreed upon capital structure for the regulated business" in consideration of the EB-2020-0290 settlement. Amounts shown in line 5 represent a calculation equivalent to dividing the preliminary actual dollar regulatory return for each of the regulated nuclear and hydroelectric business segements by 45% of the corresponding actual rate base for each of these segment for 2025.

As stated in EB-2020-0290, Ex. L-A1-03-Staff-008, OPG operates as a single company, with a single management structure, a single corporate cost structure, and a single OEB-authorized cost of capital that covers both the hydroelectric and nuclear generating facilities, and obtains corporate financing as a single company. Accordingly, OPG reports achieved return on equity for the prescribed facilities as a whole. The calculation provided in this Appendix 1 is to satisfy the requirements of the EB-2020-0290 settlement.

Table 1
Summary of Projected Capitalization and Cost of Capital - OPG
Year Ending December 31, 2026[1]

Line No.	Capitalization	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
		(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:				
1	**Short-term Debt**	414.3	1.8%	2.47%	16.1
2	**Existing Long-term Debt**	5,445.6	23.4%	4.42%	240.6
3	**Other Long-term Debt Provision**	6,935.4	29.8%	4.42%	306.4
4	**Total Debt**	12,795.2	55.0%	4.40%	563.2
5	**Common Equity**	10,468.8	45.0%	5.63%	589.8
6	**Rate Base Financed by Capital Structure**	23,264.1	99.1%	4.96%	1,153.0
7	**Adjustment for Lesser of UNL or ARC**	202.5	0.9%	4.72%	9.6
8	**Rate Base**	23,466.6	100.0%	4.95%	1,162.6

Notes:
1 From Ex. C1-1-1, Table 6.

Table 2 Projected Regulatory Return on Equity - OPG ($M) Year Ending December 31, 2026					
Line No.	**Description**	**Note**	**Regulated Hydroelectric**	**Nuclear**	**Total**
			(a)	(b)	(c)
1	**Accounting EBIT (includes rounding)**	1	548.9	495.0	1,043.9
Accounting Expenses/Revenues not Included in Regulatory EBIT:					
2	**Add: Accretion on Nuclear Fixed Asset Removal and Nuclear Waste Management Liabilities**	1	N/A	[redacted]	[redacted]
3	**Deduct: Earnings/(Losses) on Nuclear Fixed Asset Removal and Nuclear Waste Management Funds**	1	N/A	[redacted]	[redacted]
Differences Between Accounting and Regulatory Treatment:					
4	**Deduct: Shareholder Portion of Hydroelectric Incentive Mechanism Revenue**	2	[redacted]	N/A	[redacted]
5	**Deduct: Shareholder Portion of Heavy Water Sales Net of Costs**	3	N/A	[redacted]	[redacted]
6	**Deduct: Amortization of Return on Equity Components of Variance and Deferral Account Balances**	4	6.6	13.7	20.3
7	**Regulatory EBIT** (lines 1+2-3-4-5-6)		542.3	462.1	1,004.4
Deemed Cost of Capital:					
8	**Deduct: Cost of Deemed Debt for Regulated Assets**	5	208.4	354.7	563.2
9	**Deduct: Cost Related to UNL/ARC Adjustment**	5	N/A	9.6	9.6
10	**Add: Cost of Capital Variance and Deferral Account Additions**	6	75.3	82.1	157.4
11	**Regulatory EBT** (line 7 - line 8 - line 9 + line 10)		409.2	179.9	589.0
Determination of Regulatory Return on Equity:					
12	**Deduct: Regulatory Income Taxes on Regulated Assets**	7	33.8	(34.6)	(0.8)
13	**Regulatory Return on Equity** (line 11 - line 12)		375.3	214.5	589.8

See Table 2a for notes

Table 2a
Projected Regulatory Return on Equity - OPG ($M)
Year Ending December 31, 2026
Notes to Table 2

Notes:

1 Projected amounts on lines 1, 2, and 3 are determined in accordance with US GAAP, as approved by the OEB for use by OPG for regulatory accounting, reporting and rate-making purposes. These amounts are determined using the same methodology as reflected in the 2019/2018 audited financial statements for OPG's prescribed facilities filed in EB-2020-0290 Ex. A2-1-1, Attachment 2.

2 The hydroelectric incentive mechanism (HIM) revenue in 2026 was forecasted pursuant to the mechanism approved by the OEB in EB-2013-0321, EB-2016-0152 and continued in EB-2020-0290.

[redacted]

3 Heavy water sales net of costs are applied by the OEB as a reduction to OPG's nuclear revenue requirement. In EB-2010-0008, the OEB approved a sharing mechanism for heavy water sales net of costs between OPG and ratepayers. The shareholder portion of heavy water sales net of costs represents the excess, if any, of the forecast sales net of costs in 2026 reflected in the EB-2020-0290 Payment Amounts Order.

4 Amounts represent differences between the cost of capital additions forecast in the variance and deferral accounts, and the corresponding regulatory assets that would be reflected in the US GAAP financial statements. In accordance with US GAAP, OPG limits the portion of cost of capital additions recognized as a regulatory asset in the financial statements to amounts calculated using the average rate of capitalized interest applied by OPG to construction and development in progress balances.

5 Costs related to deemed debt and UNL/ARC adjustment for 2026 are allocated to Regulated Hydroelectric and Nuclear based on projected rate base, using the same methodology applied in EB-2020-0290, as follows:

Table to Note 5 ($M)			
Line No.	Item	Regulated Hydroelectric	Nuclear
		(a)	(b)
1a	Interest Rate (Table 1, line 4, col. (c))	4.40%	4.40%
2a	Rate Base (Table 1, line 8, col. (a))	8,610.5	14,856.2
3a	ARC / UNL Adjustment (Table 1, line 7, col. (a))	N/A	202.5
4a	Rate Base Financed by Capital Structure	8,610.5	14,653.6
	(line 2a - line 3a)		
5a	Debt Ratio (Table 1, line 4, col. (b))	55.0%	55.0%
6a	Deemed Debt (line 4a x line 5a)	4,735.8	8,059.5
7a	Cost of Deemed Debt for Regulated Assets	208.4	354.7
	(line 1a x line 6a)		
8a	Cost Related to UNL/ARC Adjustment	N/A	9.6
	(Table 1, line 7, col. (c) x line 3a)		

6 The amounts represent projected cost of capital additions to the Capacity Refurbishment Variance Account, the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account, the Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account, and the Nuclear Liability Deferral Account.

7 Refer to Ex. I1-1-1, Table 5, line 22.

Numbers may not add due to rounding.
Highlighted for redaction

Table 3
Comparison of Projected Regulatory Return on Equity to Board Approved for Nuclear - OPG ($M)
Year Ending December 31, 2026

Line No.	Description	Note	OEB Approved	Projected	(b) - (a) Variance
			(a)	(b)	(c)
	Revenues:				
1	**Revenue Requirement**	1	2,439.5		
2	**Ancillary and Other Revenue**	1	[redacted]		
3	**Bruce Lease Revenues Net of Direct Costs**	1	(38.3)		
4	**Amortization of Variance & Deferral Account Amounts**	11	214.1		
4a	**Income Tax Impact from Amortization of Pension & OPEB Cash Versus Accrual Differential Deferral Account**	12	58.3		
5	**Total Revenues** (lines 1 through 4a)	2	[redacted]	[redacted]	[redacted]
	Expenses:				
6	**OM&A**	1, 3	1,038.9	2,118.2	1,079.3
7	**Fuel**	1, 3	148.0	239.2	91.2
8	**Depreciation & Amortization, including Amortization of Variance & Deferral Account Amounts**	4	766.5	831.8	65.3
9	**Property Taxes**	1, 3	9.8	13.5	3.7
10	**Total Expenses** (lines 6 through 9)		1,963.2	3,202.7	1,239.5
11	**Other Losses/(Gains)**		0.0	0.0	0.0
	Cost of Capital Excluding Return on Equity:				
12	**Cost of Deemed Debt for Regulated Assets**	5	263.3	354.7	91.4
13	**Adjustment for Lesser of UNL or ARC**	1, 6	0.0	9.6	9.6
14	**Cost of Capital Variance and Deferral Account Additions**	7	0.0	(82.1)	(82.1)
15	**Total Cost of Capital Excluding Return on Equity** (lines 12 through 14)		263.3	282.2	18.9
16	**Variance and Deferral Account Additions excluding Income Tax and Cost of Capital Components**	13	0.0	391.5	391.5
17	**Income Tax**	1	[redacted]		
17a	**Income Tax Impact from Amortization of Pension & OPEB Cash Versus Accrual Differential Deferral Account**	12	58.3		
17b	**Total Income Tax** (line 17 + line 17a)	8	[redacted]	(34.6)	[redacted]
18	**Reporting Adjustment**	9	N/A	[redacted]	N/A
18a	**Cumulative Nuclear Stretch Dollars**	1	27.7		
19	**Regulatory Return on Equity** (line 5 - line 10 - line 11 - line 15 - line 16 - line 17b + line 18 + line 18a)	1, 10	502.6	214.5	(288.1)

Notes:

1 OEB-approved amounts are the sum of corresponding amounts in EB-2020-0290 Payment Amounts Order, App. A, Table 5 (2026 Nuclear).
2 Projected amounts in col. (b) is calculated as the sum of Ex. I1-1-1, Table 5, col. (b), lines 3 and 9.
3 Projected amounts in col. (b) from Ex. I1-1-1, Table 5, col. (b), lines 4, 5 and 7, respectively.
4 OEB-approved amount in col. (a) is calculated as the sum of line 17, col. (c) in EB-2020-0290 Payments Amount Order, App. A, Table 5, plus line 4, col. (a) above. Projected amounts in col. (b) is calculated as the sum of Ex. F4-1-1, Table 2, line 11, col. (g) and line 4, col. (a) above.
5 OEB-approved amounts are the sum of short-term debt cost and long-term debt cost from the EB-2020-0290 Payment Amounts Order (App. A, Table 5, lines 10 and 11). Projected amounts are from Table 2, line 8, col. (b).
6 Projected amount in col. (b) from Table 2, line 9, col. (b).
7 Projected amount in col. (b) from Table 2, line 10, col. (b).
8 Projected amount in col. (b) from Table 2, line 12, col. (b).
9 The Reporting Adjustment line is included solely to maintain the confidentiality of the amount of forecast heavy water sales net of costs.
10 Projected amount in col. (b) is as shown in Table 2, line 13, col. (b).
11 OEB-approved amount is the sum of EB-2020-0290 PAO, App. D, Table 1, lines 25 and 29, col. (l) and EB-2023-0336 Decision and Order, Attachment A, Table 2, lines 26 and 28, col. (i).
12 OEB-approved amount is the sum of EB-2020-0290 PAO, App. D, Table 1, lines 26 - 28, col. (l) and EB-2023-0336 Decision and Order, Attachment A, Table 2, line 27, col. (i).
13 Projected amount in col. (b) is calculated as: (Ex. I1-1-1, Table 5, line 15, col. (b) + line 14, col. (b) above) x -1

Appendix 1 - OPG ($M)
Year Ending December 31, 2026

Line No.	Item	Regulated Hydroelectric	Nuclear
		(a)	(b)
1	Projected Rate Base Financed by Capital Structure (Table 2a, Note 5, line 4a)	8,610.5	14,653.6
2	Equity Ratio (Table 1, line 5, col. (b))	45%	45%
3	Common Equity (line 1 x line 2)	3,874.7	6,594.1
4	Projected Regulatory Return on Equity (Table 2, line 13)	375.3	214.5
5	Projected Regulatory Return on Equity Divided by 45% of Rate Base (line 4 / line 3) [1]	0.0969	0.0325

Note:

1 Per EB-2020-0290 Decision and Order, Schedule A, Appendix A, Page 1, OPG agreed to provide, as part of its annual reporting, "a calculation equivalent to dividing the actual dollar regulatory return for each of the regulated nuclear and hydroelectric business segments by 45% of the corresponding rate base for each of these segments, where 45% is the equity thickness in the agreed upon capital structure for the regulated business" in consideration of the EB-2020-0290 settlement. Amounts shown in line 5 represent a calculation equivalent to dividing the projected dollar regulatory return for each of the regulated nuclear and hydroelectric business segements by 45% of the corresponding projected rate base for each of these segment for 2026.

As stated in EB-2020-0290, Ex. L-A1-03-Staff-008, OPG operates as a single company, with a single management structure, a single corporate cost structure, and a single OEB-authorized cost of capital that covers both the hydroelectric and nuclear generating facilities, and obtains corporate financing as a single company. Accordingly, OPG reports achieved return on equity for the prescribed facilities as a whole. The calculation provided in this Appendix 1 is to satisfy the requirements of the EB-2020-0290 settlement.

Board Staff Interrogatory #267

Interrogatory

Reference:
Ref 1: Exhibit I1 / Tab 3 / Schedule 2

Preamble:

With Reference 1, OPG presents its payment amount shaping proposal.

Question(s):

a) Please identify and explain all other payment amount mitigation proposals the Applicants considered.

b) Please outline and describe the decision criteria the Applicants used to determine the proposed payment amount shaping and deferral account should be the proposal brought forward in this application.

Response

a) Refer to Ex. L-H1-Staff-254.

b) Two payment amount shaping criteria (customer bill impact, particularly in 2027, and financial viability) are discussed in Ex. I1-3-2, Section 4.1. Customer input on payment amount shaping options is discussed in Ex. I1-3-2, Section 4.3. The combination of the two criteria and input from customers informed the payment amount shaping proposal in Ex. I1-3-2, Section 4.4.

Board Staff Interrogatory #268

Interrogatory

Reference:
Ref 1: Exhibit I1 / Tab 4 / Schedule 1
Ref 2: EB-2020-0290, OPG Letter RE: Interim Payment Amounts and Timing of Final Payment Amounts Order, December 23, 2021

Preamble:

With Reference 1, OPG provides a description of the IESO settlement process used for OPG's regulated generation facilities and the Darlington New Nuclear Program (DNNP) facilities. The evidence states that a final rate order establishing new payment amounts would have to be issued by the 20th day of the second month prior to the implementation month. Reference 1 provides the example that a rate order would have to be issued by January 20 to implement payment amounts for March 1:

> OPG and DNNP LP understand that in order for revised payment amounts and riders to be implemented on the first of a given month, a final rate order establishing the new payment amounts and riders would have to be issued by the 20th of the second month prior to the implementation month. This timing is necessary for the IESO to update their systems and perform the settlement without retroactive adjustment. For example, for implementation on March 1st, the rate order would have to be issued in January, before the 20th.

Reference 2 is a letter from OPG in the EB-2020-0290 proceeding. In that letter, OPG states that it conferred with the IESO as to the latest date that a final payment amounts order could be issued to avoid additional riders to recover foregone revenue. That letter provides the example that a payment amounts order would have to be issued by February 20 to ensure that the IESO could implement payment amounts for January 1.

OPG has conferred with the IESO as requested. The IESO indicated that issuance of the final payment amounts order by February 20, 2022 will ensure that the IESO will be able to implement an effective date of January 1, 2022 without the need for a separate shortfall mechanism.

Question(s):

a) Please confirm the latest date for the OEB to issue a payment amounts order so that the IESO could implement payment amounts for January 1, 2027 without additional riders to recover foregone revenue.

Response

The settlement process outlined in Ex. I1-4-1 describes the IESO's use of a retroactive adjustment and the associated settlement timeline with respect to the implementation date of a revised payment amount. In contrast, OPG's EB-2020-0290 letter referenced in the question outlines timing consideration applicable to a separate shortfall mechanism (e.g., a payment amount rider), which is required if the IESO is unable to utilize retroactive adjustments to reflect a particular effective date.

As part of the IESO's Replacement of the Settlement System project, which was implemented in 2023, the use of manual retroactive adjustments was replaced by the Recalculated Settlement Statement ("RCSS") process. As OPG expects that the use of the RCSS would impact the timing constraints around the implementation of any separate shortfall mechanism, OPG has conferred with the IESO, as requested, to determine the associated "latest date".

To avoid the need for additional riders for the Applicants to recover forgone revenues, the IESO indicated a 23-month limitation period following the OEB payments amounts order issue date with an effective date of January 1, 2027. This limitation period is set out in the IESO's Market Rules Ch. 9, Section 6.9.2. Within this limitation period, the IESO would use RCSS process, which is designed to reflect changes for prior month(s) such as the payment amounts order in this proceeding, from an effective date of January 1, 2027 to the implementation date without the need for a separate shortfall recovery mechanism.

While the IESO could theoretically resettle the period up to 23 months past January 1, 2027, a delay in the Applicants collecting revenue of such magnitude would have substantial implications on the Applicants' financial position and would not be in keeping with the OEB's performance standards for processing applications. The Applicants therefore do not believe that such an approach would be reasonable.