SUMMARY OF REVENUE REQUIREMENT AND REVENUE DEFICIENCY

1.0 PURPOSE

This evidence provides a summary of the 2027-2031 revenue requirements for:

- OPG's nuclear facilities;
- OPG's regulated hydroelectric facilities; and
- DNNP LP's facility.

This evidence also includes the revenue deficiency amounts for the same period for OPG's nuclear and regulated hydroelectric facilities.

2.0 REVENUE REQUIREMENT

For OPG's regulated hydroelectric facilities, this Application is seeking approval of a proposed 2027 revenue requirement of $1,668.3M, as presented in Ex. I1-1-1, Table 1.

For OPG's nuclear facilities, this Application is seeking approval of proposed revenue requirements, net of the stretch factor, of $4,062.8M for 2027, $4,257.3M for 2028, $4,676.5M for 2029, $4,881.7M for 2030, and $5,736.9M for 2031, as presented in Ex. I1-1-1, Table 2.

For the DNNP facilities, this Application is seeking approval of proposed revenue requirements of $302.0M for 2027, $381.4M for 2028, $417.0M for 2029, $582.1M for 2030, and $1,076.1M for 2031, as presented in Ex. I1-1-1, Table 2a.

The revenue requirement amounts above do not include the recovery of deferral and variance account balances. OPG is seeking to clear certain deferral and variance accounts using a hydroelectric payment rider and a nuclear payment rider as discussed in Ex. H1-2-1.

3.0 REVENUE DEFICIENCY

Exhibit I1-1-1, Table 3a compares:

a) OPG's forecast revenues determined using the 2026 regulated hydroelectric payment amount set in EB-2020-0290 (i.e., 2026 regulated hydroelectric payment amount multiplied by the regulated hydroelectric production forecast for 2027 proposed in this Application); and
b) the regulated hydroelectric revenue requirement for 2027 proposed in this Application.

OPG's revenue deficiency for the regulated hydroelectric facilities is $243.9M for 2027.

Exhibit I1-1-1, Table 3b compares:

a) Forecast revenues determined using the 2026 nuclear payment amount approved in EB-2020-0290 (i.e., 2026 nuclear payment amount multiplied by the production forecast for 2027-2031 for the OPG nuclear facilities); and
b) the OPG nuclear revenue requirements net of stretch factor proposed in this Application.

The revenue deficiency for the nuclear facilities is $1,981.8M for 2027, $1,285.7M for 2028, $1,885.8M for 2029, $1,895.4M for 2030, and $2,514.7M for 2031.

Exhibit I1-1-1, Tables 4 and 5 present the determination of OPG's 2025 and 2026 forecast regulated return on equity ("ROE") at current payment amounts. Chart 1 below provides these forecast ROE for 2025 and 2026, along with the actual ROE for 2022-2024 as well as the expected average ROE for the 2022-2026 period.

Chart 1 - Actual and Forecast ROE

	2022	2023	2024	2025	2026	Average
OPG ROE	12.7%	13.8%	5.8%	12.7%	6.1%	10.22%
OEB-approved[1]	8.93%	8.93%	8.93%	8.93%	8.93%	8.93%

[1] 8.93% is a rate-base-weighted average of the 8.66% ROE approved for the nuclear business in EB-2020-0290 and 9.33% ROE approved for the hydroelectric business in EB-2013-0321.

4.0 REVENUE REQUIREMENT WORK FORM

A Revenue Requirement Work Form ("RRWF") is attached as Attachment 1 to this exhibit and has also been filed in MS Excel worksheet format. The OEB provides a proprietary RRWF model as a filing requirement for transmission and distribution applications, intended to support the calculation of revenue deficiency or sufficiency. The Application includes a RRWF customized to OPG and DNNP LP's circumstances in order to provide a mechanism to support the Application for 2027-2031 payment amounts for the prescribed nuclear facilities and the 2027 payment amount for the prescribed hydroelectric facilities. This is consistent with the approach taken in EB-2020-0290.

Similar to the OEB RRWF, adjustments are entered in a single worksheet with the effect of these adjustments presented in subsequent worksheets.

LIST OF ATTACHMENTS

Attachment 1: Revenue Requirement Work Form

Numbers may not add due to rounding.

Filed: 2025-12-12
EB-2025-0297
Exhibit I1
Tab 1
Schedule 1
Table 1

Table 1
Summary of Revenue Requirement - Regulated Hydroelectric ($M)
Year Ending December 31, 2027

Line No.	Description	Note	2027
			(a)
	Rate Base		
1	**Net Fixed Assets**	1	9,115.6
2	**Working Capital**	1	0.3
3	**Cash Working Capital**	1	19.3
4	**Total Rate Base**		9,135.1
	Capitalization		
5	**Short-Term Debt**	2	152.4
6	**Long-Term Debt**	2	4,232.4
7	**Common Equity**	2	4,750.3
8	**Total Capital**		9,135.1
	Cost of Capital		
9	**Short-Term Debt**	3	7.7
10	**Long-Term Debt**	3	193.8
11	**Common Equity**	3	432.8
12	**Total Cost of Capital**		634.2
	Expenses:		
13	**OM&A**	4	499.3
14	**GRC**	5	352.2
15	**Depreciation & Amortization**	6	215.4
16	**Property Tax**	7	2.1
17	**Total Expenses**		1,069.0
	Less:		
	Other Revenues		
18	**Ancillary and Other Revenue**	8	62.2
19	**Total Other Revenues**		62.2
20	**Income Tax**	9	27.3
21	**Revenue Requirement** (line 12 + line 17 - line 19 + line 20)		1,668.3
22	**Amortization of Variance & Deferral Account Amounts**	10	(37.9)
23	**Revenue Requirement Plus Variance & Deferral Account Amounts** (line 21 + line 22)		1,630.4

Notes:

1 Per Ex. B1-1-1 Table 1.
2 Regulated hydroelectric portion of totals from Ex. C1-1-1 Table 5, (col. (a)). Capitalization is allocated to regulated hydroelectric and OPG's nuclear facilities using rate base financed by capital structure.
3 Regulated hydroelectric portion of totals from Ex. C1-1-1 Table 5, (col. (d)). Cost of Capital is allocated to regulated hydroelectric and OPG's nuclear facilities using rate base financed by capital structure.
4 Per Ex. F1-1-1, Table 1, line 6.
5 Per Ex. F1-1-1, Table 1, line 7.
6 Per Ex. F4-1-1, Table 1, line 10.
7 Per Ex. F4-2-1, Table 1, line 5.
8 Per Ex. G1-1-1, Table 1, line 7.
9 Per Ex. F4-2-1, Table 1, line 1.
10 Per Ex. H1-2-1 Table 1, col. (h), line 19.

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

Line No.	Description	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
	Rate Base						
1	**Net Fixed Assets**	1	14,920.0	15,375.4	15,247.3	15,769.2	22,435.9
2	**Working Capital**	1	897.1	975.3	1,040.2	1,120.8	1,174.5
3	**Cash Working Capital**	1	(22.5)	(22.4)	(22.5)	(22.5)	(22.5)
4	**Total Rate Base**		15,794.7	16,328.3	16,265.0	16,867.5	23,587.9
	Capitalization						
5	**Short-Term Debt**	2	261.9	259.9	248.9	246.6	274.6
6	**Long-Term Debt**	2	7,271.5	7,566.6	7,558.3	7,849.8	11,047.6
7	**Common Equity**	2	8,087.3	8,412.7	8,398.2	8,717.2	12,216.1
7a	**EB-2020-0290 Settlement Adjustment for Equity at Long-Term Debt Rate**	13	73.9	66.1	59.6	53.9	49.6
8	**Adjustment for Lesser of UNL or ARC**	2	100.1	23.0	0.0	0.0	0.0
9	**Total Capital**		15,794.7	16,328.3	16,265.0	16,867.5	23,587.9
	Cost of Capital						
10	**Short-Term Debt**	3	13.3	12.2	12.0	11.4	13.2
11	**Long-Term Debt**	3	332.9	362.0	370.4	389.9	550.5
12	**Common Equity**	3	736.8	766.4	765.1	794.1	1,112.9
12a	**EB-2020-0290 Settlement Adjustment for Equity at Long-Term Debt Rate**	13	3.4	3.2	2.9	2.7	2.5
13	**Adjustment for Lesser of UNL or ARC**	3	4.7	1.1	0.0	0.0	0.0
14	**Total Cost of Capital**		1,091.0	1,144.9	1,150.5	1,198.1	1,679.0
	Expenses:						
15	**OM&A**	4	1,863.7	1,756.0	1,917.4	1,856.3	2,153.5
16	**Fuel**	5	150.9	221.7	223.6	261.2	306.1
17	**Depreciation & Amortization**	6	663.3	708.5	730.3	779.8	992.6
18	**Property Tax**	7	14.0	14.2	14.5	14.8	15.0
19	**Total Expenses**		2,691.9	2,700.5	2,885.7	2,912.1	3,467.2
	Less:						
	Other Revenues						
20	**Bruce Lease Revenues Net of Direct Costs**	8	(5.2)	11.5	(18.1)	7.3	(17.1)
21	**Ancillary and Other Revenue**	9	6.3	32.7	13.8	13.5	23.6
22	**Total Other Revenues**		1.1	44.2	(4.3)	20.8	6.5
22a	**Concurrent Cost Recovery - Pickering Refurbishment Program**	14	297.6	479.9	667.7	832.0	646.2
23	**Income Tax**	10	(16.6)	(16.6)	(16.6)	(16.6)	(16.6)
24	**Revenue Requirement Before Stretch Factor** (line 14 + line 19 - line 22 + Line 22a + line 23)		4,062.8	4,264.4	4,691.6	4,904.8	5,769.3
25	**Cumulative Nuclear Stretch Dollars**	11	0.0	7.1	15.1	23.1	32.4
26	**Revenue Requirement Net of Stretch Factor** (line 24 - line 25)		4,062.8	4,257.3	4,676.5	4,881.7	5,736.9
27	**Amortization of Variance & Deferral Account Amounts**	12	134.5	134.5	134.5	67.7	67.7
28	**Revenue Requirement Net of Stretch Factor Plus Variance & Deferral Account Amounts** (line 26 + line 27)		4,197.3	4,391.8	4,810.9	4,949.4	5,804.7

Notes:

1 Per Ex. B1-1-1 Table 2.
2 OPG's nuclear facilities portion of totals from Ex. C1-1-1 Tables 1 through 5, (col. (a)). Capitalization is allocated to regulated hydroelectric and OPG's nuclear facilities using rate base financed by capital structure.
3 OPG's nuclear facilities portion of totals from Ex. C1-1-1 Tables 1 through 5, (col. (d)). Cost of Capital is allocated to regulated hydroelectric and OPG's nuclear facilities using rate base financed by capital structure.
4 Per Ex. F2-1-1, Table 1a, line 16.
5 Per Ex. F2-1-1, Table 1a, line 17.
6 Per Ex. F4-1-1, Table 2, line 11.
7 Per Ex. F4-2-1, Table 2, line 4.
8 Per Ex. G2-2-1, Table 1, line 3.
9 Per Ex. G2-1-1, Table 1, line 7.
10 Per Ex. F4-2-1, Table 2, line 1.
11 Per Ex. I1-3-1, Table 2, line 23.
12 Per Ex. H1-2-1 Table 2, col. (h)-(l), line 32.
13 Per Ex. C1-1-1, Tables 1-5, line 5. Represents the portion of rate base financed by common equity that is subject to return at the long-term debt rate until 2036 per the OEB-approved settlement proposal in EB-2020-0290 (Settlement Proposal, p. 23).
14 Per Ex. I1-1-1, Table 7, line 7.

Numbers may not add due to rounding.

Table 2a
Summary of Revenue Requirement - DNNP Facilities ($M)
Years Ending December 31, 2027 to 2031

Line No.	Description	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
	Rate Base						
1	**Net Fixed Assets**	1	0.0	0.0	0.0	1,360.5	6,507.4
2	**Working Capital**	1	0.0	0.0	2.1	11.1	25.0
3	**Cash Working Capital**	1	0.0	0.0	0.0	(0.6)	(2.4)
4	**Total Rate Base**		0.0	0.0	2.1	1,371.1	6,530.0
	Capitalization						
5	**Short-term Debt**	2	0.0	0.0	0.0	0.0	0.0
6	**Long-Term Debt**	2	0.0	0.0	0.0	0.0	0.0
7	**Common Equity**	2	0.0	0.0	2.1	1,371.1	6,530.0
8	**Total Capital**		0.0	0.0	2.1	1,371.1	6,530.0
	Cost of Capital						
9	**Short-term Debt**	3	0.0	0.0	0.0	0.0	0.0
10	**Long-Term Debt**	3	0.0	0.0	0.0	0.0	0.0
11	**Common Equity**	3	0.0	0.0	0.2	124.9	594.9
12	**Total Cost of Capital**		0.0	0.0	0.2	124.9	594.9
	Expenses:						
13	**OM&A**	4	77.9	82.8	82.9	141.5	293.3
14	**Fuel**		9.1	13.8	12.7	18.1	49.8
15	**Depreciation & Amortization**	5	0.0	0.0	0.0	22.6	109.7
16	**Property Tax**	6	0.0	0.0	0.0	0.8	3.7
17	**Total Expenses**		87.1	96.6	95.6	183.0	456.6
	Less:						
	Other Revenues						
18	**Ancillary and Other Revenue**		0.0	0.0	0.0	0.0	0.0
19	**Total Other Revenues**		0.0	0.0	0.0	0.0	0.0
20	**Concurrent Cost Recovery - DNNP**	7	214.9	284.8	321.2	274.2	24.6
21	**Income Tax**	8	0.0	0.0	0.0	0.0	0.0
22	**Revenue Requirement** (line 12 + line 17 - line 19 + line 20 + line 21)		302.0	381.4	417.0	582.1	1,076.1
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)		302.0	381.4	417.0	582.1	1,076.1

Notes:
1 Per Ex. B1-1-1 Table 3.
2 Per Ex. C1-1-1 Tables 14 through 18 (col. (a)).
3 Per Ex. C1-1-1 Tables 14 through 18 (col. (d)).
4 Per Ex. F2-1-1, Table 1b, line 9.
5 Per Ex. F4-1-1, Table 2, line 12.
6 Per Ex. F4-2-1, Table 2a, line 2.
7 Per Ex. I1-1-1, Table 6, line 7.
8 Per Ex. F4-2-1, Table 2a, line 1.

Table 3a
Summary of Revenue Deficiency - Regulated Hydroelectric
January 1, 2027 to December 31, 2027

Line No.	Description	Note	2027
			(a)
1	**Forecast Production (TWh)**	1	32.5
2	**2026 Payment Amount per EB-2020-0290 ($/MWh)**	2	43.88
3	**Indicated Production Revenue ($M)** (line 1 x line 2)		1,424.4
4	**Revenue Requirement ($M)**	3	**1,668.3**
5	**Revenue Requirement Deficiency ($M)** (line 4 - line 3)		**243.9**

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

Numbers may not add due to rounding.

Table 3b
Summary of Revenue Deficiency - OPG Nuclear Facilities
January 1, 2027 to December 31, 2031

Line No.	Description	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
1	**Forecast Production (TWh)**	1	18.7	26.7	25.1	26.8	28.9
2	**2026 Payment Amount per EB-2020-0290 ($/MWh)**	2	111.33	111.33	111.33	111.33	111.33
3	**Indicated Production Revenue ($M)** (line 1 x line 2)		2,081.0	2,971.6	2,790.6	2,986.3	3,222.2
4	**Revenue Requirement Net of Stretch Factor ($M)**	3	**4,062.8**	**4,257.3**	**4,676.5**	**4,881.7**	**5,736.9**
5	**Revenue Requirement Deficiency ($M)** (line 4 - line 3)		**1,981.8**	**1,285.7**	**1,885.8**	**1,895.4**	**2,514.7**

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

Numbers may not add due to rounding.

Table 4
Determination of 2025 Forecast Return on Equity ($M)

Line No.	Description	Note	2025 Forecast Regulated Hydroelectric	2025 Forecast Nuclear	2025 Forecast Total
			(a)	(b)	(c)
1	**Forecast Production (TWh)**	1	33.0	36.9	69.9
2	**Payment Amount ($/MWh)**	2	47.18	111.61	n/a
3	**Indicated Production Revenue ($M)** (line 1 x line 2)		1,556.2	4,119.0	5,675.2
	Expenses:				
4	**OM&A**	3	427.9	2,044.5	2,472.4
5	**Fuel and GRC**	4	357.2	255.1	612.3
6	**Depreciation**	5	190.8	540.3	731.0
7	**Property Taxes**	6	1.1	12.2	13.3
8	**Total Expenses**		977.0	2,852.1	3,829.0
9	**Ancillary and Other Revenue**	7	70.9	46.6	117.5
	Cost of Capital Excluding Return on Equity				
10	**Short-term Debt**	8	4.6	7.3	12.0
11	**Long-Term Debt**	9	177.8	281.8	459.6
12	**Adjustment for Lesser of UNL or ARC**	10	0.0	15.5	15.5
13	**Cost of Capital Excluding Return on Equity**		182.4	304.6	487.0
	Deferral and Variance Account Adjustments				
14	**Amortization of Previously Approved Amounts**	11	(99.5)	(214.1)	(313.6)
15	**Transactions Excluding Income Tax Components**	12	46.6	294.7	341.3
16	**Total Deferral and Variance Account Adjustments**		(52.9)	80.6	27.7
17	**Revenue Requirement Excluding Income Tax and Return on Equity, Plus Deferral and Variance Account Amounts Excluding Income Tax Components** (line 8 - line 9 + line 13 - line 16)		1,141.4	3,029.5	4,170.9
18	**2025 Forecast Regulatory Earnings Before Tax** (line 3 - line 17)		414.7	1,089.6	1,504.3
19	**Income Tax**	13	68.8	180.0	248.8
20	**Deferral and Variance Account Transactions - Income Tax Variance Components**	14	14.3	37.8	52.1
21	**Income Tax Benefit of EB-2020-0290 Tax Losses Carried Forward**	15	0.0	(6.0)	(6.0)
22	**Total Income Tax** (line 19 + line 20 + line 21)		83.1	211.8	294.9
23	**2026 Forecast Return on Equity** (line 18 - line 22)		331.6	877.7	1,209.3
24	**ROE as a Percent of Equity Financed by Capital Structure (line 23 / Ex. C1-1-1, Table 7, col. (a), line 5)**				12.7%

Notes:
Refer to Table 4a

Table 4a

Notes to Ex. I1-1-1 Table 4

Notes:

1 Col. (a) from Ex. E1-1-1, Table 1, line 4, col. (j). Col. (b) from Ex. E2-1-1, Table 1, line 3, col. (f).

2 Col. (a) is the sum of the regulated hydroelectric payment amount of $43.88/MWh (EB-2020-0290 PAO, p. 4), regulated hydroelectric payment rider of $0.69/MWh (EB-2020-0290 PAO, App. C, Table 1, col. (k), line 23 and regulated hydroelectric payment rider of $2.61/MWh (EB-2023-0336 Payment Amounts Order, App. A, Table 1, col. (h), line 21.
Col. (b) is the sum of the nuclear payment amount of $102.85/MWh (EB-2020-0290 PAO, p. 5), nuclear payment rider of $5.34/MWh (EB-2020-0290 PAO, App. D, Table 1, col. (k), line 32 and nuclear payment rider of $3.42/MWh (EB-2023-0336 Payment Amounts Order, App. A, Table 2, col. (h), line 31.

3 Col. (a) from Ex. F1-1-1 Table 1, line 6, col. (j). Col. (b) from Ex. F2-1-1 Table 1a, line 16, col. (f).

4 Col. (a) from Ex. F1-1-1 Table 1, line 7, col. (j). Col. (b) from Ex. F2-1-1 Table 1a, line 17, col. (f).

5 Col. (a) from Ex. F1-1-1 Table 1, line 8, col. (j). Col. (b) from Ex. F2-1-1 Table 1a, line 18, col. (f).

6 Col. (a) from Ex. F1-1-1 Table 1, line 10, col. (j). Col. (b) from Ex. F2-1-1 Table 1a, line 20, col. (f).

7 Col. (a) from Ex. G1-1-1, Table 1, col. (j), line 7. Col. (b) from Ex. G2-1-1, Table 1, col. (f), line 7.

8 Col. (c) from Ex. C1-1-1, Table 7, col. (d), line 1.
Col. (a) equal to col. (c) multiplied by ratio of regulated hydroelectric rate base to total regulated rate base. Col. (b) equal to col. (c) multiplied by ratio of nuclear rate base to total regulated rate base.
Regulated hydroelectric ratio determined by dividing Ex. B1-1-1, Table 1, col. (d), line 12 by Ex. C1-1-1, Table 7, line 8, col. (a).
Nuclear ratio determined by dividing Ex. B1-1-1, Table 2, col. (f), line 7 by Ex. C1-1-1, Table 7, line 8, col. (a).

9 Col. (c) from Ex. C1-1-1, Table 7, col. (d): line 2 plus line 3.
Col. (a) equal to col. (c) multiplied by ratio of regulated hydroelectric rate base to total regulated rate base. Col. (b) equal to col. (c) multiplied by ratio of nuclear rate base to total regulated rate base.
Regulated hydroelectric ratio determined by dividing Ex. B1-1-1, Table 1, col. (d), line 12 by Ex. C1-1-1, Table 7, line 8, col. (a).
Nuclear ratio determined by dividing Ex. B1-1-1, Table 2, col. (f), line 7 by Ex. C1-1-1, Table 7, line 8, col. (a).

10 From Ex. C1-1-1, Table 7, col. (d), line 7.

11 Col. (a) is the sum of EB-2020-0290 PAO, App. C, Table 1, line 16, col. (k) and EB-2023-0336 PAO, App. A, Table 1, col. (h), line 16.

12 Forecast 2025 Transactions Excluding Income Tax Components are computed as follows:

Table to Note 12 ($M)

Line No.	Description	Amount ($M)
	Regulated Hydroelectric:	
12a	Total Transactions Impacting Calculation of Regulatory Return on Equity	45.4
12b	Less: Tax Gross-up Components of Transactions in:	13.1
12c	Less: Tax Variance Components of Transactions in:	(14.3)
12d	Transactions Excluding Income Tax Components	46.6
	Nuclear :	
12e	Total Transactions Impacting Calculation of Regulatory Return on Equity	250.6
12f	Less: Tax Gross-up Components of Transactions in:	(6.3)
12g	Less: Tax Variance Components of Transactions in:	(37.8)
12h	Transactions Excluding Income Tax Components	294.7

13 Col. (a) from Ex. F4-2-1 Table 1, line 1, col. (j). Col. (b) from Ex. F4-2-1 Table 2, line 1, col. (f).

14 Regulated Hydroelectric: Sum of Note 12, line 12c. Nuclear: line 12g.

15 EB-2020-0290 PAO, Table 22, col. (d) line 2 + line 3 x 25%

Table 5
Determination of 2026 Forecast Return on Equity ($M)

Line No.	Description	Note	2026 Forecast Regulated Hydroelectric	Nuclear	Total
			(a)	(b)	(c)
1	**Forecast Production (TWh)**	1	32.8	32.5	65.2
2	**Payment Amount ($/MWh)**	2	47.18	123.76	n/a
3	**Indicated Production Revenue ($M)** (line 1 x line 2)		1,545.8	4,016.8	5,562.6
	Expenses:				
4	**OM&A**	3	439.4	2,118.2	2,557.6
5	**Fuel and GRC**	4	354.3	239.2	593.5
6	**Depreciation**	5	194.8	617.7	812.4
7	**Property Taxes**	6	1.0	13.5	14.5
8	**Total Expenses**		989.5	2,988.6	3,978.0
9	**Ancillary and Other Revenue**	7	76.0	39.4	115.4
	Cost of Capital Excluding Return on Equity				
10	**Short-term Debt**	8	5.9	10.2	16.1
11	**Long-Term Debt**	9	200.7	346.3	547.1
12	**Adjustment for Lesser of UNL or ARC**	10	0.0	9.6	9.6
13	**Cost of Capital Excluding Return on Equity**		206.6	366.1	572.7
	Deferral and Variance Account Adjustments				
14	**Amortization of Previously Approved Amounts**	11	(99.5)	(214.1)	(313.6)
15	**Transactions Excluding Income Tax Components and Concurrent Cost Recovery**	12	84.8	(354.6)	(269.8)
16	**Total Deferral and Variance Account Adjustments**		(14.7)	(568.7)	(583.4)
17	**Revenue Requirement Excluding Income Tax and Return on Equity, Plus Deferral and Variance Account Amounts Excluding Income Tax Components** (line 8 - line 9 + line 13 - line 16)		1,134.8	3,884.0	5,018.8
18	**2026 Forecast Regulatory Earnings Before Tax** (line 3 - line 17)		411.0	132.8	543.8
19	**Income Tax**	13	37.6	(63.5)	(25.9)
20	**Deferral and Variance Account Transactions - Income Tax Variance Components**	14	37.1	27.2	64.3
21	**Income Tax Benefit of EB-2020-0290 Tax Losses Carried Forward**	15	0.0	(24.7)	(24.7)
22	**Total Income Tax** (line 19 + line 20 + line 21)		74.7	(60.9)	13.8
23	**2026 Forecast Return on Equity** (line 18 - line 22)		336.3	193.8	530.0
24	**ROE as a Percent of Equity Financed by Capital Structure (line 23 / Ex. C1-1-1, Table 8, col. (a), line 5)**				6.1%

Notes:
Refer to Table 5a

Table 5a

Notes to Ex. I1-1-1 Table 5

Notes:

1 Col. (a) from Ex. E1-1-1, Table 1, line 4, col. (k). Col. (b) from Ex. E2-1-1, Table 1, line 5, col. (g).

2 Col. (a) is the sum of the regulated hydroelectric payment amount of $43.88/MWh (EB-2020-0290 PAO, p. 4), regulated hydroelectric payment rider of $0.69/MWh (EB-2020-0290 PAO, App. C, Table 1, col. (l), line 23 and regulated hydroelectric payment rider of $2.61/MWh (EB-2023-0336 Payment Amounts Order, App. A, Table 1, col. (i), line 21.
Col. (b) is the sum of the nuclear payment amount of $111.33/MWh (EB-2020-0290 PAO, p. 5), nuclear payment rider of $7.58/MWh (EB-2020-0290 PAO, App. D, Table 1, col. (l), line 32 and nuclear payment rider of $4.85/MWh (EB-2023-0336 Payment Amounts Order, App. A, Table 2, col. (i), line 31.

3 Col. (a) from Ex. F1-1-1 Table 1, line 6, col. (k). Col. (b) from Ex. F2-1-1 Table 1a, line 16, col. (g).

4 Col. (a) from Ex. F1-1-1 Table 1, line 7, col. (k). Col. (b) from Ex. F2-1-1 Table 1a, line 17, col. (g).

5 Col. (a) from Ex. F1-1-1 Table 1, line 8, col. (k). Col. (b) from Ex. F2-1-1 Table 1a, line 18, col. (g).

6 Col. (a) from Ex. F1-1-1 Table 1, line 10, col. (k). Col. (b) from Ex. F2-1-1 Table 1a, line 20, col. (g).

7 Col. (a) from Ex. G1-1-1, Table 1, col. (k), line 7. Col. (b) from Ex. G2-1-1, Table 1, col. (g), line 7.

8 Col. (c) from Ex. C1-1-1, Table 6, col. (d), line 1.
Col. (a) equal to col. (c) multiplied by ratio of regulated hydroelectric rate base to total regulated rate base. Col. (b) equal to col. (c) multiplied by ratio of nuclear rate base to total regulated rate base.
Regulated hydroelectric ratio determined by dividing Ex. B1-1-1, Table 1, col. (e), line 12 by Ex. C1-1-1, Table 6, line 8, col. (a). Nuclear ratio determined by dividing Ex. B1-1-1, Table 2, col. (g), line 7) by Ex. C1-1-1, Table 6, line 8, col. (a).

9 Col. (c) from Ex. C1-1-1, Table 6, col. (d): line 2 plus line 3.
Col. (a) equal to col. (c) multiplied by ratio of regulated hydroelectric rate base to total regulated rate base. Col. (b) equal to col. (c) multiplied by ratio of nuclear rate base to total regulated rate base.
Regulated hydroelectric ratio determined by dividing Ex. B1-1-1, Table 1, col. (e), line 12 by Ex. C1-1-1, Table 6, line 8, col. (a). Nuclear ratio determined by dividing Ex. B1-1-1, Table 2, col. (g), line 7) by Ex. C1-1-1, Table 6, line 8, col. (a).

10 From Ex. C1-1-1, Table 6, col. (d), line 7.

11 Col. (a) is the sum of EB-2020-0290 PAO, App. C, Table 1, line 16, col. (l) and EB-2023-0336 PAO, App. A, Table 1, col. (i), line 16.
Col. (b) is the sum of EB-2020-0290 PAO, App. D, Table 1, col. (l), line 25 and EB-2023-0336 PAO, App. A, Table 2, col. (i), line 26.

12 Forecast 2026 Transactions Excluding Income Tax Components are computed as follows:

Table to Note 12 ($M)

Line No.	Description	Amount ($M)
	Regulated Hydroelectric:	
12a	Total Transactions Impacting Calculation of Regulatory Return on Equity	57.8
12b	Less: Tax Gross-up Components of Transactions in:	10.2
12c	Less: Tax Variance Components of Transactions in:	(37.1)
12d	Transactions Excluding Income Tax Components	84.8
	Nuclear :	
12e	Total Transactions Impacting Calculation of Regulatory Return on Equity	(369.7)
12f	Less: Tax Gross-up Components of Transactions in:	12.1
12g	Less: Tax Variance Components of Transactions in:	(27.2)
12h	Transactions Excluding Income Tax Components	(354.6)

13 Col. (a) from Ex. F4-2-1 Table 1, line 1, col. (k). Col. (b) from Ex. F4-2-1 Table 2, line 1, col. (g).

14 Regulated Hydroelectric: Note 12, line 12c. Nuclear: Note 12, line 12g.

15 EB-2020-0290 PAO, Table 22, col. (e) line 2 + line 3 x 25%

Table 6
Calculation of Forecast Concurrent Cost Recovery - Darlington New Nuclear Program
January 1, 2026 to December 31, 2031 ($M)

Line No.	Description	Note	2026	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)	(f)
1	**Opening Balance**	1	2,250.5	3,884.0	5,504.7	6,401.4	6,706.1	494.3
2	**Capital Expenditures**	1	1,633.5	1,620.7	896.7	304.7	373.2	0.0
3	**In-Service**	2	0.0	0.0	0.0	0.0	6,584.9	0.0
4	**Closing Balance** (line 1 + line 2 - line 3)		3,884.0	5,504.7	6,401.4	6,706.1	494.3	494.3
5	**Capital Costs for Purposes of Calculating CCR** ((line 1 + line 4) / 2	2	3,067.2	4,694.3	5,953.0	6,553.7	5,520.8	494.3
6	**OPG Cost of Long-Term Borrowing**	3	3.65%	4.58%	4.78%	4.90%	4.97%	4.98%
7	**Concurrent Cost Recovery** (line 5 x line 6)	4	112.0	214.9	284.8	321.2	274.2	24.6

Notes

1 Per Ex. D2-4-8, Table 1, line 3. Opening balance in col. (a) per Ex. D2-4-8, Table 1, sum of line 3, col. (a) through col. (f).

2 In-service additions exceeding $50M are reflected in the month of the addition instead of using mid-year average (see Ex. B1-1-1, p. 9). 2030 in-service is weighted 2.5/12 months based on in-service date of October 17, 2030. Per Ex. B3-3-1, Table 2a, Note 1.

3 Per Ex. C1-1-1, Tables 1-5: line 2, col. (c).

4 Over the 2027-2031 period, concurrent cost recovery amounts of $1,004.9M relate to Unit 1 and $114.9M relate to Units 2 through 4.

Numbers may not add due to rounding.

Table 7
Calculation of Forecast Concurrent Cost Recovery - Pickering Refurbishment Program
January 1, 2026 to December 31, 2031 ($M)

Line No.	Description	Note	2026	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)	(f)
1	**Opening Balance**	1	1,887.0	4,773.3	8,225.9	11,833.5	15,411.7	18,093.2
2	**Capital Expenditures**	1	3,045.6	3,473.2	3,607.6	3,578.3	2,681.4	1,860.5
3	**In-Service**	2	159.3	20.6	0.0	0.0	0.0	9,688.0
4	**Closing Balance** (line 1 + line 2 - line 3)		4,773.3	8,225.9	11,833.5	15,411.7	18,093.2	10,265.7
5	**Capital Costs for Purposes of Calculating CCR** ((line 1 + line 4) / 2	2	3,303.6	6,499.6	10,029.7	13,622.6	16,752.5	12,968.4
6	**OPG Cost of Long-Term Borrowing**	3	3.65%	4.58%	4.78%	4.90%	4.97%	4.98%
7	**Concurrent Cost Recovery**		120.6	297.6	479.9	667.7	832.0	646.2

Notes
1 Per Ex. D2-3-8, Table 1, line 4. Opening balance in col. (a) per Ex. D2-3-10, Table 1, sum of line 4: col. (a) through col. (f).
2 In-service additions exceeding $50M are reflected in the month of the addition instead of using mid-year average (see Ex. B1-1-1, p. 9). The 2031 in-service is weighted 7.5/12 based on in-service date of May 15, 2031. See Ex. B3-3-1 Table 2a, Note 1 for further details.
3 Per Ex. C1-1-1, Tables 1-5: line 2, col. (c).

CONSUMER IMPACT

1.0 PURPOSE

This evidence describes the estimated impact of the proposed payment amounts and payment rider changes on a residential electricity consumer consuming at the 750 kWh per month level (the "typical consumer").

2.0 CONSUMER IMPACT

The Application has calculated the weighted average of regulated hydroelectric and shaped nuclear payment amounts and payment amount riders, weighted by forecast production to be $110.05/MWh for 2027, $118.67/MWh for 2028, $123.62/MWh for 2029, $126.20/MWh for 2030, and $141.55/MWh for 2031.[1,2]

The annual change in weighted average payment amounts and riders is applied to the typical consumer's usage of OPG's regulated hydroelectric and regulated nuclear facilities and the DNNP facilities, after adjusting for line losses and accounting for these facilities' share of the province's generation. Typical consumer data is based on the average electricity distributor bill information provided on the OEB's website at:
https://www.oeb.ca/consumer-protection/energy-contracts/bill-calculator

The estimated monthly consumer bill impacts associated with the revenue requirements and clearance of deferral and variance accounts are reflected in Chart 1, as calculated in Ex. I1-1-2, Table 1.

Chart 1 - Annualized Residential Consumer Impact

	2027	2028	2029	2030	2031
Typical Bill ($/Month)	$142.10	$142.10	$142.10	$142.10	$142.10
Typical Bill Impact ($/Month)	$7.94	$2.45	$1.37	$0.74	$4.67
Typical Bill Impact (%)	5.6%	1.7%	1.0%	0.5%	3.3%

---

[1] Includes shaped 2027-2031 nuclear payment amounts applicable to OPG's nuclear facilities and the DNNP facilities, as illustrated in Ex. I1-3-1, Table 1. An illustrative regulated hydroelectric payment amount is used for the 2028-2031 period, using the proposed ratemaking methodology, as per Ex. I1-2-1.

[2] Determination of weighted average payment amounts per Ex. I-1-2, Table 2.

Table 1
Annualized Residential Consumer Impact
EB-2020-0290/EB-2023-0336 to EB-2025-0297

Line No.	Description	2027 Amount	2028 Amount	2029 Amount	2030 Amount	2031 Amount	2027-2031 Average
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Typical Consumption[1] (kWh/Month)**	787	787	787	787	787	787
2	**Typical Usage of OPG and DNNP LP Generation (kWh/Month)** (line 1 x line 11)	246	284	276	287	304	280
3	**Typical Bill[1] ($/Month)**	142.10	142.10	142.10	142.10	142.10	142.10
4	**Typical Bill Impact ($/Month)** (line 2 x line 8 / 1000)	7.94	2.45	1.37	0.74	4.67	3.43
5	**Typical Bill Impact (%)** (line 4 / line 3)	5.6%	1.7%	1.0%	0.5%	3.3%	2.4%
6	Prior Year weighted average rate with proposed payment amounts and riders[2,3] ($/MWh)	77.75	110.05	118.67	123.62	126.20	
7	Current Year weighted average rate with proposed payment amounts and riders[2,3] ($/MWh)	110.05	118.67	123.62	126.20	141.55	
8	Change in weighted average rate ($/MWh) (line 7 - line 6)	32.30	8.62	4.95	2.58	15.35	
9	Total Regulated Production[4] (TWh)	51.2	59.2	57.5	59.8	63.3	
10	Forecast of 2027 Provincial Demand[5] (TWh)	163.9	163.9	163.9	163.9	163.9	
11	OPG and DNNP LP Proportion of Consumer Usage (line 9 / line 10)	31.2%	36.1%	35.1%	36.5%	38.6%	

Notes:

1 Typical monthly consumption (750 kWh) and typical monthly bill are based on the OEB "Bill Calculator" for estimating monthly electricity bills (using Time of Use pricing), available at: https://www.oeb.ca/consumer-information-and-protection/bill-calculator, accessed November 20, 2025. Typical Consumption includes line losses (Average loss factor of utility rate zones = 1.04996)

2 From Ex. I1-1-2 Table 2, line 9.

3 Per Ex. I1-3-1 Table 1.

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

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

Numbers may not add due to rounding.

Table 2
Computation of Percent Change in Payment Amounts
EB-2020-0290/EB-2023-0336 to EB-2025-0297

Line No.	Description	Note	2026	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)	(f)
			Note 1	Note 2	Note 2	Note 2	Note 2	Note 2
1	**Hydroelectric Payment Amount (HPA) ($/MWh)**	3	43.88	51.39	54.97	59.20	62.02	64.21
2	**Hydroelectric Payment Rider (HPR) ($/MWh)**	4	3.30	(1.17)	(1.17)	(1.17)	0.00	0.00
3	**Hydroelectric Production Forecast (HPF) TWh**	5	33.0	32.5	32.5	32.5	32.5	32.5
4	**Nuclear Payment Amount (NPA) ($/MWh)**	6	111.33	206.76	192.52	203.20	199.97	220.68
5	**Nuclear Payment Rider (NPR) ($/MWh)**	7	12.43	7.19	5.04	5.36	2.48	2.19
6	**Nuclear Production Forecast (NPF) TWh**	8	21.9	18.7	26.7	25.1	27.3	30.9
7	**Regulated Hydroelectric Portion of Weighted Average Payment Amount ($/MWh)** (HPA + HPR) x HPF / (NPF+HPF)		28.35	31.87	29.52	32.75	33.68	32.91
8	**Nuclear Portion of Weighted Average Payment Amount ($/MWh)** (NPA + NPR) x NPF / (NPF+HPF)		49.41	78.18	89.14	90.87	92.52	108.64
9	**Weighted Average Payment Amount ($/MWh)** (((NPA + NPR) x NPF) + (HPA + HPR) x HPF) / (NPF + HPF)		77.75	110.05	118.67	123.62	126.20	141.55
10	**Percentage Change in Weighted Average Payment Amount (Year over Year)**			41.5%	7.8%	4.2%	2.1%	12.2%

Notes:
1 Payment amounts, riders and production forecasts approved in EB-2020-0290 Payment Amounts Order plus payment riders approved in EB-2023-0336.
2 Payment amounts and payment riders proposed in this application.
3 Per Ex. I1-2-1, Table 1. Cols. (c) to (f) are illustrative only.
4 Per Ex. H1-2-1, Table 1, line 21.
5 For 2027: Per Ex. E1-1-1, Table 1, col. (a), line 8.
6 Per Ex. I1-3-1, Table 1, line 5. 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.

CONCURRENT COST RECOVERY

1.0 PURPOSE

This evidence provides a description of the framework for recovery of interest amounts associated with the Pickering Refurbishment Program ("PRP") and the Darlington New Nuclear Program ("DNNP") prior to such assets being placed in service as prescribed by Ontario Regulation 53/05 ("O. Reg. 53/05") ("concurrent cost recovery" or "CCR") and presents such forecast interest amounts sought for recovery in this Application.

2.0 OVERVIEW

Pursuant to the requirements of O. Reg. 53/05, the Application seeks approval to include:

- In DNNP LP's revenue requirements, an amount calculated by multiplying the forecast cumulative capital costs incurred in respect of the DNNP by OPG's long-term cost of debt rate;[1] and
- In OPG's revenue requirements, an amount calculated by multiplying the forecast cumulative capital costs incurred in respect of the PRP by OPG's long-term cost of debt rate.

Additionally, O. Reg. 53/05 establishes variance accounts related to CCR interest amounts:

- For DNNP LP, an account that records the difference between the forecast DNNP CCR amount included in DNNP LP's revenue requirement (as determined above) and an amount calculated by multiplying the actual cumulative capital costs incurred by DNNP LP in respect of the DNNP by OPG's long-term cost of debt rate;[2] and
- For OPG, an account that records the difference between the forecast PRP CCR amount included in OPG's revenue requirement (as determined above) and an amount calculated

[1] O. Reg. 53/05 also requires DNNP CCR amounts in OPG's revenue requirement prior to certain conditions being met in establishing DNNP LP as a prescribed generator. Since the Application assumes that DNNP LP will meet these requirements before January 1, 2026, this evidence focuses on the DNNP LP provisions.

[2] O. Reg. 53/05 also establishes a CCR-related variance account for OPG, to be effective up until certain conditions are met in establishing DNNP LP as a prescribed generator. Since the Application assumes that DNNP LP will meet these requirements before January 1, 2026, this evidence focuses on the DNNP LP provisions.

by multiplying the actual cumulative capital costs incurred by OPG in respect of the PRP by OPG's long-term cost of debt rate.

Additional information on the PRP is provided in Ex. D2-3-1 through Ex. D2-3-11. Additional information on the DNNP is provided in Ex. D2-4-1 through Ex. D2-4-10. The two variance accounts are identified in Ex. H1-1-1.

Section 3.0 summarizes the CCR requirements set out in O. Reg. 53/05. Section 4.0 presents the calculation of the CCR interest amounts, in respect of the DNNP, for inclusion in DNNP LP's revenue requirements. Section 5.0 presents the calculation of the CCR interest amounts, in respect of the PRP, for inclusion in OPG's nuclear revenue requirements. Section 6.0 presents the Application's implementation proposal for the requirement to disposition annually the balances in the CCR variance accounts pursuant to O. Reg. 53/05, including amounts that will be recorded in 2026 and must be recovered during 2027.

3.0 REQUIREMENTS OF O. REG. 53/05

O. Reg. 53/05, as amended in December 2025, requires the OEB to provide for the recovery of CCR interest amounts in respect of the DNNP and the PRP prior to the underlying assets being placed in service.

Darlington New Nuclear Program

The applicable amendments to O. Reg. 53/05 appear in Part II and Part III of the regulation, with Part III only applying after DNNP LP is recognized as a prescribed generator for purposes of section 78.1 of the *Ontario Energy Board Act, 1998*.[3] Prior to Part III of the regulation taking effect, the rules governing the determination of payment amounts under section 6(2)11.1 and the variance account established under section 5.4.1 apply to OPG as the prescribed generator. Following Part III of the regulation taking effect, the rules governing the

[3] Section 8 of O. Reg. 53/05 requires the OEB to issue an order specifying satisfaction with certain conditions relating to DNNP LP before Part III takes effect. The Application expects that these requirements will be met by the end of 2025.

determination of payment amounts under section 14(2)5 and the variance account established under section 12 apply to DNNP LP as the prescribed generator.

As set out below, the sections outlining rules governing the determination of payment amounts are the same under Part II and Part III, with the only exception being the prescribed generator to which the rules apply. Similarly, the variance accounts established under Part II and Part III are the same, with the only exception being the prescribed generator to which the accounts apply.

For the DNNP facilities, Section 14(2)5 requires CCR interest amounts to be included in the DNNP LP revenue requirement as follows:

> In setting payment amounts for the DNNP Nuclear Generating Station, the Board shall,
>
> i. include in the Board-approved revenue requirement of the DNNP generator for each year the amount calculated by multiplying the forecast cumulative capital costs incurred by the DNNP generator in respect of the Darlington New Nuclear Project, other than capital costs incurred in respect of any small modular reactor that has come into service or been abandoned, by Ontario Power Generation Inc.'s long-term debt rate,
>
> ii. ensure that the balance recorded in the variance account established under subsection 12 (1) is recovered on an annual basis in the year following the year in which the balance was recorded, to the extent that the Board is satisfied that the amounts are accurately recorded in the account, and

Under Section 12, a Darlington New Nuclear Project Variance Account re Capital Cost Amounts (herein referred to as "DNNP CCR variance account") is established as follows:[4]

[4] Section 8 of O. Reg. 53/05 requires the OEB issue an order specifying satisfaction with certain conditions relating to DNNP LP before section 12 takes effect. Section 12(3) and 14(2)1 add that the account shall include amounts after the effective date of the lease between OPG and DNNP LP. The Application expects that these requirements, including the lease between OPG and DNNP LP, will be met by the end of 2025.

Darlington New Nuclear Project variance account re capital cost amounts

12. (1) The DNNP generator shall establish a variance account in connection with section 78.1 of the Act that records differences between,

(a) the amount calculated by multiplying the actual cumulative capital costs incurred by the DNNP generator in respect of the Darlington New Nuclear Project by Ontario Power Generation Inc.'s long-term debt rate; and

(b) the amount included in payments made under section 78.1 of the Act in accordance with subparagraph 5 i of subsection 14(2).

(2) The account shall not include,

(a) amounts respecting capital costs in respect of any small modular reactor that has come into service or been abandoned; or

(b) amounts already included in a variance account established under subsection 5.4.1 (1) or 11 (1).

(3) The account shall include any amounts referred to in clause (1) (a) that arose on or after the effective date of the lease referred to in paragraph 2 of section 8 and before the DNNP transition date.

(4) The DNNP generator shall record interest on the balance of the account at Ontario Power Generation Inc.'s long-term debt rate, compounded annually.

Pickering Refurbishment Program

The requirements of Section 6(2)12.1 of O. Reg. 53/05 are as follows:

12.1 In setting payment amounts for the nuclear facilities, the Board shall,

i. include in the Board-approved revenue requirement for the nuclear facilities for each year the amount calculated by multiplying the forecast cumulative capital costs incurred by Ontario Power Generation Inc. in respect of the Pickering B

> Refurbishment Project, other than the capital costs referred to in clauses 5.8 (2) (a) and (b), by Ontario Power Generation Inc.'s long-term debt rate,
>
> ii. ensure that the balance recorded in the variance account established under subsection 5.8 (1) is recovered on an annual basis in the year following the year in which any amount was recorded, to the extent that the Board is satisfied that the amounts are accurately recorded in the account, and
>
> iii. ensure that any duplication of amounts accepted by the Board as capital costs under subparagraph 2 i of subsection 14 (2) is avoided.

Under Section 5.8 of O. Reg. 53/05, a PRP CCR variance account is established as follows:

> **Pickering B Refurbishment Project variance account**
> **5.8** (1) Ontario Power Generation Inc. shall establish a variance account in connection with section 78.1 of the Act that records the difference between,
>
> (a) the amount calculated by multiplying the actual cumulative capital costs incurred by Ontario Power Generation Inc. in respect of the Pickering B Refurbishment Project by Ontario Power Generation Inc.'s long-term debt rate; and
>
> (b) the amount included in payments made under section 78.1 of the Act in accordance with subparagraph 12.1 i of subsection 6 (2).
>
> (2) The account shall not include,
>
> (a) amounts respecting capital costs related to a generating unit that has been refurbished and returned to service as part of the Pickering B Refurbishment Project;
>
> (b) amounts respecting capital costs related to the refurbishment, construction or acquisition of a structure, equipment or other thing that is part of the Pickering B Refurbishment Project and that has been returned to or come into service; or

(c) amounts included in the variance account established under section 5.7.

(3) Ontario Power Generation Inc. shall record interest on the balance of the account at its long-term debt rate, compounded annually.

4.0 CONCURRENT COST RECOVERY INTEREST AMOUNTS – DNNP

Pursuant to the requirements identified in Section 3.0 above, the Application seeks to include CCR interest amounts of $214.9M in 2027, $284.8M in 2028, $321.2M in 2029, $274.2M in 2030, and $24.6M in 2031 in respect of the DNNP in the DNNP LP's revenue requirements. The calculations supporting these forecast amounts can be found at Ex. I1-1-1, Table 6. In accordance with Section 14(2)5 of O. Reg. 53/05, there are three inputs into the calculation of these interest amounts:

1) **Forecast of DNNP cumulative capital costs**. Interest is calculated on the forecast of cumulative capital costs to be expended. DNNP capital expenditures are discussed in Ex. D2-4-8, and the amounts used in the CCR calculation can be found in Ex. D2-4-8, Table 1. As discussed in Ex. D2-4-8, these amounts do not include capitalization of interest effective January 1, 2026.
2) **In-service amounts**. Per section 14(2)5 of O. Reg. 53/05, interest is not calculated on capital costs in respect of facilities that have come into service or been abandoned. In-service amounts therefore reduce the cumulative capital costs on which interest is applied. The DNNP in-service amount in 2030 is discussed in Ex. D2-4-8, and the amount used in the calculation can be found in Ex. D2-4-8, Table 3.
3) **OPG cost of long-term borrowing**. Per section 14(2)5 of O. Reg. 53/05, in conjunction with the definition of "long-term debt" in subsection 0.1(1), interest is to be calculated using OPG's long-term debt rate as approved by the OEB. The long-term debt rates proposed for the IR term can be found in Ex. C1-1-1, Tables 1-6 and are discussed in Ex. C1-1-2.

As further discussed in Ex. H1-1-1, Section 6.3, O. Reg. 53/05 Section 12 establishes a DNNP CCR variance account to record the difference between: (i) the amount calculated by multiplying the actual cumulative capital costs incurred by DNNP LP in respect of the DNNP by OPG's OEB-approved long-term debt rate; and (ii) the CCR interest amount included in DNNP LP revenue requirement as determined above. O. Reg. 53/05 Section 14(2)5(ii) requires the balance of this account to be recovered on an annual basis in the year following the year in which any amount was recorded. This includes amounts to be recorded in the account for 2026, which must be recovered during 2027. Exhibit I1-1-1, Table 6 presents the forecast 2026 CCR interest amount of $112.0M in respect of the DNNP.

As shown in Ex. I1-1-1, Table 6, the forecast CCR interest amounts sought in the Application are calculated on an annual basis using a mid-year average methodology, with in-service additions over $50M weighted using the month in which they are reflected to improve accuracy. The actual CCR interest amounts will be derived in the same manner as the forecast amounts, but will be based on the actual capital expenditures and in-service amounts and will be calculated on a monthly basis to provide greater precision and facilitate monthly entry-making into the DNNP CCR Variance Account.

5.0 CONCURRENT COST RECOVERY INTEREST AMOUNTS – PRP

Pursuant to the requirements identified in Section 3.0 above, the Application seeks to include CCR interest amounts of $297.6M in 2027, $479.9M in 2028, $667.7M in 2029, $832.0M in 2030, and $646.2M in 2031 in respect of the PRP in OPG's revenue requirements. The calculations supporting these forecast amounts can be found at Ex. I1-1-1, Table 7. In accordance with Section 6(2)12.1 of O. Reg. 53/05, there are three inputs into the calculation of these interest amounts:

1) **Forecast of PRP cumulative capital costs**. Interest is calculated on the forecast of cumulative capital costs to be expended. PRP capital expenditures are discussed in Ex. D2-3-8, and the amounts used in the CCR calculation can be found in Ex. D2-3-8, Table 1. As discussed in Ex. D2-3-8, these amounts do not include capitalization of interest effective January 1, 2026.
2) **In-service amounts.** Per section 6(2)12.1 and section 5.8(2) of O. Reg. 53/05, interest is not calculated on capital costs related to facilities once that facility has been returned to or come into service. In-service amounts therefore reduce the cumulative capital costs on

which interest is applied. PRP in-service amounts are discussed in Ex. D2-3-8, and the amounts used in the calculation can be found in Ex. D2-3-8, Table 2.

3) **OPG cost of long-term borrowing.** Per Section 6(2)12.1 of O. Reg. 53/05, in conjunction with the definition of “long-term debt” in subsection 0.1(1), interest is to be calculated using OPG’s long-term debt rate as approved by the OEB. These long-term debt rates proposed for the IR term can be found in Ex. C1-1-1, Tables 1-6, and are discussed in Ex. C1-1-2.

As discussed in Ex. H1-1-1, Section 5.30, O. Reg. 53/05 Section 5.8 establishes a PRP CCR variance account to record the difference between: (i) the amount calculated by multiplying the actual cumulative capital costs incurred by OPG in respect of the PRP by OPG’s OEB-approved long-term debt rate; and (ii) the CCR interest amount included in OPG’s revenue requirement as determined above. O. Reg. 53/05 section 6(2)12.1 requires the balance of this account to be recovered on an annual basis in the year following the year in which any amount was recorded. This includes amounts to be recorded in the account for 2026, which must be recovered during 2027. Exhibit I1-1-1, Table 7 presents the forecast 2026 CCR interest amount of $120.6M in respect of the PRP.

As shown in Ex. I1-1-1, Table 7, the forecast CCR interest amounts sought in the Application are calculated on an annual basis using a mid-year average methodology, with in-service additions over $50M weighted using the month in which they are reflected to improve accuracy. The actual CCR interest amounts will be derived in the same manner as the forecast amounts, but will be based on the actual capital expenditures and in-service amounts and will be calculated on a monthly basis to provide greater precision and facilitate monthly entry-making into the PRP CCR variance account.

6.0 PROPOSED PROCESS FOR CCR VARIANCE ACCOUNT ANNUAL CLEARANCE

As noted above, O. Reg. 53/05 requires the balances of the DNNP CCR variance account and the PRP CCR variance account to be recovered in the year following which they are recorded. The Application expects this to begin with recovering the 2026 balances during 2027.

The Application proposes to file a CCR annual clearance application in the first quarter of each year of the IR term, starting with Q1 2027. In each annual CCR clearance application, the balances of the DNNP CCR variance account and the PRP CCR variance account will be provided with supporting calculations comparing the CCR interest on actual capital expenditures (taking into account actual in-service amounts), to the CCR interest on the forecast capital expenditures underpinning CCR interest amounts included in OEB-approved payment amounts.

It is expected that the annual CCR clearance application will propose to recover the sum of the balances in the two accounts through a rate rider, over a forecast combined nuclear production (i.e., OPG nuclear facilities and the DNNP facilities)[5], over the remaining months of the year. For example, if the annual CCR clearance application is filed and adjudicated before the end of February, the application could propose recovering the balance over the period from March 1-December 31. If more time is required and a decision is issued in April, for example, the balance could be recovered over the period from May 1-December 31.

[5] Recovering the sum of the DNNP CCR variance account and PRP CCR variance account balances over the sum of production from the DNNP facilities and OPG nuclear facilities is consistent with O. Reg. 53/05, Section 14(2)8, which requires the OEB to determine a blended payment amount rider for OPG and the DNNP LP.

REGULATED HYDROELECTRIC PAYMENT AMOUNT

1.0 PURPOSE

This evidence presents OPG's requested 2027 payment amount for its regulated hydroelectric facilities.

2.0 REGULATED HYDROELECTRIC PAYMENT AMOUNT

OPG is seeking approval of a payment amount for its regulated hydroelectric facilities of $51.39/MWh, effective January 1, 2027, for the average hourly net energy production ("MWh") from the regulated hydroelectric facilities in any given month for each hour of that month.

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

- For the resource(s) at regulated hydroelectric facilities, for each hour where the IESO day-ahead market energy schedule (the "Day-Ahead Energy Schedule") differs from the average hourly energy schedule from the IESO's day-ahead market for that day (the "Average Day-Ahead Energy Schedule"), OPG's revenues will be adjusted by the difference between the Day-Ahead Energy Schedule and the Average Day-Ahead Energy Schedule, multiplied by the day-ahead locational marginal price for the resource for that hour. For the resource(s) at regulated hydroelectric facilities, for each hour where (1) the difference between the net energy production supplied to the IESO's real-time market and the Day-Ahead Energy Schedule ("Real-Time Energy Difference") differs from (2) the difference between the average hourly net energy production over that day and the Average Day-Ahead Energy Schedule for that day ("Average Real-Time Energy Difference"), OPG's revenues will be adjusted by the difference between the Real-Time Energy Difference and the Average Real-Time Energy Difference, multiplied by the real-time locational marginal price for the resource for that hour, calculated on a five-minute basis.

The requested payment amount is calculated in Ex. I1-2-1, Table 1. This table also presents the proposed regulated hydroelectric payment rider of $(1.17)/MWh effective January 1, 2027-December 31, 2029, as calculated in Ex. H1-2-1, Table 1.

Payment amounts for 2028-2031, determined using the ratemaking methodology proposed in Ex. A1-3-2, are included in the table for illustrative purposes.

Table 1
Payment Amounts and Riders – Regulated Hydroelectric Facilities
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. I1-2-1 Table 2, line 10)	5		**4.33%**	**5.02%**	**2.04%**	**0.77%**
8	**GRC Adjustment** (Ex. I1-2-1 Table 2, Note 3, line 3c)	6		**-0.70%**	**-0.66%**	**-0.61%**	**-0.58%**
9	**Price Cap Index**			**6.96%**	**7.70%**	**4.76%**	**3.53%**
10	**Prior Year Hydroelectric Payment Amount ($/MWh)**			51.39	54.97	59.20	62.02
11	**Prior Year Price Cap Adjusted Hydroelectric Payment Amount ($/MWh)**	7	51.39	54.97	59.20	62.02	64.21
12	**Hydroelectric Payment Rider ($/MWh)**	8	(1.17)	(1.17)	(1.17)	0.00	0.00
14	**Total of Hydroelectric Payment Amounts Plus Riders** (line 11 + line 12 + line 13)		50.22	53.80	58.03	62.02	64.21

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 2: 15.3% labour cost (line 2), 9.3% non-labour cost (line 3) and 75.4% capital cost (line 3).

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 2
Calculation of Capital Factor for Regulated Hydroelectric Facilities
January 1, 2027 to December 31, 2031 ($M)

Line No.	Description	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
			Note 1				
1	**Depreciation**	Ex. F4-1-1 Table 1, line 10	215.4	228.4	249.6	263.6	271.7
2	**Cost of Debt**	Note 2	201.5	222.3	254.3	272.9	286.9
3	**Return on Equity**	Note 2	432.8	458.9	512.3	543.4	568.8
4	**Income Taxes**	Ex. F4-2-1 Table 3b, line 24	27.3	70.3	87.6	101.6	110.7
5	**Capital Related Revenue Requirement**	Sum lines 1 to 4	876.9	979.9	1,103.8	1,181.5	1,238.1
6	**Regulated Hydroelectric Stretch Factor Capital Related Revenue Requirement Adjustment**	0.15% * line 5 (cumulative)		1.5	3.1	4.9	6.8
7	**Capital Related Revenue Requirement after Stretch**	line 5 - line 6	876.9	978.5	1,100.7	1,176.6	1,231.4
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)	876.9	906.2	1,011.1	1,137.5	1,215.9
9	**Capital Related Revenue Requirement Shortfall**	line 7 - line 8	-	72.2	89.6	39.1	15.5
10	**Custom Capital Factor (C-Factor)**	line 9_t / line 14_{t-1}		4.3%	5.0%	2.0%	0.8%
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)	1,668.3	1,784.5	1,921.9	2,013.5	2,084.4

Notes:

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

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. B1-1-1, Table 1	9,135.1	9,687.1	10,814.1	11,471.1	12,007.4
2b	Short-Term Debt	Ex. C1-1-1 Tables 1-4	7.7	7.3	8.0	7.8	6.7
2c	Long-Term Debt	Ex. C1-1-1 Tables 1-4	193.8	215.1	246.3	265.1	280.2
2d	Common Equity	Ex. C1-1-1 Tables 1-4	432.8	458.9	512.3	543.4	568.8

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%

NUCLEAR PAYMENT AMOUNTS

1.0 PURPOSE

This evidence presents the blended payment amounts requested by OPG and DNNP LP for OPG's nuclear facilities and the DNNP facilities for 2027, 2028, 2029, 2030, and 2031.

2.0 PAYMENT AMOUNT

The Application is seeking approval of the following shaped payment amounts:

- $206.76/MWh for the nuclear facilities effective January 1, 2027;
- $192.52/MWh for the nuclear facilities effective January 1, 2028;
- $203.20/MWh for the nuclear facilities effective January 1, 2029;
- $199.97/MWh for the nuclear facilities effective January 1, 2030; and
- $220.68/MWh for the nuclear facilities effective January 1, 2031.

The basis for the requested payment amounts is presented in Ex. I1-3-1, Table 1.

Table 1
Payment Amounts - Combined Nuclear
January 1, 2027 to December 31, 2031

Line No.	Description	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
1	Revenue Requirement - OPG Nuclear Facilities	1	4,062.8	4,257.3	4,676.5	4,881.7	5,736.9
2	Revenue Requirement - DNNP Facilities	2	302.0	381.4	417.0	582.1	1,076.1
3	**Combined Nuclear Revenue Requirement Net of Stretch Factor ($M)**		4,364.8	4,638.7	5,093.5	5,463.8	6,813.0
4	**OPG Nuclear Revenue Requirement Shaping Adjustment ($M)**	3	(500.0)	500.0	0.0	0.0	0.0
5	**Combined Nuclear Revenue Requirement After Shaping Adjustment ($M)** (line 3 + line 4)		3,864.8	5,138.7	5,093.5	5,463.8	6,813.0
6	Production Forecast - OPG Nuclear Facilities	4	18.7	26.7	25.1	26.8	28.9
7	Production Forecast - DNNP Facilities	5	0.0	0.0	0.0	0.5	1.9
8	**Combined Nuclear Forecast Production (TWh)**		18.7	26.7	25.1	27.3	30.9
9	**Blended Nuclear Payment Amount ($/MWh)** (line 5 / line 8)	6	206.76	192.52	203.20	199.97	220.68

Notes:
1 From Ex. I1-1-1 Table 2, line 26.
2 From Ex. I1-1-1, Table 2a, line 22.
3 The Application's payment amount shaping proposal is discussed in Ex. I1-3-2.
4 From Ex. E2-1-1 Table 1, line 3.
5 From Ex. E2-1-1 Table 1, line 4.
6 From Ex. I1-1-2 Table 2, line 4.

Table 2
Calculation of OPG Nuclear Facilities Stretch Factor
January 1, 2027 to December 31, 2031 ($M)

Line No.	Description	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
	Stretch Factor Applicable Nuclear OM&A Expenses						
	Darlington Nuclear OM&A Expenses						
1	Base OM&A	1		709.8	745.1	750.8	765.8
2	Project OM&A	2		54.2	53.9	51.6	54.3
3	Outage OM&A	3		112.7	219.1	121.6	115.8
4	Allocation of Corporate Costs	4		205.8	214.9	214.6	222.4
5	**Darlington Total OM&A Expenses Subject to Stretch Factor** (line 1 through line 4)			1,082.5	1,232.9	1,138.7	1,158.2
	Pickering Total Nuclear OM&A Expenses						
6	Base OM&A	5		140.9	153.4	166.0	459.7
7	Project OM&A	6		16.5	19.6	23.0	22.5
8	Outage OM&A	7		0.0	0.0	0.0	26.5
9	Pickering Cyclical Maintenance OM&A	8		160.9	168.9	169.9	106.6
10	Allocation of Corporate Costs	9		206.4	217.8	230.1	249.1
11	**Pickering Total OM&A Expenses Subject to Stretch Factor** (line 6 through line 10)			524.7	559.7	589.0	864.4
12	Asset Service Fees			73.9	89.5	99.0	99.4
	Stretch Factor Applicable Nuclear Capital Related Revenue Requirement						
	Darlington and Operations & Project Support Capital Related Revenue Requirement						
13	Cost of Capital	10		318.8	337.9	391.3	457.1
14	Depreciation Expense	10		233.4	265.5	305.7	352.4
15	Income Tax Expense on Cost of Capital and Depreciation Expense	10		149.1	163.5	188.5	218.5
16	**Total Darlington and Operations & Project Support Capital Related Revenue Requirement Subject to Stretch Factor** (line 13 + line 14 + line 15)			701.3	766.9	885.5	1,028.0
	Pickering Capital Related Revenue Requirement						
17	Cost of Capital	11		24.1	29.3	45.0	59.4
18	Depreciation Expense	11		23.9	23.7	27.0	38.2
19	Income Tax Expense on Cost of Capital and Depreciation Expense	11		13.4	14.4	19.0	25.9
20	**Total Pickering Capital Related Revenue Requirement Subject to Stretch Factor** (line 18 + line 19 + line 20)			61.4	67.4	91.0	123.5
21	Income Tax Expense- Capital Cost Allowance	13		(82.8)	(44.0)	(132.6)	(193.2)
22	**Total Revenue Requirement Amount Subject to Stretch Factor** (line 5 + line 11 + line 12 + line 16 + line 20 + line 21)			2,361.0	2,672.3	2,670.6	3,080.3
23	OPG Nuclear Facilities Stretch Factor	12		0.30%	0.30%	0.30%	0.30%
24	**OPG Nuclear Facilities Stretch Factor Revenue Requirement Adjustment ($M)** (line 22_t * line 23_t) + line 24_{t-1}	14		**7.1**	**15.1**	**23.1**	**32.4**

Notes:

Refer to Table 2a

Table 2a
Notes to Ex. I1-3-1 Table 2

Notes:

1 Col. (b) from Ex. F2-2-1, Table 11, line 13, col.(a); Col.(c) from Ex. F2-2-1, Table 12, line 13, col.(a); Col.(d) from Ex. F2-2-1, Table 13, line 13, col.(a); Col.(e) from Ex. F2-2-1, Table 14, line 13, col.(a).
2 From Ex. F2-3-1, Table 1: line 1 + line 3a + line 3d.
3 From Ex. F2-4-1,Table 1, line 3.
4 From Ex. F3-1-1, Table 3a, line 10.
5 Col. (b) from Ex. F2-2-1, Table 11, line 13, col.(b). Col.(c) from Ex. F2-2-1, Table 12, line 13, col.(b). Col.(d) from Ex. F2-2-1, Table 13, line 13, col.(b). Col.(e) from Ex. F2-2-1, Table 14, line 13, col.(b).
6 From Ex. F2-3-1, Table 1: line 2 + line 3b + line 3e.
7 From Ex. F2-4-1_Table 1, line 6.
8 From Ex. F2-4-1, Table 1, line 14.
9 From Ex. F3-1-1, Table 3b, line 10.
10 Cost of capital component of Darlington and Operations & Project Support Capital Related Revenue Requirement for 2028-2031 is calculated as follows:

		2027	2028	2029	2030	2031
10a	Darlington GS and Operations & Project Support Net Fixed Asset Rate Base excluding Net Fixed Asset Rate Base for which common equity is subject to return at the long-term debt rate. 2028: Ex. B3-3-1, Table 2, col. (f), lines 13 and 20 less Ex. B3-4-1 Table 2, col. (f), lines 37 and 44. Less line 10b. 2029: Ex. B3-3-1, Table 2, col. (f), lines 25 and 32 less Ex. B3-4-1 Table 2, col. (f), lines 49 and 56. Less line 10b. 2030: Ex. B3-3-1, Table 2, col. (f), lines 37 and 44 less Ex. B3-4-1 Table 2, col. (f), lines 61 and 68. Less line 10b. 2031: Ex. B3-3-1, Table 2, col. (f), lines 49 and 56 less Ex. B3-4-1 Table 2, col. (f), lines 73 and 80. Less line 10b.		4,447.4	4,687.9	5,426.9	6,347.4
10b	Darlington GS and Operations & Project Support Net Fixed Asset Rate Base for which common equity is subject to return at long-term debt rate. 2028-2031: Ex. C1-1-1, Table 13, col. (c).		127.1	114.6	103.7	95.5
10c	Return on Equity at ROE Rate (line 10a x 52% x 9.11%)		210.7	222.1	257.1	300.7
10d	Return on Equity at Long-Term Debt Rate (line 10b x 52% x Ex. C1-1-1, Tables 1-4, col. (c), line 4a)		3.2	2.9	2.7	2.5
10e	Cost of Debt ((line 10a + line 10b) x 48% x Ex. C1-1-1, Tables 1-4, col. (c), line 4)		105.0	112.9	131.6	154.0
10f	Total Cost of Capital (lines 10c + 10d + 10e)		**318.8**	**337.9**	**391.3**	**457.1**
10g	Depreciation Expense (Ex. B3-4-1, Table 2, col. (b): lines 37 & 44; lines 49 & 56; lines 61 & 68; lines 73 & 80)		233.4	265.5	305.7	352.4
10h	Net Regulatory Taxable Income Increase / (Decrease) (line 10c + line 10d + line 10g)		447.2	490.5	565.5	655.5
10i	Income Tax Expense (line 10h x 25% / (1 - 25%))		**149.1**	**163.5**	**188.5**	**218.5**

11 Cost of capital component of Pickering Capital Related Revenue Requirement for 2028-2031 is calculated as follows:

11a	Pickering GS Net Fixed Asset Rate Base excluding Net Fixed Asset Rate Base for which common equity is subject to return at the long-term debt rate. 2028: Ex. B3-3-1, Table 2, col. (f), line 17 less Ex. B3-4-1 Table 2, col. (f), line 41. Less line 11b. 2029: Ex. B3-3-1, Table 2, col. (f), line 29 less Ex. B3-4-1 Table 2, col. (f), line 53. Less line 11b. 2030: Ex. B3-3-1, Table 2, col. (f), line 41 less Ex. B3-4-1 Table 2, col. (f), line 65. Less line 11b. 2031: Ex. B3-3-1, Table 2, col. (f), line 53 less Ex. B3-4-1 Table 2, col. (f), line 77. Less line 11b.		343.2	412.9	632.4	833.5
11b	Pickering GS Net Fixed Asset Rate Base for which Common Equity is Subject to Return at Long-Term Debt Rate.		0.0	0.0	0.0	0.0
11c	Return on Equity at ROE Rate (line 10a x 52% x 9.11%)		16.3	19.6	30.0	39.5
11d	Return on Equity at Long-Term Debt Rate (line 10b x 52% x Ex. C1-1-1, Tables 1-4, col. (c), line 4a)		0.0	0.0	0.0	0.0
11e	Cost of Debt ((line 10a + line 10b) x 48% x Ex. C1-1-1, Tables 1-4, col. (c), line 4)		7.9	9.7	15.0	19.9
11f	Total Cost of Capital (lines 10c + 10d + 10e)		**24.1**	**29.3**	**45.0**	**59.4**
11g	Depreciation Expense (Ex. B3-4-1, Table 2, col. (b): lines 41, 53, 65, 77)		**23.9**	**23.7**	**27.0**	**38.2**
11h	Net Regulatory Taxable Income Increase / (Decrease) (line 10c + line 10d + line 10g)		40.2	43.2	57.0	77.7
11i	Income Tax Expense (line 10h x 25% / (1 - 25%))		**13.4**	**14.4**	**19.0**	**25.9**

12 Per Ex. A1-3-2, Section 3.2.1.

13 Income tax component of CCA-related revenue requirement for 2028-2031 is calculated as follows:

		2027	2028	2029	2030	2031
(a)	Capital Cost Allowance (Ex. F4-2-1 Table 3d, line 16 less DRP and PRP amounts per Ex. F4-2-1 Table 3f Note 3)		(248.3)	(132.0)	(397.8)	(579.6)
(b)	Income Tax Expense (line (a) x 25% / (1 - 25%))		**(82.8)**	**(44.0)**	**(132.6)**	**(193.2)**

14 The nuclear stretch factor revenue requirement adjustment can be further broken down as follows:

		2027	2028	2029	2030	2031
14a	OM&A Stretch Factor Adjustment ((line 5 + line 11 + line 12) * line 24)		5.0	10.7	16.2	22.5
14b	Capital-related Stretch Factor Adjustment (line 16 + line 20 + line 21) * line 24)		2.0	4.4	6.9	9.8
14c	Total Nuclear Stretch Factor Revenue Requirement Adjustment (line 14a + line 14b)		7.1	15.1	23.1	32.4

PAYMENT AMOUNT SHAPING

1.0 PURPOSE

This evidence sets out the Application's proposal for shaping payment amounts during the 2027-2031 IR term.

2.0 OVERVIEW

OPG proposes a payment amount shaping approach intended to help manage the 2027 ratepayer impacts, while balancing the company's financing needs over the 2027-2031 period. To enable payment amount shaping, the Application proposes to establish a Payment Amount Shaping Deferral Account ("PASDA") to record the difference between: (1) OPG's total annual nuclear revenue requirement approved by the OEB; and (2) the portion of that revenue requirement in (1) that is used in connection with setting the nuclear payment amounts in each year.[1]

For the 2027-2031 IR term, OPG proposes to defer $500M of its proposed 2027 nuclear revenue requirement to 2028, with resulting PASDA entries[2] of $500M in 2027, $(500)M in 2028, $0M in 2029, $0M in 2030, and $0M in 2031 and resulting weighted average payment amounts ("WAPA")[3] of $110.05/MWh in 2027, $118.67/MWh in 2028, $123.62/MWh in 2029, $126.20/MWh in 2030, and $141.55/MWh in 2031. This proposal is consistent with customer feedback received during OPG's customer engagement (See Attachment 1).

The estimated average residential customer bill impact of the weighted average payment amounts proposed in this Application inclusive of the payment amount shaping proposal is 2.4% annually or approximately $3.43 on a typical monthly residential customer bill each year.[4]

[1] Ex. H1-1-1 Section 7.4.
[2] Ex. I1-3-1 Table 1, line 2.
[3] Ex. I1-1-2 Table 2, line 9.
[4] Ex. I1-1-2 Table 1, lines 4 and 5, col. (f).

Section 3.0 describes the calculation of the WAPA and the resulting WAPA and bill impacts in this Application, before rate shaping. Section 4.0 sets out the Application's rate shaping proposal and OPG's customer engagement efforts.

3.0 WEIGHTED AVERAGE PAYMENT AMOUNTS AND BILL IMPACTS

3.1 Calculation of the Weighted Average Payment Amount

OPG determines WAPA for a year through the following formula:

$$\frac{((BNPA + BNPR) \times TNPF) + ((HPA + HPR) \times HPF)}{(TNPF + HPF)}$$

BNPA (**Blended Nuclear Payment Amount**) is the pre-shaping blended payment amount for the year in respect of the OPG nuclear facilities and the DNNP facilities[5]

BNPR (**Blended Nuclear Payment Riders**) represents any payment amount riders for the year in respect of the recovery (or repayment) of balances recorded in the deferral accounts and variance accounts established for the OPG nuclear facilities and the DNNP facilities

TNPF (**Total Nuclear Production Forecast**) is the sum of the production forecasts for the year for the OPG nuclear facilities and the DNNP nuclear facilities

HPA (**Hydroelectric Payment Amount**) is the payment amount for the year in respect of OPG's prescribed hydroelectric facilities

HPR (**Hydroelectric Payment Riders**) represents any payment amount riders for the year in respect of the recovery (or repayment) of balances

[5] Further description of the blended payment amount can be found in Ex. A1-3-2, Section 3.1.

recorded in the deferral accounts and variance accounts established for OPG's prescribed hydroelectric facilities

HPF (**Hydroelectric Production Forecast**) is the production forecast for OPG's prescribed hydroelectric facilities for the year

3.2 WAPA and Bill Impacts without Shaping

This section lays out the WAPA and estimated customer bill impacts resulting from the revenue requirements and production forecasts proposed in this Application.

Blended Nuclear Payment Amount ("BNPA"):

The nuclear revenue requirements for OPG's nuclear facilities and the DNNP facilities proposed in this application are summarized in Chart 1 below and the production forecasts for OPG's nuclear facilities and the DNNP facilities are summarized in Chart 2 below.

Chart 1 - Nuclear Revenue Requirements Before Shaping[6]

	2027	2028	2029	2030	2031
OPG Nuclear Revenue Requirement Net of Stretch Factor ($M)	4,062.8	4,257.3	4,676.5	4,881.7	5,736.9
DNNP Revenue Requirement ($M)	302.0	381.4	417.0	582.1	1,076.1

Chart 2 - Nuclear Production Forecasts[7]

	2027	2028	2029	2030	2031
OPG Nuclear Production Forecast (TWh)	18.7	26.7	25.1	26.8	28.9
DNNP Production Forecast (TWh)	0.0	0.0	0.0	0.5	1.9

Based on the information provided in Chart 1 and Chart 2, the proposed pre-shaping BNPA amounts are $233.50/MWh in 2027, $173.79/MWh in 2028, $203.20/MWh in 2029, $199.97/MWh in 2030, and $220.68/MWh in 2031.

[6] Ex. I1-3-1 Table 1, lines 1 and 2.
[7] Ex. E2-1-1 Table 1, line 3 and line 4.

Hydroelectric Payment Amount ("HPA"): Per Ex. I1-2-1 Table 1, line 11, the proposed HPA is $51.39/MWh in 2027. Final payment amounts beyond 2027 will be determined annually using the approved ratemaking methodology, proposed in Ex. A1-3-2. The illustrative hydroelectric payment amounts calculated using the proposed methodology and included in Ex. I1-2-1 Table 1 are $54.97/MWh in 2028, $59.20/MWh in 2029, $62.02/MWh in 2030, and $64.21/MWh in 2031. These illustrative HPAs are based on the proposed Gross Revenue Charge Factor, Custom Capital Factor, Stretch Factor, and the most recently published I Factor, to be updated annually.

Blended Nuclear Payment Rider ("BNPR") and Hydroelectric Payment Rider ("HPR"): Per Ex. H1-2-1, OPG is requesting recovery or repayment of certain audited December 31, 2024 balances in the deferral and variance accounts, adjusted for 2025-2026 amortization amounts approved in EB-2020-0290 and EB-2023-0336, through nuclear payment riders and hydroelectric payment riders over the January 1, 2027 to December 31, 2031 period. The proposed blended nuclear payment rider[8] is $7.19/MWh in 2027, $5.04/MWh in 2028, $5.36/MWh in 2029, $2.48/MWh in 2030, and $2.19/MWh in 2031. The proposed hydroelectric payment rider[9] is $(1.17)/MWh in 2027, $(1.17)/MWh in 2028, $(1.17)/MWh in 2029, $0.00/MWh in 2030, and $0.00/MWh in 2031.

Determination of WAPA: Chart 3 lays out the calculation of WAPA absent payment amount shaping, based on the proposals in this Application.

[8] Ex. H1-2-1, Table 2, Line 34
[9] Ex. H1-2-1, Table 1, Line 21.

Chart 3 – Determination of WAPA

Line No.	Description	2027	2028	2029	2030	2031
1.	**BNPA ($/MWh)**	$233.50/MWh	$173.79/MWh	$203.20/MWh	$199.97/MWh	$220.68/MWh
2.	**BNPR ($/MWh)**	$7.19/MWh	$5.04/MWh	$5.36/MWh	$2.48/MWh	$2.19/MWh
3.	**TNPF (TWh)**	18.7TWh	26.7TWh	25.1TWh	27.3TWh	30.9TWh
4.	**HPA ($/MWh)**[10]	$51.39/MWh	$54.97/MWh	$59.20/MWh	$62.02/MWh	$64.21/MWh
5.	**HPR ($/MWh)**	$(1.17)/MWh	$(1.17)/MWh	$(1.17)/MWh	$0.00/MWh	$0.00/MWh
6.	**HPF (TWh)**	32.5TWh	32.5TWh	32.5TWh	32.5TWh	32.5TWh
7.	**WAPA ($/MWh)** Pre-shaping	$119.83/MWh	$110.22/MWh	$123.62/MWh	$126.20/MWh	$141.55/MWh
8.	**WAPA (% y/y change)**	54.1%	-8.0%	12.2%	2.1%	12.2%
9.	**Typical Residential Monthly Bill Impact (%)**[11]	7.3%	-1.9%	2.6%	0.5%	3.3%

The year-over-changes in WAPA (line 8) and typical residential consumer residential monthly bills (line 9) show that the highest increase is in 2027, followed by a decrease in 2028 and increases in 2029, 2030, and 2031.

4.0 PAYMENT AMOUNT SHAPING PROPOSAL AND CUSTOMER ENGAGEMENT

To help manage the 2027 customer bill impacts and the associated volatility in year-over-year changes, OPG proposes to defer recovery of a portion of its 2027 nuclear revenue requirement to subsequent years in the IR term.

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[10] Regulated hydroelectric payment amounts beyond 2027 are for illustrative purposes only.
[11] Further discussion on OPG's methodology for determining the impact of proposed payment amounts and payment riders on a typical residential electricity consumer monthly bill is found in Ex. I1-1-2.

4.1 Payment Amount Shaping Criteria

In determining the shaping amounts in each year, the Application was guided by two principles: customer bill impact and financial viability.

Customer Bill Impact: The primary objective of the payment amount shaping approach is to reduce the 2027 customer bill impact, and this is accomplished by deferring recovery of $500M of OPG's proposed nuclear revenue requirement from 2027. As a secondary objective, the analysis considered the trajectory of bill impacts over the remaining four years in the 2027-2031 period. This is addressed by varying how the $500M deferred from 2027 is recovered over the remaining years in the IR term.

Financial Viability: As discussed in Ex. A2-2-1 Section 3.3, OPG closely monitors credit metrics used by rating agencies (S&P, Moody's and DBRS), as these metrics significantly influence assigned credit ratings, which in turn affect the cost and availability of debt financing. As OPG undertakes substantial capital investments in support of Ontario's energy needs, all three rating agencies' reports have identified increasing pressure on the credit metrics as a risk.

In considering payment amount shaping options, OPG determined that deferring recovery of more than approximately $500M from 2027 could adversely affect its key credit metrics. Maintaining the current credit ratings is important to OPG's ability to access effective debt financing and, thus, OPG did not consider payment amount shaping options that deferred recovery of more than $500M from 2027.[12]

4.2 Payment Amount Shaping Options

OPG considered three options for payment amount shaping, as summarized in Chart 4, below. Approach A is a status quo scenario with no shaping of proposed payment amounts. Approach B reduces recovery by $500M in 2027 and increases recovery by $500M in 2028. Approach C reduces recovery by $500M in 2027 and increases recovery by $250M in 2028, $50M in 2029,

[12] See Ex. A2-2-1, Section 3.3 for further discussion OPG's credit metrics and credit ratings.

and $200M in 2030. The figures are stated before interest costs that would be associated with the deferral.

Chart 4 – Estimated Residential Monthly Bill Impacts Under Payment Amount Shaping Options

Line No.	Scenario	2027	2028	2029	2030	2031
1	**Approach A**	$10.34 7.3%	$(2.73) -1.9%	$3.70 2.6%	$0.74 0.5%	$4.67 3.3%
2	**Approach B**	$7.94 5.6%	$2.45 1.7%	$1.37 1.0%	$0.74 0.5%	$4.67 3.3%
3	**Approach C**	$7.94 5.6%	$1.25 0.9%	$2.78 2.0%	$1.45 1.0%	$3.65 2.6%

OPG presented these scenarios to customers as part of a customer engagement process conducted by Innovative Research Group Inc. ("INNOVATIVE"), as discussed below in Section 4.3.[13]

4.3 Customer Engagement Feedback

OPG engaged INNOVATIVE to conduct a customer engagement process that included seeking feedback on OPG's approach to payment amount shaping.

INNOVATIVE sought customer input on the value proposition that different payment amount shaping options present for customers. INNOVATIVE presented payment amount shaping as "[smoothing] out the annual change in rates by deferring a portion of 2027 costs to subsequent years, making the 2027 rate increase lower and spreading out the cost over future years' rates". The workbook presented customers with three illustrative scenarios with varying degrees of shaping. These scenarios were generally aligned with those presented in Chart 4 above.

[13] In the customer engagement process, these payment amount shaping scenarios were presented in terms of the portion of a monthly bill paid to OPG over the period rather than in terms of the bill impact dollars and percentages shown in Chart 4.

The results of the customer engagement survey show that a plurality of customers supported at least some degree of rate shaping, with a combined 48% of panellists preferring Approach B or C.[14] Managing the volatility present in the pre-shaping payment amounts comes at a cost. In providing additional feedback in the customer engagement survey, the two most common types of responses related to concerns about future interest costs, and increases in costs more generally.[15] Customer preferences are discussed further in the INNOVATIVE report, filed as Attachment 1 to this schedule.

The Application's payment amount shaping proposal considered these customer preferences, while also balancing the Customer Bill Impact and Financial Viability criteria outlined in Section 4.1.

4.4 Payment Amount Shaping Proposal

The Application proposes Approach B, as it best reflects customer preferences collected through the customer engagement process as summarized above. This proposal helps to manage the 2027 increase and results in a lower amount of interest recorded to the PASDA as compared to Approach C.

Based on this analysis, the proposed nuclear payment amounts presented in Ex. I1-3-1 have been determined based on Approach B. The Application therefore proposes to defer the collection of $500M in OPG's nuclear revenue requirement from 2027 to 2028, as shown in Ex. I-1-3-1, Table 1 and reproduced in Chart 5, below.

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[14] Attachment 1, p. 20.
[15] *Ibid.*, p. 21.

Chart 5 - Proposed Combined Nuclear Revenue Requirement and Payment Amounts[16]

	2027	2028	2029	2030	2031
Proposed Combined Revenue Requirement Before Shaping ($M)	$4,364.8	$4,638.7	$5,093.5	$5,463.8	$6,813.0
OPG Revenue Requirement Shaping Adjustment ($M)	$(500.0)	$500.0	$0.0	$0.0	$0.0
Proposed Shaped Combined Revenue Requirement ($M)	$3,864.8	$5,138.7	$5,093.5	$5,463.8	$6,813.0
Total Nuclear Production Forecast (TWh)	18.7	26.7	25.1	27.3	30.9
Blended Nuclear Payment Amount After Shaping ($/MWh)	$206.76	$192.52	$203.20	$199.97	$220.68

[16] Includes OPG nuclear facilities and DNNP facilities.

LIST OF ATTACHMENTS

Attachment 1: *2025 Customer Engagement Report*, Innovative Research Group Inc.

INNOVATIVE
RESEARCH GROUP

Online Survey
2025 Customer Engagement Report

ONTARIO POWER GENERATION

This report and all of the information and data contained within it may not be released, shared or otherwise disclosed to any other party, without the prior, written consent of Ontario Power Generation.

November 2025

Introduction & Methodology

Innovative Research Group Inc. (INNOVATIVE) was engaged by Torys LLP on behalf of its client Ontario Power Generation Inc. (Ontario Power Generation or OPG) to help design, execute and document the results of OPG's customer engagement in support of its 2027 to 2031 rate application.

Unlike other utility rate applications in Ontario, much of OPG's plan and are determined as a matter of system planning and cannot be influenced by customer preferences. As such, this customer engagement survey focuses on 3 key principles:

1. Focus on customer, not company outcomes
2. Do not expect customers to be subject-matter experts
3. Provide customers with the necessary background/context to make informed decisions

Method: A random sample of online panellists were invited to complete the survey from a set of partner panels based on the Lucid exchange platform. These partners are typically double opt-in survey panels, blended to manage potential skews in the data from a single source.

Sample Size: This survey was conducted online among a representative sample of n=2,524 (weighted to n=2,500) Ontarians, 18 years or older who at least share responsibility for paying their household electricity bill.

Field Dates: **November 12th to November 18th, 2025**

Weighting: Results are weighted by age, gender, region, and education to ensure that the overall sample's composition reflects that of the actual population according to Census data; in order to provide results that are intended to approximate a probability sample.

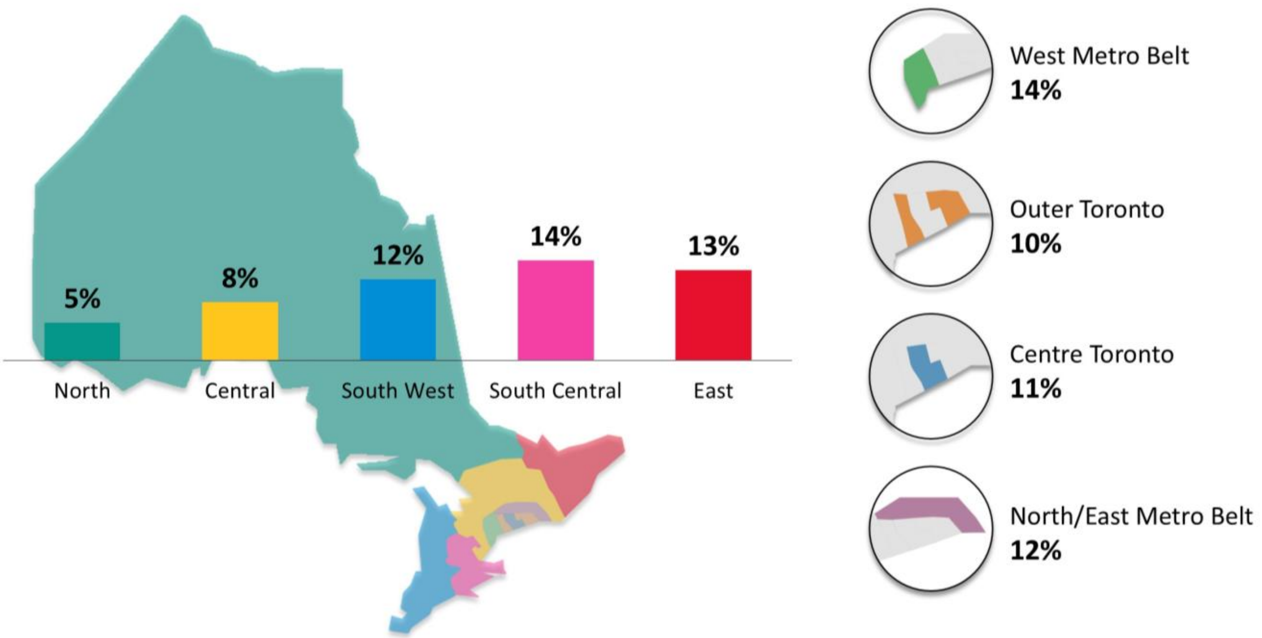
Margin of Error: This is a representative sample. However, since the online survey was not a random probability-based sample, a margin of error cannot be calculated. Statements about margins of sampling error or population estimates do not apply to most online panels.

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

Regional Segmentation

To ensure that the survey results are regionally representative of the Ontario population, respondents are categorized into 9 Ontario regions based on the first three characters of their postal code.

As shown below, the 9 regions are then further combined into 4 regions: **Toronto** (Outer Toronto + Centre Toronto), **Rest of GTA** (the Metro Belts), **South/West** (South West + South Central), and **North/East** (East + Central + North).



The table below summarizes the unweighted and weighted (in brackets) sample breakdown by age, gender, and region. Totals may not correspond with cell values as some respondents prefer to self-describe their gender. Weights are calculated based on all available information for a given respondent.

Region	Age-Gender						Total
	Men 18-34	Men 35-54	Men 55+	Women 18-34	Women 35-54	Women 55+	
Toronto	70 (69)	100 (90)	109 (79)	99 (86)	75 (98)	75 (89)	528 (510)
Rest of GTA	87 (84)	135 (117)	140 (115)	92 (82)	98 (138)	101 (124)	653 (660)
South/West	114 (80)	117 (113)	162 (129)	66 (82)	86 (109)	118 (142)	665 (656)
North/East	83 (65)	113 (111)	175 (152)	76 (72)	100 (122)	131 (151)	678 (673)
Total	354 (298)	465 (430)	586 (475)	333 (321)	359 (467)	425 (505)	2,524 (2,500)

Understanding Segmentation

In addition to segmenting electricity customers based on where they reside in Ontario, it is important to be able to identify factors that may influence customer preferences and distinguish between what is within and what is outside of OPG's influence or control.

Segmentation has been used throughout this report to look beyond the topline numbers to analyze the results for key segments:

Region: As mentioned earlier, the first three characters of a respondent's postal code are used to split Ontario ratepayers into one of four regions for analysis.

Bill Impact on Finances: Segmentation that INNOVATIVE refers to as "Bill Impact on Finances" is provided. This segment is determined based on the extent to which customers agree with the following statement: *The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.*

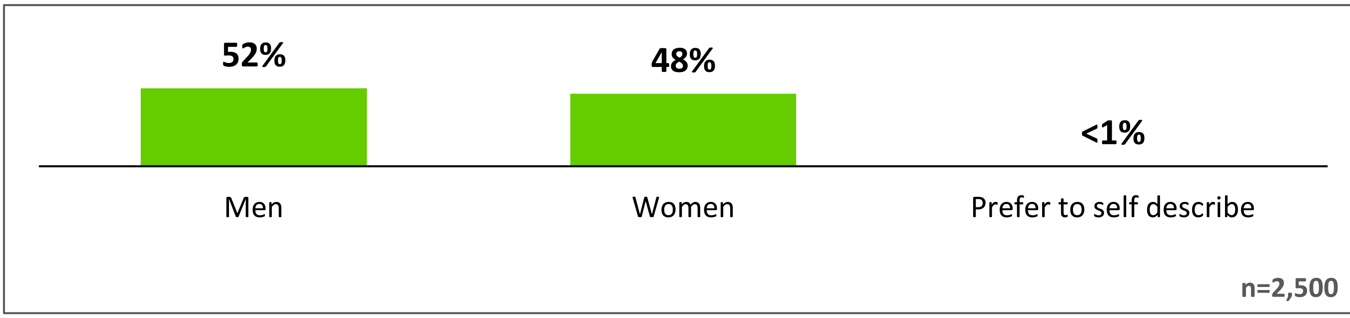
Vulnerable Consumers: Using a combination of household size and combined household income, the report identifies customers who would be eligible for financial assistance programs. The methodology used to calculate this segmentation is based on the OEB's Ontario Electricity Support Program (OESP) criteria.

Understanding Segmentation

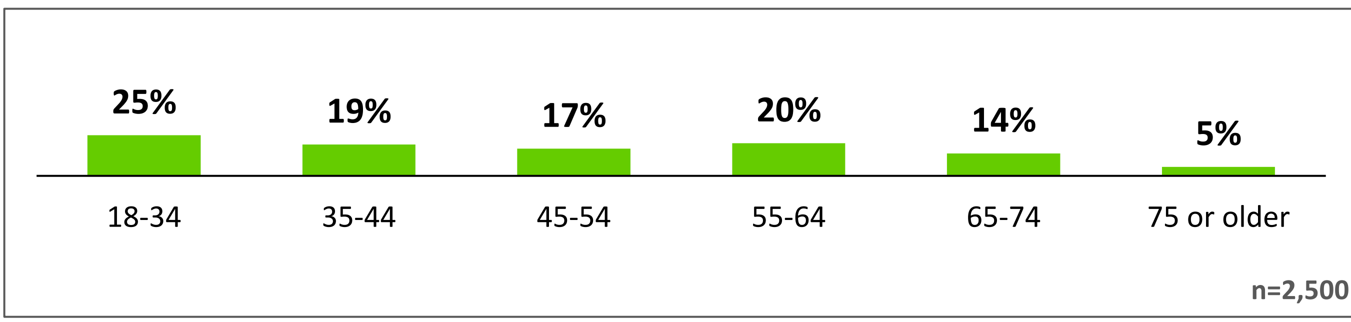
Segmentation is an effective way of looking past the topline numbers and digging deeper into the needs and preferences of the customer segments above. For instance, while it is valuable to know, overall, how many Ontarians are satisfied with OPG, it is also important to understand whether satisfaction differs based on region or based on perceptions that may be outside of the OPG's influence or control. Segmentation allows readers of this report to quickly look past the topline numbers and understand how various segments of customers feel about various issues.

Demographic Breakdown

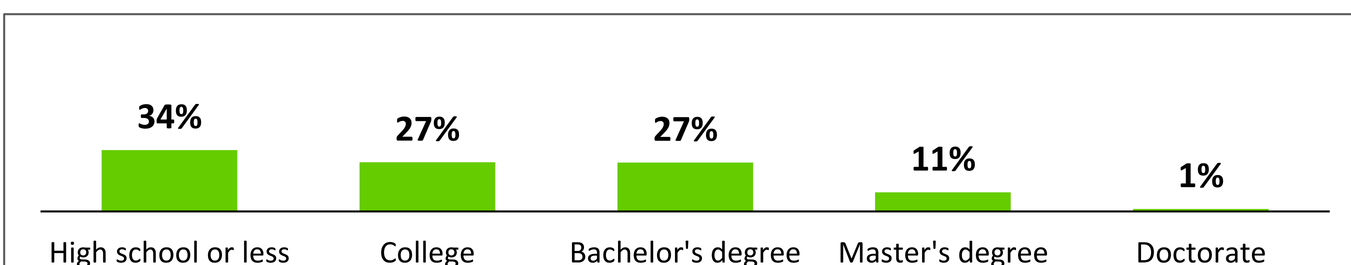
Q Gender



Q Age



Q Education

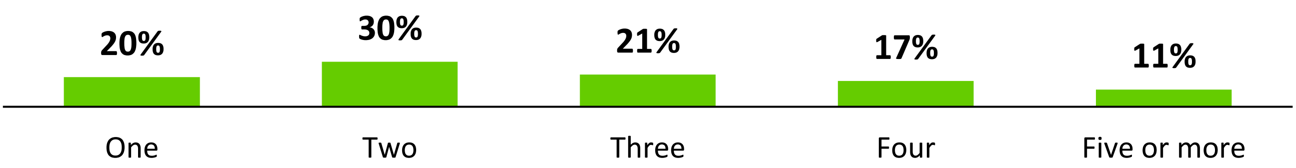


"Other" (1%) and "Prefer not to say" (<1%) not shown.

n=2,500

Demographic Breakdown

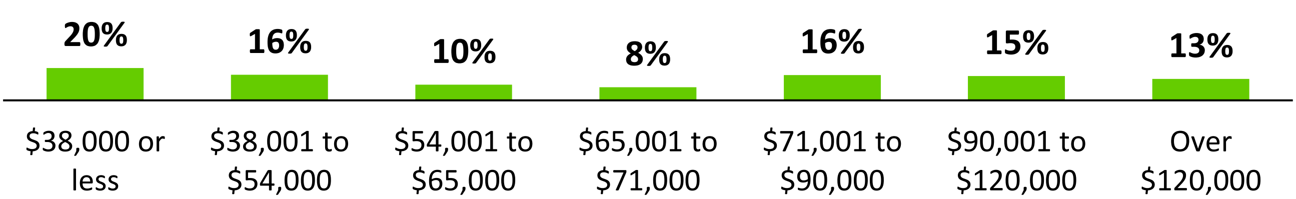
Q Household Size



"Prefer not to say" (<1%) not shown.

n=2,500

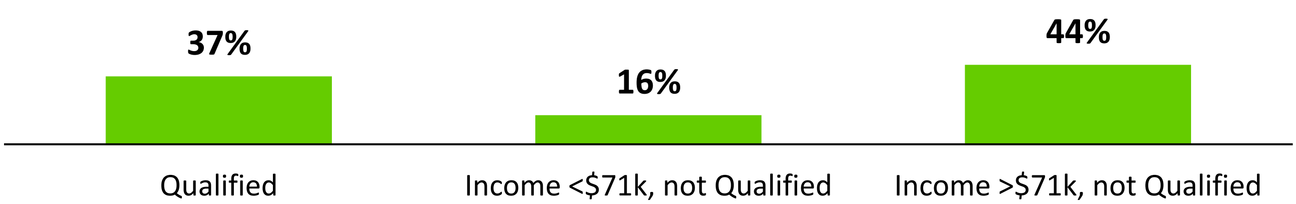
Q After Tax Household Income



"Prefer not to say" (3%) not shown.

n=2,500

Q **LEAP/OESP Qualification** (based on household size and income)

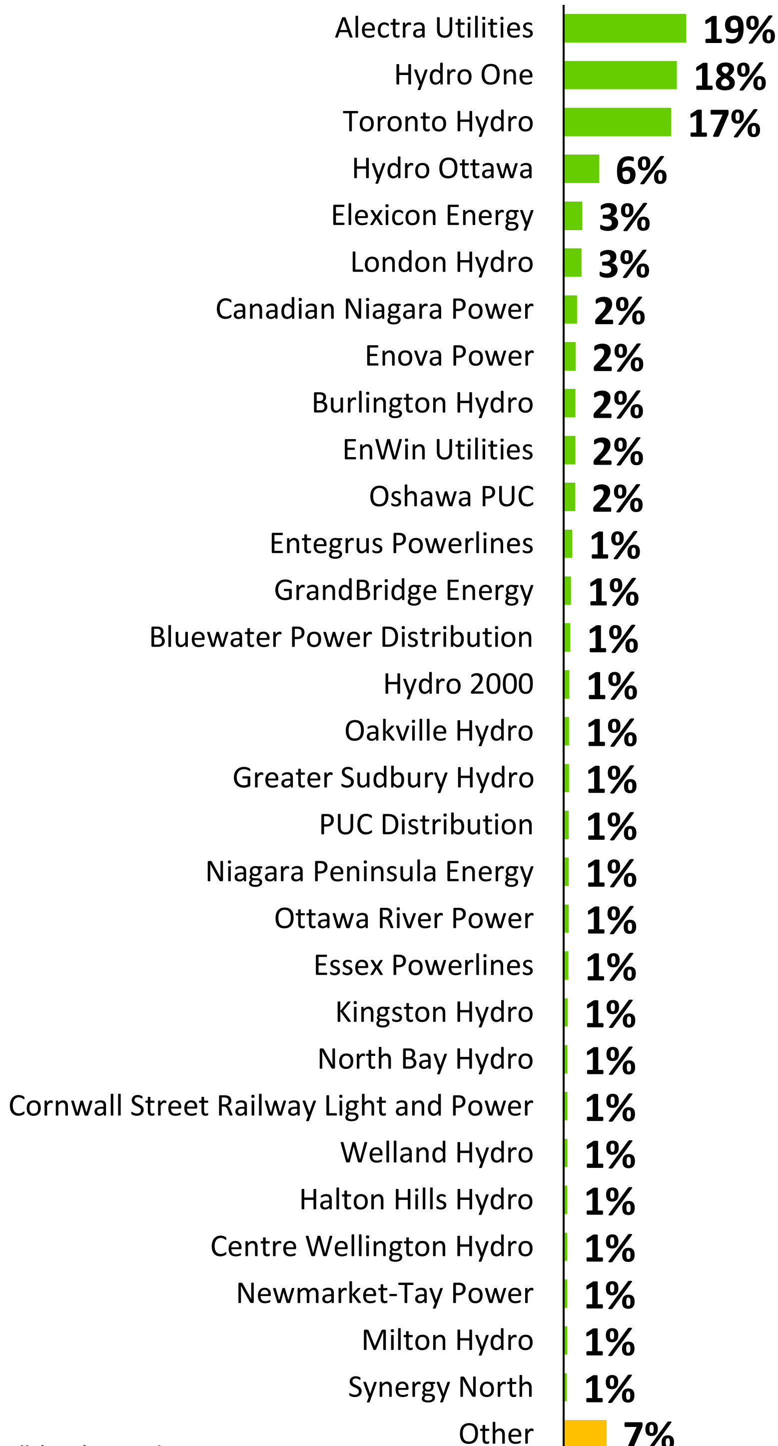


"Prefer not to say" (3%) not shown.

n=2,500

Demographic Breakdown

Q Electricity Provider



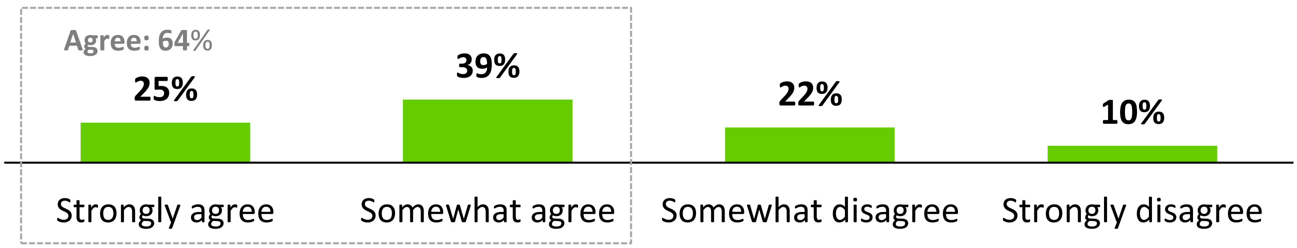
“Don’t know” (4%) not shown.

n=2,500

Environmental Controls

To what extent do you agree or disagree with the following statements?

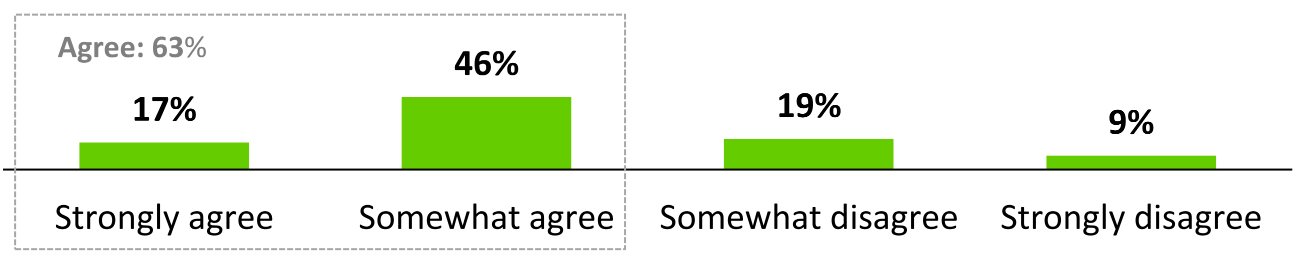
Q The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.



"Don't know/no opinion" (4%) not shown.

n=2,500

Q Consumers are well-protected with respect to prices and the reliability and quality of electricity service in Ontario.



"Don't know/no opinion" (9%) not shown.

n=2,500

INNOVATIVE RESEARCH GROUP

Residential Ratepayers
Familiarity & Experience

Preamble:

Ontario Power Generation's (OPG), Ontario's largest electricity generator, is looking for input into choices that will impact the rates Ontarians pay for electricity.

The goal of this survey is to understand your point of view as a **residential** ratepayer.

Familiarity & Experience

Bill Familiarity

How much of your electricity bill goes to OPG?

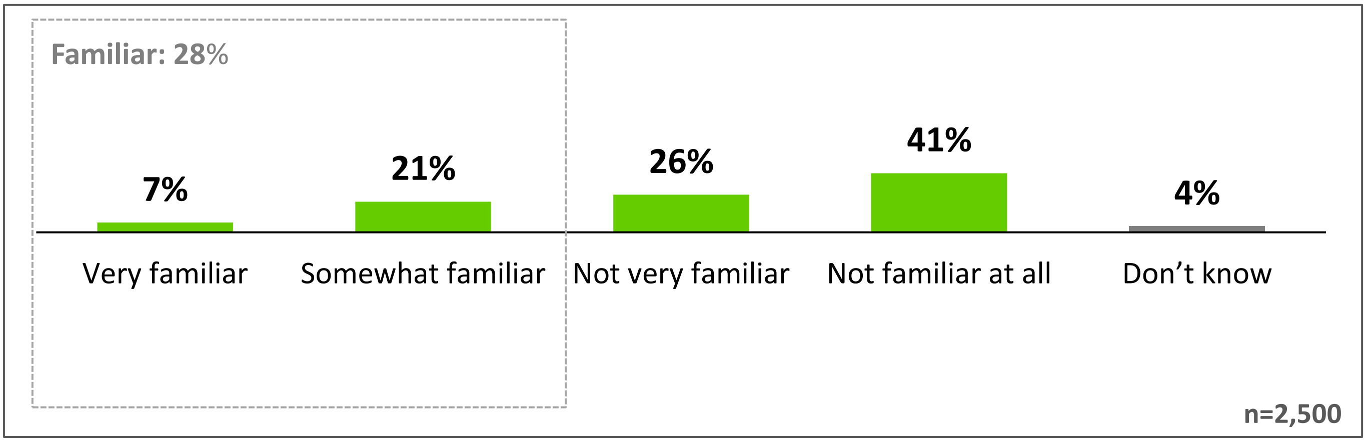
Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board, the provincial energy regulator.

As of **August 1st, 2025**, the average monthly bill for a typical residential customer consuming 750 kWh is about $135 after taxes and the Ontario Electricity Rebate.

On average, **about 15% or approximately $20 of the monthly electricity bill for a typical residential ratepayer** goes to OPG to pay for the power they generate. However, OPG's share of the bill depends on your consumption level and can be higher or lower in any given month.

The rest of the bill goes to pay for other generators, transmission companies, distribution companies, regulatory agencies, and government taxes.

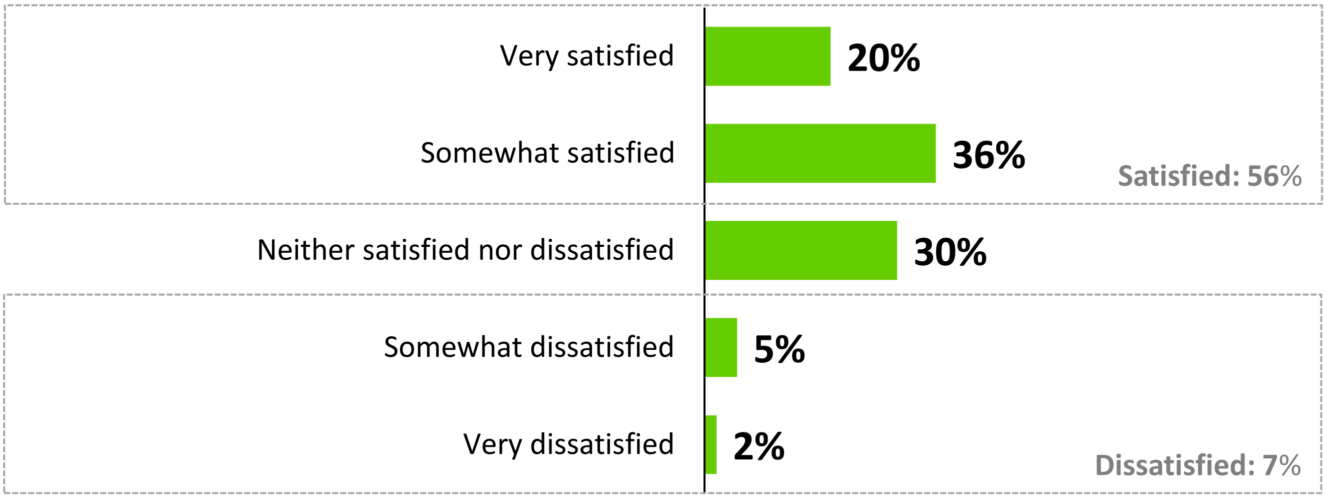
Q Before this survey, how familiar were you with the amount of your electricity bill that went to **OPG** for the generation of electricity?



Familiarity & Experience

Overall Satisfaction with OPG

Q Now that you've read a bit more about **OPG** and how it fits into Ontario's electricity system, how satisfied are you with **OPG's** performance?



"Don't know" (6%) not shown.

n=2,500

Region

	Toronto	Rest of GTA	South/ West	North/ Central/ East
Very satisfied	22%	20%	17%	21%
Somewhat satisfied	37%	41%	34%	34%
Neither	29%	27%	33%	32%
Somewhat dissatisfied	5%	5%	6%	4%
Very dissatisfied	1%	2%	2%	2%
Don't know	6%	4%	8%	8%
Satisfied (Very + Somewhat)	**59%**	**61%**	**51%**	**55%**
Dissatisfied (Very + Somewhat)	**6%**	**8%**	**8%**	**6%**

Familiarity & Experience

Overall Satisfaction with OPG

Q Now that you've read a bit more about **OPG** and how it fits into Ontario's electricity system, how satisfied are you with **OPG's** performance?

		LEAP/OESP Qualification			Bill Impact	
	Overall	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Very satisfied	20%	17%	20%	22%	19%	22%
Somewhat satisfied	36%	34%	35%	40%	37%	35%
Neither	30%	33%	29%	27%	30%	31%
Somewhat dissatisfied	5%	5%	6%	4%	6%	3%
Very dissatisfied	2%	2%	3%	1%	3%	1%
Don't know	6%	8%	8%	4%	5%	8%
Satisfied (Very + Somewhat)	**56%**	**51%**	**55%**	**63%**	**56%**	**57%**
Dissatisfied (Very + Somewhat)	**7%**	**7%**	**9%**	**6%**	**9%**	**4%**

Familiarity & Experience

How can OPG do better?

Q Is there anything in particular that **OPG** could do better for you?

Response	%
Lower rates/reduce costs	11.7%
Improve communication or transparency	2.2%
No improvements needed/satisfied as is	1.8%
Help public better understand OPG's role/don't know what they do	1.4%
Increase investment in renewable energy/energy alternatives/green options	1.0%
Clearer information on bills/what goes to OPG	0.8%
Provide energy-saving incentives, programs, or guidance	0.7%
Upgrade/better maintain infrastructure	0.5%
Improve reliability	0.4%
Support low-income or vulnerable customers	0.2%
Improve environmental/wildlife protection practices	0.1%
Other	1.4%
None/Don’t know	77.9%

Note: Only responses >0.1% shown

OPG's 2027-2031 Proposed Plan

Preamble:

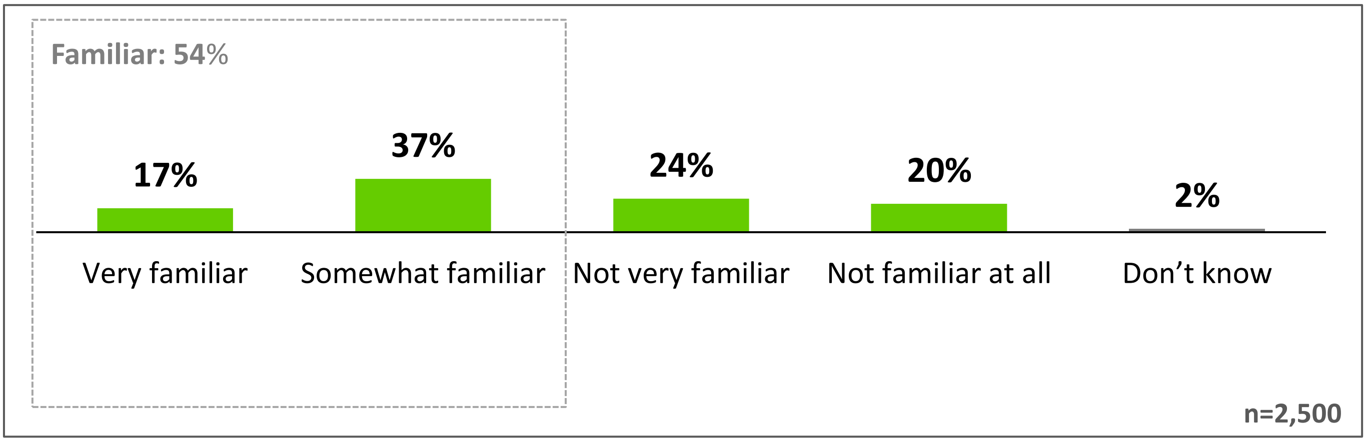
Now, let's talk about OPG's upcoming draft plan for 2027 to 2031.

OPG's 2027-2031 Proposed Plan

Familiarity with Future Electricity Demand

According to the **Independent Electricity System Operator (IESO)**, Ontario's independent electricity planning expert, annual electricity demand in the province is anticipated to grow significantly by 2050.

Q Before this survey, how familiar were you with the fact that Ontario's electricity demand is anticipated to increase in the next 25 years?



OPG's 2027-2031 Proposed Plan

Familiarity with OPG's Hydroelectric/Nuclear Operations

As the company that is responsible for generating about half of Ontario's electricity, OPG's 2027 to 2031 plan will play an important role in meeting future electricity demand in Ontario.

OPG plans its investments in Ontario's electricity generating stations using a variety of inputs from Provincial system planners to independent experts and OPG's own engineers and asset managers.

However, much of OPG's plan and objectives are set by the Ontario government.

What's in OPG's plan for 2027 to 2031?

Hydroelectric power currently provides about 24 per cent of Ontario's electricity, and OPG's 2027 to 2031 plan includes significant investments in refurbishing hydroelectric generating stations across the province, which have an average age of 90 years. Costs associated with operating and investing in **the hydroelectric fleet account for 30% of OPG's 2027-2031 plan**.

OPG's two **nuclear generating stations** play a significant role in Ontario's energy mix. Darlington and Pickering Stations operate continuously to produce a steady and reliable supply of electricity, providing a foundation for the province's power needs. Costs associated with operating and investing in **the nuclear fleet account for 65% of OPG's 2027-2031 plan**.

A significant portion of OPG's 2027-2031 nuclear budget will fund the refurbishment of the Pickering nuclear plant, pending approvals. Once refurbished, this plant would continue to provide over 2,000 MW of baseload generating capacity for more than 30 years, the equivalent of powering approximately two million homes.

Finally, roughly **5%** of OPG's proposed 2027-2031 budget will fund development of the first grid-scale **Small Modular Reactor (SMR)** project in North America, if approved. An SMR is smaller and designed to simplify construction by using modular components, which can shorten construction times, reduce costs, and promote simplified and safe operation.

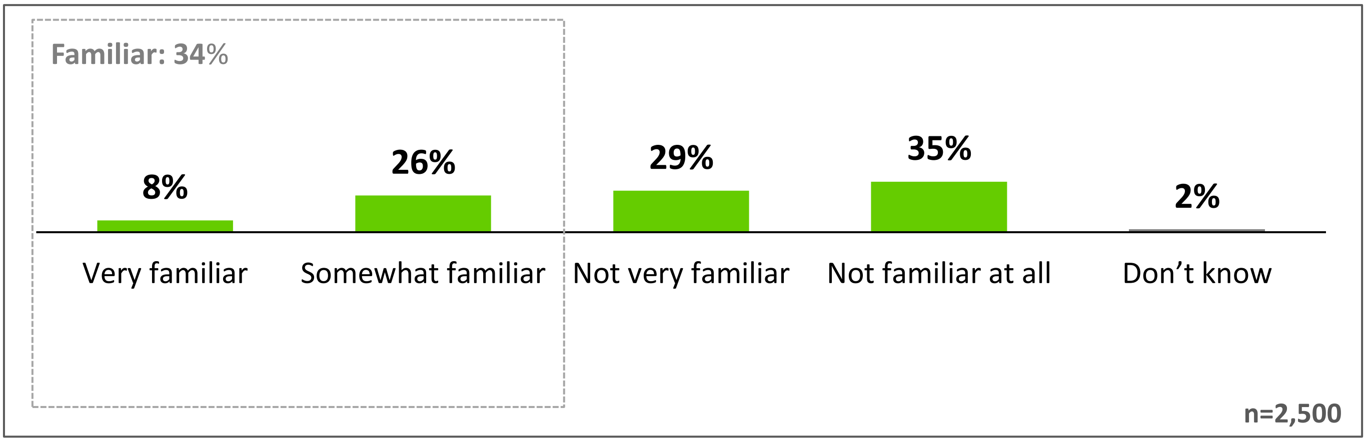
OPG's budget also goes toward meeting safety, legal, and regulatory requirements and all other aspects of running a large business.

SURVEY PAGE

OPG's 2027-2031 Proposed Plan

Familiarity with OPG's Hydroelectric/Nuclear Operations

Q Before this survey, how familiar were you that **OPG** manages both a hydroelectric and nuclear fleet?



INNOVATIVE
RESEARCH GROUP

Rate Shaping

Rate Shaping

Approaches to OPG's Proposed Plan

OPG has calculated the cost of their proposed plan.

Under its plan, depending on customer feedback, for a typical residential customer consuming 750 kWh per month, the portion of their monthly bill that goes to OPG could increase by up to $17, over the course of five years, from the start of 2027 to the end of 2031*, to fund the investments described on the preceding pages to maintain existing generation and build new projects to meet growing electricity demand which will support stable baseload generation.

OPG has developed three representative approaches for how these rate increases could potentially be rolled out over the 2027 to 2031 period. OPG is seeking customer feedback on these approaches before they submit their plan to the Ontario Energy Board, the provincial energy regulator, for review.

How much of a typical customer's monthly bill would go to OPG:

	2026	2027	2028	2029	2030	2031
Approach A	$20.00	$30.00	$27.00	$31.00	$32.00	$36.50
Approach B	$20.00	$27.50	$30.00	$31.50	$32.50	$37.00
Approach C	$20.00	$27.50	$29.00	$31.50	$33.50	$37.50

* Based on a point-in-time average for the typical residential customer with an average monthly bill of ~$135; annual changes are based on OPG impacts only, and do not consider the Ontario Electricity Rebate (OER).

Approach A represents the true cost of OPG's investments. This approach would result in a roughly $10 increase on the monthly bill in the first year of the plan (2027) and an average annual increase of about $2 in each of the following 4 years (2028-2031).

Approach B and **Approach C** "smooth out" the annual change in rates by deferring a portion of 2027 costs to subsequent years, making the 2027 rate increase lower and spreading out the cost over future years' rates.

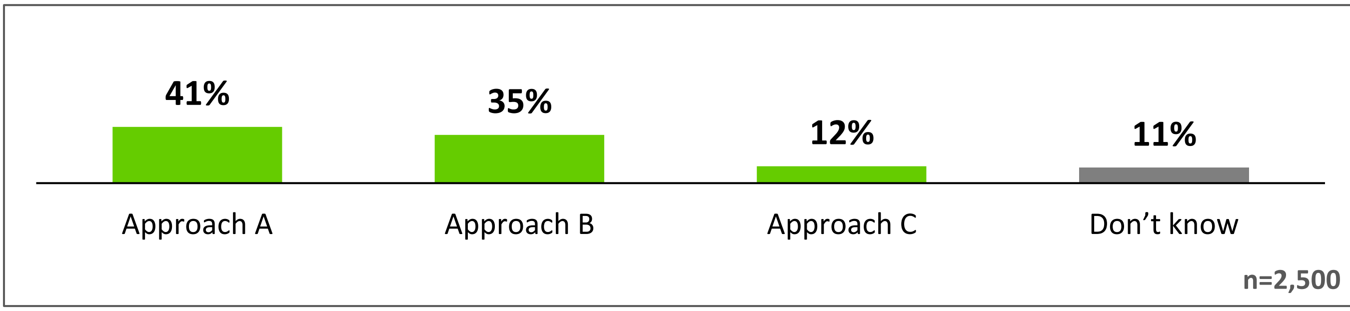
In both **Approach B** and **Approach C,** to pay for the work in the short term, OPG would borrow more money instead of raising it through rates, incurring interest costs that would be paid by customers in later years.

SURVEY PAGE

Rate Shaping

Approaches to OPG's Proposed Plan

Q Which of the following approaches do you prefer?



Summary of Findings: Overall, 48% of Ontario electricity ratepayers prefer some degree of rate shaping (Approach B or C). 41% of electricity ratepayers prefer Approach A, which includes no rate shaping. The remaining 11% don't know which of the three approaches they prefer.

This sentiment is consistent across both region and among more financially vulnerable customers.

Region

	Toronto	Rest of GTA	South/ West	North/ Central/ East
Approach A	37%	44%	40%	42%
Approach B	36%	36%	37%	33%
Approach C	16%	12%	11%	11%
Don't know	11%	9%	12%	13%

	LEAP/OESP Qualification			Bill Impact	
	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Approach A	39%	39%	43%	39%	44%
Approach B	34%	35%	36%	37%	32%
Approach C	13%	12%	12%	13%	11%
Don't know	13%	13%	8%	10%	13%

Rate Shaping

Additional Feedback

Q Do you have any additional feedback on the approaches above that you would like to share?

Response	%
Support for upfront payment/concern about future interest costs (A)	4.4%
Increase is too high/lower costs	2.9%
No preference/all options are fine	1.9%
Preference for more gradual increase (B or C)	1.7%
Need for transparency/more information	1.5%
Affordability/cost of living concerns (low-income, seniors, fixed income)	0.8%
Distrust in OPG/perception of mismanagement/profit-driven motives	0.7%
OPG should find their own efficiencies/cost savings	0.6%
Confusion/difficulty understanding the approaches	0.1%
Include programs to support low-income/vulnerable households	0.1%
Other	1.9%
None/Don’t know	83.3%

Note: Only responses >0.1% shown

Building Understanding.

Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for Ontario Power Generation. The conclusions drawn and opinions expressed are those of the authors.

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IESO SETTLEMENT PROCESS

1.0 PURPOSE

This evidence provides a description of the IESO settlement process used for OPG's regulated generation facilities and the DNNP facilities.

2.0 DESCRIPTION OF SETTLEMENT PROCESS

The general IESO settlement process is described in Chapter Nine of the Ontario Market Rules. 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.

If applicable, OPG and DNNP LP expect that retroactive adjustment will be used for the months prior to the implementation date back to the effective date of new payment amounts and riders. For example, assuming a rate order on January 20th, retroactive adjustment would be used for the months of January and February, with unadjusted implementation for the month of March and beyond.

The timelines for implementation are based on general rate structure changes reflecting OPG's prior applications.

The Application expects that all payments ordered in this Application will be made to OPG on behalf of itself and DNNP LP, consistent with direction provided in O. Reg. 53/05, s. 14(2)9:

> In making a DNNP blended payment order, the Board shall require that payments be paid to Ontario Power Generation Inc., acting on its own behalf and as agent and nominee of the DNNP generator.