AMPCO Interrogatory #103

Interrogatory

Reference:
F1-3-3 Table 4b

Question(s):

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

Response

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

Chart 1 – Status of Projects with 2025 Potential Start Date

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

SEC Interrogatory #154

Interrogatory

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

Question(s):

With respect to Hydroelectric Base OM&A:

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

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

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

Response

a) Refer to Attachment 1.

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

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

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

Numbers may not add due to rounding.

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

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

Numbers may not add due to rounding.

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

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

Notes:

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

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

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

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

SEC Interrogatory #156

Interrogatory

Reference:
F1-3-1, p. 3

Question(s):

With respect to hydroelectric portfolio projects:

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

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

Response

a) Refer to Attachment 1.

b) Refer to Attachment 2.

Numbers may not add due to rounding.

Filed: 2026-04-22
EB-2025-0297
Exhibit L
F1-SEC-156
Attachment 1

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

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

Numbers may not add due to rounding.

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

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

Board Staff Interrogatory #177

Interrogatory

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

Preamble:

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

Question(s):

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

Response

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

Chart 1 – OM&A Purchased Services

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

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

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

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

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

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

Chart 2 - S&P Global Canadian Indices 2026

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

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

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

CCC Interrogatory #070

Interrogatory

Reference:
Exhibit F2, Tab 1, Schedule 1, Attachment 2

Question(s):

Please advise whether OPG completes a nuclear benchmarking report each year. If so, please file the 2025 nuclear benchmarking report assuming it has been completed.

Response

Yes, OPG completes a nuclear benchmarking report each year. See Attachment 1 for the 2025 Nuclear Benchmarking Report.

2025 Nuclear Benchmarking Report

Safety • Reliability • Value for Money • Human Performance

ONTARIO POWER GENERATION | Electrifying life

Filed: 2026-04-22
EB-2025-0297
Exhibit L
F2-CCC-070
Attachment 1
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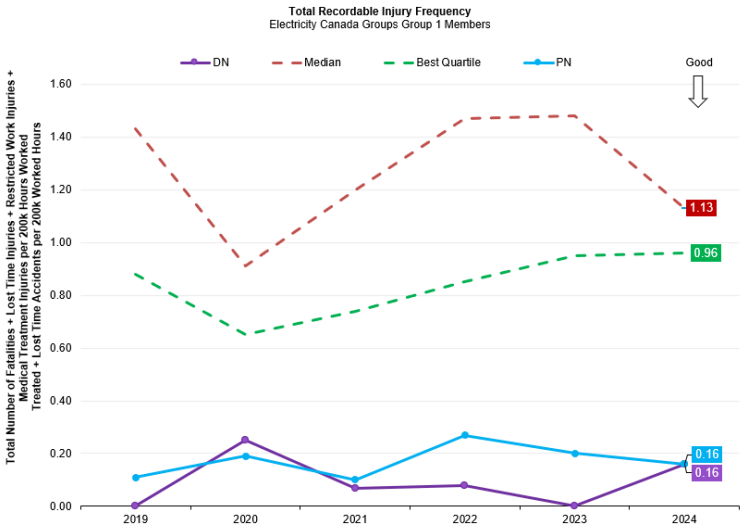
Table of Contents

In 2024, Ontario Power Generations (OPG) results reflected strong performance relative to industry peers in multiple critical performance areas, while also identifying expected post-Refurbishment trends which will improve as the station enters steady-state.

Safety

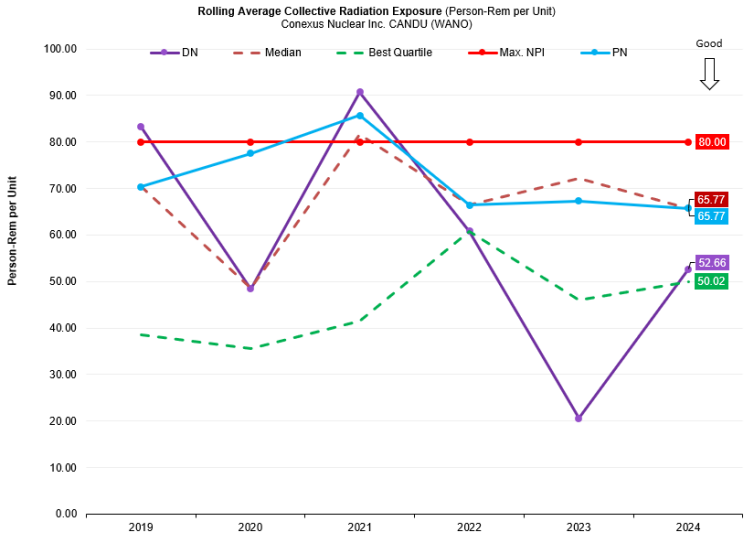
Total Recordable Injury Frequency (TRIF)



Both Darlington Nuclear Generating Station (DNGS) and Pickering Nuclear Generating Station (PNGS) continued to deliver best quartile safety performance in 2024, maintaining excellent TRIF results compared to other Electricity Canada Group 1 members.

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

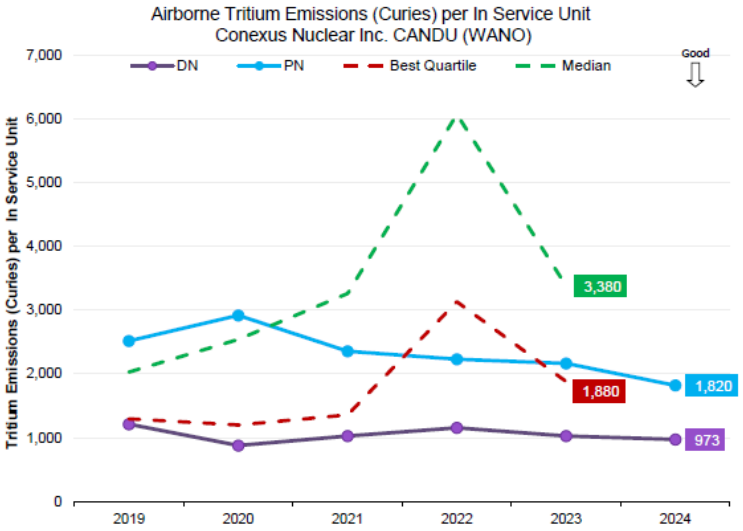
Collective Radiation Exposure (CRE)



DNGS and PNGS continued to achieve maximum WANO Performance Indicator Index (WPII) points in 2024, previously identified as Nuclear Performance Index (NPI). DNGS CRE performance declined as a result of one major planned outage in 2024 compared to zero in 2023. PNGS CRE performance improved due to a reduced number of maintenance, forced and planned unbudgeted outages in 2024 compared to 2023.

DNGS and PNGS have implemented source term controls to reduce worker exposure including improved shielding to reduce dose rates and having dedicated tritium emissions reduction teams. DNGS is also utilizing a new design of channel closure plugs.

Airborne Tritium Emissions

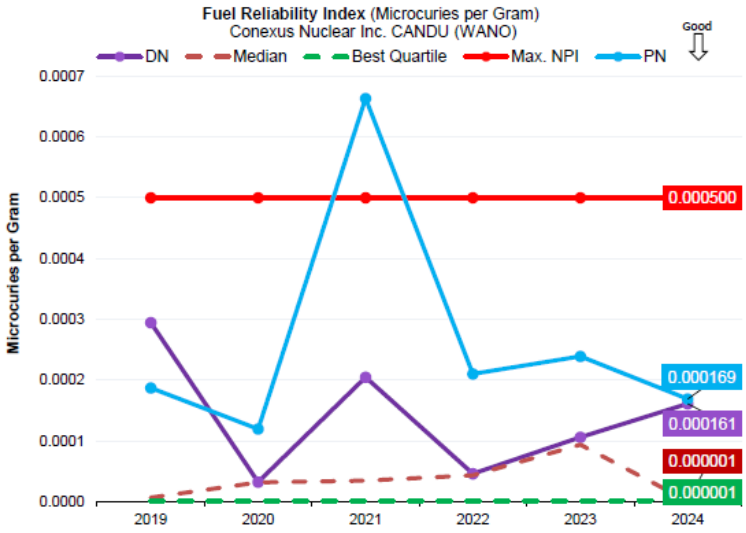


DNGS and PNGS Airborne Tritium Emissions remain at a very small fraction of regulatory limits.

DNGS and PNGS continued to achieve best quartile performance in 2024, largely attributable to ongoing improvements to tritium identification and reduction activities at both sites.

Both sites have continued tritium reduction activities driven by dedicated teams, enhancing focus on tritium sources identification and elimination. In addition, collaboration between both sites to exchange operating experience, innovation activities on tritium mitigation, and benchmark performance.

Fuel Reliability Index (FRI)



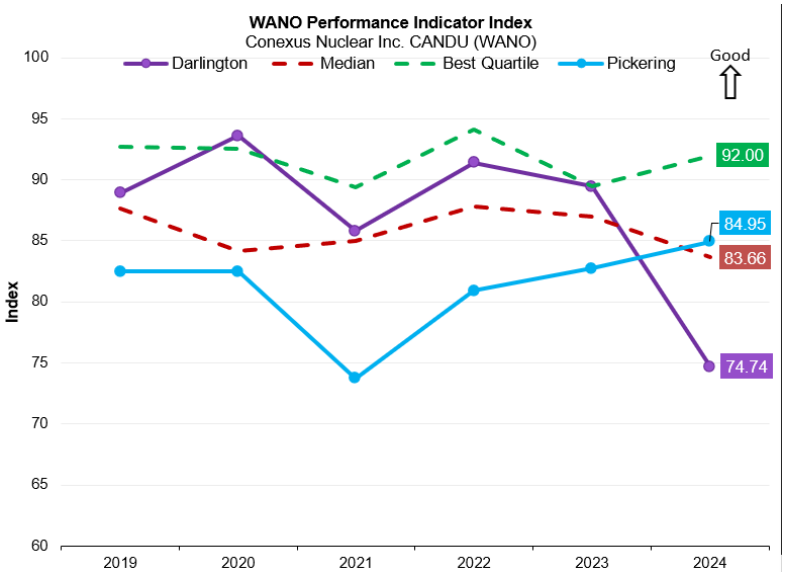
DNGS and PNGS continued to achieve maximum WPII points in 2024.

Three fuel defects were observed at DNGS in 2024 compared to one in 2023. PNGS FRI improved slightly in 2024, due to one fuel defect being observed in 2024 compared to two in 2023. All defects were discharged.

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

The five other safety- related metrics at DNGS and PNGS were favourable and achieved green ratings in 2024. Both DNGS and PNGS achieved maximum World Association of Nuclear Operators (WANO) performance Indicator Index (WPII) results and best quartile performance for all WPII Safety sub-metrics.

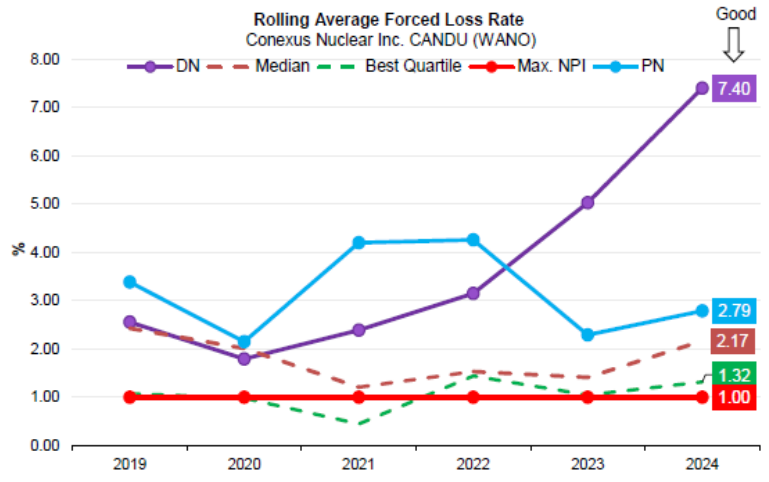
WANO Performance Indicator Index (WPII)



In 2024, DNGS performance was third quartile compared to top quartile in 2023. The decline in performance is attributable to elevated Forced Loss Rate (FLR) and Unit Capability Rate (UCR) performance as a result of two forced outages in 2024. DNGS continued with excellent performance for all seven of the safety metrics.

PNGS performance improved in 2024, achieving second quartile performance compared to third quartile performance in 2023. The improvement in performance is mainly attributed to the industry definition and weighting change from WPII Method 4 to WPII Method 10. PNGS sustained performance for all seven safety metrics and was partially offset by lower Chemistry Performance Index (CPI), Forced Loss Rate (FLR) and Unit Capability Rate (UCR) performance.

Forced Loss Rate (FLR)



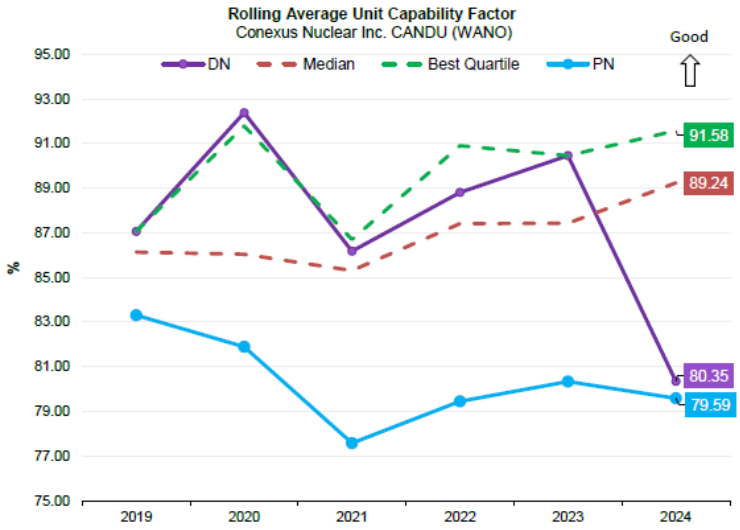
In 2024, FLR performance declined at DNGS due to post-Refurbishment forced outages and PNGS due to forced outages.

DNGS experienced four forced outages attributable to post refurbishment outage events on Unit 2. Increased FLR is expected post refurbishment and will improve with support of ongoing initiatives to strengthen Plant reliability, Human Performance and Equipment reliability. PNGS slight decline in performance is attributable to elevated FLR in 2024 compared to 2022, which is no longer in the rolling window.

Fuel Handling contributions reduced in 2024 and remains a fleet focus area to improve sustainability. Focused initiatives including vulnerability identification and elimination, project execution, and proficiency building at both stations to increase plant reliability.

Unit Capability Factor (UCF)

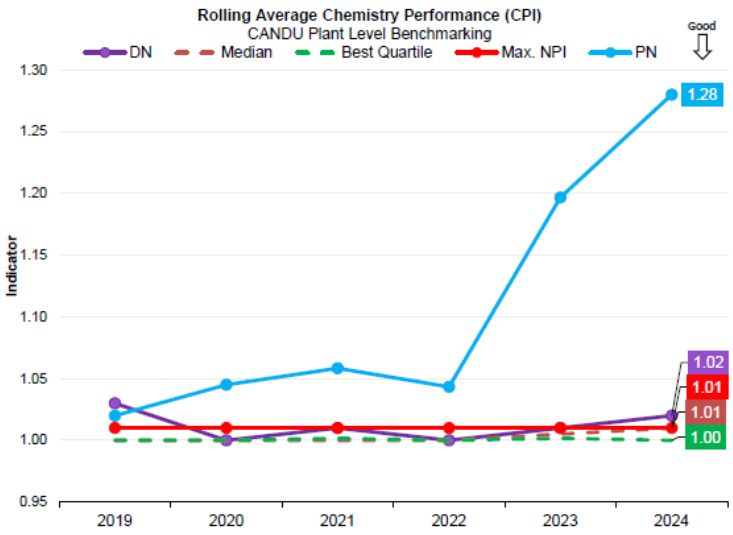
In 2024, both DNGS and PNGS achieved third quartile performance. DNGS and PNGS decline in performance compared to 2023 was attributable to the declined FLR performance at both stations. DNGS performance is attributable to post refurbishment outage events on Unit 2. PNGS slight decline in performance is attributable to elevated FLR in 2024 compared to 2022, which is no longer in the rolling window.



Focused initiatives including vulnerability identification and elimination, proficiency building and project execution at both stations to increase plant reliability.

Chemistry Performance Index (CPI)

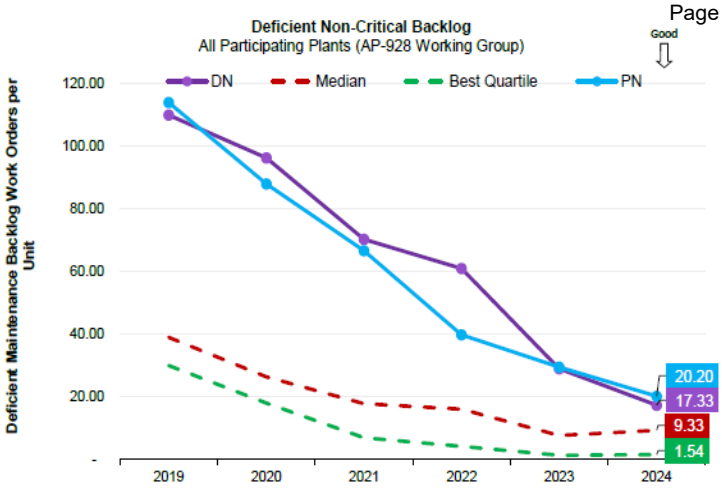
DNGS performance was third quartile in 2024 compared to top quartile in 2023. The decline in performance in 2024 compared to 2023 can be attributed to Unit 2 elevated feedwater corrosion product transport post unit start-ups and condenser tube leaks.



PNGS decline in performance in 2024 compared to 2023 can be attributed to start-up boiler sulphates and condenser tube leaks that resulted in elevated boiler ions.

DNGS and PNGS continue to have a Chemistry Outage Single Point of Contact (SPOC) to provide improved coordination/planning such that system chemistry control is improved during start-ups/outages and explore implementing corrosion product transport formation reduction and removal processes. DNGS will improve early detection of condenser tube leaks and improve reliability of condenser equipment. PNGS also aims to improve boiler chemistry during refurbishment to improve boiler ions upon unit start-up.

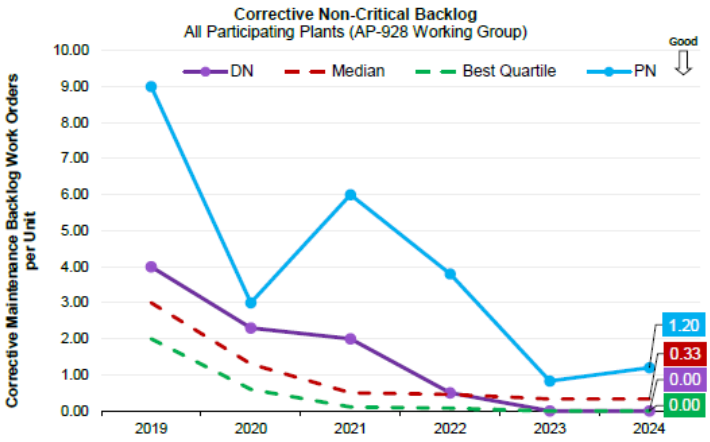
On-Line Deficient Non-Critical Backlog and Deficient Critical Backlog



DNGS improved their On-line Deficient Non-Critical Backlog by 40% compared to 2023 and Deficient Critical Backlog sustained a best quartile score of zero as a result of continued station focus, overall maintenance efficiency and improved schedule quality.

The favourable trend for Backlog performance at PNGS continued into 2024, with improvements for On-line Deficient Non-Critical Backlogs (32% improvement) from fourth in 2023 to third quartile in 2024 and slight improvement for On-line Deficient Critical Backlog compared to 2023 results.

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

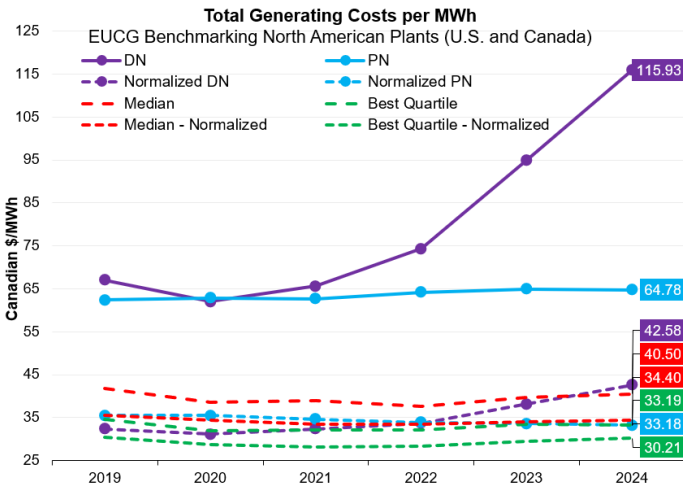


DNGS remained in best quartile score of zero for both Corrective Critical and Corrective Non-Critical Backlog metrics.

PNGS sustained best quartile performance for the Corrective Critical backlog metric with a score of zero and sustained third quartile for On-Line Corrective Non-Critical performance sustained.

Value for Money

TGC/MWh

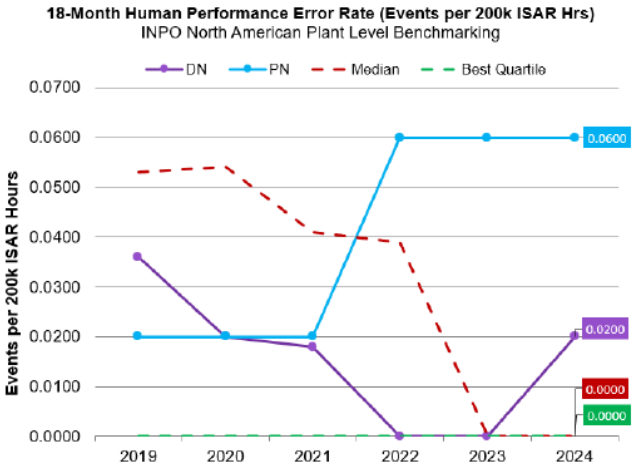


In 2024, normalized Total Generating Cost per Megawatt-hour (TGC/MWh) performance remained in the third quartile for DNGS and second quartile for PNGS after normalizing[1] for refurbishment, technology including outage duration and age-related impacts.

DNGS normalized performance was impacted by capital investment requirements for life post-refurbishment and reduced 3-year generation related to the refurbishment schedule while PNGS normalized performance reflects continued reduction in capital investment as the station approaches Refurbishment for Units 5-8 operations in 2026.

Human Performance

Human Performance Error Rate



In 2024, DNGS performance was third quartile compared to first quartile in 2023. This can be attributed to two Site Event Free Day Resets (S-EFDR) experienced in 2024 compared to zero in 2023. PNGS experienced two S-EFDR's in 2024 compared to one in 2023. Event causes were identified, and corrective actions were implemented to address the gaps.

Human Performance continues to be a focus around the fleet with actions to improve performance by continuously improving the Observation & Coaching program as well as integration of Fail-Safe strategies and trending processes to strengthen values and behaviours of Nuclear Professionals. Human performance is being further enhanced by continuing to build a positive stop culture that recognizes workers who stop work due to unknown or unexpected events.

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

Benchmarking Results – Plant Level Summary

Table 1 provides a complete summary of 2024 performance compared to benchmark results.

Metric	2024 Actuals					
	NPI Max	Best Quartile	Median	Third Quartile	Pickering	Darlington
Safety						
Total Recordable Injury Frequency (#/200k hours worked)		0.96	1.13	1.91	0.16	0.16
Rolling Average[2] Total Industrial Safety Accident Rate TISA) (#/200k hours worked)[1]	0.20	0.00	0.00	0.04	0.00	0.00
Rolling Average[2] Collective Radiation Exposure (Person-rem per unit)[1]	80.00	50.02	65.77	87.53	65.77	52.66
Airborne Tritium Emissions (Curies) per Unit [3]		1,880	3,380	4,595	1,820	973
Fuel Reliability Index (microcuries per gram)[1]	0.000500	0.000001	0.000001	0.000161	0.000169	0.000161
2-Year Reactor Trip Rate (# per 7,000 hours)[1]	0.500	0.000	0.310	0.420	0.382	0.310
3-Year Auxiliary Feedwater System Unavailability (#)[1]	0.0200	0.0000	0.0000	0.0023	0.0000	0.0000
3-Year Emergency AC Power Unavailability (#)[1]	0.0250	0.0001	0.0003	0.0035	0.0000	0.0000
3-Year High Pressure Safety Injection Unavailability (#)[1]	0.0200	0.00000	0.00000	0.00000	0.0000	0.0002
Reliability						
Rolling Average[2] WPII (Index)[1]		92.00	83.66	74.74	84.95	74.74
Rolling Average[2] Forced Loss Rate (%)[1]	1.00	1.32	2.17	4.21	2.79	7.40
Rolling Average [2] Unit Capability Rate (%)[1]	98.00	98.50	97.83	92.60	96.82	92.60
Rolling Average[2] Unit Capability Factor (%)[1]	92.00	91.58	89.24	79.59	79.59	80.35
Rolling Average[2] Chemistry Performance Indicator (Index)[1]	1.01	1.00	1.01	1.03	1.28	1.02
1-Year Online Deficient Non-Critical Backlog (work orders per unit) [3]		1.54	9.33	28.58	20.20	17.33
1-Year Online Corrective Non-Critical Backlog (work orders per unit) [3]		0.00	0.33	1.33	1.20	0.00
1-Year Online Deficient Critical Backlog (work orders per unit) [1]		0.00	0.00	0.50	0.60	0.00
1-Year Online Corrective Critical Backlog (work orders per unit) [1]		0.00	0.00	0.00	0.00	0.00
Value for Money						
3-Year Total Generating Costs per MWh ($ per Net MWh) [1]		33.19	40.50	50.89	64.78	115.93
Normalized 3-Year Total Generating Cost per MWh ($ per Net MWh)		30.21	34.40	43.20	33.18	42.58
3-Year Total Generating Cost per Unit (M $ per Unit)		285.39	315.55	365.38	231.03	745.77
Normalized 3-Year Total Generating Cost per Unit (M $ per Unit)		251.15	283.59	331.97	134.61	278.21
3-Year Non-Fuel Operating Costs per MWh ($ per Net MWh) [1]		19.63	24.58	32.23	58.44	74.69
3-Year Normalized Non-Fuel Operating Cost per Net MWh ($/MWh)		19.63	24.58	32.23	--	47.88
3-Year Fuel Costs per MWh ($ per Net MWh)[1]		5.93	6.60	7.15	3.98	4.43
3-Year Capital Costs per MW DER (k$ per MW)[1]		38.99	67.13	107.93	16.37	269.70
Normalized 3-Year Capital Cost per MW DER (k$ per MW)		38.99	67.13	107.93	--	115.91
Human Performance						
18-Month Human Performance Error Rate (# per 200k ISAR and contractor hours) [1]		0.0000	0.0000	0.0455	0.0600	0.0200

1. Best Quartile, Median and Third Quartile are from Q4 2024 best available information.

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

3. Best Quartile, Median, Third Quartile are from the Q4 2023 which is the most current available benchmark for these metrics.

Legend

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

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Background

This report presents a comparison of OPG Nuclear's performance to that of nuclear industry peer groups. Benchmarking results are used during business planning to drive top-down target setting with business improvement as the objective.

Performance Indicators

Good performance indicators used for benchmarking are metrics with standard definitions, reliable data sources, and utilization across a representative portion of the industry. Good indicators allow for benchmarking to be repeated year after year in order to track performance and improvement. Additionally, when selecting an appropriate and relevant set of metrics, a balanced approach covering all key areas of the business is essential. In accordance with these criteria, key performance indicators have been selected for comparison to provide a balanced view of performance and for which consistent, comparable data is available. These indicators are defined in Section 6.0.

Each indicator reflects a particular duration of historical performance in accordance with peer group expectations. For example, Electric Utility Cost Group (EUCG) data for Value for Money metrics are based on three-year average performance, whereas WPII safety and reliability metrics reflect multi-year rolling averages based on each station's outage cycle. For WPII metrics, Darlington and Pickering's results reflect a three-year and two-year outage cycle, respectively.[2]

Industry Peer Groups

Peer groups were selected based on performance indicators widely utilized within the nuclear industry. Overall, six different peer groups were used as illustrated in Table 2 of Section 6.0 and panel members are detailed in Tables 3 to 8 of Section 6.0.

Report Structure

Sections 2.0 to 5.0 of the report focus on safety, reliability, value for money and human performance areas.

The Major Operator Section (historically Section 6.0) was removed from this report, consistent with ScottMadden's recommendations with respect to streamlining the report and ensuring consistency with leading practices and value for stakeholders. The Major Operator section provided a fleet operator level summary across a few key metrics, primarily across North America, utilizing a simple average of the results (mean) from each of their units/plants. While the operator level summary can be informative, it is more appropriate to look at OPG's two nuclear facilities individually given that they are at different stages of their lifecycle, have different sized units and reflect different generations of CANDU technology. This view is aligned with ScottMadden's most recent evaluation OPG Nuclear Benchmarking. The detailed data in sections 2.0 to 5.0 of the report provides a more complete picture of OPG's performance.

Section 6.0 provides an appendix of supporting information, including common acronyms, definitions, peer group and panel composition details.

[2] The planned outage cycle for each unit at Pickering is transitioning from a 24-month to a 30-month outage cycle. Pickering continues to assume a 24-month rolling average for benchmarking to be consistent with WANO reporting expectations.

Methodology and Sources of Data

The majority of safety metrics were calculated using data from WANO. Data labelled as invalid by WANO were excluded from all calculations. Indicator values of zero are not plotted or included in calculations except in cases where zero is a valid result. Current data was obtained and consolidated with previous benchmarking data.

The WANO Performance Indicator Index (WPII), a maximum score of 100 is possible. The WPII is an operational performance indicator comprised of 10 metrics, 7 of which are analyzed in this section:

- Total Industrial Safety Accident Rate (TISA) [Rolling Average]
- Collective Radiation Exposure (CRE) [Rolling Average]
- Fuel Reliability Index (FRI) [Annual]
- 2-Year Unplanned Automatic Reactor Trips
- 3-Year Auxiliary Feedwater Safety System Performance Unavailability
- 3-Year Emergency AC Power Safety System Performance Unavailability
- 3-Year High Pressure Safety Injection Unavailability

The remaining three WPII metrics are included in the Reliability Section (Section 3.0).

Note: To benchmark performance, Max WPII is used to indicate best quartile performance for metrics that perform better than the Max WPII benchmark. If metric performance is not better than Max WPII, quartile benchmarks are used to benchmark performance.

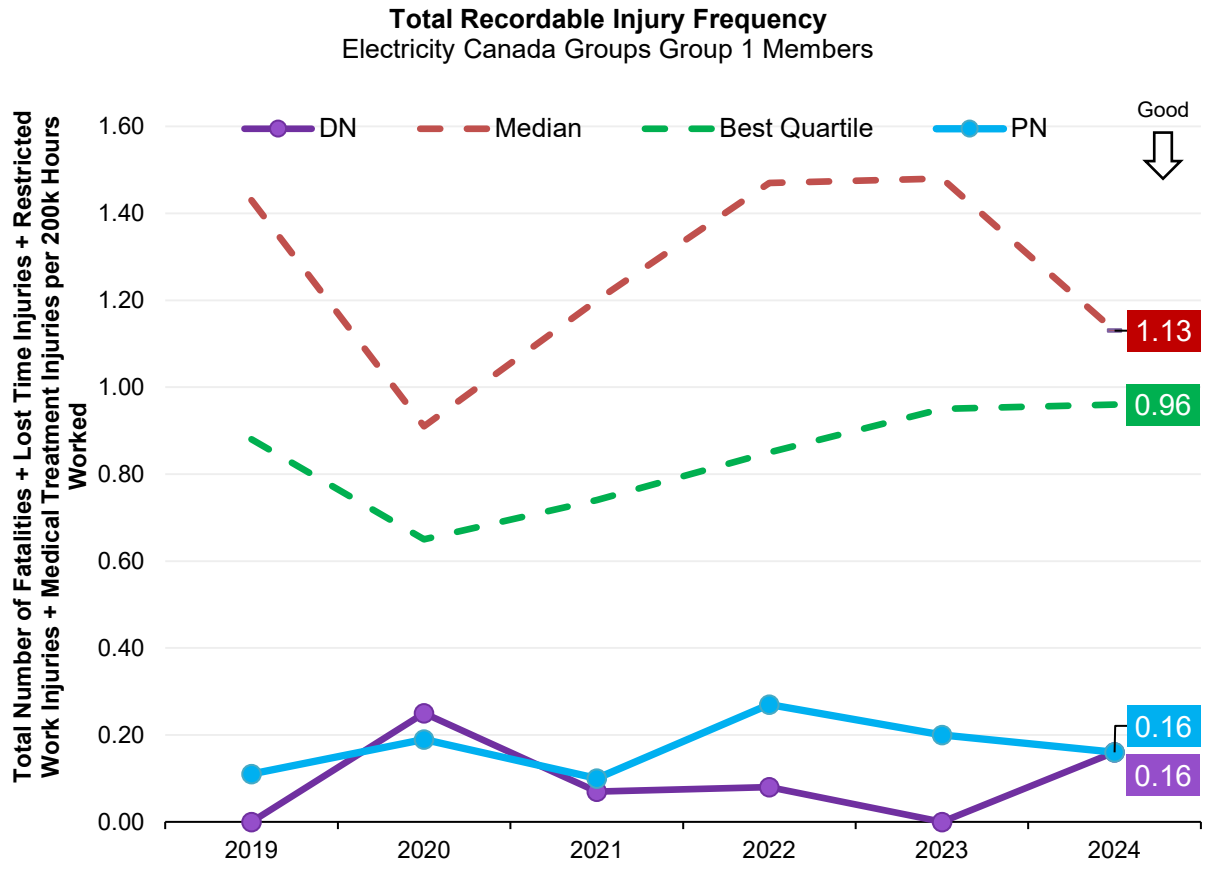
In addition to the WPII safety sub-indicators listed above, Total Recordable Injury Frequency and Airborne Tritium Emissions per In Service Unit are included in this section of the report.

Total Recordable Injury Frequency (TRIF) was calculated using data from Electricity Canada (EC). The peer group are members of Electricity Canada (EC) (Section 6.0, Table 6).

- OPG benchmarks against EC Group 1 peers (a subset of all EC members), which incorporates organizations with more than 1,500 employees, including most provincial utilities, leveraging EC's Occupational Health & Safety Statistics 2024 Report.

Airborne Tritium Emissions per In Service Unit data was collected from the Conexus Nuclear Inc. The peer group for this metric is all CANDUs who are members of Conexus Nuclear Inc. There is a one-year lag for the industry values associated with this metric.

Total Recordable Injury Frequency (TRIF)



Note: Annual Value

	2024 Value
DN	0.16
PN	0.16
Best Quartile	0.96
Median	1.13

Factors Contributing to Performance

- In 2024, DNGS and PNGS continued to achieve best quartile safety performance, maintaining excellent TRIF results compared to other Electricity Canada Group 1 members (1500+ employees).
- All injuries at DNGS and PNGS in 2024 were low-severity injuries (e.g., cuts, pinches).
- OPG remains focused on advancing safety improvements through its fleetwide fail-safe culture. OPG's fail-safe culture includes ensuring appropriate safety controls are in place to protect employees should an event occur, and sharing knowledge and lessons learned from safety events with particular attention on high-energy incidents that can cause serious injuries or fatalities. DNGS and PNGS have also implemented a Positive Stop culture that recognizes workers who stop work due to unknown or unexpected events.

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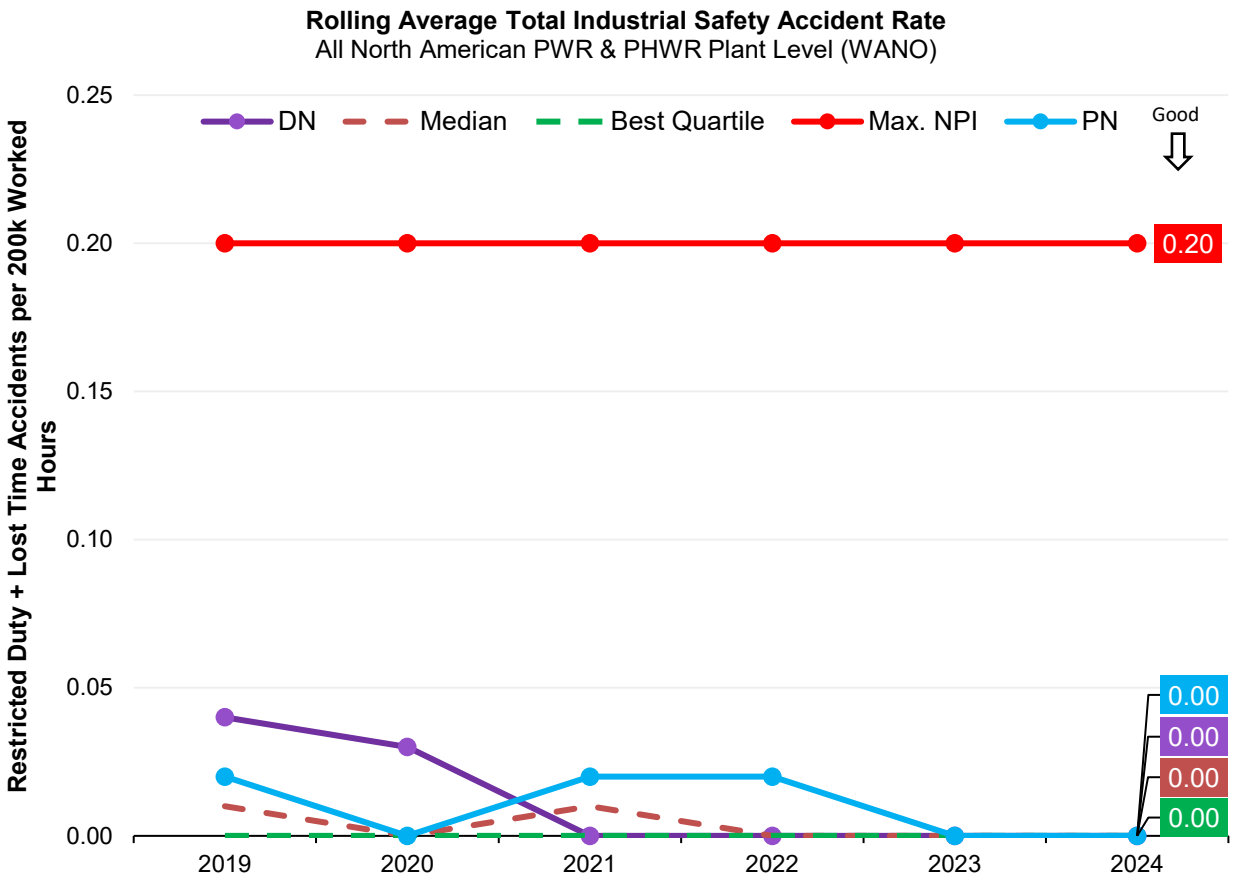
- OPG supports the prevention of injuries through initiatives such job aids to help employees recognize workplace energy hazards, ongoing enhancements to OPG's Electronic Safe Work Planning & Pre-Job Briefing (eSWP) platform, interactive activities and coaching to engage employees and encourage meaningful discussions about safety. The eSWP platform also features the "Energy Wheel" tool designed to help identify energy hazards that are often overlooked, and to support workers in implementing additional safety precautions for high-energy tasks that pose significant risks in the event of human error or equipment failure.

Initiatives to improve and sustain favorable performance include:

- In April 2024, OPG began using the Edison Electric Institute's Safety Classification and Learning (SCL) model. The SCL model helps enable early recognition and mitigation of Serious Injuries & Fatalities (SIF) precursor conditions as well as allows OPG to objectively classify safety events and better learn from events to prevent their recurrence. It also helps OPG identify a wider range of safety trends and will facilitate benchmarking with electrical industry peers. OPG added SCL performance data to its intranet safety reporting dashboards to raise awareness of SCL concepts, measure if barriers/controls were in place when safety events occurred and improve the characterization of exposures to high-energy hazards.
- OPG is committed to continually improving its health and safety managed system in accordance with ISO 45001 requirements, including taking corrective action to address findings from self-assessments, internal and external audits, and industry peer reviews.
- OPG is conducting a detailed self-assessment, including identification of gaps and actions plans, of the World Association of Nuclear Operators' (WANO) significant operating experience report for "Leadership in Preventing Fatalities and Severe Injuries" (SOER 2024-1).

Rolling Average Total Industrial Safety Accident Rate (TISA) * +



Sub-indicator for WPII
+ 3-year avg DNGS - Unit 2 (U4 in Refurbishment. Unit 3 RTS Q3 2023 & Unit 1 RTS Q4 2024, not online for 3 years), 2-year avg PNGS - Unit 4 & 5-8 (U1 end of commercial life Q3 2024)
** Previously ISAR (2019-2023), 2024 onwards is TISA*

	2024 Value
DN	0.00
PN	0.00
Best Quartile	0.00
Median	0.00

Factors Contributing to Performance:

- DNGS and PNGS continued to achieve maximum WANO Performance Indicator Index (WPII) points.
- DNGS achieved best quartile performance in 2024, with zero TISA events during the last three-year rolling average reporting period.
- PNGS achieved best quartile performance in 2024, with zero TISA events recorded during the last two-year rolling average reporting period.

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Initiatives to Improve and Sustain Favorable Performance:

- Continued implementation of the "Fail Safe" health and safety program, focusing on high-energy work, sequential control measures, event learning, and a variety of targeted strategies:
  - Use of Electronic Safe Work Planning (eSWP), which assesses and applies direct controls to address high-energy hazards during work execution.
  - Ongoing use of the Edison Electric Institute Safety Classification and Learning (SCL) model to identify additional learning opportunities through safety classifications and enable more effective industry benchmarking.
  - Use of Quality of Safety Practices (QSP) as a leading indicator to monitor high and low energy conventional safety risks to identify vulnerabilities and opportunities for improvement.
  - Continuous oversight to monitor performance for prevention and early intervention, with increased focus on addressing behaviors and program gaps through Observation and Coaching (O&C's), performance metrics, audits and assessments, benchmarking, and event learning.
  - Advancement of safety innovation through technology, including Peer-to-Peer Coaching Kiosks, Confined Space Application, Hazardous Material Application, Housekeeping Application, Lighting Application, Signage Kiosks, and Remote Temperature Monitoring Systems.

- These efforts collectively support the ongoing achievement of high standards in safety, reliability, and overall operational performance in the nuclear industry.

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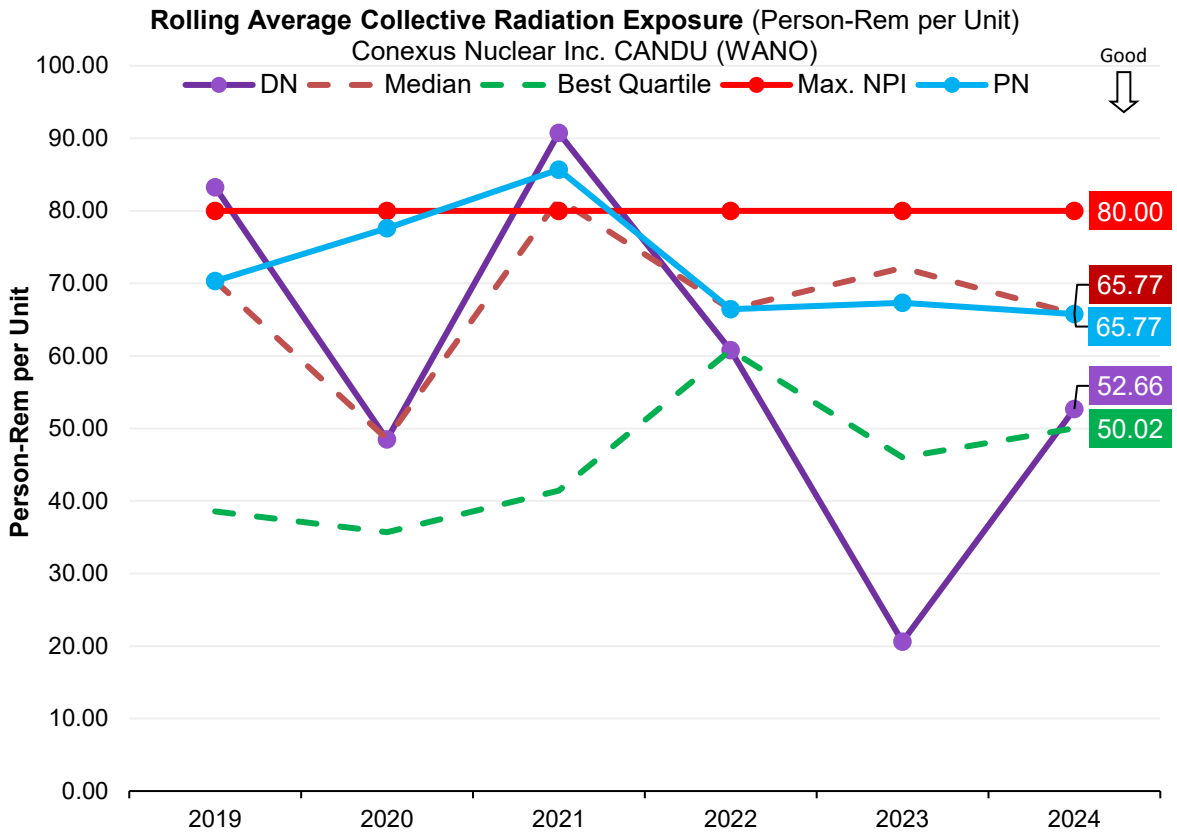
Rolling Average Collective Radiation Exposure (CRE) * +



Sub-indicator for WPII
+ 3-year avg DNGS - Unit 2 (U4 in Refurbishment. Unit 3 RTS Q3 2023 & Unit 1 RTS Q4 2024, not online for 3 years), 2-year avg PNGS - Unit 4 & 5-8 (U1 end of commercial life Q3 2024)

	2024 Value
DN	52.66
PN	65.77
Best Quartile	50.02
Median	65.77

Factors Contributing to Performance:

- DNGS and PNGS continued to achieve maximum WANO Performance Indicator Index (WPII) points.

- DNGS performance declined in 2024 compared to 2023 was a result of a major planned outage for Unit 2 in 2024 and zero planned outages in 2023.
  - A major planned maintenance outage on Unit 2 following unit refurbishment was executed which contributed to dose. Work included feeder inspections, reactor area bridge and carriage maintenance, calandria rupture disc replacements, various period inspection programs, and pressurizer heater replacements. CRE from this planned outage was 23% below target.

- PNGS performance improved in 2024, as a result of:

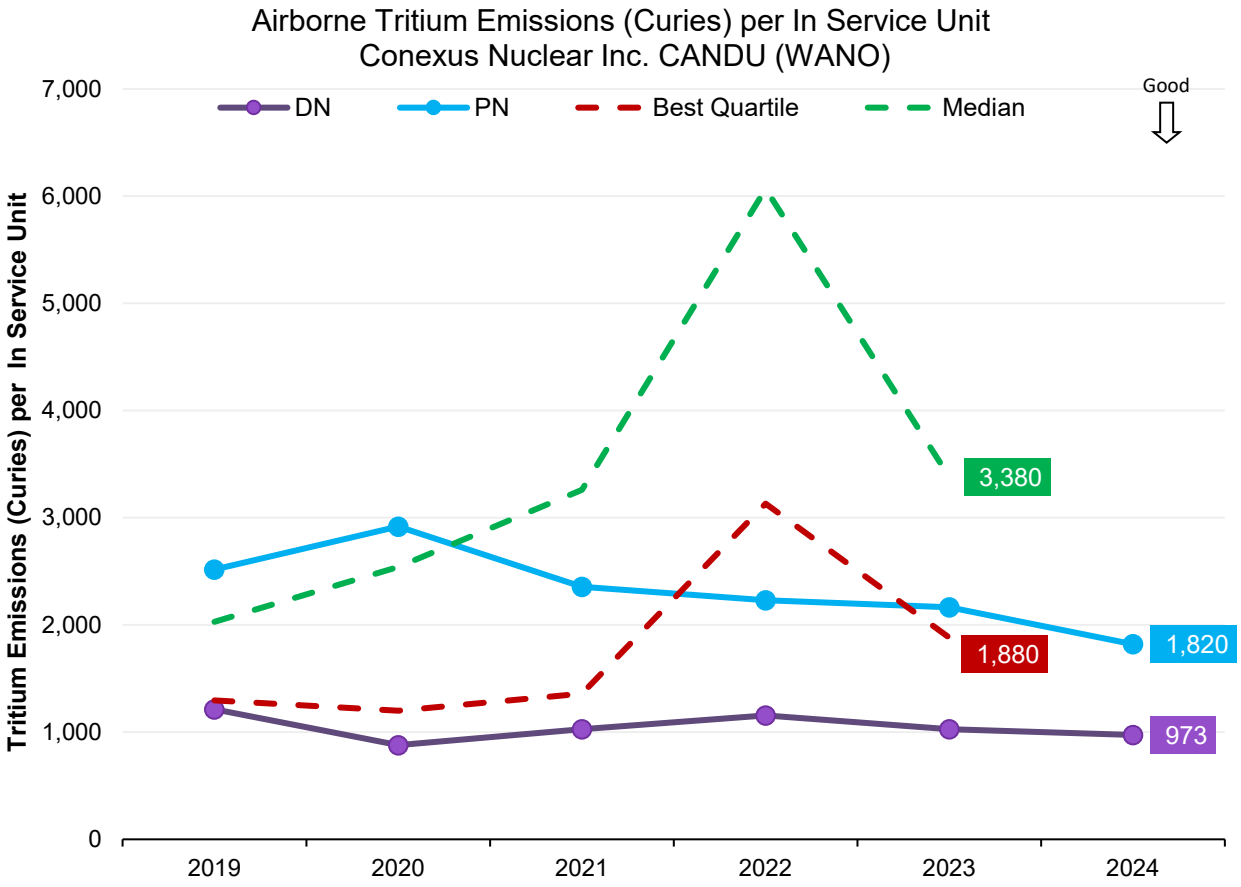
- Two planned maintenance outages, one forced outage and one planned unbudgeted outage in 2024, compared to three planned maintenance outages, two planned unbudgeted outages and six forced outages in 2023.
- Work programs for the planned maintenance outages which contributed to dose included fuel channel components periodic inspection, boiler inspections and a Single Fuel Channel Replacement (SFCR).
- Scope of work for the planned unbudgeted outage was to repair vault Air Conditioning Unit (ACU) leaks and recovery of stuck irradiated fuel bundles, and the forced outage was to address emergent conditions.
- Unit 1 was shut down for safe storage in September and Unit 4 at the end of December.

Initiatives to Improve and Sustain Favourable Performance Include:

- DNGS is undertaking various opportunities to reduce worker exposures and keeping collective doses As Low As Reasonably Achievable (ALARA). This includes, but is not limited to, the following initiatives and programs:
  - Utilizing a new design of channel closure plugs that effectively manage D_2O channel leakage. As a result, tritium levels in the vault decrease significantly. Thus, this also reduces worker tritium exposure.
  - Upcoming deployment of enhancing fuel channel inspection techniques by utilizing a Rapid Delivery Machine (RDM) to perform Advanced Non-Destructive Examination (ANDE), ANDE replication and Machine Delivered Scrape (MDS). Utilizing these systems reduces worker exposure by eliminating ice plug work inside feeder cabinets and workers performing channel inspection in front of the reactor face, which will also aid in tritium recovery in containment by maximizing performance on the Vault Vapour Recovery System (VVRS).
  - Modifying Emergency Coolant Injection (ECI) steel band to facilitate shielding on all units, outstanding installation on Unit 3 to be completed by 2026 during the planned maintenance outage. The expected benefit from this initiative will reduce worker exposure while working or traversing near the ECI lines.
  - A tritium oversight committee provides weekly updates on site tritium recovery systems to ensure tritium emission to environment is maintained ALARA.

- PNGS CRE for 2024 received maximum WANO Performance Indicator Index (WPII) points due to the initiatives and activities conducted in the last calendar year to improve the control of worker exposure and radiological hazards. Some of these initiatives and activities include:
  - Use of shielded canopy platform and customized shielded transport flasks during the Unit 7 Single Fuel Channel Replacement (SFCR) project contributed to reduction in dose rates to workers.
  - Dedicated Tritium emissions reduction team contributed to the lower than target performance for tritium emissions and lower internal collective radiation exposure for the year by ensuring proper dryer maintenance and revised procedures to optimize equipment performance.
  - ALARA initiatives, such as improved shielding, source term reduction initiatives and work methods improvements and efficiencies, contribute to improvements in dose performance.
  - Application of specialized source term reduction agents (i.e., Lanxess resin, fueling machine filter pore size reduction)
  - Continued focus on foreign material management and chemistry heat transport purification management.

Airborne Tritium Emissions



Annual Value
Median and Best Quartiles are plotted until 2023 as the 2024 results were unavailable at the time of benchmarking (one-year lag).
** Darlington values exclude Tritium Removal Facility (TRF) and associated West Annex emissions (consistent with Conexus Nuclear benchmark results).*
Unit 1 and Unit 4 refurbishment periods, and the Retube Waste Processing Building (RWPB)

	2024 Value
DN	973
PN	1,820
Best Quartile	1,880
Median	3,380

Factors Contributing to Performance:

- DNGS and PNGS Airbourne Tritium Emissions remain at a very small fraction of regulatory limits.
- Both sites have continued tritium reduction activities driven by dedicated teams that focus on day-to-day tritium reduction activities such as heavy water leaks and repairs, drier performance, continued management oversight and communication of priorities, utilized enhanced monitoring system station wide to provide real-time tritium monitoring capability.

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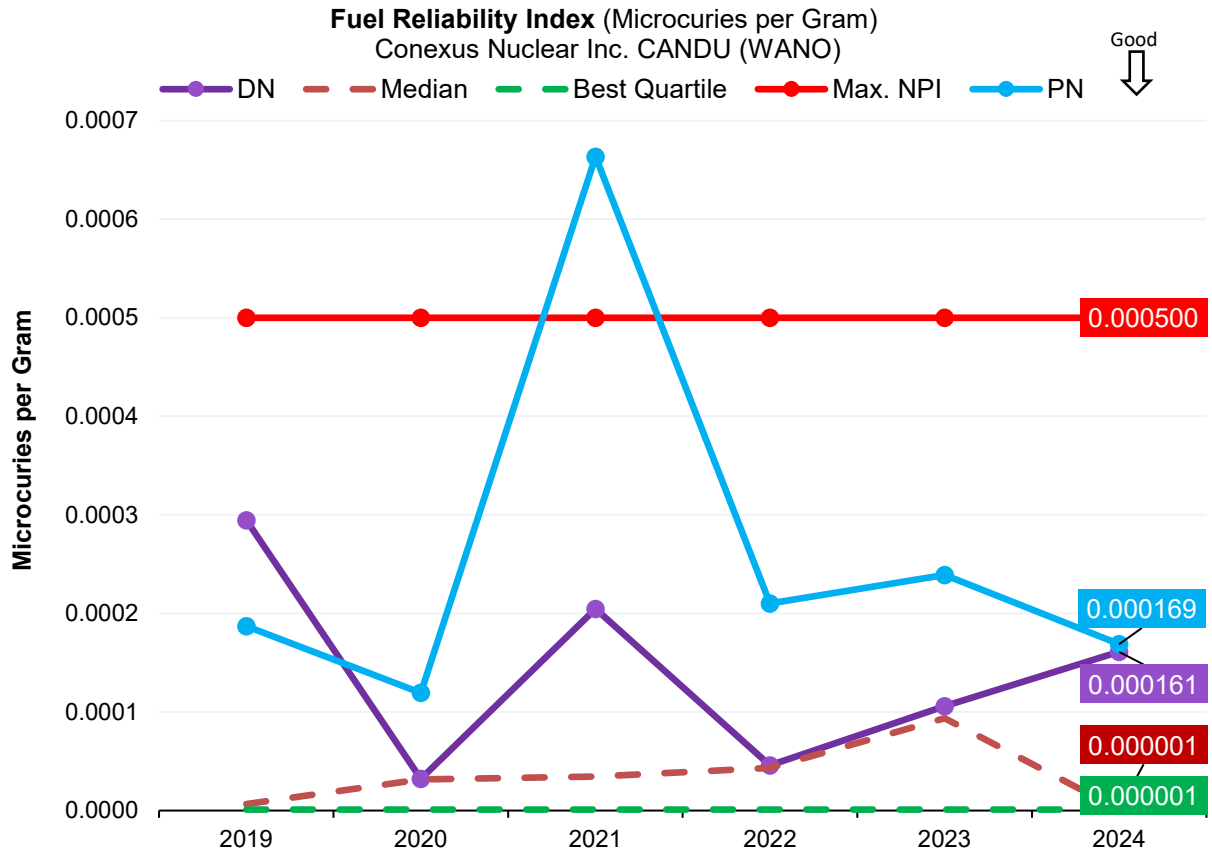
- DNGS continues to achieve best quartile performance in 2024. This was mainly attributed to efforts by the station to focus on tritium identification and reduction activities such as prioritizing repairs of leaking equipment and driers, utilizing enhanced monitoring system station-wide to provide real-time tritium monitoring capability, and ensuring Operations responded promptly to field deficiencies to minimize airborne tritium emission impacts.

- PNGS continued to achieve industry best quartile performance in 2024. This can be attributed to the efforts made by dedicated teams in place to drive station tritium reduction activities such as a focused effort on reducing drier downtime, and prioritizing repairs and equipment leaks clean up, thus minimizing airborne impact.

Initiatives to Improve and Sustain Favourable Performance Include:

- Dedicated teams at both sites focus on identifying and eliminating tritium sources, including improving drier performance and repairing heavy water leaks.
- Continued management oversight and communication of priorities to focus tritium reduction activities daily at Integrated Station Brief (ISB) meetings at both sites.
- Collaboration between both sites to share operating experience and benchmark tritium mitigation efforts to improve performance.
- Source term reduction on heat transport and moderator water.
- Tritium Oversight Committee at DNGS develops long-term plans, provide oversight, and proactively schedules preventive maintenance activities.
- Incorporated tritium reduction discussions during the re-occurring Operations United meeting at DNGS, enabling risk identification and constructive challenges to further improve performance.
- Ongoing participation in Conexus Nuclear Inc. environmental benchmarking of participating CANDU stations to determine best environmental practices.

Fuel Reliability Index (FRI) *



Sub-indicator for WPII
Note: 2024 Most Recent Operating Quarter
+ DNGS – Unit 2 (U4 in Refurbishment. Unit 3 RTS Q3 2023 & Unit 1 RTS Q4 2024, not online 3 years), PNGS - Unit 4 & 5-8 (U1 end of commercial life Q3 2024)

	2024 Value
DN	0.000161
PN	0.000169
Best Quartile	0.000001
Median	0.000001

Factors Contributing to Performance

- DNGS and PNGS continued to achieve maximum WANO Performance Indicator Index (WPII) points.
- Three fuel defects were observed and discharged at DNGS in 2024, compared to one in 2023.
- One fuel defect was observed at PNGS in 2024 and discharged in 2025, compared to two fuel defects observed in 2023 that were discharged in 2024.

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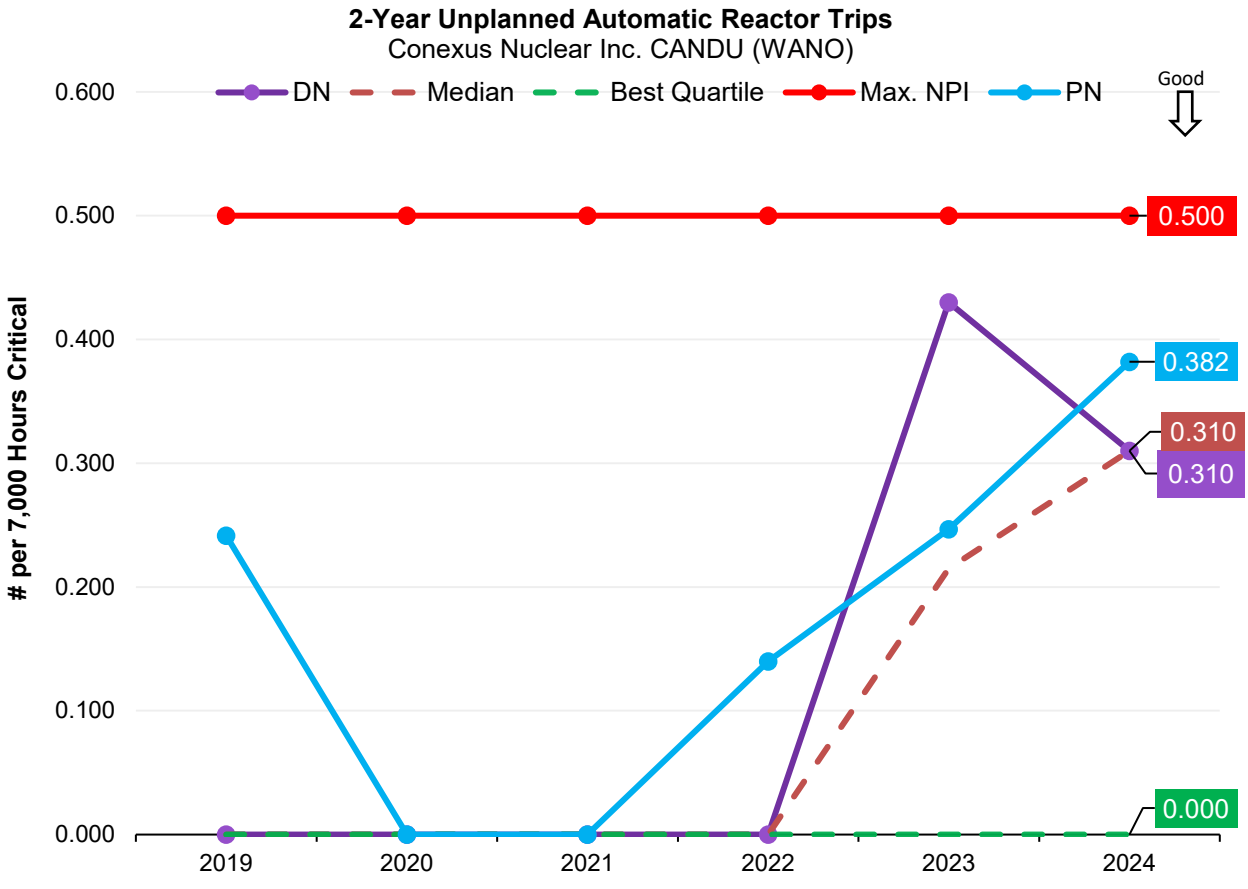
Initiatives to Improve and Sustain Favourable Performance Include:

- Both sites maintained their respective fuel design manuals and fuel drawing sets. These documents strictly control the manufacturing process, fuel operating limits, fuel handling limits and the fuel performance limits. OPG continues to source fuel with tighter manufacturing tolerances at both sites, thereby eliminating certain modes of fuel defecting following fuelling runs.

- DNGS improvement initiatives include:
  - Foreign Material Exclusion (FME) practices continue to mitigate debris fretting fuel failures as shown by the low number of defects following DNGS reactor refurbishment activities. Proactive measures are in place in an effort to avoid FME shutdowns with a planned post-Refurbishment outage on D2512.
  - Improving and sustaining awareness that the impact foreign material, specifically micro-debris potentially introduced through Fuel Handling and Outage activities, has on fuel performance.

- PNGS improvement initiatives include:
  - Enhancing surveillance by increasing the scope of Primary Heat Transport System (PHTS) grab sampling and analysis when defects are in-core continues to assist in earlier detection and removal minimizing the risk of foreign materials.
  - Improving and sustaining awareness of the impact foreign material in the PHTS, specifically micro-debris potentially introduced through Fuel Handling and Outage activities, has on fuel performance.
  - Improved capability among Units 5 to 8 of detecting defected fuel bundles following discharge from the fuelling machines continues to assist in re-directing failed fuel to the inspection area in support of root cause analysis and driving corrective actions.
  - Initiated planning for a confirmatory out-of-reactor test series to address risks associated with prolonged crossflow exposure during fueling incidents.

2-Year Unplanned Automatic Reactor Trips *



Sub-indicator for WPII
+ DNGS – Unit 2 (U4 in Refurbishment. Unit 3 RTS Q3 2023 & Unit 1 RTS Q4 2024, not online 3 years), PNGS - Unit 4 & 5-8 (U1 end of commercial life Q3 2024)
Note 3: Reactor Trip Rate was replaced by Reactor Automatic & Manual Trip Rate following the WPII Method 10 transition in 2024. The indicator change includes the change from Unplanned Automatic Scrams (UA7) to Unplanned Total Scrams (US7). Method 4 utilized UA7 metric which only included the automatic scram data. The new indicator, US7, includes both automatic and manual scrams.

	2024 Value
DN	0.310
PN	0.382
Best Quartile	0.000
Median	0.310

Factors Contributing to Performance:

- DNGS and PNGS continued to achieve maximum WANO Performance Indicator Index (WPII) points.

- DNGS had no unplanned automatic or manual reactor trips in 2024 compared to one trip occurring in 2023. Improved performance is due to the excellence in Human Performance and Operator and Maintenance fundamentals.

- PNGS decline in performance in 2024 was impacted by the following unplanned automatic or manual reactor trips:

    - Unit 8: A manual Shutdown System (SDS)1 trip occurred due to the loss of Liquid Zone Control zones. The cause of this event was a passing liquid zone traps that resulted in compressors short cycling and high cover gas hydrogen levels.
    - Unit 4: A reactor trip on Heat Transport Low Flow (HTLF) trip parameter associated with the Reactor Protective System (SDS) and Shutdown System Enhancement (SDSE), which was caused by a failure of protection circuit in Hydro 1 switchyard, Unit 4 was load rejected, leading to a total loss of Class IV power.
    - Unit 5: During the warm-up of Heat Transport System (HTS), reactor trip occurred on Boiler Low Level (BLL) trip parameter (SDS2). This event is due to the heat sink challenge, which was not recognized nor resolved during turnover following ending of HTS warm up.

Initiatives to Improve and Sustain Favourable Performance Include:

The following measures are being implemented at DNGS and PNGS:

- On-going performance monitoring and improvement activities by Station Operations, Engineering, and Maintenance organizations.
- OPEX and lessons learned from the continuous exchange of information among Canadian utilities are incorporated into the OPG governance and governance support documents.
- Internal and external audits as well as inspections and self-assessments are performed to verify compliance and recommend future improvement opportunities.
- Training and qualification requirements are established and reviewed to be up to date to execute the job tasks at all levels of Operations, Maintenance and Engineering.

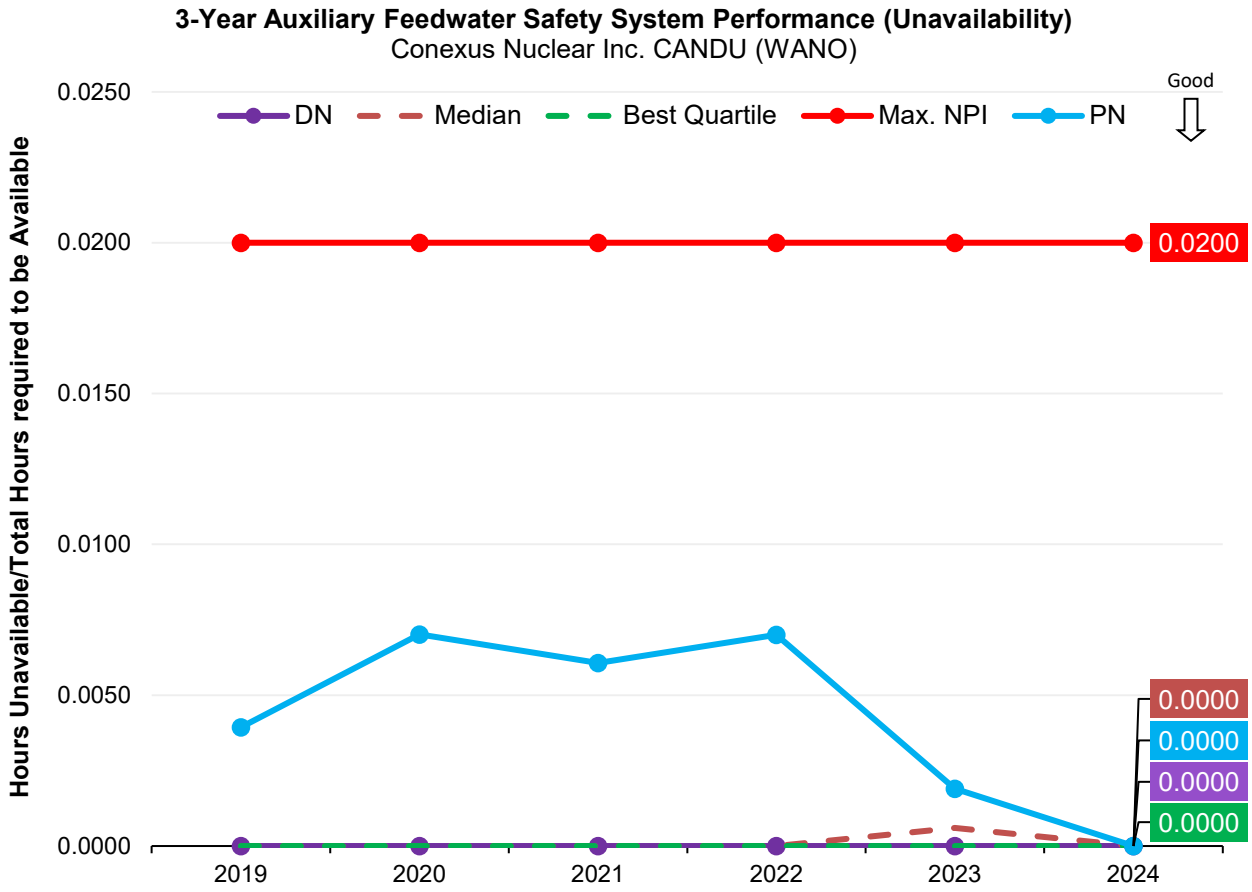
DNGS planned actions are as follows:

- Continuous actions, such as, Engineering Technical Surveillance Program, are being implemented in Darlington to ensure the best performance through Safety Related System Tests.

PNGS planned actions are as follows:

- Establish clear criteria for maintaining effective supervisory oversight during critical unit activities over turnover.
- Revise the Overall Unit Manual for HT pressurization and warm-up.
- Perform a focused roll-out of Conduct of Control Room Turnover.
- Provide control room operations staff with key information in preparation for unit warm-up tasks.
- Reduce the number of equipment-related challenges in the control room during critical evolutions.
- Address knowledge gaps in Authorized Training for HT pressurization
- Isolation of all traps on all units.
- Continuous monitoring of Liquid Zone chemistry and compressor cycle.
- Organizational Effectiveness Group leads paired learning sessions to drive risk elimination behaviors with chosen station work groups (Engineering, Maintenance, Operations, Chemistry and Fuel Handling).

3-Year Auxiliary Feedwater Safety System Performance (Unavailability)*



Sub-indicator for WPII
+ DNGS – Unit 2 (U4 in Refurbishment. Unit 3 RTS Q3 2023 & Unit 1 RTS Q4 2024, not online 3 years), PNGS - Unit 4 & 5-8 (U1 end of commercial life Q3 2024)

	2024 Value
DN	0.0000
PN	0.0000
Best Quartile	0.0000
Median	0.0000

Factors Contributing to Performance:

- DNGS and PNGS continued to achieve maximum WANO Performance Indicator Index (WPII) points.
- DNGS achieved best quartile performance of zero unavailability. Factors contributing to performance include:
  - Identifying critical work on the plant reliability list.
  - Scheduling work using Integrated Planning Group and Cycle Plan processes.
  - Adhering to the cycle planning.
  - Following the System Performance Monitoring Plan.
  - Adhering to the Health Report 10-Year Improvement Plan.

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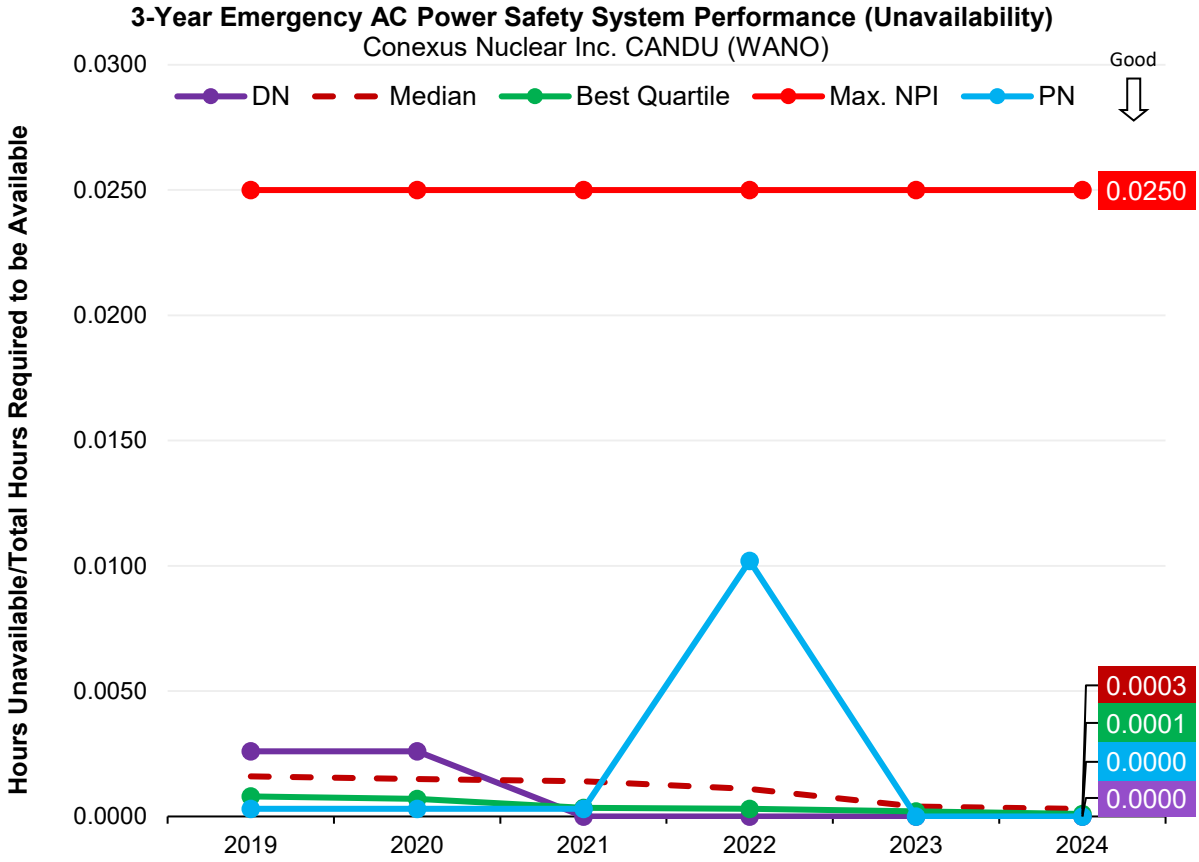
- PNGS achieved the best quartile performance of zero unavailability due to ongoing improvement actions.

Initiatives to Improve and Sustain Favourable Performance Include:

- DNGS design changes to the Auxiliary Boiler Feed (ABF) system include:
  - Installing gland injection cooling on pump seals to resolve mechanical seal O-ring failure.
  - Replacement of reverse rotation device for main and ABF pumps.

- The following was implemented on PNGS to improve the ABF system performance:
  - Perform evaluation of repeat failures of Units 1 and 4 ABFP discharge pressure control valves.

3-Year Emergency AC Power Safety System Performance (Unavailability) *



Sub-indicator for WPII
+ DNGS – Unit 2 (U4 in Refurbishment. Unit 3 RTS Q3 2023 & Unit 1 RTS Q4 2024, not online 3 years), PNGS - Unit 4 & 5-8 (U1 end of commercial life Q3 2024)

	2024 Value
DN	0.0000
PN	0.0000
Best Quartile	0.0001
Median	0.0003

Factors Contributing to Performance:

- DNGS and PNGS continued to achieve maximum WANO Performance Indicator Index (WPII) points.
- DNGS Emergency AC Power system achieved the best quartile performance of zero unavailability. Factors contributing to performance include:
  - Identifying critical work on the plant reliability list.
  - Scheduling work using Integrated Planning Group and Cycle Plan processes.
  - Adhering to the 10-year Outage Maintenance Strategy for the Standby Generators (SGs) and Health Report Improvement Plan.
  - Following the System Performance Monitoring Plan.
  - Adhering to the Health Report 10-Year Improvement Plan.

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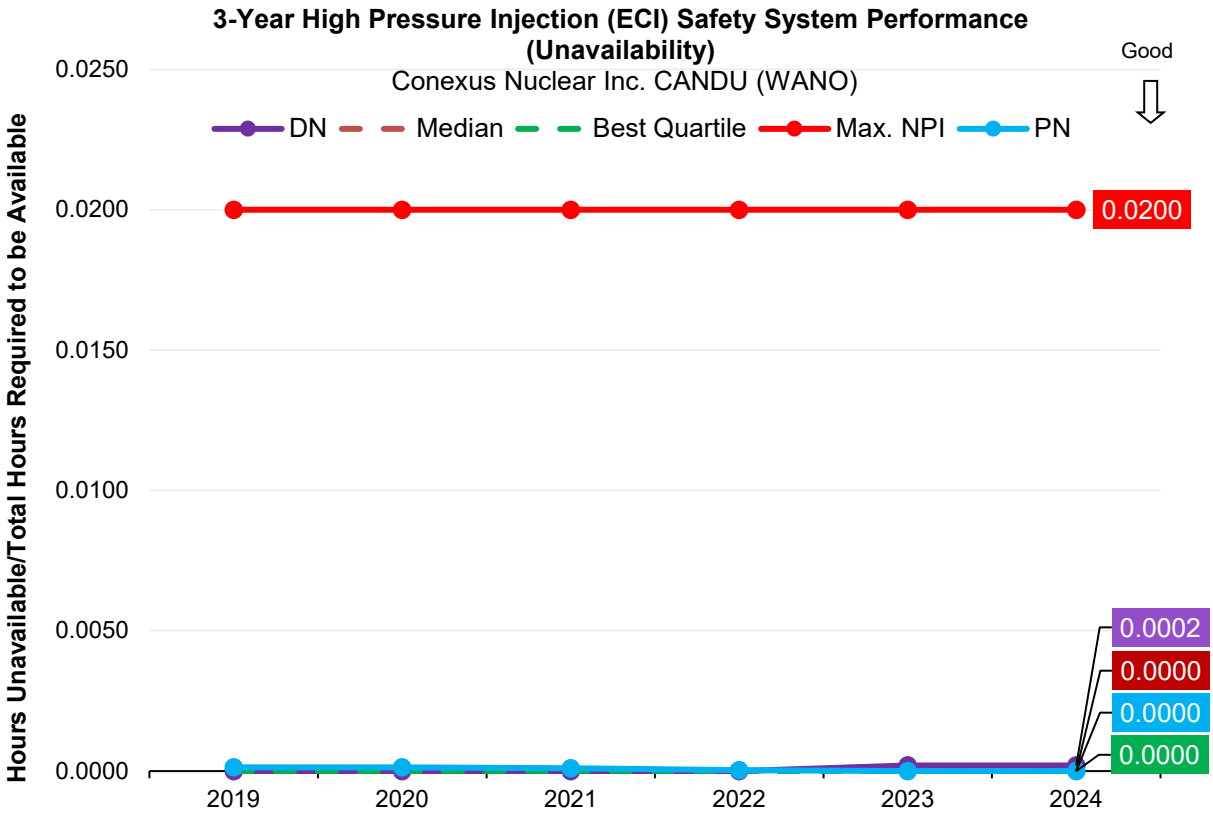
- PNGS Emergency AC Power system achieved the best quartile performance of zero unavailability. Factors contributing to performance include:
  - Inspection of 058 Standby Generators (SGs) for power turbine cracking failures, repairing SGs as required.

Initiatives to Improve and Sustain Favourable Performance Include:

- DNGS planned actions include
  - A 10-year project is in progress on the SG protective relays to replace all the old electro-mechanical relays with modern digital versions directly proceeding the end of each SG outage. Installation and commissioning for SG3 is complete. SG1, SG2, and SG4 will proceed in 2024 and 2025

- PNGS planned actions include:
  - Actions to ensure timely review/implementation of the corrective and routine maintenance.
  - Cracked power turbine casings will be repaired or replaced.

3-Year High Pressure Injection (ECI) Safety System Performance (Unavailability) *



Sub-indicator for WPII
+ DNGS – Unit 2 (U4 in Refurbishment. Unit 3 RTS Q3 2023 & Unit 1 RTS Q4 2024, not online 3 years), PNGS - Unit 4 & 5-8 (U1 end of commercial life Q3 2024)

	2024 Value
DN	0.0002
PN	0.0000
Best Quartile	0.0000
Median	0.0000

Factors Contributing to Performance

- DNGS and PNGS continued to achieve maximum WANO Performance Indicator Index (WPII) points.
- DNGS High Pressure Safety Injection (HPSI) unavailability was 0.0002. The factors contributing to performance includes:
  - Reducing fault occurrences by improving equipment reliability through Preventative Maintenance Optimization, Performance Monitoring and Life Cycle Management programs.
  - Planned maintenance on ECIs is being managed to ensure the target is met, providing unplanned faults/maintenance remain at historical levels.

- Improving scheduling of discretionary maintenance so that equipment unavailability is reduced during quarters with lower reactor critical hours.

- PNGS continued with the best High Pressure Safety (HPSI) quartile performance of zero unavailability. Continuous improvement through mitigation of aggregate risk to maintain system redundancy contributed to PNGS performance.

Initiatives to Improve and Sustain Favourable Performance Include:

- Darlington HPSI related activities include the following:
  - Units 1-4 injection valve internals were overhauled.
  - On-going equipment reliability improvement work.
  - Performing preventive maintenance on schedule to reduce component failures and unplanned unavailability hours and scheduling maintenance work to maximize availability.
  - Overhaul or replacement of critical components during outages to increase equipment reliability (i.e., ECI Hydraulic Power Unit (HPU)/ECI Accumulator Control Module (AMCA)).
  - Completion of equipment reliability improvement work is driven via the 52-week cycle plan and Plant Reliability List (PRL) initiatives.

- Pickering HPSI related activities include the following:
  - Placing an additional Calandria face cooling fan to rectify erroneous moderator level indications.
  - Fixing the leaking H_2O injection valve.
  - Mitigating the leakage to the miscellaneous collection tank from a motorized valve.
  - Due to drift issues, 40V DC power supplies to ECI channel S logic instrumentation are being replaced on all units.
  - Engineering Change Request (ECR) has been approved to address the incorrect logic associated with ECI storage tank low level annunciation.

Methodology and Sources of Data

The majority of reliability metrics were calculated using data from WANO. Any data labelled as invalid by WANO was excluded from all calculations. Indicator values of zero are not plotted or included in calculations except in cases where zero is a valid result. Complete data for the review period was obtained, and averages are as provided by WANO.

For the WANO Performance Indicator Index (WPII), a maximum score of 100 is possible. The WPII is an operational performance indicator comprised of 10 metrics, three of which are analyzed in this section:

- Forced Loss Rate (FLR) [Rolling Average]
- Rolling Average Unit Capability Rate (UCR) [Rolling Average]
- Chemistry Performance Indicator (CPI) [Rolling Average]

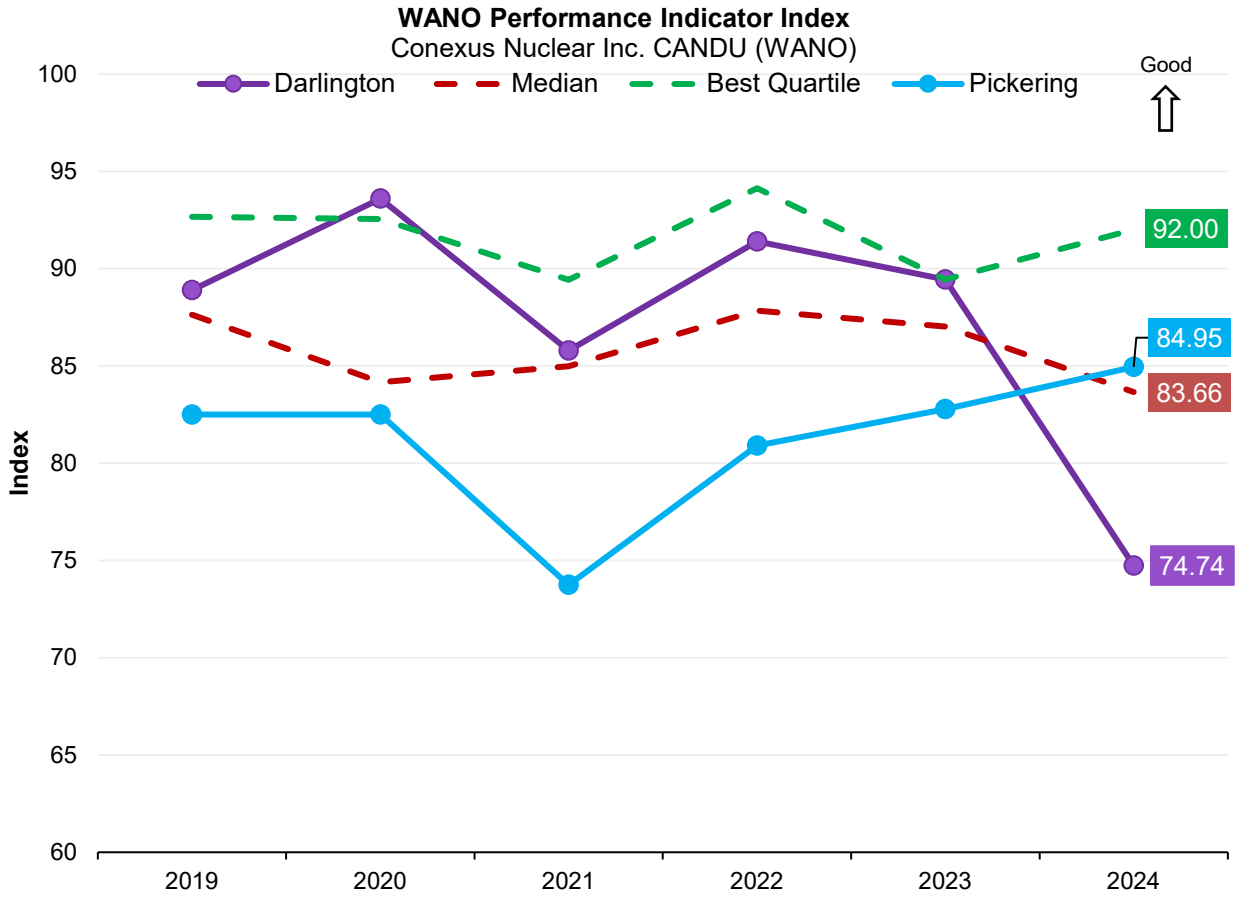
The other seven WPII components are shown in the Safety Section (Section 2.0).

Note: To benchmark performance, Max WPII is used to indicate best quartile performance for metrics that perform better than the Max WPII benchmark. If metric performance is not better than Max WPII, benchmark quartiles are utilized to indicate quartile performance.

In addition to the WPII indicators listed above, Unit Capability Factor (UCF) is also included in this section, and the calculations utilize data from WANO. Data points benchmarked for UCF are a rolling average.

Backlog metrics for On-line Deficient and Corrective Maintenance are also included within this section and the data comes from an industry sponsored Institute of Nuclear Power Operators (INPO) AP-928 subcommittee. Data points benchmarked on backlogs are annual, not a rolling average. All data is self-reported.

WANO Performance Indicator Index (WPII) +



+ 3-year avg DNGS - Unit 2 (U4 in Refurbishment. Unit 3 RTS Q3 2023 & Unit 1 RTS Q4 2024, not online for 3 years), 2-year avg PNGS - Unit 4 & 5-8 (U1 end of commercial life Q3 2024)

** WPII methodology changed from Method 4 to Method 10 starting in 2024. This adjustment affects both the metric's definition and index weighting. Data from 2019 through 2023 was calculated using Method 4, 2024 onward will reflect Method 10.*

	2024 Value
DN	74.74
PN	84.95
Best Quartile	92.00
Median	83.66

Factors Contributing to Performance:

- DNGS WPII performance declined in 2024 compared to 2023. The decline in performance is attributed to elevated Forced Loss Rate (FLR) and Unit Capability Rate (UCR) performance as result of two forced outages in 2024. Since FLR and UCR have the most significant weighting (15 and 10 points respectively) in the WPII method 10 calculation, the resulting score of WPII was reduced. DNGS continued with excellent performance for all seven safety metrics.

- PNGS performance improved by 2.17 points primarily due the industry definition and weighting change from WPII method 4 to WPII method 10.
  - UCR and FLR have the most significant weighting in the WPII calculation.

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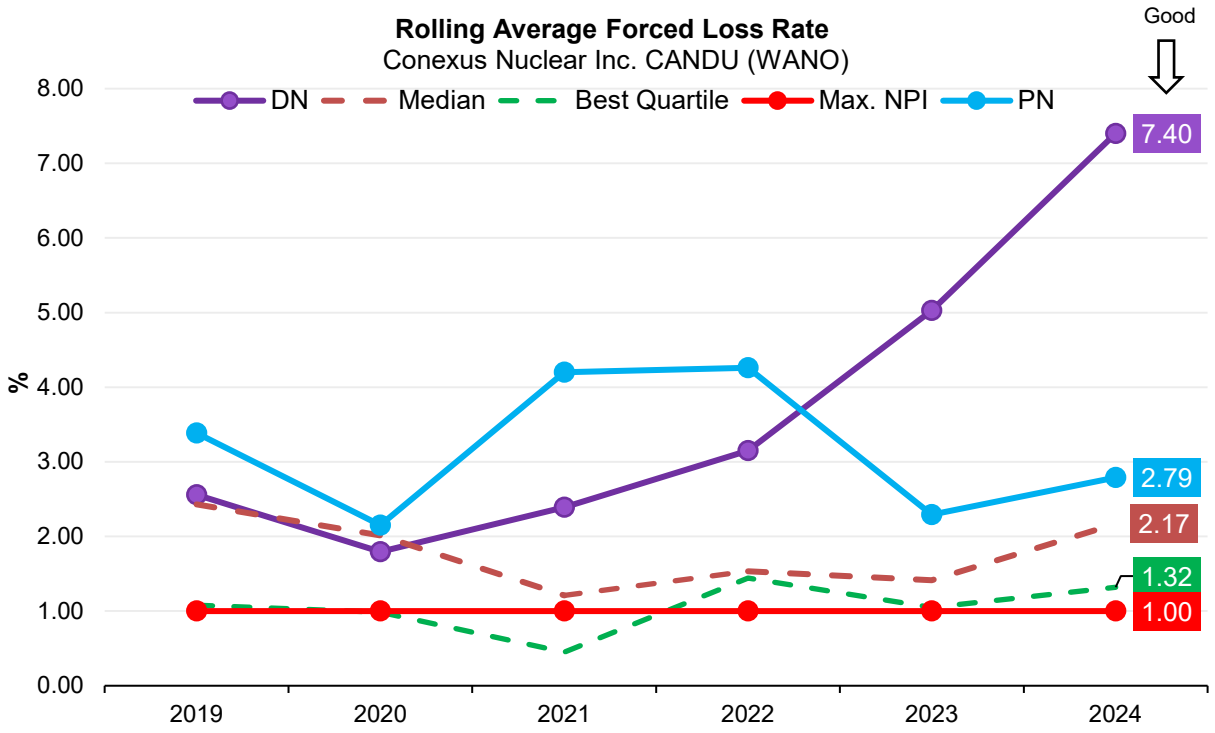
- Sustained performance for all seven safety was partially offset by lower Chemistry Performance Index (CPI), Forced Loss Rate (FLR) and Unit Capability Rate (UCR) performance.

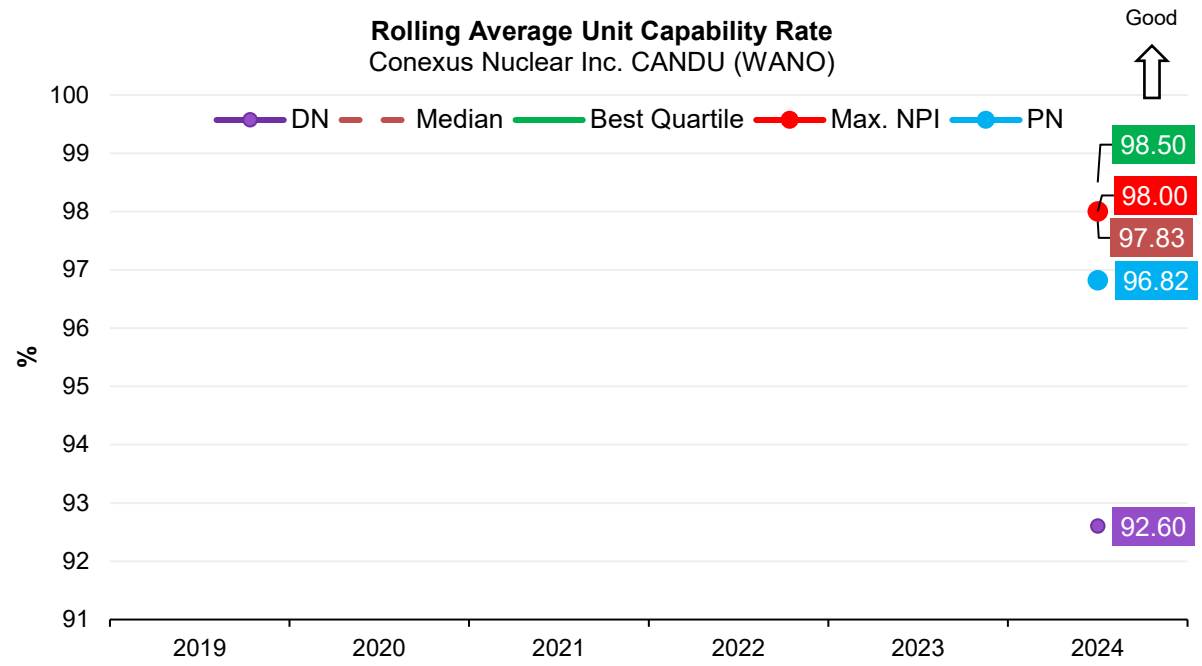
Further details on factors contributing to performance and initiatives to improve and sustain favourable performance are discussed within each respective WPII sub-metric in this report.

Rolling Average Forced Loss Rate (FLR) * +



Sub-indicator for WPII
+ 3-year avg DNGS - Unit 2 (U4 in Refurbishment. Unit 3 RTS Q3 2023 & Unit 1 RTS Q4 2024, not online for 3 years), 2-year avg PNGS - Unit 4 & 5-8 (U1 end of commercial life Q3 2024)

Rolling Average Unit Capability Rate (UCR) * +



Note: New metric for WPII Method 10, replacing Unit Capability Factor (UCF) for WPII Method 4

	2024 FLR	2024 UCR
DN	7.40	92.60
PN	2.79	96.82
Best Quartile	1.32	98.50
Median	2.17	97.83

Factors Contributing to Performance:

- DNGS decline in performance is attributable to post-Refurbishment forced outages. As the metric is a rolling average, in 2023 & 2024 only Unit 2 results are included (Units 1, 3, 4 were in refurbishment during all or part of the window), compared to only Unit 4 being included prior to entering Refurbishment in 2022. Increased FLR is expected post refurbishment and will improve with support of ongoing initiatives to strengthen Plant reliability, Human Performance and Equipment reliability. DNGS experienced four forced outage events related to Unit 2 post-Refurbishment on Generator (2024), Primary Heat Transport (2023), and Turbines & Main Power Output (2022).

- PNGS slight decline in performance is attributable to elevated FLR in 2024 compared to 2022, which is no longer included in the rolling window. In 2024, there were three forced outages related to Primary Heat Transport, Liquid Zone Control and Generator systems, and six forced outages related to Turbine, Boiler Feedwater, Main Output, and Human Performance in 2023. Unit 6 obtained Industry Best Quartile FLR in 2024.

Initiatives to Improve and Sustain Favourable Performance Include:

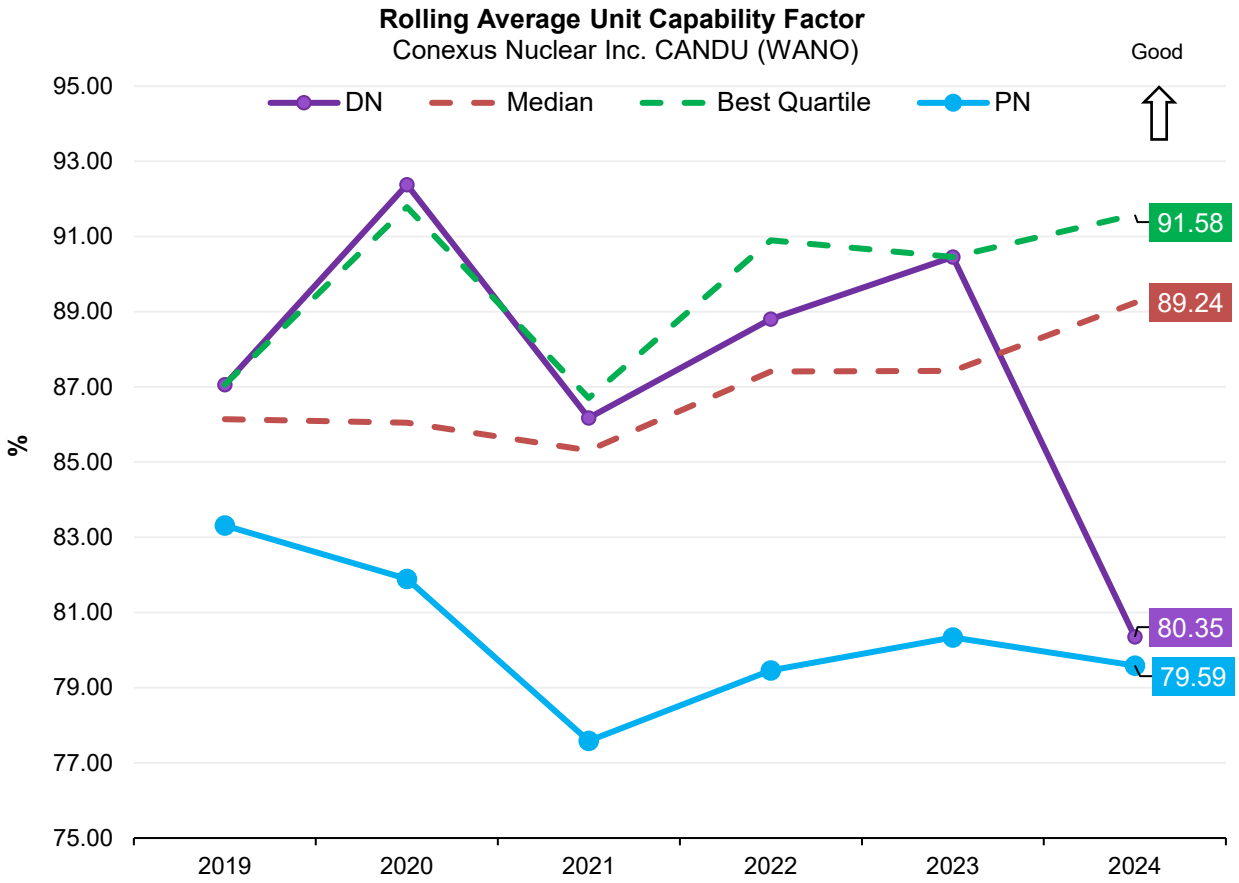
- Focused actions, including vulnerability identification and elimination, project execution, and building proficiency at both the fleet and site level to increase plant reliability, have been implemented for identified systems that are contributing to historical and industry forced loss events.

- Major projects installed during Darlington Refurbishment have improved reliability, and major projects are scoped for Pickering Refurbishment to improve reliability of contributing systems.

- Fuel Handling fleet and industry peer teams have continued to reduce or eliminate FLR contribution year over year and remains a fleet focus area to build sustainability. DNGS has achieved industry best performance with no contributing Fuel Handling FLR.

- Internal peer teams, industry benchmarking, fleet assessments against industry best practice, enhanced participation in industry working groups are in place to help manage risks going forward. Continued actions building proficiency at both the fleet and site level have been implemented for top fleet contributors, supported by industry peers.

Rolling Average Unit Capability Factor (UCF) * +



+ 3-year avg DNGS - Unit 2 (U4 in Refurbishment. Unit 3 RTS Q3 2023 & Unit 1 RTS Q4 2024, not online for 3 years), 2-year avg PNGS - Unit 4 & 5-8 (U1 end of commercial life Q3 2024)

	2024 Value
DN	80.35
PN	79.59
Best Quartile	91.58
Median	89.24

Factors Contributing to Performance:

- DNGS decline in performance is attributable to a decline in FLR performance in 2024, which is expected post-Refurbishment. As the metric is a rolling average, only Unit 2 results are included in 2023 & 2024 (Units 1, 3 and 4 were in refurbishment during all or part of the window). 2022 results were measured against Unit 4 performance prior to entering refurbishment (Unit 1 & 3 were in refurbishment and Unit 2 was only online for two years).

- PNGS decline in performance is attributable to decline in FLR performance in 2024 compared to 2022, which is no longer in the rolling window. Unit 7 achieved Industry Best Quartile in 2023.

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Initiatives to Improve and Sustain Favourable Performance Include:

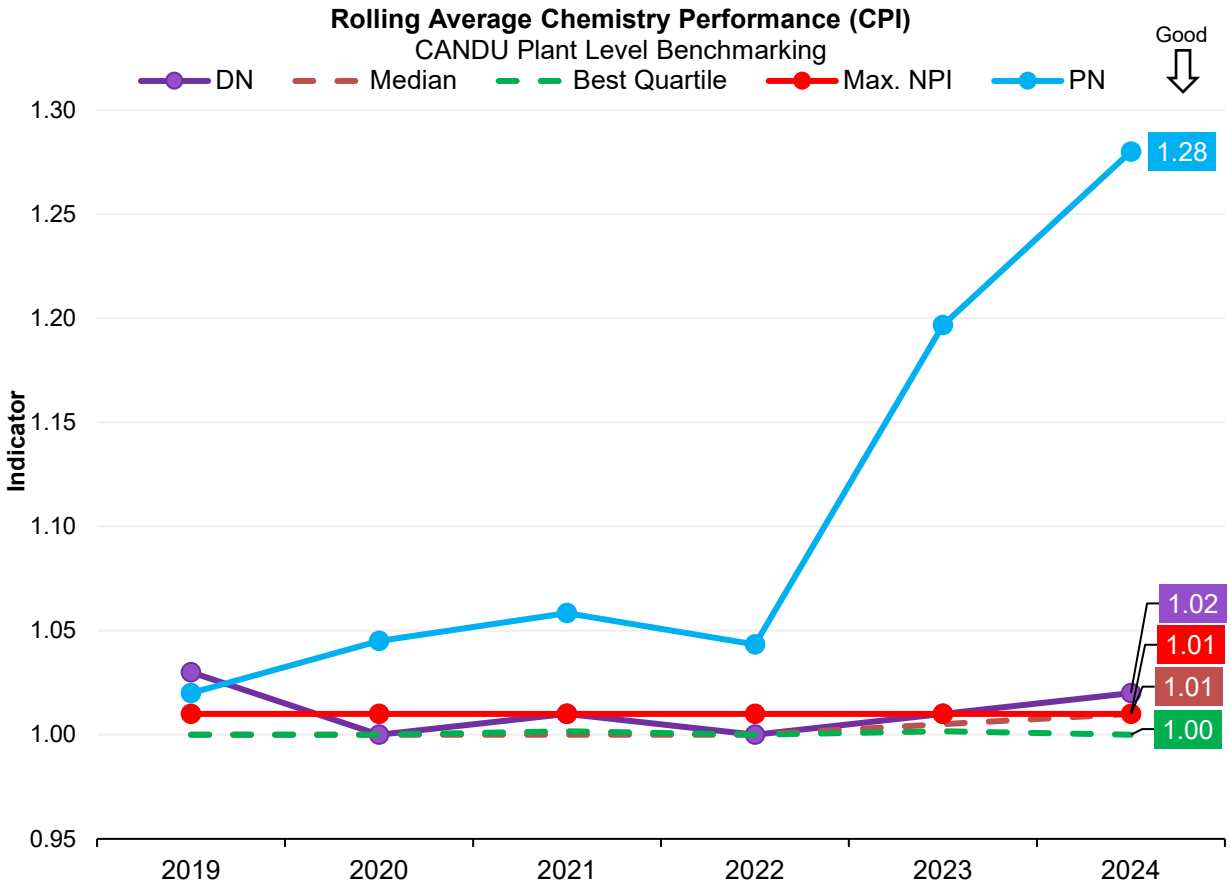
- Focused actions, including vulnerability identification and elimination, project execution, and building proficiency at both the fleet and site level have been implemented for identified systems contributing to historical and industry forced loss events.

- Major projects installed during Darlington Refurbishment have improved reliability, and major projects are scoped for Pickering Refurbishment to improve reliability of contributing systems.

- Fuel Handling fleet and industry peer teams have continued to reduce or eliminate FLR contribution year over year and remains a fleet focus area to build sustainability. DNGS has achieved industry best quartile with no contributing Fuel Handling FLR.

- Internal peer teams, industry benchmarking, fleet assessments against industry best practice, enhanced participation in industry working groups are in place to help manage risks going forward. Continued actions focused on building proficiency at both the fleet and site level have been implemented for top fleet contributors, supported by industry peers.

Rolling Average Chemistry Performance Indicator (CPI) *+



+ 3-year avg DNGS - Unit 2 (U4 in Refurbishment. Unit 3 RTS Q3 2023 & Unit 1 RTS Q4 2024, not online for 3 years), 2-year avg PNGS - Unit 4 & 5-8 (U1 end of commercial life Q3 2024)

	2024 Value
DN	1.02
PN	1.28
Best Quartile	1.00
Median	1.01

Factors Contributing to Performance:

The decline in performance at DNGS in 2024 compared to 2023 can be attributed to the following:

- Unit 2 Feedwater corrosion product transport post unit start-ups and elevated boiler ions upon unit start-ups (2024).
- Condenser tube leak on Unit 2 (2023).

The decline in performance at PNGS in 2024 compared to 2023 can be attributed to the following:

- Post Unit 7 start-up boiler sulphates for ~ 9 months (2024)
- Post Unit 5 start-up boiler sulphates for ~ 5 months (2024)

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- Post Unit 8 Condenser Tube Leak that resulted in boiler ions in Action Level 3 high (2023)
- Multiple condenser tube leaks on Unit 8 (2023)
- Post Unit 6 start-up boiler sulphates for ~ 6 months (2023)

Initiatives to Improve and Sustain Favourable Performance Include:

Both sites have an ongoing Chemistry Outage SPOC to provide improved coordination/planning such that system chemistry control has improved during outages/start-ups.

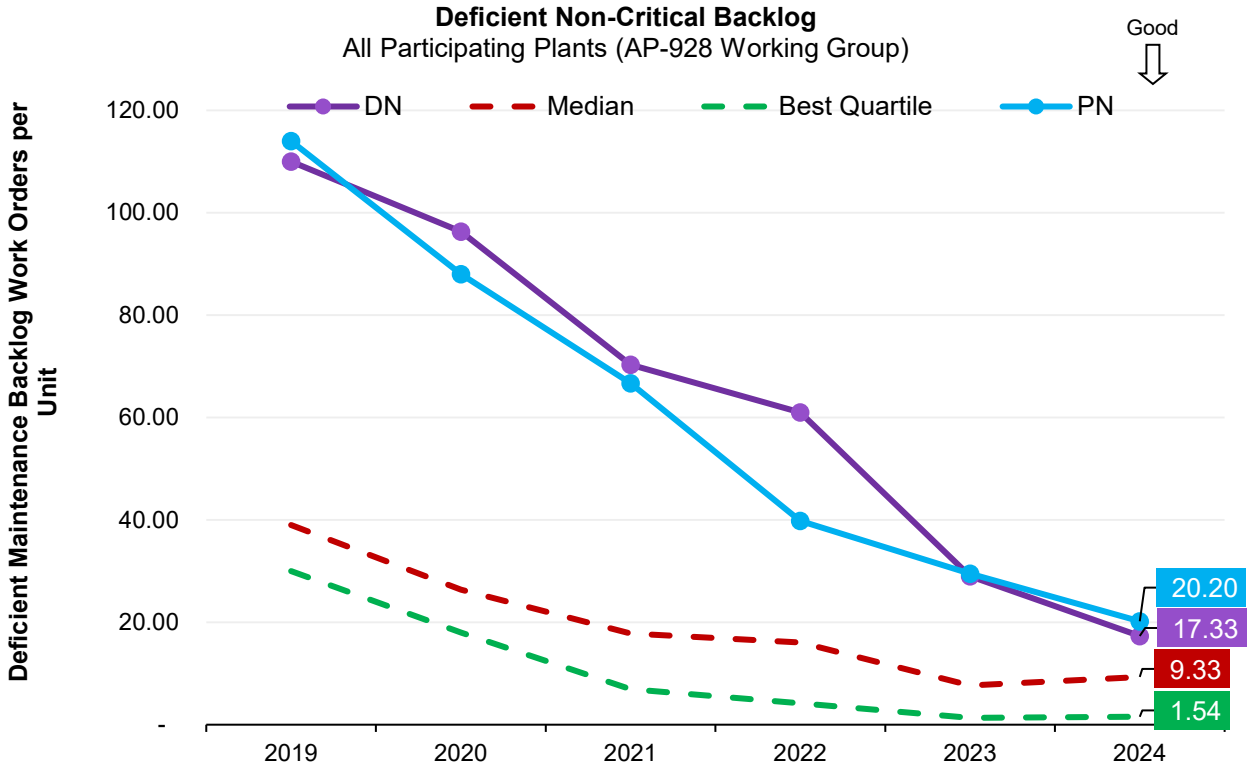
DNGS**:**

- Explore implementing film forming amine injection for corrosion product transport formation reduction.
- Explore further enhanced corrosion product transport removal processes via larger side stream filtration and/or condensate polisher.
- Improve integration into Outage meetings to optimize boiler chemistry (i.e. minimize duration where boilers are drained, improvements in Boiler Water Lancing activities etc.).
- Implemented a revised chemistry control strategy using continuous boiler blowdowns to manage secondary side chemistry control leading until Unit start-up to remove boiler ions.
- Revise the condenser tube leak response procedure and guidance to include previous operating experience and pre-decision-making logic during leak searching activities.
- Install permanent sodium hotwell analyzers for early detection of condenser tube leaks, to assist in isolating the correct Waterbox and minimize time out of specification.
- Improve reliability of condenser equipment including Condenser Tube Cleaning System (CTCS) through piping and valve replacements and increase inspections to assess condenser tube health to prevent and mitigation condenser tube leaks.

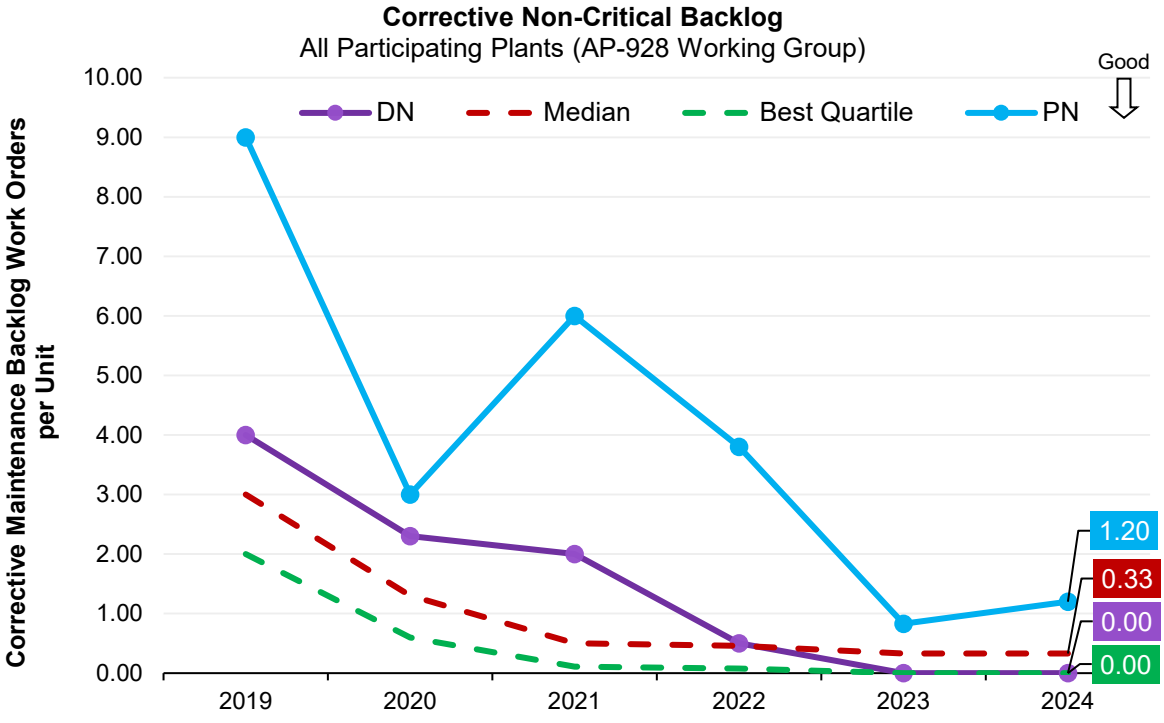
PNGS**:**

- Explore implementing film forming amine injection for corrosion product transport formation reduction.
- To improve boiler chemistry, a modification is planned during refurbishment to increase the continuous boiler blowdown capacity. This will help improve boiler ions upon unit start-up.
- Improve planning and execution of chemistry start-up activities through integration of Chemistry, Outage, and Operations.

On-Line Deficient & Corrective Non-Critical Backlog
On-Line Deficient & Corrective Critical Backlog



Note: Annual



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	Deficient Non-Critical Backlog	Deficient Critical Backlog	Deficient Maintenance Backlog	Corrective Non-Critical Backlog	Corrective Critical Backlog	Corrective Maintenance Backlog
DN	17.33	0.00	17.33	0.00	0.00	0.00
PN	20.20	0.60	20.80	1.20	0.00	1.20
Best Quartile	1.54	0.00	1.54	0.00	0.00	0.00
Median	9.33	0.00	9.33	0.33	0.00	0.33

Factors Contributing to Performance:

- DNGS and PNGS continue to achieve industry best quartile for Corrective Critical Backlog.
- DNGS continues to achieve industry best quartile for Deficient Critical Backlog.
- PNGS performance improved for Deficient Critical Backlog.
- Both sites experienced performance improvement for Deficient Non-Critical Backlog, PNGS 32%, and DNGS 40% compared to 2023.

- Factors contributing to performance:
  - Continued focus on reducing backlog using Fix It Now (FIN) and Work Management (WM) processes.
  - Actions completed to make FIN process sustainable for Live Zero backlog, including enhancements for long-lead parts and grace periods.
  - Weekly cross-functional meetings to review all current backlog work orders and ensure proper coding quality.
  - Initiated cross-functional Backlog Recovery Teams.
  - Oversight of Refurbishment and Safe Storage activities requires strengthening to reduce online backlog impacts
  - Not all station backlog targets were set to Industry Top Quartile for 2024.

Initiatives to Improve and Sustain Favorable Performance Include:

- Continued review of opportunities to execute online work during unit shutdowns and specific unit configurations.
- Improved oversight and support for Safe Storage activities that impact online Backlogs and Refurbishment Backlogs to ensure targets are met.
  - DNGS and PNGS FIN Managers coordinate with the Refurbishment Maintenance and Work Management teams to ensure targets are met during the transfer of Backlog work orders into/out of Refurbishment and Online.

- Improved oversight at New Work Screening to ensure proper coding of work orders.
- Monitor and track actions as well as metrics via weekly Integrated Station Briefing meetings (DNGS), monthly Senior Work Management meetings, and monthly Station Management meetings.

Note: Factors Contributing to Performance and Initiatives to Improve and Sustain Favorable Performance are relevant to all backlogs.

Methodology and Sources of Data

The Electric Utility Cost Group (EUCG) database is the source for cost benchmarking data. Data was collected for three-year rolling averages for all financial metrics. All data submitted to and subsequently extracted from EUCG by OPG is presented in Canadian dollars.

EUCG automatically applies a purchasing power parity (PPP) in an effort to adjust all values across national borders. The primary function of the PPP value is attempting to adjust for currency exchange rate fluctuations, but also attempting to adjusts for additional cross-border factors, which may impact purchasing power of companies in different jurisdictions. As a result, cost variations between plants are limited, as much as possible, to real differences and not due to advantages of utilizing one currency over another.

The benchmarking panel utilized for value for money metrics is made up of all North American (U.S. & Canada) plants reporting to EUCG. Bruce Power is the only other CANDU technology plant reporting within that panel. The remaining plants are Boiling Water Reactors or Pressurized Water Reactors making it challenging to compare performance across plants with technology differences. As a result, beginning with 2017 results, both PNGS and DNGS TGC/MWh and TGC/Unit performance has been normalized for CANDU technology (including outage duration) and age-related impacts.

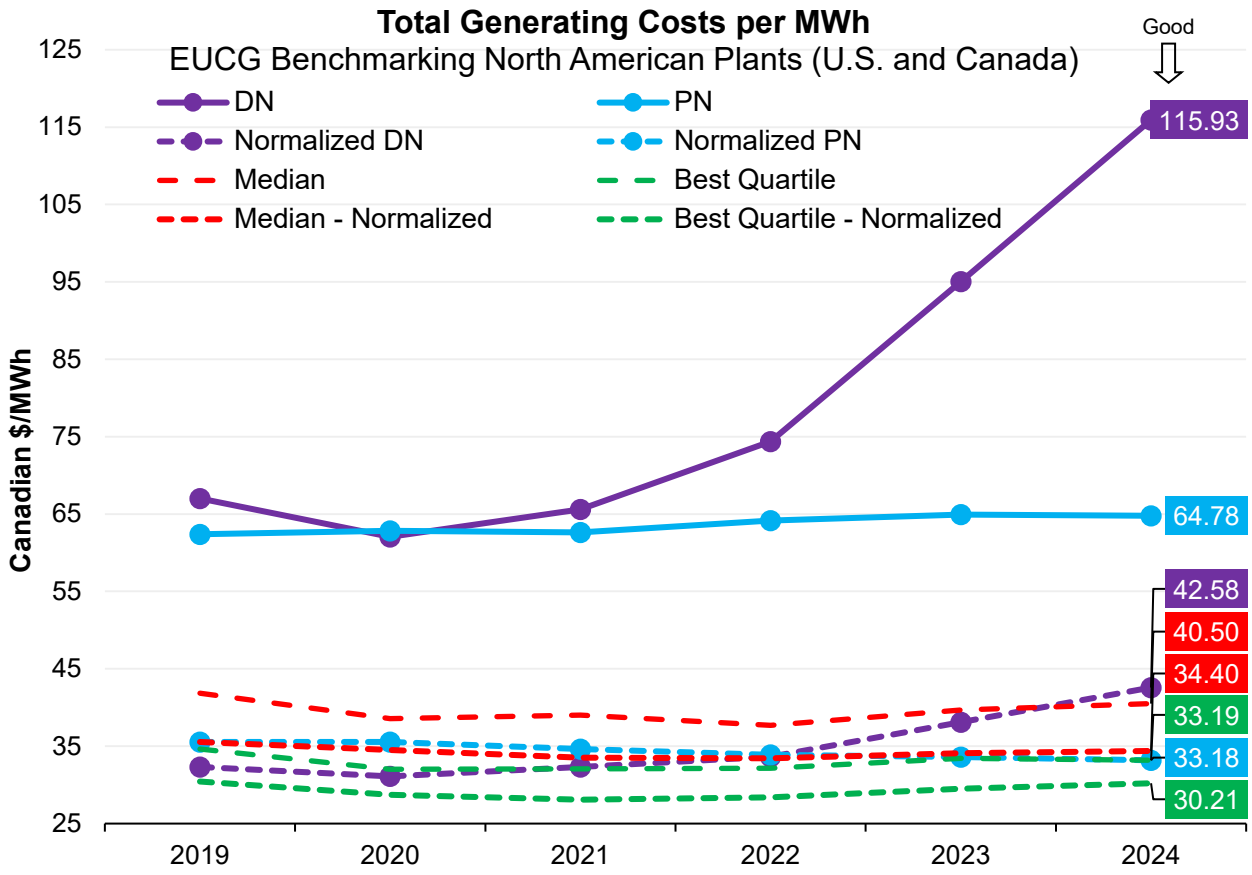
Darlington's TGC/MWh, TGC/Unit, Non-Fuel Operating Costs (NFOC)/MWh and Capital Cost/MW DER performance have also been normalized for refurbishment. The refurbishment normalization methodology allows OPG to adjust the distribution of actual operating and capital costs to reflect Darlington's number of operating units rather than a four-unit site. OPG is performing a mid-life refurbishment at Darlington, which involves bringing units offline for the replacement of certain life-limiting components. It is necessary to normalize these metrics during refurbishment to allow for comparisons to prior site performance and industry peers, given reduced generation and no corresponding decline in fixed costs.

OPG engaged ScottMadden Management Consultants (ScottMadden) to develop the normalization methodologies[3]. The combined normalization allows for a more comparable assessment of performance between peers.

Total Generating Cost per MWh is the sum of Non-Fuel Operating Cost (NFOC), Fuel Cost and Capital Cost measured on a per MWh basis for benchmarking purposes.
Given the differences between OPG's nuclear generating stations and most North American plants with respect to non-fuel operating costs, fuel and capital costs, it is difficult to compare plants using non-fuel operating cost, fuel cost or capital cost metrics separately.

[3] Two ScottMadden normalization reports provide details on the normalization methodologies: 1) *OPG Nuclear Cost Performance Benchmarking A Study of Factors Impacting TGC/MWh Performance with Normalizing Adjustments to Facilitate Closer Comparison* and 2) *OPG Nuclear Cost Performance Benchmarking Methodology to Adjust for Refurbishment and Validation of Implementation*

3-Year Total Generating Cost (TGC) per MWh



+ DNGS – Unit 2 RTS Q2 2020, Unit 3 RTS Q3 2023, Unit 1 RTS Q4 2024. (U4 in Refurbishment)
** Utilizing the updated technology, age-related and outage duration normalization methodology from ScottMadden*

	2024 Non-Normalized Value	2024 Normalized Value
DN	115.93	42.58
PN	64.78	33.18
Best Quartile	33.19	30.21
Median	40.50	34.40

Factors Contributing to Performance

- DNGS normalized performance declined in 2024 compared to 2023 due to reduced 3-year generation related to the Refurbishment outage schedule with the equivalent of two units being in refurbishment outages the full year in 2024 (Unit 4 full year, Unit 1 offline until Q4 2024) compared to one unit in 2021 (Unit 3 offline full year), increasing spending on sustaining investments to ensure long term reliability, and higher OM&A costs in 2024 from increased unionized compensation as a result of the Ontario Superior court decision finding unconstitutional provincial legislation that set limits on compensation increases for employees in the Ontario public sector in which the maximum annual increase in both wages and total compensation to one percent for a three-year period (Bill 124 Court Decision), partially offset by lower fuel & OM&A costs due to refurbishment schedule.

- DNGS non-normalized performance declined in 2024 compared to 2023 due to reduced 3-year generation related to the Refurbishment outage schedule (as per above), higher OM&A costs in 2024 from increased unionized compensation as a result of the Bill 124 court ruling (as per above), and increased capital investment requirements for life post-refurbishment, partially offset by lower fuel costs due to refurbishment schedule.

- PNGS normalized and non-normalized 2024 performance is similar to 2023, reflecting reduced capital spending while maintaining reliable operations in the period leading up to the Refurbishment of Units 5-8 in 2026, partially offset by higher OM&A costs from increased unionized compensation as a result of the Bill 124 court ruling (as per above).

- PNGS units are the smallest in the peer group at 540 MW/unit compared to the peer average of 1,026 MW, a factor for which results have not been normalized.

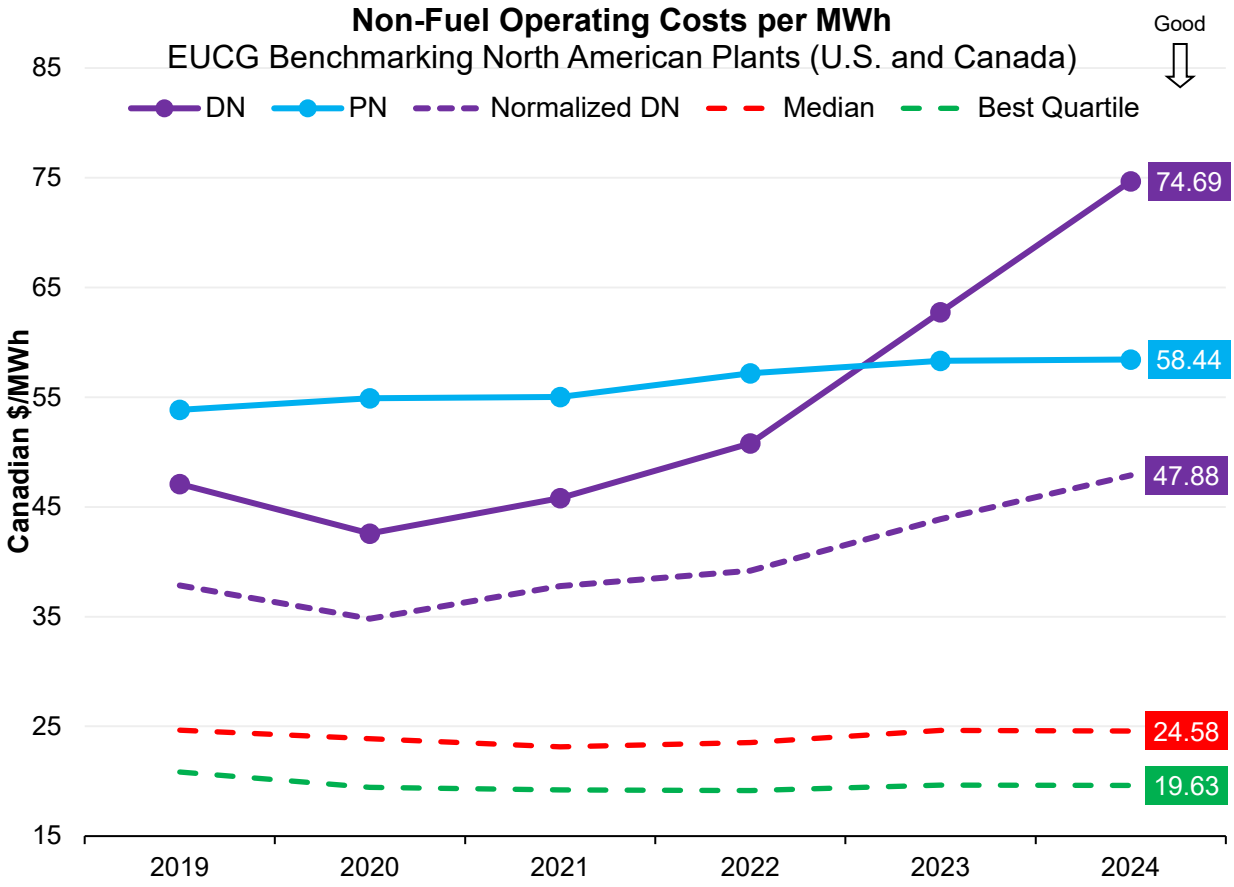
Initiatives to Improve and Sustain Favourable Performance Include:

- Maximizing generation: See initiatives to improve and sustain favourable performance for Reliability Metrics UCF and FLR.

- Continue to utilize opportunities to reduce operating costs through strategic initiatives, excellence plans, technology deployment and resource planning.

- Employing a portfolio and asset management approach to assess, prioritize and deliver all nuclear operations projects which are developed to meet regulatory commitments (e.g., from the Canadian Nuclear Safety Commission), increase system or unit reliability, address system obsolescence, or optimize station generation.

3-Year Non-Fuel Operating Cost per MWh



+ DNGS – Unit 2 RTS Q2 2020, Unit 3 RTS Q3 2023, Unit 1 RTS Q4 2024. (U4 in Refurbishment)

	2024 Non-Normalized Value	2024 Normalized Value
DN	74.69	47.88
PN	58.44	-
Best Quartile	19.63	19.63
Median	24.58	24.58

Factors Contributing to Performance

- DNGS normalized performance declined in 2024 compared to 2023 due to reduced 3-year generation related to the Refurbishment outage schedule with the equivalent of two units being in refurbishment outages the full year in 2024 (Unit 4 full year, Unit 1 offline until Q4 2024) compared to one unit in 2021 (Unit 3 offline full year), higher OM&A costs in 2024 from increased unionized compensation as a result of the Ontario Superior court decision finding unconstitutional provincial legislation that set limits on compensation increases for employees in the Ontario public sector in which the maximum annual increase in both wages and total compensation to one percent for a three-year period (Bill 124 Court Decision).

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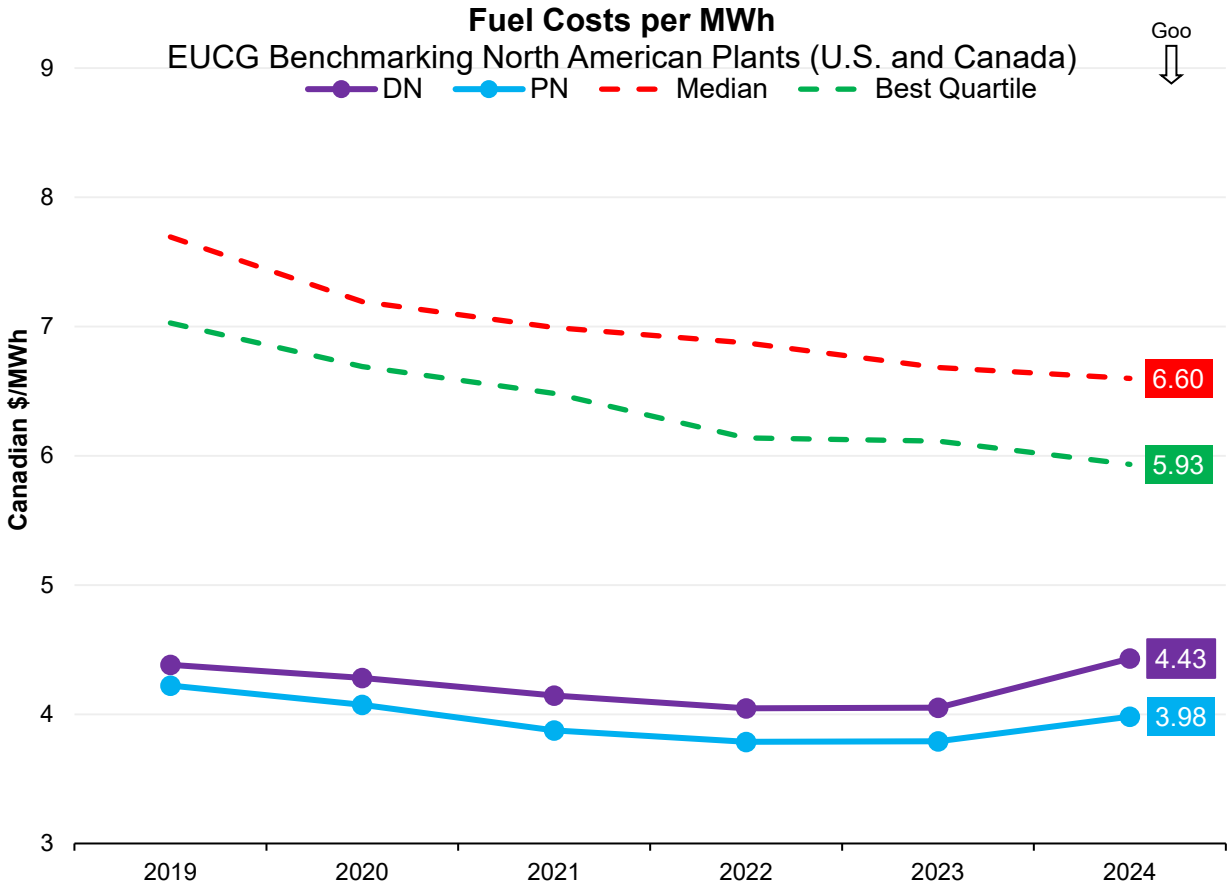
- PNGS non-normalized performance reflects higher OM&A costs in 2024 from increased unionized compensation as a result of the Bill 124 court ruling (as per above).

- PNGS units are the smallest in the peer group at 540 MW/unit compared to the peer average of 1,026 MW, a factor for which results have not been normalized.

Initiatives to Improve and Sustain Favourable Performance – refer to TGC/MWh.

3-Year Fuel Cost per MWh



+ DNGS – Unit 2 RTS Q2 2020, Unit 3 RTS Q3 2023, Unit 1 RTS Q4 2024. (U4 in Refurbishment)

	2024 Value
DN	4.43
PN	3.98
Best Quartile	5.93
Median	6.60

Factors Contributing to Performance

- Fuel costs are lower for OPG than most North American Pressurized Water Reactors or Boiling Water Reactors (PWR/BWR) reactors as CANDUs do not require enriched uranium like PWRs and BWRs.
  - Raw uranium is processed directly into uranium dioxide to make fuel pellets, without the additional cost and process complexity of enriching the fuel as required in light water reactors.
  - CANDU reactors are also the most efficient reactors in using uranium, requiring less uranium than PWRs and BWRs for each megawatt hour of electricity.
  - These two factors provide a significant advantage for OPG and other CANDUs in this cost category.

- Regular entry into the uranium market has allowed OPG to reduce uranium input costs year over year for the past several years. Historical multi-year contracts signed between 2015 and 2021, and for which deliveries were made in 2022, 2023 and 2024, have allowed OPG to take deliveries of uranium on both fixed price and market price basis during a period of historically low uranium spot market prices (2015-2021) not seen since 2005 and earlier.

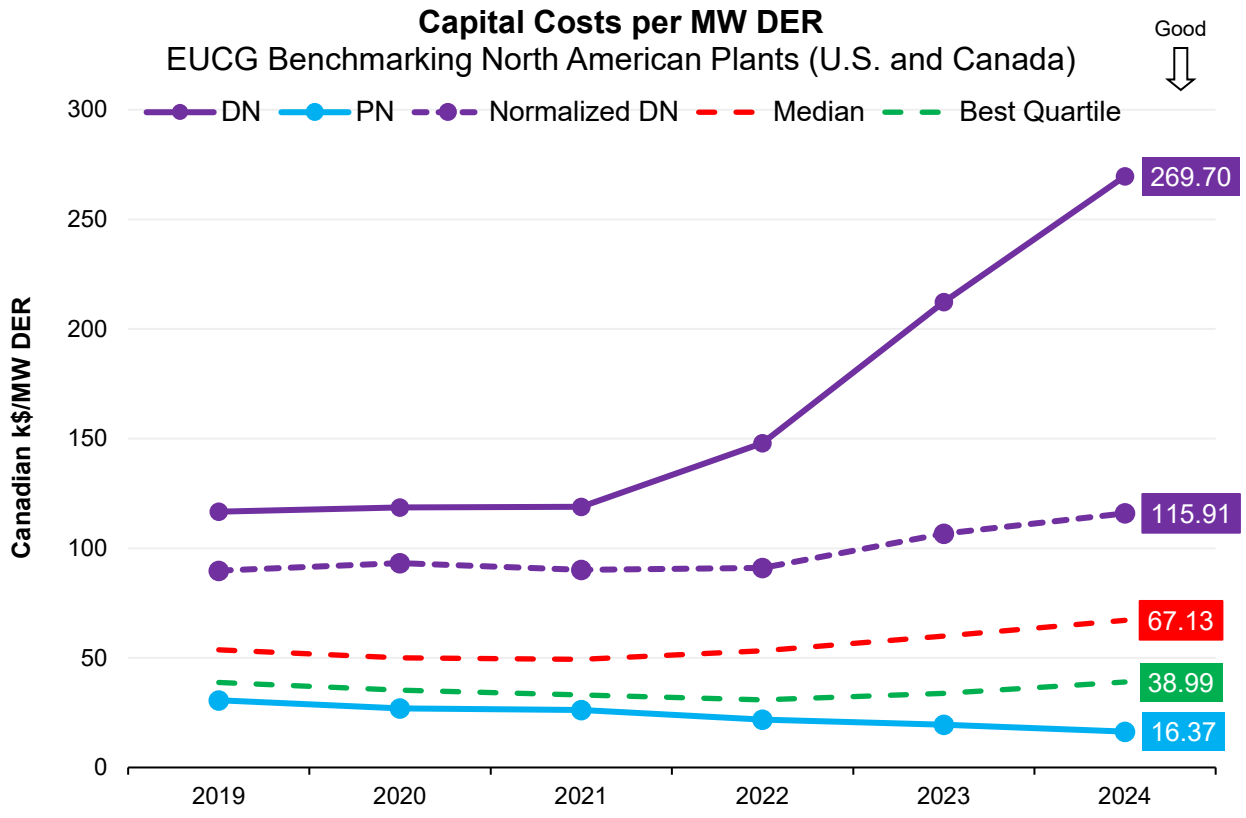
- In 2017, the uranium spot market price reached its cyclical low point and has continued an increasing trend up to the present, and this trend is projected to continue. Over the coming years, as historical uranium contracts are completed and new contracts are entered into, the effect of the more recent increasing uranium price trend is expected to place upward pressure on the 3-year rolling average fuel cost per MWh. The increase in fuel costs at PNGS and DNGS from 2023 to 2024 can be attributed to this uranium price trend and by general escalation in fuel conversion and fuel fabrication costs.

Initiatives to Improve and Sustain Favourable Performance

- Certain factors are expected to place upward cost pressures on nuclear fuel supply chains over the next several years, including:
  - Resurgence in global demand for nuclear power due to carbon emissions targets of world governments, leading to increased global demand for uranium, conversion, and enrichment services.
  - Uranium supply constrained by many years of under-investment in new mine development due to low prices, as well as constrained Western conversion and enrichment capacities.
  - Global conflicts, including the war in Ukraine, leading to a bifurcation of global nuclear fuel supply chains, along with legislative actions such as the recent U.S. ban on the import of Russian nuclear fuel products.

- OPG will continue to seek improvements in contract pricing for its nuclear fuel supply to sustain favourable comparative fuel costs, while also ensuring a resilient and robust nuclear fuel supply chain, given recent and ongoing geopolitical and economic events

3-Year Capital Cost per MW DER (Design Electrical Rating)



+ DNGS – Unit 2 RTS Q2 2020, Unit 3 RTS Q3 2023, Unit 1 RTS Q4 2024. (U4 in Refurbishment)

	2024 Non-Normalized Value	2024 Normalized Value
DN	269.70	115.91
PN	16.37	-
Best Quartile	38.99	38.99
Median	67.13	67.13

Factors Contributing to Performance:

- DNGS performance in 2024 remained the same on a normalized basis compared to 2023, as the station remained in the third quartile. The large increase in the absolute DNGS Capital Cost per MW in 2024 is mainly due to the reduction in available MW as units were in refurbishment outages throughout the majority of the 3-year period as well as increased spending on sustaining investments to ensure long term reliability. The changes over the trend period reflects increased spending, steam generator replacements, sustaining investments, and infrastructure. The change over the trend period reflects increased spending on life extension, performance improvements, sustaining investments, information technology and capital spares to support operations before, during and after Darlington refurbishment.

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- Historically, DNGS capital expenditures were better than the industry median. Once the decision to refurbish Darlington and extend end of life was made, OPG began an extensive program to replace obsolete and/or life-expired plant equipment to support performance and reliability of Darlington's unit's post-refurbishment. Once these investments have been made, DNGS performance is expected to improve.

- PNGS is performing in the first quartile with a slight improvement in 2024 and improvement over the trend period. This reflects reductions in spending while maintaining reliable operations leading up to the end of commercial operations (Units 1 & 4) which is consistent with spending trends observed at other nuclear facilities approaching their end of commercial operations and a planned refurbishment of four generating units (Units 5-8). However, as with investments related to DNGS and its refurbishment, this trend is not expected to continue as planned investments in PNGS are expected to increase with the plant life extension.

Initiatives to Improve and Sustain Favourable Performance Include:

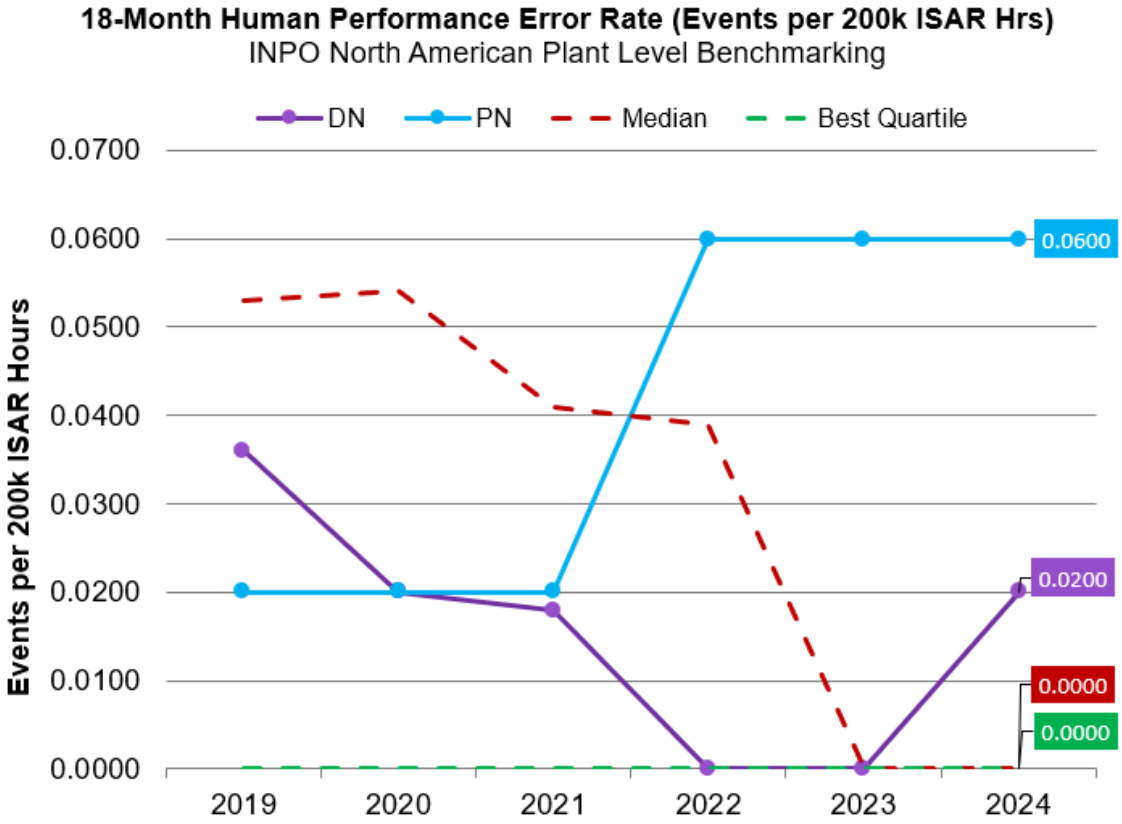
- OPG continues to prioritize an integrated portfolio and asset management approach to assess, prioritize, and deliver all nuclear operations projects which are developed to meet regulatory commitments (i.e. from the Canadian Nuclear Safety Commission), increase system or unit reliability, address system obsolescence, optimize station generation, focus on investments in life extension and critical system upgrades, and enhanced project delivery practices.

- Enhanced project management practices, combined with the adoption of digital technologies and continuous improvement efforts, enable OPG to deliver capital projects more efficiently.

Methodology and Sources of Data

The Human Performance Error Rate metric is used to benchmark the performance of OPG's Nuclear fleet against other INPO utilities in the area of Human Performance.

18-Month Human Performance Error Rate



	2024 Value
DN	0.0200
PN	0.0600
Best Quartile	0.0000
Median	0.0000

Factors Contributing to Performance:

- DNGS performance declined from best quartile in 2023 to third quartile in 2024 due to two Site Event Free Day Resets (S-EFDR) compared to zero in 2023. Event causes were identified, and corrective actions were implemented to address the gaps.
- PNGS experienced two Site Event Free Day Resets (S-EFDR) compared to one in 2023. Event causes were identified, and corrective actions were implemented to address the gaps.

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Initiatives to Improve and Sustain Favourable Performance Include:

- Use of Trend Vision to provide key insights and trends based on Station Condition Records (SCR) and Observation & Coaching (O&C) for stations.
- Continuing to build upon Fail Safe Strategies across the fleet through Pre-Job Briefs (PJB) and O&C programs.
- Renewed Trigger training licenses to end of 2026 for DNGS & PNGS
- PNGS continued to complete the "Coaching to Enhance Performance" training for Supervisors.
- Proactive strategies and actions taken around heightened periods of risk, such as Holiday and Outage planning, as well as more proactive activities including Safety Light and communications.
- Continued focus on the Stop When Unsure campaign as part of O&C improvement plan.
- TPI (Trending, Prevention, and Intervention) program to provide additional oversight on identified trends, with key actions put in place.
- Utilization of Validation of Trend (VOT) process to proactively identify and verify emerging trends adverse to safety and quality.
- Human performance is being further enhanced by continuing to build a positive stop culture that recognizes workers who stop work due to unknown or unexpected events.

Acronyms

Acronym	Meaning
ABF	Auxiliary Boiler Feed
ABFP	Auxiliary Boiler Feedwater Pump
AC	Alternating Current
ACU	Air Conditioning Units
ALARA	As Low as Reasonably Achievable
AMCA	Accumulator Control Module
ANDE	Advanced Non-Destructive Examination
BLC	Boiler Level Control
BLL	Boiler Low Level
BWR	Boiling Water Reactor
CANDU	CANada Deuterium Uranium (type of PHWR)
CC	Corrective Critical
CM	Corrective Maintenance
CN	Corrective Non-Critical
CNSC	Canadian Nuclear Safety Commission
CPI	Chemistry Performance Index
CRE	Collective Radiation Exposure
CTCS	Condenser Tube Cleaning System
D2O	Heavy Water
DC	Deficient Critical
DER	Design Electrical Rating
DM	Deficient Maintenance
DN	Deficient Non-Critical
DNGS	Darlington Nuclear Generating Station
EACP	Emergency AC Power
EC	Electricity Canada
ECI	Emergency Coolant Injection
ECR	Engineering Change Request
EPS	Emergency Power Supply
eSWP	Electronic Safe Work Plans
EUCG	Electric Utility Cost Group
FIN	Fix It Now
FLR	Forced Loss Rate
FME	Foreign Material Exclusion
FRI	Fuel Reliability Index
GWH	Gigawatt Hours
HIT	High Impact Team
HPER	Human Performance Error Rate

Acronym	Meaning
HPSI	High Pressure Safety Injection
HPU	Hydraulic Power Unit
HTHT	Heat Transport High Temperature
HTLF	Heat Transport Low Flow
HTS	Heat Transport System
HU	Human Performance
INPO	Institute of Nuclear Power Operators
ISAR	Industrial Safety Accident Rate
ISB	Integrated Station Brief
LBL	Low Boiler Level
MDS	Machine Delivered Scrape
MW	Mega-Watt
NFOC	Non-Fuel Operating Cost
NPI	Nuclear Performance Index
O&C	Observation & Coaching
OM&A	Operating, Maintenance & Administrative
OPEX	Operating Experience
OPG	Ontario Power Generation
PAWCS	Post-Accident Water Cooling System
PJB	Pre Job-Brief
PNGS	Pickering Nuclear Generating Station
PHTS	Primary Heat Transport System
PHWR	Pressurized Heavy Water Reactor
PM	Preventive Maintenance
PPP	Purchasing Power Parity
PRL	Plant Reliability List
PWR	Pressurized Water Reactor
QSP	Quality of Safety Practices
RDM	Rapid Delivery Machine
RTR	Reactor Trip Rate
RWPB	Retube Waste Processing Building
SATPS	Systematic Approach to Technical Problem Solving
SCL	Safety Classification and Learning
SDS	Shutdown System
SDSE	Shutdown System Enhancement
S-EFDR	Site event free day resets
SFCR	Single Fuel Channel Replacement
SG	Standby Generators
SPNMDI	System Does Not Meet Design Intent

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Acronym	Meaning
SIF	Serious Injuries and Fatalities
SIR	Significant Issue Response
SPOC	Single Point of Contact
TGC	Total Generating Costs
TGC/MWH	Total Generating Costs per Mega-Watt Hour
TISA	Total Industrial Safety Accident Rate
TPI	Trending, Prevention, and Intervention
TRF	Tritium Removal Facility
TRIF	Total Recordable Injury Frequency
UCF	Unit Capability Factor
UCR	Unit Capability Rate
VOT	Validation of Trend
VVRS	Vault Vapour Recovery System
WANO	World Association of Nuclear Operators
WM	Work Management
WPII	WANO Performance Indicator Index

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Safety and Reliability Definitions

The following definitions are summaries extracted from industry peer group databases.

Total Recordable Injury Frequency (TRIF)
The number of fatalities, lost time injuries, medical treatment injuries and restricted work injuries per 200,000 hours worked.

Total Industrial Safety Accident Rate (TISA)
This indicator is defined as the number of accidents for personnel at the station, including all utility personnel (permanent or temporary staff and except contractor personnel) assigned to the station, contractors, supplemental personnel and all other non-utility personnel working onsite that result in one or more days away from work (excluding the day of the accident) or one or more days or restricted work (excluding the day of the accident) or fatalities per 200,000 person-hours worked. TISA will combine site Industrial Safety Accident (ISA) rate and Contractor Safety Industrial Accident (CISA) rate.

Collective Radiation Exposure (CRE)
Total external and internal whole-body exposure determined by a dose control device (e.g., electronic personal dosimeter, dose recording device, etc.) and internal exposure calculations. All measured exposure should be reported for station personnel, contractors, and those personnel visiting the site or station on official utility business.
Visitors, for purposes of this indicator, include only those monitored visitors who are visiting the site or station on official utility business.

Airborne Tritium Emissions per Unit
Tritium emissions to air.

Fuel Reliability Index (FRI)
Inferred from fission product activities present in the reactor coolant. Due to design differences, this indicator is calculated differently for different reactor types. For PHWR's, the indicator is defined as the steady-state primary coolant iodine-131 activity (Becquerels/gram or Microcuries/gram), corrected for the tramp uranium contribution and power level, and normalized to a common purification rate.

Reactor Automatic & Manual Trip Rate
The number of unplanned automatic reactor trips (reactor protection system logic actuations) and unplanned manual trips that occur per 7,000 hours of critical operation. For the purposes of the WANO Performance Indicator Index, the indicator is calculated over a rolling two years, on a unit basis. It is noted that to attain the maximum allotted points towards the WANO Performance Indicator Index, the Reactor Trip indicator must be less than or equal to 0.5. The Reactor Automatic and Manual Trip indicator contributes a maximum of 15% towards the WANO Performance Indicator Index.

The indicator is further defined as follows:

- Unplanned means that the trip was not an anticipated part of a planned test.
- Trip means the automatic shutdown of the reactor by a rapid insertion of negative reactivity (e.g., by control rods, liquid injection shutdown system, etc.) that is caused

by actuation of the reactor protection system. The trip signal may have resulted from exceeding a set point or may have been spurious.

- Automatic means that the initial signal that caused actuation of the reactor protection system logic was provided from one of the sensors' monitoring plant parameters and conditions, rather than the manual trip switches or, in certain cases described in the clarifying notes, manual turbine trip switches (or pushbuttons) provided in the main control room.
- Critical means that, during the steady-state condition of the reactor prior to the trip, the effective multiplication factor (k_{eff}) was essentially equal to one.
- The value of 7,000 hours is representative of the critical hours of operation during a year for most plants and provides an indicator value that typically approximates the actual number of scrams occurring during the year.

Safety System Performance Indicators include the following:

- Auxiliary boiler feedwater system
- Emergency AC power
- High pressure emergency coolant injection system

These systems were selected for the safety system performance indicator based on their importance in preventing reactor core damage or extended plant outage. They include the principal systems needed for maintaining reactor coolant inventory following a loss of coolant, for decay heat removal following a reactor trip or loss of main feedwater, and for providing emergency AC power following a loss of plant off-site power. (Gas cooled reactors have an additional decay heat removal system instead of the coolant inventory maintenance system).

WANO Performance Indicator Index (WPII)

INPO sponsored performance measure and is a weighted composite of 10 WANO Performance Indicators related to safety and production performance reliability. Effective January 01, 2024, Method 10 is replacing the previous Method 4.

Forced Loss Rate (FLR)

Ratio of all unplanned forced energy losses during a given period of time to the reference energy generation minus energy generation losses corresponding to planned outages and any unplanned outage extensions of planned outages, during the same period, expressed as a percentage.

Unplanned Energy Losses

Either unplanned forced energy losses (unplanned energy generation losses not resulting from an outage extension) or unplanned outage extension of planned outage energy losses.

Unplanned Forced Energy Loss

Energy that was not produced because of unplanned shutdowns or unplanned load reductions due to causes under plant management control when the unit is considered to be at the disposal of the grid dispatcher. Causes of forced energy losses are considered to be unplanned if they are not scheduled at least four weeks in advance. Causes considered to be under plant management control are further defined in the clarifying notes.

Unplanned Outage Extension Energy Loss

Energy that was not produced because of an extension of a planned outage beyond the original planned end date due to originally scheduled work not being completed, or because newly scheduled work was added (planned and scheduled) to the outage less than four weeks before the scheduled end of the planned outage.

Planned Outage Energy Losses
Corresponding to outages or power reductions which were planned and scheduled at least four weeks in advance (see clarifying notes for exceptions).

Reference Energy Generation
Energy that could be produced if the unit were operated continuously at full power under reference ambient conditions throughout the given period. Reference ambient conditions are environmental conditions representative of the annual mean (or typical) ambient conditions for the unit.

Unit Capability Rate (UCR)
Ratio of the available energy generation over a given time period to the reference energy generation over the same time period but not counting planned energy losses in the denominator. UCR, like UCF, is expressed as a percentage. All energy generation terms are determined relative to reference ambient conditions.

Available Energy Generation
Energy that could have been produced under reference ambient conditions considering only limitations within control of plant management, i.e., plant equipment and personnel performance, and work control.

Reference Energy Generation
Energy that could be produced if the unit were operated continuously at full power under reference ambient conditions.

Reference Ambient Conditions
Environmental conditions representative of the annual mean (or typical) ambient conditions for the unit.

Unit Capability Factor (UCF)
Ratio of the available energy generation over a given time period to the reference energy generation over the same time period, expressed as a percentage. Both of these energy generation terms are determined relative to reference ambient conditions.

Chemistry Performance Indicator (CPI)
CPI compares the concentration of selected impurities and corrosion products to corresponding limiting values. Each parameter is divided by its limiting value, and the sum of these ratios is normalized to 1.0. If an impurity concentration is equal to or better than the limiting value, the limiting value is used as the concentration. This prevents increased concentrations of one parameter from being masked by better performance in another. As a result, if a plant is at or below the limiting value for all parameters, its indicator value would be 1.0, the lowest chemistry indicator value attainable under the indicator definition.

The following is used to determine each unit's chemistry indicator value for PHWRs:

- *Inconel-600 or Monel tubes
  - Steam generator blowdown chloride
  - Steam generator blowdown sulfate
  - Steam generator blowdown sodium
  - Final feedwater iron
  - Final feedwater copper
  - Final feedwater dissolved oxygen

- Incoloy-800 tubes
  - Steam generator blowdown chloride
  - Steam generator blowdown sulfate
  - Steam generator blowdown sodium
  - Final feedwater iron
  - Final feedwater dissolved oxygen

Online Deficient Maintenance (DM) Backlog
Average number of active on-line maintenance work orders per operating unit classified as Deficient Critical (DC) or Deficient Non-Critical (DN) that can be worked on without requiring the unit shutdown. This metric identifies deficiencies or degradation of plant equipment components that need to be remedied, but which do not represent a loss of functionality of the component or system.

Online Corrective Maintenance (CM) Backlog
Average number of active on-line maintenance work orders per operating unit classified as Corrective Critical (CC) or Corrective Non-Critical (CN) that can be worked on without requiring the unit shutdown. This metric identifies deficiencies or degradation of components that need to be remedied and represents a loss of functionality of a major component or system.

On-line Maintenance
Performed with the main generator connected to the grid.

Value for Money Definitions

The following definition summaries are taken from the January 2022 EUCG Nuclear Committee Data Definitions and Nuclear Integrated Information Database.

Capital Costs
All costs associated with improvements and modifications made during the reporting year. These costs should include design and installation costs in addition to equipment costs. Other miscellaneous capital additions such as facilities, computer equipment, moveable equipment, and vehicles should also be included. These costs should be fully burdened with indirect costs, but exclude AFUDC (interest and depreciation), spent fuel storage costs and/or reimbursements, capital write-off expenditures, taxes (except Payroll), and COVID response costs.

Nuclear Fuel Costs
Total cost associated with a load of fuel in the reactor which is burned up in a given year. Fuel burn costs should NOT include spent fuel storage costs or fuel impairment.

Fuel impairment is the write-down of the value of the Nuclear fuel and thus reduces the amortization or fuel expense, occurs in plants either announcing shutdown or are in a pending shutdown.

Net Generation
Gross electrical output of the unit measured at the output terminals of the turbine-generator minus the normal station service loads during the hours of the reporting period, expressed in Gigawatt hours (GWh).

Design Electrical Rating (DER)
Nominal net electrical output of a unit specified by the utility and used for plant design (DER net expressed in MWe). Design Electrical Rating should be the value that the unit was certified/designed to produce when constructed. The value would change if a power uprate was completed. After a power uprate, the value should be the certified or design value resulting from the uprate.

Operating Costs (Non-Fuel Operating Costs - NFOC)
All costs associated with normal operations, maintenance, and outage periods that occur within the current EUCG data reporting year. These costs should be fully burdened and reflect the total operating costs for labour, materials & equipment, outside services and other costs, but exclude depreciation, interest, taxes (except Payroll), COVID response costs, spent fuel storage costs and/or reimbursements, capital write-off expenditures, and new plant expenditures

New Plant Expenditures
All costs for supporting new nuclear generation and licensing efforts

Total Generating Costs (TGC)
Sum of operating costs, fuel costs and capital costs

Total Generating Costs (TGC) per MWh
Sum of operating costs, fuel costs and capital costs divided by Net Generation

Total Generating Costs (TGC) per Unit
Sum of operating costs, fuel costs and capital costs divided by Number of Units at Station

Non-Fuel Operating Costs (NFOC) per MWh
Operating costs divided by Net Generation

Fuel Costs per MWh
Nuclear Fuel costs divided by Net Generation

Capital Cost per MW DER
Capital costs divided by Design Electrical Rating (DER)

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Human Performance Definitions

The following definition summary is taken from the Institute of Nuclear Power Operations (INPO) database.

Human Performance Error Rate (HPER)
Represents the number of site level human performance events in an 18-month period per 200,000 Industrial Safety Accident Rate (ISAR) hours worked (including on site supplemental personnel).

Formula = {(# of S-EFDRs) / (Total ISAR Hours + Total Contractor Hours)} x 200,000 Hours *(Calculated as an 18-month rolling average)*

Non-utility Personnel
Includes contractors, supplemental personnel assigned to perform work activities on site or at other buildings that directly support station operation. This includes personnel who deliver and receive equipment, deliver fuel oil, remove trash and radioactive waste, and provide building and grounds maintenance within the owner-controlled areas or facilities that support the station.

Event
An initiating action (error) by an individual or group of individuals (event resulting from an active error) or an initiating action (not an error) by an individual or group of individuals during an activity conducted as planned (event resulting from a flawed defense or latent organizational weakness). They may be related to Nuclear Safety, Radiological Safety, Industrial Safety, Facility Operations or considered to be a Regulatory Event reportable to a regulator or governing agency. OPG Nuclear's criteria for defining station event free day resets have been developed based on INPO guidelines.

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Industry Peer Groups

All data provided by the peer groups (WANO, INPO, EC, and EUCG) is confidential. A redacted version of this report, which removes individual plant and unit names, is available from Nuclear Business Planning and Benchmarking should there be a requirement to publicly release this report.

Table 2: Industry Peer Groups

	Conexus Nuclear Inc. CANDU (WANO)	All North American PWR and PHWRs	INPO AP-928 Workgroup	INPO	EC	EUCG North American Plants (US and Canada)
Safety						
Total Recordable Injury Frequency					X	
Rolling Average Total Industrial Safety Accident Rate*+x		X				
Rolling Average Collective Radiation Exposure*+x	X					
Airborne Tritium Emissions	X					
Fuel Reliability Index*x	X					
2-Year Reactor Trip Rate*x	X					
3-Year Auxiliary Feedwater System Unavailability*x	X					
3-Year Emergency AC Power Unavailability*x	X					
3-Year High Pressure Safety Injection Unavailability*x	X					
Reliability						
Rolling Average WANO WPII *x	X					
Rolling Average Forced Loss Rate*+x	X					
Rolling Average Unit Capability Rate*+x	X					
Rolling Average Unit Capability Factor*+x	X					
Rolling Average Chemistry Performance Indicator*+x	X					
1-Year On-line Deficient Maintenance Backlogx			X			
1-Year On-line Deficient Critical Backlogx			X			
1-Year On-line Corrective Maintenance Backlogx			X			
1-Year On-line Corrective Critical Backlogx			X			
Value for Money						
3-Year Total Generating Costs / MWh						X
3-Year Non-Fuel Operating Costs (OM&A) / MWh						X
3-Year Fuel Costs / MWh						X
3-Year Capital Costs / MW DER						X
Human Performance						
18-Month Human Performance Error Ratex				X		

** Sub-indicator of WANO WPII*

+ Rolling 2 Year Average PNGS ; Rolling 3 Year Average DNGS

x Metric data is available in the INPO PIC/IRIS software systems.

Safety and Reliability Peer Groups

Primary source of benchmarking data for operational performance (Safety and Reliability) indicators is the World Association of Nuclear Operators (WANO). Eleven out of the twenty benchmarking metrics have been compared to the Conexus Nuclear Inc. CANDU (WANO) panel. Industrial Safety Accident Rate (ISAR) is compared to the All North American PWR and PHWR (WANO) panel.

All WANO performance indicators are presented at the unit and plant levels except the Industrial Safety Accident Rate (ISAR) and Emergency AC Power Unavailability which are only measured at the plant level.

Different peer groups were used for 5 specialized operating metrics which are not tracked through WANO:

- *Total Recordable Injury Frequency*: Electricity Canada panel was utilized. OPG benchmarks against EC Group 1 peers (a subset of all EC members), which incorporates organizations with more that 1,500 employees, including most provincial utilities.

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- *On-line Deficient Maintenance Backlog, On-line Deficient Critical Backlog, On-line Corrective Maintenance Backlog, On-line Corrective Critical Backlog:* Institute of Nuclear Power Operations (INPO) AP-928 working group was utilized.

Value for Money Peer Group

For financial performance comparisons, data compiled by the Electric Utility Cost Group (EUCG) was utilized. EUCG is a nuclear industry operating group and the recognized source for cost benchmark information. EUCG cost indicators are presented at the plant level and compared on a net megawatt hour generated basis and on a per megawatt (MW) design electrical rating (DER) basis. The only CANDU operators reporting data to EUCG were OPG and Bruce Power which is not a sufficiently large panel to provide a basis for comparison; hence, the data sets were not limited to a CANDU specific panel. Should more CANDU operators choose to join EUCG in the future, comparisons to a CANDU specific panel will be reconsidered.

Human Performance Peer Group

For human performance comparisons, data was obtained from INPO.

Panels/Members

Table 3: WANO Panel

Operator	Plant
Ameren Missouri	Callaway
Arizona Public Service Co.	Palo Verde
Bruce Power	Bruce A Bruce B
Dominion Energy	Millstone North Anna Surry V.C. Summer
Duke Energy	Catawba Harris Mcguire Oconee Robinson
Entergy Nuclear	Waterford ANO
Constellation Energy	Braidwood Byron Calvert Cliffs R.E. Ginna
American Electric Power Co.	Cook
International CANDU	Cernavoda Embalse Qinshan 3 Wolsong A Wolsong B

Operator	Plant
New Brunswick Power	Point Lepreau
NextEra Energy Inc	Point Beach Seabrook St Lucie Turkey Point
Ontario Power Generation	Darlington Pickering
Pacific Gas & Electric Co.	Diablo Canyon
Public Service Enterprise Group Nuclear	Salem
Southern Nuclear Operating Co.	Farley Vogtle
STP Nuclear Operating Co.	South Texas
Tennessee Valley Authority	Sequoyah Watts Bar
Vistra Corp	Beaver Valley Comanche Peak Davis-Besse
Wolf Creek Generating Station	Wolf Creek
Xcel Energy Inc	Prairie Island

Table 4: EUCG Panel

Operator	Plant
AmerenUE	Callaway
American Electric Power Co. Inc.	Cook
Arizona Public Service Co.	Palo Verde
Bruce Power	Bruce
Dominion Generation	Millstone North Anna Surry V.C. Summer
DTE Energy	Fermi
Duke Energy	Brunswick Catawba Harris Mcguire Oconee Robinson
Energy Northwest	Columbia
Entergy Nuclear	Arkansas Nuclear One Grand Gulf River Bend Waterford
Constellation Energy	Braidwood Byron Calvert Cliffs Clinton Dresden Fitzpatrick Lasalle Limerick Nine Mile Peach Bottom Quad Cities R.E. Ginna
FirstEnergy Nuclear Operating Co.	Beaver Valley Davis-Besse Perry
Florida Power & Light Co.	St Lucie Turkey Point
Luminant Generation	Comanche Peak
Nebraska Public Power District	Cooper
NextEra Energy Resources	Point Beach Seabrook
Northern States Power Company	Monticello Prairie Island
Ontario Power Generation	Darlington Pickering
Pacific Gas & Co.	Diablo Canyon
Public Service Enterprise Group Nuclear	Hope Creek Salem
Southern Nuclear Operating Co.	Farley Hatch Vogtle
STP Nuclear Operating Co.	South Texas
Talen Energy	Susquehanna
Tennessee Valley Authority	Browns Ferry Sequoyah Watts Bar
Wolf Creek Nuclear Operations Corp.	Wolf Creek

Table 5: Conexus Nuclear Inc. CANDU (WANO)

Operator	Plant
Bruce Power	Bruce A Bruce B
China (CNNO)	Qinshan 3
NASA	Embalse
Korea (KHNP)	Wolsong A Wolsong B
New Brunswick Power	Point Lepreau
OPG	Darlington Pickering
Romania	Cernavoda

Table 6: Electricity Canada Members

Companies
Alectra Inc.
AltaLink
ATCO Electric (Alberta Power Ltd.)
BC Hydro
Bluewater Power Distribution Corporation
Canadian Power Holdings
Capital Power
City of Medicine Hat
City of Red Deer
Clearlight Energy
Elexicon
ENMAX Corporation
EPCOR Utilities Inc.
Evolugen
FortisAlberta Inc.
FortisBC Inc.
FortisOntario
Hydro One Inc.
Hydro Ottawa
Hydro-Québec
IESO
Invenergy

Companies
London Hydro
Manitoba Hydro
Maritime Electric
New Brunswick Power
Newfoundland and Labrador Hydro
Newfoundland Power Inc.
Northwest Territories Power Corporation
Nova Scotia Power/Emera
Oakville Enterprises Corporation
Ontario Power Generation
Qulliq Energy Corporation
Rio Tinto
Saint John Energy
Saskatoon Light & Power
SaskPower
TC Energy
Toronto Hydro Corporation
TransAlta Corporation
Utilities Kingston
Wataynikaneyap Power
Yukon Energy Corporation

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Table 7: INPO Members for On-Line Maintenance Backlogs

Plant	
Arkansas Nuclear One (ANO)	McGuire
Barakah	Millstone
Beaver Valley	Monticello
Braidwood	Nine Mile Point
Browns Ferry	North Anna
Bruce	Oconee
Brunswick	Oyster Creek
Byron	Palo Verde
Callaway	Peach Bottom
Calvert Cliffs	Perry
Catawba	Pickering
Clinton	Pilgrim
Columbia Gen	Point Beach
Comanche Peak	Point Lepreau
Cook	Prairie Island
Cooper	Quad Cities
Darlington	River Bend
Davis-Besse	Robinson
Diablo Canyon	Salem
Dresden	Seabrook
Duane Arnold	Sequoyah
Farley	South Texas
Fermi 2	St. Lucie
Fitzpatrick	Summer
Ginna	Surry
Grand Gulf	Susquehanna
Harris	Turkey Point
Hatch	Vogtle
Hope Creek	Waterford
Koeberg	Watts Bar
LaSalle	Wolf Creek
Limerick	

Table 8: INPO Members for Human Performance Error Rate

Plant	
Arkansas Nuclear One (ANO)	McGuire
Barakah	Millstone
Beaver Valley	Monticello
Braidwood	Nine Mile Point
Browns Ferry	North Anna
Bruce	Oconee
Brunswick	Oyster Creek
Byron	Palo Verde
Callaway	Peach Bottom
Calvert Cliffs	Perry
Catawba	Pickering
Clinton	Pilgrim
Columbia Gen	Point Beach
Comanche Peak	Point Lepreau
Cook	Prairie Island
Cooper	Quad Cities
Darlington	River Bend
Davis-Besse	Robinson
Diablo Canyon	Salem
Dresden	Seabrook
Duane Arnold	Sequoyah
Farley	South Texas
Fermi 2	St. Lucie
Fitzpatrick	Summer
Ginna	Surry
Grand Gulf	Susquehanna
Harris	Turkey Point
Hatch	Vogtle
Hope Creek	Waterford
Koeberg	Watts Bar
LaSalle	Wolf Creek
Limerick	

CCC Interrogatory #072

Interrogatory

Reference:
Exhibit F2, Tab 1, Schedule 1, Attachment 4
EB-2020-0290, Exhibit F2, Tab 1, Schedule 1, Attachment 5

Question(s):

a) Please provide the number of OPG purchased services-related FTEs that were excluded from the study.

b) Please further explain why a comparison of Purchased Service-related FTEs between OPG and the peer group was possible in the previous study (2020) and is no longer possible.

c) Please advise whether IT-related FTEs are included in the current study.

d) Please provide the detailed calculations, and explanations, with respect to the "work week" normalization and the "reactor count" normalization in the current study. Please explain any differences in the methodology applied in the current study relative to the previous study.

e) Please further explain Appendix C in the current study. More specifically, please explain how the FTE ratio was determined.

f) Please explain the main drivers for the difference between the current benchmarked OPG FTEs (4,458) and the previous benchmarked OPG FTEs (5,016).

g) Please explain the main drivers for the difference between the current benchmarked peer FTEs (4,913) and the previous benchmarked peer FTEs (5,255).

Response

a) Refer to Ex. L-F2-Staff-180.

b) Refer to Ex. L-F2-SEC-165, part b).

c) Refer to Ex. L-F2-Staff-191, part a) i).

The following responses (d-f) were prepared by Indeavor:

d) **Work Week:** OPG's 35-hour work week was normalized against the US 40-hour standard. Functions involving administrative/professional staff received the adjustment; maintenance trades and operations shift staff (where staffing is driven by coverage requirements) did not. This is the same treatment as all prior studies.

Reactor Count: 2-unit benchmark scaled to 4-unit using 1.8x (most functions), 2.0x (Operations and related), "Ratio" (Admin and related). Pickering A stays at 2-unit with an additional 16 FTE for cross-tied systems. The “Ratio” was utilized in the previous studies and represents proportional scaling factor used to size and allocate support functions (such as Admin and Accounting) based on the total staff they support; as site staffing rises or falls, these support roles adjust accordingly.

Differences from prior study: None. All normalization factors carried forward identically. The only thing that changes the output is the different 2-unit PWR baseline (different peer data).

Refer to Attachment 1 for the detailed scaling amounts for “work week” and “reactor count” by function.

e) The Appendix C ratios convert EUCG Account Level data to Indeavor Functions. The FTE Ratio was needed because five of eight sites provided data at the EUCG level. The FTE ratios (e.g., EUCG "Engineering" split into Design/Drafting 0.03, Eng-Computer 0.09, Eng-Mods 0.31, Eng-Plant 0.39, Eng-Reactor 0.09, Eng-Technical 0.10) were derived from historical Goodnight data that was shared with Indeavor before the database closed. These FTE ratios were applied to the peer groups' EUCG level data in order to map to the Indeavor Functions. The functional definitions have not changed.

f) Chart 1 provides a breakdown of OPG’s current and previously benchmarked FTEs. The chart below includes external purchased services (“PS”) as identified in column (b) which were excluded from the current staff benchmarking study, as discussed in Ex. L-F2-Staff-180. Inclusion of these FTEs enables a more appropriate comparison to the prior study amount of 5,016 FTEs, which included external purchased services as identified in column (d). For clarity, the decreases shown in the Chart include the effects of the permanent shutdown of Pickering Units 1 and 4 in 2024.

Chart 1: OPG Benchmarked FTEs – 2024 Benchmarked OPG FTEs vs 2019 Benchmarked OPG FTEs

Process Area Summary	2024 Total OPG Benchmarked FTEs (a)	2024 External PS (not included in Study) (b)	2024 Total OPG FTEs (including excluded PS) (c)	2019 Total OPG Benchmarked FTEs (d)	Var FTEs (c)-(d)	% Change
Administrative Services	92	-	92	105	(13)	-12%
Configuration Management	207	13	220	205	15	8%
Equipment Reliability	390	27	417	461	(44)	-10%
Loss Prevention	168	42	210	176	34	20%
Operate The Plant	840	11	851	1,031	(180)	-17%
Personnel Services	654	22	676	685	(9)	-1%
Plant Maintenance	1,283	167	1,450	1,470	(20)	-1%
Radiation Protection	150	2	152	158	(6)	-4%
Supply Chain	183	2	185	186	(1)	0%
Work Management	373	22	395	392	3	1%
Below the Line[1]	118	2	120	147	(27)	-18%
Total OPG FTEs	**4,458**	**310**	**4,768**	**5,016**	**(248)**	**-4.9%**

1. Below the line, is a Nuclear Staff Benchmarking term, which contains Fire Department and Management Support as well as Security Support FTEs (2019 study).

g) Refer to Ex. L-F2-SEC-164, parts b) and d).

CCC Interrogatory #075

Interrogatory

Reference:
Exhibit F2, Tab 3, Schedule 3, Table 4

Question(s):

For each unallocated portfolio project shown in Table 4, please provide a detailed description of the project and the estimated cost per year over the duration of the project.

Response

Refer to Ex. L-D2-SEC-56, Attachment 4, for detailed project descriptions and Attachment 1 for estimated costs per year over the IR term.

As discussed in Ex. L-D2-SEC-61, part a), the unallocated capital portfolio includes potential projects expected to start in the future, as selected and prioritized through the asset management process described in Ex. D2-1-1, Section 3.2, and recognizes that these proposed investments have not yet been fully scoped and are based on pre-Class 5 estimates. These considerations also apply to the unallocated Project OM&A portfolio.

Additionally, as the project portfolios are reviewed as part of the annual business planning process based on risk and business need, some investments in the unallocated portfolio may not proceed as anticipated at the time of the approved plan or may be replaced by new investments necessary to address an emerging risk. Notwithstanding the inherently dynamic nature of these early-stage candidate investments, they inform the reasonableness of the overall unallocated Project OM&A envelope.

CCC Interrogatory #076

Interrogatory

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

Preamble:

The evidence sets out the proposed Outage and Cyclical maintenance costs planned by OPG from 2027 to 2031.

Question(s):

a) Please describe what happens when a planned outage is avoided or deferred, i.e. are the planned outage costs entirely obviated?

b) Please confirm that the scope and timing of outages and cyclical maintenance included in this category of cost are defined by regulatory requirements, and that neither the scope nor the timing of either can be changed without regulatory approval. If not confirmed, please split the costs for the 2027 to 2031 period included on Table 1 between costs relating to work that the scope and timing of which is dictated by regulatory requirements, and work that the scope and timing of which is determined by OPG.

c) How much outage OM&A was included on a forecast basis for the Darlington Unit 2 Turbine Control and Auxiliary Systems Upgrade originally scheduled for 2025?

d) How much outage OM&A is included in the 2027 forecast for the Darlington Unit 2 Turbine Control and Auxiliary Systems Upgrade originally scheduled for 2025?

Response

OPG understands the question is referring to OPG Nuclear Facilities Outage OM&A in Ex. F2-1-1, Table 1a, line 3 and not Ex. F1-1-1, Table 1 cited in the Reference.

a) Planned outages and associated outage costs cannot be avoided. There is a regulatory requirement to perform a Periodic Inspection Program on major components (e.g., fuel channels, feeders, steam generators), which require outages to be taken at regular intervals. The CNSC-approved outage interval is 30-months for Pickering and 36-months for Darlington and OPG is required to demonstrate fitness-for-service to operate to the next planned outage. Planned

outages are also required to execute necessary maintenance and replacements or modifications of equipment that can only be performed when the unit is shut down, as described in Ex. E2-1-1, Section 2.2, p. 3, lines 11-16. Although a planned outage cannot be avoided, there have been instances where an outage start time has been changed (i.e., typically within six months of the planned outage) and the corresponding planned outage costs would be incurred based on execution at that time.

b) Partially confirmed. A portion of the scope of each outage and the timing of each outage is defined by regulatory requirements, and the remaining portion of the scope of each outage is within OPG's discretion. As discussed in part a), outage timing is defined by regulatory requirements for preventative maintenance and inspections and requires regulatory approval to change. This typically represents 40-60% of each outage's scope; the remainder is comprised of additional preventative maintenance, corrective maintenance, and projects to sustain and improve plant reliability.

   Due to the level of complexity and nature of outage planning, OPG is unable to split 2027-2031 Outage OM&A costs included in Ex. F2-1-1, Table 1, line 3 between regulatory and non-regulatory scope requirements. As documented in Ex. E2-1-1, Section 2.2, p. 3, lines 4-8, a typical outage has up to 20,000 work activities. As each outage scope is different and scope freeze milestones are one to two years in advance of an outage start, OPG is unable to provide the requested outage cost split.

c) Zero outage OM&A costs was included on a forecast basis for the Darlington Unit 2 Turbine Control and Auxiliary Systems Upgrade originally scheduled for 2025 as that scope is a capital project.

d) Zero outage OM&A costs is included in the 2027 forecast for the Darlington Unit 2 Turbine Control and Auxiliary Systems Upgrade as that scope is a capital project.

CCC Interrogatory #080

Interrogatory

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

Preamble:

The PRP is primarily a capital project but includes Project OM&A expenses for removal costs and volumetric low & intermediate level waste ("L&ILW") variable expenses related to disposal costs.

The removal costs are associated with the replacement of existing assets in the period in which they are incurred. They include costs associated with disassembling and removal of a component to gain access to a subcomponent to be replaced. Removal costs encompass direct execution removal activities plus any specific execution indirect cost related to the removal program. These costs have been forecasted as part of the PRP Release Quality Estimate.

Question(s):

a) Please confirm that the L&ILW variable expenses are included in the calculated nuclear liability expense. If not confirmed, please provide further explanation as to why these L&ILW costs are incremental to the costs tracked as part of the nuclear liability expense.

b) Please explain why the removal costs are considered OM&A costs and not capital costs, since they relate to the refurbishment. Please explain whether or not the removal costs involve the permanent removal of assets, or only the temporary removal of assets in order to access assets that are being replaced, with the "removed" assets ultimately being put back in place.

Response

a) OPG confirms that all low & intermediate level waste ("L&ILW") variable expenses within Project OM&A expenses for the Pickering Refurbishment Program are included in the calculation of the revenue requirement of OPG's nuclear liabilities, which is shown at Ex. C2-1-1, Table 1.

b) As noted in Ex. F2-8-1, p. 2, lines 13-16, removal costs include the permanent removal of existing assets along with costs associated with disassembling and

temporary removal of a component to gain access to a subcomponent to be replaced. Removal costs encompass direct execution of removal activities plus any specific execution of indirect cost related to the removal program.

Removal costs are accounted for as OM&A costs in accordance with US GAAP. This treatment is consistent with how OPG's other projects, including the Darlington Refurbishment Program, have accounted for such costs.

Minogi Corp Interrogatory #008

Interrogatory

Reference:

- **Exhibit F2, Tab 2, Schedule 1**
- **Exhibit F2, Tab 3**
- **Exhibit F2, Tab 6**
- **Exhibit F2, Tab 7, Schedule 1**
- **Exhibit F2, Tab 8, Schedule 1**
- **Exhibit F3, Tab 3, Schedules 1 and 2**

Question(s):

a) Please identify all forecast OM&A, corporate, HR, IT, or compliance costs for implementing, administering, monitoring, or reporting on procurement requirements, including *Buy Ontario Act*.

b) For each cost identified in part a), please provide:

(i) amounts by year for 2027 to 2031;
(ii) business unit/cost centre;
(iii) nature of cost; and
(iv) rationale for cost.

c) Please outline outreach measures for local and First Nation rightsholder suppliers near Pickering and Darlington to ensure visibility and practical access to procurement opportunities.

d) Please provide any internal analyses on local and First Nation rightsholder participation reducing mobilization, logistics, or schedule risks for Pickering refurbishment or DNNP.

Response

a) Based on the *Buy Ontario Act* and the requirements issued to date, related administrative costs are embedded within OPG's existing procurement process and does not result in incremental or material costs beyond those already reflected in OPG's 2025-2031 Business Plan. The Applicants will continue to monitor additional requirements issued by the Province of Ontario and assess any impacts at that time.

b) Not applicable.

c) OPG's supplier outreach strategies focus on expanding awareness of procurement opportunities and improving access for a broad and diverse supplier base. This includes sharing upcoming contracting opportunities through supplier information sessions and industry days, maintaining clear procurement information, and engaging with the market to explain requirements, timelines, and how to do business with OPG. OPG works with Indigenous and other diverse suppliers by promoting networking and capability-building opportunities, with the aim of increasing participation, competition, and value in its supply chain. Refer to Ex. L-F3-MC-011 for information regarding outreach and economic inclusion initiatives.

d) Refer to Ex. L-D3-MC-005.

OAPPA Interrogatory #012

Interrogatory

Reference:
Exhibit F2 / Tab 5 / Schedule 1 / Page 5 of 18, Chart 2 – "Fuel Costs per MWh (2024 Benchmark Report)"

Question(s):

a) Please reconcile the $4.43/MWh for Darlington and $3.98/MWh for Pickering shown in this chart, versus the $4.65/MWh otherwise shown as the cost average for both, in the other Exhibit F2 Tables (for e.g. in F2 / Tab 5 / Schedule 1 / Tab 1b, line 2).

Response

a) The benchmarked amounts ($4.43/MWh for Darlington and $3.98/MWh for Pickering) shown in Ex. F2-5-1, p. 5, Chart 2 and the $4.65/MWh total CANDU fuel bundle cost in Ex. F2-5-1, Table 1a are calculated on different bases, which prevents these amounts from being reconciled. The benchmarked amounts are calculated for each station for 2023 based on a three-year rolling average (i.e., 2021-2023), whereas the $4.65/MWh total CANDU fuel bundle cost reflects a single-year (2024) average for both stations combined.

OAPPA Interrogatory #013

Interrogatory

Reference:
Exhibit F2 / Tab 5 / Schedule 1 / Page 6

Preamble:

"The OPG nuclear fuel supply objectives are to:

- Ensure security of supply: OPG must minimize the risk of its reactors being shut down due to lack of fuel bundles, including the risk that any step in the supply chain is substantially delayed due to a lack of materials from an earlier step.

- Minimize cost: OPG seeks to obtain its fuel supply at the lowest cost, consistent with its fuel quality requirements".

Question(s):

a) How does OPG quantify and consequently manage the supply risk associated with the DNNP, GE-Hitachi's BWRX-300 fuel supply from foreign-controlled sources, if different from domestic Candu fuel sources?

b) Is there any reliance on the current NAFTA, or other trade agreements that will ensure that the reliability of GE-Hitachi's BWRX-300 fuel supply? If so, please explain. Please describe any contingency plans.

c) Will the GE-Hitachi's BWRX-300 fuel supply be subject to tariffs or duties from the US? If there is a risk, how significant is it? Please describe any contingency plans.

d) Are the transportation requirements for the GE-Hitachi's BWRX-300 fuel supply different than those required for the Candu fuel bundles? Is so, please describe.

e) How does the current costing mechanism share nuclear fuel price risk between OPG and rate payers?

Response

a) As discussed in Ex. F2-5-1, the nuclear fuel for the DNNP BWRX-300 reactors requires low-enriched uranium whereas the nuclear fuel for CANDU reactors requires natural uranium. This difference means that the DNNP facilities require

several services as part of their nuclear fuel supply chain which are currently not available in Canada, including uranium enrichment services, low-enriched uranium hexafluoride deconversion services and low-enriched fuel fabrication services.

OPG identifies and assesses foreign nuclear fuel supply chain risks through nuclear fuel planning, sourcing and procurement process that draws on market intelligence and ongoing engagement with key suppliers and industry stakeholders. OPG manages supply chain risks across the short, medium, and long term through a deliberate set of mitigating measures, including diversifying suppliers across jurisdictions. Additional details can be found at Ex. C1-1-1, Attachment 3, pp. 23-27. OPG is also working with government and industry partners to support ongoing efforts to strengthen Canadian supply chain sovereignty for low-enriched fuel.

b) and c)

There is a reliance on the Canada – United States – Mexico Agreement ("CUSMA") to facilitate transportation of nuclear material in various forms between Canada and the United States and vice versa. For example, natural uranium hexafluoride will be transported from Canada to the United States for enrichment, and finished fuel assemblies will be transported from the United States to Canada at the DNNP site. Additionally, imports of uranium into the United States from Canada are currently exempt from tariffs.

OPG monitors and assesses the trade environment between Canada and the United States to identify and mitigate associated risks. OPG is unable to speculate on the specific extent of impacts that may arise in the future trade environment between Canada and the United States. Refer to the part a) for a discussion of risk mitigation.

d) Yes, the transportation requirements for GE-Hitachi BWRX-300 fuel supply are different than those required for CANDU fuel bundles. There are differences in import license requirements, transportation packaging and packing licensing requirements, transportation license requirements and insurance coverages as between the two types of nuclear fuel.

e) Under the proposals in the Application, the Applicants assume all nuclear fuel price risk for the IR term, with the exception of any such risks covered by the proposed Change of Laws Deferral Accounts. Refer to Ex. L-F2-OAPPA-014 for additional discussion.

OAPPA Interrogatory #014

Interrogatory

Reference:
Exhibit F2 / Tab 5 / Schedule 1 / Page 9

Preamble:

"OPG's financial coverage limits specify the maximum and minimum portion of supply to be under fixed-price or base-escalated arrangements, expressed as a percentage of OPG's aggregate amount under contract. OPG's financial coverage limits are unchanged from EB-2020-0290, with a minimum to maximum range of 45% to 65%".

Question(s):

a) Acknowledging that fixed-price arrangements are effective price insurance mechanisms, it is understood that they inherently include a cost, or premium, for mitigating volatile market price risk. Consequently, fixed price arrangements are more likely to affect higher fuel costs, over the longer term, all other things being equal. Could OPG opine on an alternative mechanism – perhaps, but not necessarily, analogously to how Enbridge currently manages its natural gas purchases for its "system gas" rate payers - such that both OPG and Rate Payers could be protected from market price volatility and lower fuel costs in the longer term?

Response

a) The Applicants are not in a position to opine on how Enbridge Gas Distribution currently manages its natural gas purchases. As discussed in Ex. F2-5-1, Section 4.2, OPG maintains prudent physical and financial coverage limits for uranium procurement with a view to managing cost, supply and other risks.

   The Applicants have considered the possibility of requesting a nuclear fuel cost variance account similar to the one granted to OPG in EB-2007-0905[1]; however, having considered the OEB's decision in EB-2010-0008[2] that discontinued the account, have not made this request in this Application.

[1] EB-2007-0905 Payment Amounts Order, App. F, pp. 5-6.
[2] EB-2010-0008 Decision with Reasons, March 10, 2011, p. 55.

SEC Interrogatory #157

Interrogatory

Reference:
F2-1-1
EB-2020-0290, F2-Staff-196

Question(s):

With respect to OPG's nuclear benchmarking performance:

a) Please provide a table that compares OPG's actual performance between 2021-2025, against its annual targets provided in EB-2020-0290, F2-Staff-196, Charts 3 and 4. Please ensure the same methodology used for the targets is used for actual performance.

b) Please provide a comparison of OPG's actual performance between 2021-2025, against the annual targets for Normalized Total Generation Cost Per MWh and Normalized Total Generation Cost Per Unit provided in EB-2020-0290, F2-Staff-196, Charts 3 and 4. In doing so please, a) use the same methodology for the targets that is used for actual performance, b) revise the annual targets to reflect the actual in-service dates as a result of the DRP, as compared to what was forecast when setting the targets, c) revise the annual targets to reflect Pickering extended operations and extension timing, compared to what was forecast when setting the targets. For each of (b) and (c) please explain the specific calculations made and their basis.

c) For each of OPG's Value For Money metric scores, please provide all underlying calculations of the scores, and provide direct reference to amounts included in the cost and production tables in its pre-filed evidence for those numbers. If adjustments were made from information included in the various cost and production forecast included in the evidence, please provide a full explanation.

Response

a) Chart 1 and Chart 2 below show 2021-2025 annual actual results and such annual targets provided in EB-2020-0290, Ex. L-F2-Staff-196, Charts 3 and 4 for Pickering and Darlington, respectively.

Chart 1 - Pickering 2021-2025 Annual Actuals and Targets

Benchmarking Indicators	Pickering									
	2021		2022		2023		2024		2025	
	Actual	Target	Actual	Target	Actual	Target	Actual	Target	Actual	Target
Safety										
Total Recordable Injury Frequency (#/200k hours worked)	0.10	0.13	0.27	0.10	0.20	0.09	0.20	0.09	0.07	0.08
Total Industrial Safety Accident Rate (#/200k hours worked)[1]	0.03	0.10	0.00	0.10	0.00	0.10	0.00	0.10	0.00	0.10
Collective Radiation Exposure (person-rem per unit) [6]	67.74	94.50	69.99	101.00	67.17	99.50	47.02	72.70	34.14	19.50
Airborne Tritium Emissions (Curies) per unit	2,331	2,250	2,229	2,200	2,164	2,200	1,820	2,070	1,392	2,000
Fuel Reliability Index (microcuries per gram)	0.0008	0.0005	0.0002	0.0005	0.0003	0.0005	0.0002	0.0005	0.0009	0.0005
Reactor Automatic and Manual Trip Rate (# per 7,000 hours)[2]	0.00	0.50	0.139	0.50	0.247	0.50	0.32	0.50	0.36	0.50
Auxiliary Feedwater System Unavailability (#)	0.0085	0.02	0.001	0.02	0.00	0.02	0.00	0.02	0.00	0.02
Emergency AC Power Unavailability (#)	0.00	0.025	0.00	0.025	0.00	0.025	0.00	0.025	0.00	0.025
High Pressure Safety Injection Unavailability (#)	0.00	0.02	0.00	0.02	0.00	0.02	0.00	0.02	0.00	0.02
Reliability										
WANO Performance Indicator Index (%)[3]	73.80	74.70	80.9	76.90	81.20	75.70	84.95	80.30	88.11	85.60
Forced Loss Rate (%)	6.22	3.50	1.81	3.50	2.78	3.50	2.56	3.50	2.96	3.50
Unit Capability Rate (%) [4]	-	-	-	-	-	-	96.36	-	96.72	-

Unit Capability Factor (%) [4]	78.92	80.00	80.01	74.10	80.66	79.40	83.30	83.30	91.49	93.20
Chemistry Performance Indicator (Index)	1.06	1.01	1.03	1.03	1.18	1.01	1.22	1.01	1.08	1.00
On-line Deficient Non-Critical Backlog (work orders / unit)	68.00	57.00	39.80	52.00	29.50	46.00	20.20	39.00	12.75	39.00
On-line Deficient Critical Backlog (work orders /unit)	1.30	0.00	0.80	0.00	0.67	0.00	0.60	0.00	0.00	0.00
On-line Corrective Non-Critical Backlog (work orders /unit)	6.30	2.00	3.80	2.00	0.83	2.00	1.20	2.00	0.25	2.00
On-line Corrective Critical Backlog (work orders /unit)	0.30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Value for Money [5]										
Normalized Total Generating Cost per Net MWh - Updated Methodology ($/MWh)**	33.36	-	30.06	-	37.36	-	32.03	-	32.04	-
Normalized Total Generating Cost per Net MWh - Original Methodology ($/MWh)**	44.76	45.31	39.55	47.49	48.02	42.12	41.74	37.62	41.78	23.48
Total Generating Cost per Net MWh ($/MWh)**	64.75	64.50	60.05	68.72	69.98	61.76	64.30	57.02	70.53	46.61
Normalized Total Generating Cost per Unit - Updated Methodology ($/MWh)**	140.45	-	121.17	-	153.88	-	128.77	-	135.95	-
Normalized Total Generating Cost per Unit - Original Methodology ($/MWh)**	169.54	173.85	151.79	169.43	184.98	160.43	159.69	144.39	183.29	69.39

Total Generating Cost per Unit ($M/unit)**	227.59	229.93	214.11	226.44	250.49	218.38	228.49	203.31	290.23	129.29
Non-Fuel Operating Cost per Net MWh ($/MWh)**	57.24	57.18	54.40	62.09	63.24	55.77	57.65	51.06	59.56	40.96
Fuel Cost per Net MWh ($/MWh)	3.72	3.83	3.75	3.90	3.90	4.01	4.29	4.17	5.12	4.52
Capital Cost per MW DER ($k/MW)***	25.79	24.10	13.12	17.45	19.71	13.54	16.27	12.33	46.69	6.07
Human Performance										
18-month Human Performance Error Rate (#/200k ISAR and contractor hours)	0.02	0.07	0.06	0.07	0.06	0.04	0.00	0.04	0.03	0.04

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

**** Design Electrical Rating (DER)*

Note 1: Industrial Safety Accident Rate (ISAR2) has been replaced by Total Industrial Safety Accident Rate (TISA2) in Q1 2024 to align with WPII methodology transition from Method 4 to Method 10. ISAR included only permanent employees when counting industrial safety accidents, while the new indicator TISA includes both contractors and permanent employees.

Note 2: Reactor Trip Rate was replaced by Reactor Automatic & Manual Trip Rate following the WPII Method 10 transition in 2024. The indicator change includes the change from Unplanned Automatic Scrams (UA7) to Unplanned Total Scrams (US7). Method 4 utilized UA7 metric which only included the automatic scram data. The new indicator, US7, which includes both automatic and manual scrams.

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

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

Note 5: All metrics, including Value for Money targets 2021 – 2025 in EB-2020-0290 are reviewed annually and updated as required as part of the business planning process.

Note 6: CRE 2024 Actuals have been corrected.

Chart 2 - Darlington 2021-2025 Annual Actuals and Targets

Benchmarking Indicators	Darlington									
	2021		2022		2023		2024		2025	
	Actual	Target	Actual	Target	Actual	Target	Actual	Target	Actual	Target
Safety										
Total Recordable Injury Frequency (#/200k hours worked)	0.07	0.17	0.08	0.10	0.00	0.09	0.20	0.09	0.08	0.08
Total Industrial Safety Accident Rate (#/200k hours worked)[1]	0.00	0.10	0.00	0.10	0.00	0.10	0.00	0.10	0.00	0.10
Collective Radiation	110.47	126.20	29.90	21.10	15.64	73.90	65.05	40.00	11.26	78.20

Exposure (person-rem per unit) [6]										
Airborne Tritium Emissions (Curies) per unit	905	970	1,157	970	1,000	970	958	970	1,060	970
Fuel Reliability Index (microcuries per gram)	0.0002	0.0005	0.0001	0.0005	0.0001	0.0005	0.0029	0.0005	0.0016	0.0005
Reactor Automatic and Manual Trip Rate (# per 7,000 hours)[2]	0.00	0.50	0.000	0.50	0.100	0.50	0.10	0.50	0.10	0.50
Auxiliary Feedwater System Unavailability (#)	0.0000	0.02	0.000	0.02	0.00	0.02	0.00	0.02	0.00	0.02
Emergency AC Power Unavailability (#)	0.00	0.025	0.00	0.025	0.00	0.025	0.00	0.025	0.00	0.025
High Pressure Safety Injection Unavailability (#)	0.00	0.02	0.00	0.02	0.00	0.02	0.00	0.02	0.00	0.02
Reliability										
WANO Performance Indicator Index (%)[3]	85.80	84.30	91.4	93.10	89.40	77.54	74.74	86.90	71.11	84.75
Forced Loss Rate (%)	3.52	3.79	7.51	2.12	1.44	1.20	12.07	5.99	2.01	6.42
Unit Capability Rate (%) [4]	-	-	-	-	-	-	86.97	-	97.18	-
Unit Capability Factor (%) [4]	82.66	76.00	86.99	85.80	96.99	78.10	74.58	81.80	95.69	68.20
Chemistry Performance Indicator (Index)	1.01	1.01	1.00	1.01	1.01	1.01	1.03	1.01	1.05	1.01
On-line Deficient Non-Critical Backlog (work orders / unit)	70.33	90.00	61.00	75.00	29.00	65.00	17.33	60.00	12.33	41.00
On-line Deficient Critical Backlog (work orders /unit)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
On-line Corrective Non-Critical Backlog (work orders /unit)	2.00	2.00	0.50	2.00	0.00	2.00	0.00	2.00	0.00	2.00
On-line Corrective Critical Backlog (work orders /unit)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Value for Money [5]										
Normalized Total Generating Cost per Net MWh - Updated Methodology ($/MWh)**	36.49	-	37.49	-	41.10	-	49.37	-	35.14	-
Normalized Total Generating Cost per Net MWh -	45.59	58.15	33.88	45.83	36.60	60.24	51.27	42.92	37.28	59.81

Original Methodology ($/MWh)**[6]										
Total Generating Cost per Net MWh ($/MWh)**	79.27	94.47	101.52	105.67	108.85	153.08	141.94	115.22	71.66	109.04
Normalized Total Generating Cost per Unit - Updated Methodology ($/MWh)**	257.48	-	237.33	-	292.34	-	305.77	-	246.14	-
Normalized Total Generating Cost per Unit - Original Methodology ($/MWh)**	297.90	348.94	238.91	313.25	287.92	377.55	308.25	280.05	282.44	323.34
Total Generating Cost per Unit ($M/unit)**	489.03	532.35	663.52	667.78	796.56	861.14	780.21	688.64	516.67	545.31
Normalized Non-Fuel Operating Cost per Net MWh ($/MWh)**	47.29	55.93	41.51	47.51	41.83	71.30	63.04	52.78	36.81	63.53
Non-Fuel Operating Cost per Net MWh ($/MWh)**	57.64	66.89	64.98	70.02	67.14	109.38	95.70	80.61	47.13	79.78
Fuel Cost per Net MWh ($/MWh)	4.00	4.08	3.82	4.10	4.32	4.35	5.29	5.16	5.23	5.11
Normalized Capital Cost per MW DER (k$/MW)***	90.52	119.86	104.28	139.75	133.09	140.56	111.39	170.48	114.84	102.52
Capital Cost per MW DER ($k/MW)***	123.88	150.87	243.57	227.16	311.66	252.11	256.36	276.82	158.52	135.48
Human Performance										
18-month Human Performance Error Rate (#/200k ISAR and contractor hours)	0.02	0.04	0.00	0.04	0.00	0.02	0.00	0.02	0.02	0.02

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

*** *Design Electrical Rating (DER)*

Note 1: Industrial Safety Accident Rate (ISAR2) has been replaced by Total Industrial Safety Accident Rate (TISA2) in Q1 2024 to align with WPII methodology transition from Method 4 to Method 10. ISAR included only permanent employees when counting industrial safety accidents, while the new indicator TISA includes both contractors and permanent employees.

Note 2: Reactor Trip Rate was replaced by Reactor Automatic & Manual Trip Rate following the WPII Method 10 transition in 2024. The indicator change includes the change from Unplanned Automatic Scrams (UA7) to Unplanned Total Scrams (US7). Method 4 utilized UA7 metric which only included the automatic scram data. The new indicator, US7, which includes both automatic and manual scrams.

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

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

Note 5: All metrics, including Value for Money targets 2021 – 2025 in EB-2020-0290 are reviewed annually and updated as required as part of the business planning process.
Note 6: CRE 2024 Actuals have been corrected.

b) OPG is unable to revise 2021-2025 annual targets to reflect (i) actual DRP in-service dates, and (ii) actual Pickering extended operations and extension timing. Doing so would require a complex adjustment to various total generating cost categories predicated on a multitude of assumptions and such a targeted revision based on hindsight would not be appropriate.

c) Chart 3 below shows the derivation of the Value for Money metric calculations, with references to amounts reflected in evidence and adjustments applied to arrive at the 2026-2031 targets shown in Chart 1 of Ex. L-F2-Staff-179 part (c) for Darlington and Chart 1 of Ex. L-F2-Staff-183 for Pickering, which represent such final targets for this business planning cycle for the reasons discussed in those interrogatory responses.

Chart 3 - Pickering and Darlington Derivation of 2026-2031 Value for Money Metric Calculations

Line #	2025-2031 BP ($M unless otherwise noted)	2026 Target			2027 Target	2028 Target	2029 Target	2030 Target	2031 Target	Source
		DN	PN		DN	DN	DN	DN	DN	
1	Generation (TWh)	21.1	11.4		18.7	26.7	25.1	26.8	27.1	Ex. E2-1-1 - Table 1, col. (g-l), line 1-2
2	Capacity (MW DER)	3,256	2,064		3,512	3,512	3,512	3,512	3,512	Ex. A1-4-3 Chart 1; Darlington: 3,512 adjusted to remove capacity undergoing refurbishment [2026 Unit 4: 3.5 months / 48 months (all 4 units) = 7.3%]
3	OPG Nuclear Facilities Base OM&A	656	554		708	710	745	751	766	Ex. F2-2-1 - Table 1a, col. (g-l), line 15 and Table 9-14, col. (a-b), line 13
4	OPG Nuclear Facilities Outage OM&A	156	53		224	113	219	122	116	Ex. F2-4-1 - Table 1, col. (g-l), lines 3 & 6
5	OPG Nuclear Facilities Project OM&A	55	18		58	59	59	57	59	Ex. F2-3-1 - Table 1, col. (g-l), line 16 – DN/PN Portion
6	PN Cyclical Maintenance OM&A	0	25		0	0	0	0	0	Ex. F2-4-1 - Table 1, col. (g-l), line 14
7	Support Services OM&A	201	215		214	206	215	215	222	Ex. F3-1-1 - Table 3a, 3b, col. (g-l), line 10
8	Centrally Held Costs	(22)	(25)		(10)	(12)	(23)	(12)	(8)	Ex. F4-4-1, Table 3, col. (g-l), line 7 – DN/PN Portion
9	Fuel-Fuel Oil	2	3		3	2	2	2	2	Ex. F2-5-1 - Table 1a, col. (g-l), line 6 – DN/PN Portion
10	Total - OM&A Prior to Value for Money Metric Adjustments	1,047	844		1,197	1,077	1,217	1,134	1,157	Sum of lines 3-9
11	Cost Allocations	(9)	10		(6)	(0)	(3)	(2)	(7)	Cost allocation adjustments (e.g., Pickering utilization of Tritium Removal Facility)
12	Exclusions per EUCG governance	63	73		62	62	68	63	58	Exclusions from TGC/MWh calculation (e.g., IESO Non-Energy Charges, Pension/ OPEB Related Costs, L&ILW Storage & Disposal)
13	Total Adjustments	54	83		57	61	65	61	51	Sum of lines 11 & 12
14	**Total OM&A for Value for Money Metrics**	**1,101**	**926**		**1,254**	**1,138**	**1,282**	**1,195**	**1,208**	Sum of lines 10 & 13

15	OPG Nuclear Facilities Capital	727	134		873	791	891	771	548	Ex. D2-1-2 - Table 2, col. (g-l), line 22 – DN/PN Portion
16	Exclusions per EUCG governance	(207)	(4)		(291)	(334)	(526)	(399)	(297)	Exclusion from TGC/MWh calculation per EUCG Governance (e.g. specified projects, new fuel load, capital interest)
17	Net Nuclear Capital	520	130		582	457	365	371	251	Sum of lines 15 and 16
18	Support Services Capital	93	81		185	130	136	139	114	Ex. D3-1-1 - Table 1, col. (g-l), line 3
19	Exclusions per EUCG governance	(40)	(47)		(127)	(89)	(103)	(120)	(106)	Exclusion from TGC/MWh calculation per EUCG Governance
20	Net Corporate Allocated Capital	53	33		58	41	33	19	8	Sum of lines 18 & 19
21	**Total Capital for Value for Money Metrics**	**573**	**164**		**640**	**498**	**398**	**391**	**259**	Sum of lines 17 & 20
22	**Fuel-Uranium**	**128**	**65**		**121**	**182**	**184**	**209**	**222**	Ex. F2-5-1 - Table 1a, col. (g-l), lines 1 & 2 Used Fuel Storage & Disposal is excluded from TGC/MWh calculation per EUCG Governance
23	**Total Generating Costs for Value for Money Metrics**	**1,801**	**1,155**		**2,014**	**1,818**	**1,863**	**1,794**	**1,690**	Sum of lines 14, 21 & 22
	Value for Money Metrics - 1 Year									
24	Total Generating Costs per MWh ($/MWh)	85.43	101.57	91.10	107.77	68.11	74.34	66.90	62.39	Line 23 / Line 1
25	Non-Fuel Operating Costs per MWh ($/MWh)	52.23	81.44	62.46	67.07	42.65	51.14	44.53	44.62	Line 14 / Line 1
26	Fuel per MWh ($/MWh)	6.05	5.75	5.95	6.49	6.80	7.33	7.80	8.19	Line 22 / Line 1
27	Capital per MW DER (k$/MW)	175.85	79.25	138.40	182.11	141.84	113.24	111.21	73.84	Line 21 / Line 2

** PN 2026 Value for Metrics Target as per Ex. F2-Staff-183 part a). DN 2026-2031 Value for Money Targets as per Ex. F2-Staff-179 part c).*

SEC Interrogatory #158

Interrogatory

Reference:
F2-1-1, p. 19-25, Chart 3 and 4

Question(s):

Please provide a revised version of Charts 3 and 4 using the existing 2018 benchmarking methodology (as applied in EB-2020-0290).

Response

The requested information can be found at Ex. F2-1-1, pp. 19-25, Chart 3 and 4 as 'Normalized Total Generating Cost per MWh – Original Methodology ($/MWh)' and 'Normalized Total Generating Cost per Unit – Original Methodology ($/MWh)'.

SEC Interrogatory #159

Interrogatory

Reference:
F2-1-1

Question(s):

Please provide a copy of the 2025 Benchmarking Report. If it is not available, please provide OPG's benchmarking results.

Response

Refer to Ex. L-F2-CCC-070, Attachment 1.

SEC Interrogatory #162

Interrogatory

Reference:
F2-1-1, Attachment 4

Question(s):

With respect to the ScottMadden, *OPG Nuclear Cost Performance Benchmarking* Report*:*

a) [F2-1-1, Attachment 7, p.2] ScottMadden was asked to "[c]conduct a new, holistic study of nuclear cost performance" in part by "determining cost metric normalizations and peer group changes to account for non-controllable factors and facilitate more reasonable benchmark comparisons."[emphasis added] Please explain how and on what basis did OPG determine that the current methodology required, at the very least, was a "more reasonable" benchmarking comparison.

b) [p.11] Please provide a separate version of the Figure on p.11 for each specific adjustment separately.

c) [p8-9] Please explain why ScottMadden believes that it can find statistically significant impact on cost for CANDU technology when it only makes up 3 of the 57 nuclear sites in its sample.

d) [p.9] Please explain why it is appropriate to consider age from the initial in-service date of the unit as opposed from the date of its full refurbishment.

e) [p.12] Please provide the outage-adjustment working papers used to calculate adjusted MWh for all 57 sites for the years 2006 to 2023. If any special treatment was applied to any plant-year in the outage adjustment (including any adjustments related to refurbishment periods), please identify the plant-years and show exactly how that treatment was implemented in the working papers.

f) [p.12] Please identify the benchmark plant use and provide its planned outage % by year and its 2006 to 2023 average (the value used as the benchmark)

g) Did ScottMadden undertake any analysis of the relationship between the number of units on a site and total generating costs? If, so please provide details.

Response

a) Consistent with the OEB-approved settlement proposal in EB-2020-0290, OPG asked ScottMadden to conduct a new nuclear benchmarking approach review using the most current available data. As part of that request, OPG asked ScottMadden to consider what normalization, if any, would facilitate a more accurate comparison between OPG and its peers, therefore, improving the reasonableness of that view.

The following responses (b-g) were prepared by ScottMadden Management Consultants:

b) Chart 1, 2, and 3 provides the 3-Year Total Generating Cost per Mega-watt hour (TGC/MWh) Updated Methodology results and quartile performance for each adjustment.

Chart 1: 2023 3-Year Technology Adjusted TGC/MWh (2021-2023)

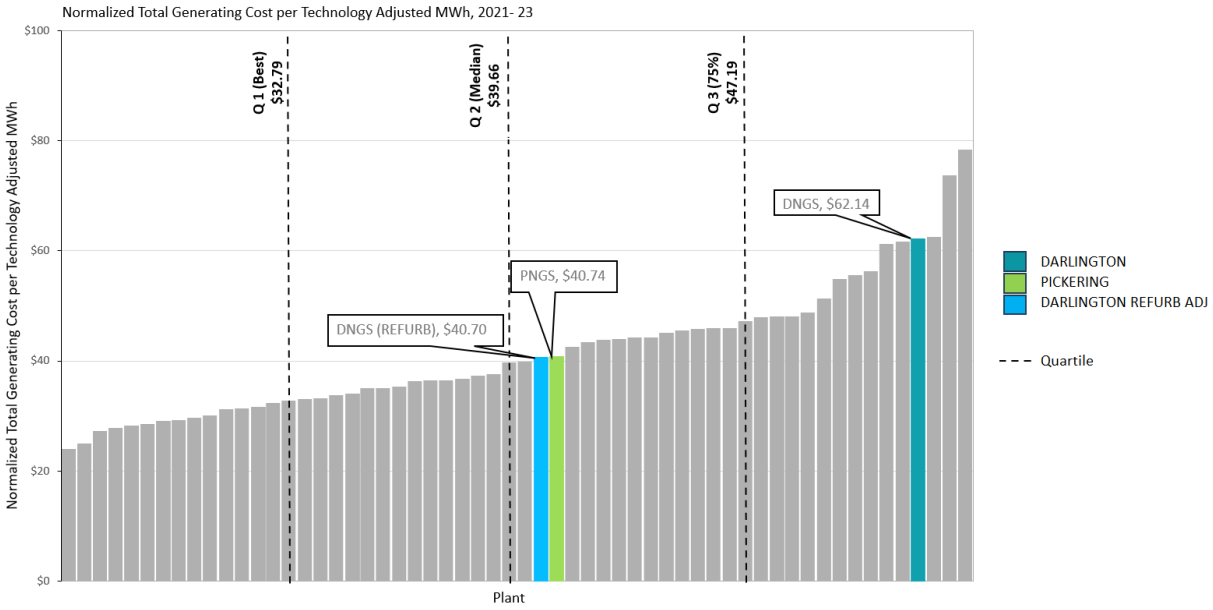


Chart 2: 2023 3-Year Unit Age Adjusted TGC/MWh (2021-2023)

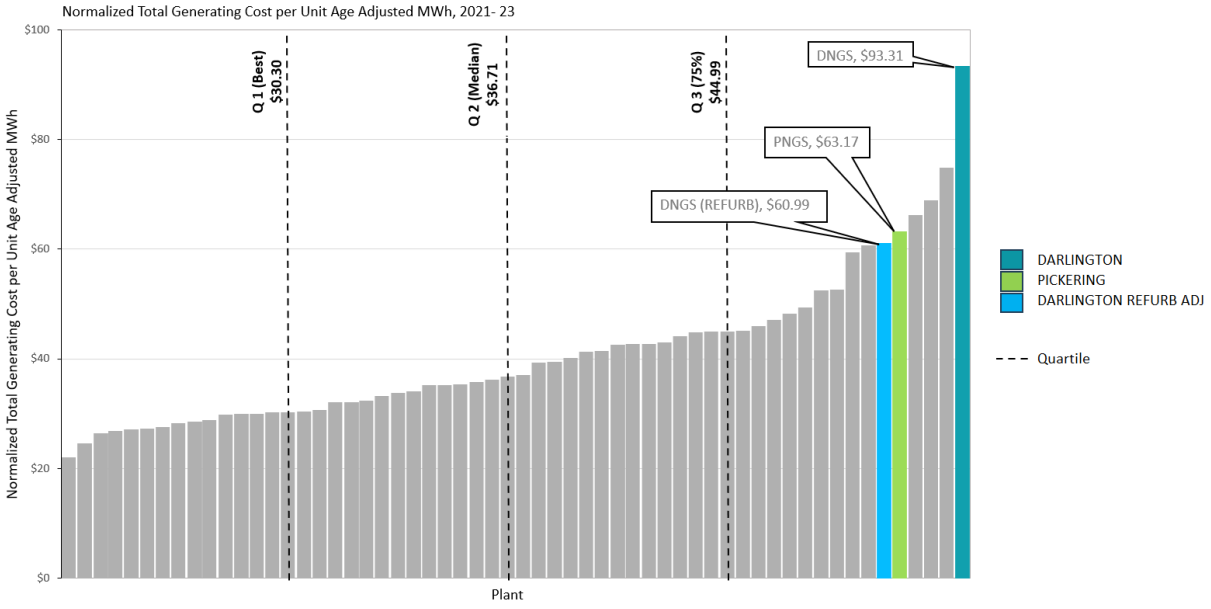
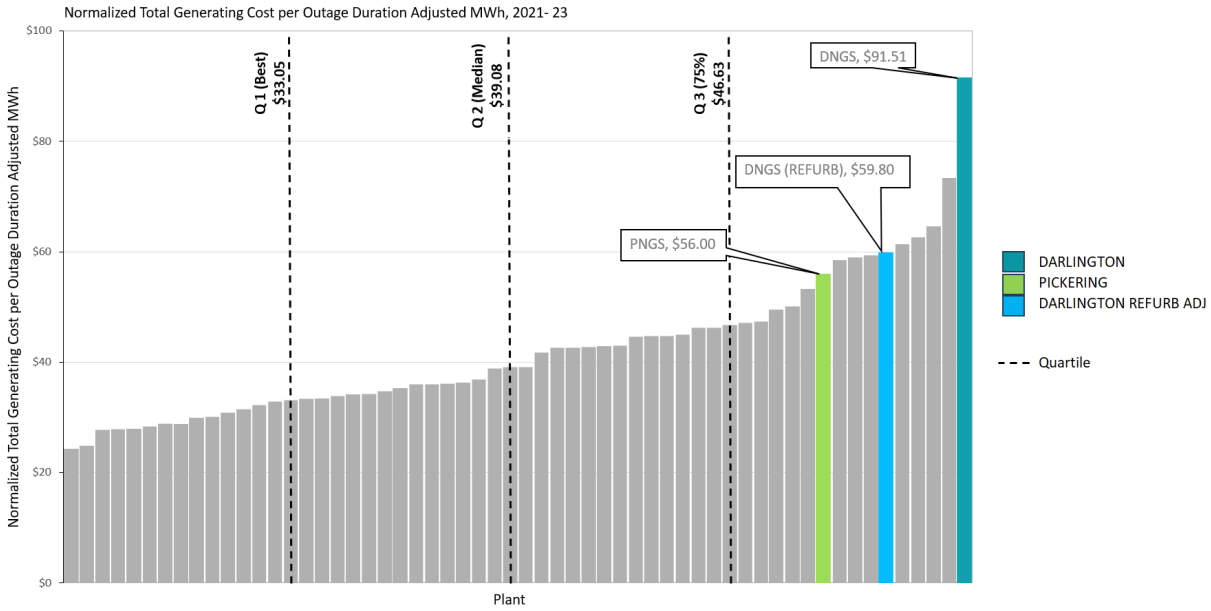


Chart 3: 2023 3-Year Outage Duration Adjusted TGC/MWh (2021-2023)



c) Refer to Ex. L-F2-Staff-324, part f).

d) Refer to Ex. L-F2-CCC-71, part e).

e) Refer to Ex. L-F2-Staff-327, part d) and Ex. L-F2-Staff-328, parts a) & b).

f) The benchmarked plant is Plant ID 278. Chart 4 below shows Plant 278's annual planned outage percentage and its average 2006-2023 planned outage percentage of 2.67% that was utilized as the benchmark.

Chart 4: 2006-2023 Planned Outage Percentage by Year For the Benchmarked Plant

Year	Planned Outage %
2006	2.74%
2007	2.88%
2008	2.47%
2009	4.15%
2010	3.53%
2011	3.47%
2012	3.23%
2013	2.82%
2014	2.47%
2015	2.19%
2016	2.33%
2017	2.63%
2018	2.05%
2019	2.48%
2020	1.74%
2021	1.92%
2022	2.54%
2023	2.42%
Average	**2.67%**

g) ScottMadden did not include the number of units as a separate variable in the final econometric model. Instead, the impact of the number of units on total generating costs is considered to be effectively captured through the site capacity (MW) variable that is included in the model.

SEC Interrogatory #163

Interrogatory

Reference:
EB-2020-0290, JT 1.27, Attachment 1

Question(s):

Please provide a revised version of EB-2020-0290 JT 1.27, Attachment 1, to include 2020-2024 actual data.

Response

See Chart 1 below.

Chart 1: EB-2020-0290 JT1.27 Updated with 2020-2024 Actual Results for Selected Nuclear Benchmarking Metrics

	Rolling – Actual Results																
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Darlington	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	((p)	(q)
WANO Nuclear Performance Index (%) [1]	95.67	95.10	94.10	92.80	96.30	90.80	92.10	83.70	87.80	82.00	90.70	88.90	93.60	85.80	91.40	89.44	74.74
Unit Capability Factor (%) [2]	91.99	90.20	89.40	89.60	92.00	90.44	89.41	83.96	86.16	82.17	86.89	87.06	92.38	86.18	88.81	90.46	80.35
3-Year Average Total Generating Costs ($/Net MWh)	30.08	32.77	33.55	33.05	31.67	34.42	37.73	44.38	45.63	54.40	59.06	67.00	62.06	65.60	74.38	95.04	115.93
3-Year Average Normalized Total Generating Costs ($/Net MWh)[3]										37.94	37.65	38.84	36.37	38.09	37.09	38.11	42.58
Pickering																	
WANO Nuclear Performance Index (%) [1]	60.90	67.17	64.30	66.10	64.70	67.50	64.30	68.50	76.30	76.70	74.90	82.50	82.49	73.74	80.90	82.78	84.95
Unit Capability Factor (%) [2]	67.65	74.47	74.57	72.50	75.62	75.77	74.50	77.32	77.03	77.36	79.55	83.31	81.90	77.58	79.46	80.34	79.59
3-Year Average Total Generating Costs ($/Net MWh)	69.82	65.81	65.00	65.86	67.16	67.18	67.93	67.36	68.06	67.22	67.76	62.39	62.84	62.62	64.17	64.93	64.78
3-Year Average Normalized Total Generating Costs ($/Net MWh)[3]										49.27	49.29	44.85	44.64	43.98	44.03	33.62	33.18
Pickering A																	
WANO NPI (Index)[2]	60.84	61.10	47.70														
Unit Capability Factor (%)	56.60	68.00	63.30														
3-Year Average Total Generating Costs ($/Net MWh)	92.27	95.41	90.21														
Pickering B																	
WANO NPI (Index)[2]	60.93	70.20	72.60														
Unit Capability Factor (%)	73.17	77.70	80.20														
3-Year Average Total Generating Costs ($/Net MWh)	58.68	54.64	54.79														

Note 1: The Nuclear Performance Index Method 10 is a WANO sponsored performance measure and is a weighted composite of ten WANO Performance Indicators related to safety and production performance reliability. In Q1 of 2024, Method 10 replaced Method 4: Unit Capability Factor (UCF) was replaced by Unit Capability Rate (UCR), Automatic Reactor Scrams (UA7) was replaced by Automatic and Manual Scrams (US7,) and Industrial Safety Accident Rate (ISAR2) – replaced by Total Industrial Safety Accident Rate (TISA2). NPI is calculated using a 2-year rolling average for PN and a 3-year rolling average for DN.
Note 2: Indicates a 2-Year Rolling Average for Pickering and a 3-Year Rolling Average for Darlington.
Note 3: Original TGC/MWh normalization methodology applied for years 2017-2022, updated methodology applied for 2023 &2024.

1st Quartile Performance
2nd Quartile Performance
3rd Quartile Performance
4th Quartile Performance
Not Applicable

SEC Interrogatory #164

Interrogatory

Reference:
F2-1-1, Attachment 5

Question(s):

With respect to the Indeavor, *OPG Nuclear Staff Benchmarking* Report:

a) [p.6] The Report states "OPG reviewed EUCG (Electric Utility Cost Group) staffing data for 2024, and allocated staffing headcount to corresponding Indeavor functions." Does this mean OPG allocated its employees or that it allocated all EUCG employees to the corresponding Indeavor function? Please explain why OPG, and not Indeavor, was responsible for this task.

b) Please explain all changes to the data collection approach and study methodology used in the previous Goodnight Studies.

c) [p.8] The study excluded the capital staffing function. How many OPG FTEs fall into this category and does the exclusion include all capital-related work and staff involved in any projects set out in Exhibit D2, including support functions?

d) [p.10] The peer group included 4 companies, and 9 sites.
   a. For each site, please provide the number of units, and MWs.
   b. How does this compare to previous staff benchmarking studies included in the last three OPG applications?

e) [p.10] OPG currently operates two sites with more than 2 units per site. Please explain how Indeavor normalized for the difference in sites per company and units per site.

f) [p.14] Please provide the chart, "Site Headcount – Indeavor Functions", in a tabular format in Excel.

g) [p.16] Please provide OPG's views on the drivers of the material variances (both positive and negative) in certain functions compared to the benchmark.

h) [p.17] Please provide a revised version of "Headcount Variance by Function", reflecting variances as a percentage of the benchmark, as opposed to variance in the headcount number.

Response

The following responses were prepared by Indeavor (with the exception of parts (c) and (g)):

Indeavor has issued a revised version of the OPG Nuclear Staff Benchmarking Report (Ex. F2-1-1, Attachment 5) to address an error in the original peer group composition. The original report inadvertently included a 3-unit BWR site that does not align with the intended 2-unit PWR benchmark group. The revised report now excludes this site, and the updated benchmark is based on eight 2-unit PWR sites. Please refer to Attachment 1 for the OPG Nuclear Staff Benchmarking Rev 1 Report.

a) The statement on p.6 refers to the allocation of OPG's own staffing data to Indeavor functions, not the allocation of peer data. OPG allocated its own employees because OPG has the best knowledge of its organizational structure, job descriptions, and departmental assignments. Allocations were determined using EUCG account mappings, department-level information, job titles, and business unit classifications, then reviewed and approved through multiple rounds of validation between Indeavor and OPG.

   For the PWR peer data, sites self-reported directly to Indeavor in either EUCG Account Level or Indeavor Functional Level format. EUCG data was converted to Indeavor functions using historical ratios (Attachment 1, p. 22). Prior Goodnight studies drew peer data from the standalone Goodnight staffing database rather than directly from sites. For this study, Indeavor built a custom staffing database for OPG using the survey responses.

b) Changes from the prior Goodnight Consulting studies (2011, 2013, 2014, 2019):

   Benchmark Data Sources and Peer Group Methodology:
   Previous Goodnight studies relied on a proprietary Nuclear Plant Staffing Database, which is no longer available following Goodnight's closure in 2021. The current Indeavor study uses a survey-based approach, with PWR sites self-reporting staffing data. The 2024 benchmark includes eight 2-unit PWR sites across four companies, compared to 17 sites across 11 companies in previous studies. Only one site is common to both benchmarks (see part (d)). Additionally, five of the eight peer sites submitted data at the EUCG Account level, which required conversion to Indeavor Functional levels using historical allocation ratios (Attachment 1, p. 22); prior studies collected data directly at the functional level.

Scope of Benchmarking and Inclusion/Exclusion of Functions:
Goodnight's methodology included detailed contractor (purchased services) data, but such data was not available from Indeavor survey participants. Therefore, purchased services were excluded from both OPG and peer site data in the 2024 benchmark. Scope changes also occurred: Security Support and Management Support, included in the 2019 benchmark, are excluded from the 2024 benchmark, while Information Technology (excluded in 2019) is now included (see Ex. L-F2-Staff-191).

c) Refer to Ex. L-F2-Staff-189, which provides the total number of OPG FTEs that were excluded for the capital staffing function. This number relates to FTEs, including support functions, who are dedicated to major capital projects (plant refurbishments), which would be included in Exhibit D.

d)

a. Eight sites across four companies provided data. See Chart 1 below for the full site list with unit counts and approximate MW ratings.

Chart 1 - OPG Nuclear Staffing Benchmarking Study Participants

Company	Site	Units	Type	~MWe/Unit *	Previous Participant
NextEra	1	2	PWR	~1,000	Y
NextEra	2	2	PWR	~800	N
NextEra	3	2	PWR	~600	N
Duke	4	2	PWR	~1,100	N
Duke	5	2	PWR	~1,100	N
Entergy	6	2	PWR	~900 avg	N
TVA	7	2	PWR	~1,150	N
TVA	8	2	PWR	~1,150	N

** MW ratings are approximate (publicly available NRC data).*

b. The prior Goodnight studies drew from the proprietary Goodnight database of large (>800 MWe) 2-unit PWRs. The peer group from the previous study as noted in EB-2020-0290 Ex. L-F2-SEC-124 was 17 sites across 11 companies. All sites were contacted for the 2024 study; only the ones noted above responded.

e) The normalization methodology is performed at the site level and not by company. Details of the methodology are provided in Ex. L-F2-CCC-072, part (d).

f) Refer to Attachment 2.

g) While the exact reasons for specific variances cannot be determined without more granular information on the organizational structures at peer utilities, OPG provides

the following perspectives on possible drivers for variance in the functions highlighted in Attachment 1, p. 16:

Variances above benchmark:

- Facilities: Variance driven by a large number of off-site facilities maintained by OPG, with future consolidation planned.

- Maintenance – Support: Includes insulators, scaffolders, procedure writers, and stores support. US plants may utilize a different operating model where different functions are contracted out, specifically during outages where a substantial portion of the work is done. Although Maintenance Support is above benchmark, it is offset by Maintenance - Electrical/I&C being below the benchmark.

- Safety Programs: Includes internal safety staff, which may differ in scope from other utilities.

- Project Management: Reflects OPG's capital investment program and the need for critical project management oversight.

- Fire Department: OPG provides certain internal services such as its own fire department and emergency response teams that many US utilities outsource to municipalities or have integrated with operating crews.

Variances below benchmark:

- RP Applied: Lower staffing levels in this function are offset by line personnel qualified to provide self-monitoring and, if qualified, monitoring of activities of groups

- Maintenance – Electrical/I&C, Engineering – Plant, Operations: The below-benchmark staffing levels in these areas are driven in part by Pickering Units 1 and 4 end of commercial operations in 2024 and the transition towards Pickering Units 5-8 preparation for the four-unit refurbishment.

h) Refer to Attachment 2.

INDEAVOR

April 2026

Ontario Power Generation (OPG) - Nuclear Staff Benchmarking Rev 1

Report Contents

- Executive Summary
- Background and Data Methodology
  - Methodology Overview – OPG
  - Methodology Overview – Benchmark
  - Methodology Overview – Exclusions
- PWR Data Normalization Process
- Benchmark Data

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Executive Summary

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Executive Summary

- OPG engaged Indeavor, a company with workforce analytics expertise in the energy sector, to conduct a nuclear staffing benchmark.
- The benchmark methodology began with staffing data from 2-unit United States (U.S.) Pressurized Water Reactor (PWR) sites, selected for their technical comparability to Canada Deuterium Uranium (CANDU) reactors. This data was scaled to reflect operations at OPG's fleet. Non-comparable functions, such as Purchased Services and CANDU-specific activities, were excluded due to the lack of detailed data from benchmarked peers.
- OPG's 2024 staffing headcount is 4,458, which is 1% below the benchmark of 4,502.
- Operations and Facilities remain the largest variance categories, consistent with prior benchmarks: −189 in Operations and +166 in Facilities.

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Data Methodology

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Methodology Overview – OPG

- OPG reviewed EUCG (Electric Utility Cost Group) staffing data for 2024, and allocated staffing headcount to corresponding Indeavor functions.
  - Indeavor function allocations were determined using a mix of EUCG account mappings, department level information, job titles, business unit classification.
  - To establish a consistent benchmark, any data that was determined to not be comparative was excluded from the analysis.*
- These functional headcount allocations were reviewed and validated by Indeavor for use to compare against the benchmark.

**Exclusion list and rationale provided on slide 8*

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Methodology Overview – Benchmark

- Surveys were sent out to comparable 2-unit PWR (Pressurized Water Reactor) sites who agreed to participate in the study; sites from across the United States self-reported their staffing data and submitted it to Indeavor for analysis.
- The survey data was normalized to ensure the benchmark was comparative with OPG data.*
- The normalized data was then rounded to the nearest whole number to eliminate any fractional headcounts.

Benchmark normalization methodology described in the next section.

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Benchmarking Methodology – Exclusions

To ensure that both OPG staffing and Benchmark staffing numbers were in alignment and reflect an accurate headcount comparison, some data sets were excluded.

Function	PWR Benchmark	OPG	Rationale
Capital Staffing	Excluded	Excluded	Staffing tied to capital projects/one-time initiatives/refurbishments was not included because it is not representative of the operations.
Outage Execution Activities	Not provided	Excluded	Not representative of the operations.
Nuclear Waste and Decommissioning	Not provided	Excluded	Not applicable for PWR sites.
Security and Security Support	Excluded	Excluded	Excluded to remain compliant with OPG security policy.
Purchased Services (Managed Tasks)	Not provided	Excluded	Excluded due to the lack of detailed data from benchmarked peers.*
CANDU Specific Activities	Not applicable	Excluded	Full detail discussed within PWR normalization section of report.

Excluding Purchased Services is a methodological change from previous studies. Without the ability to interview benchmark sites and fully analyze PWR contract staffing, the data was excluded from both data sets.

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PWR Data Normalization

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PWR Data Survey Participants

NEXTera ENERGY	DUKE ENERGY	entergy	TVA
3 Sites Provided	**2 Sites Provided**	**1 Site Provided**	**2 Sites Provided**
EUCG Account Level	***Indeavor Functional Level***	***Indeavor Functional Level***	***EUCG Account Level***

- To generate the comparable benchmark, surveys were sent to PWR nuclear operating centers within the US to request their current staffing levels. Sites self reported staffing data in one of 2 formats.
  - EUCG Account Level Data [A]
  - Indeavor Function Data [B]

- PWR Staffing Survey data was then normalized to be able to provide an accurate comparison with OPG staffing.

A, B – Full list in Appendix

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PWR Data Normalization

Once the survey data was received, it was normalized as follows:

1. Data was normalized as needed to ensure it was consistent across participants
   - Data provided at the EUCG Account level was normalized using historical ratios to split the EUCG account groups into the respective Indeavor functions. [C]
   - Data provided at the Indeavor Functional level was left at the level provided.
   - With the survey data at the same level, each function was averaged across the data set to create the baseline data for the benchmark.
2. To establish a benchmark, any data that was not consistent between PWR and OPG data sets was excluded from the analysis.*
3. Included survey data was then adjusted to account for process and technological differences between CANDU and PWR. The listed functions are unique to CANDU reactor designs and have no comparable equivalent with PWR reactor designs:
   - Fuel Handling
   - Heavy Water Handling
   - Spent Fuel/Radwaste
   - Tritium Removal Facility
   - Feeder and Fuel Channel Support
4. The data was then adjusted to account for the difference between 35 hour and 40 hour work weeks. This adjustment accounts for any staffing differences due to the yearly variance of the same position worked at 40 hours in the U.S. and 35 hours in Canada.
5. To scale staffing for reactor count differences between 2-Unit and 4-Unit sites, the work week normalized staffing data was scaled to account for 2 additional reactor units at Pickering B and Darlington. Data was also adjusted to include staffing for cross-tied operations for Units 2 & 3 at Pickering A.
6. The normalized fractional headcounts were rounded up to the nearest whole number, as less than one person cannot be staffed.

C – Full list in Appendix
** Exclusion list provided on slide 8*

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Benchmark Data

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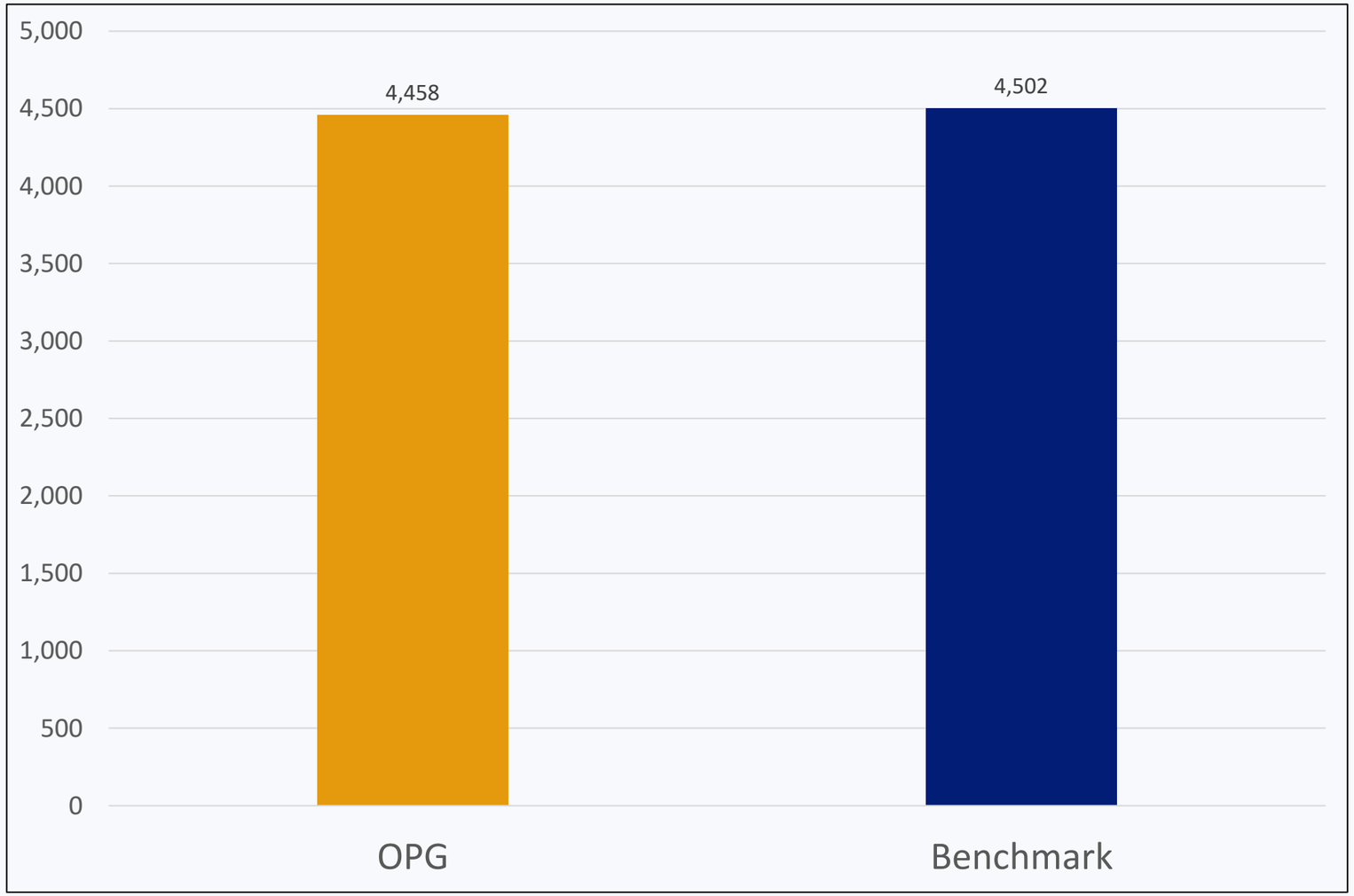
Site Headcount – Total



OPG Headcount is 44 (-1.0%) below benchmark

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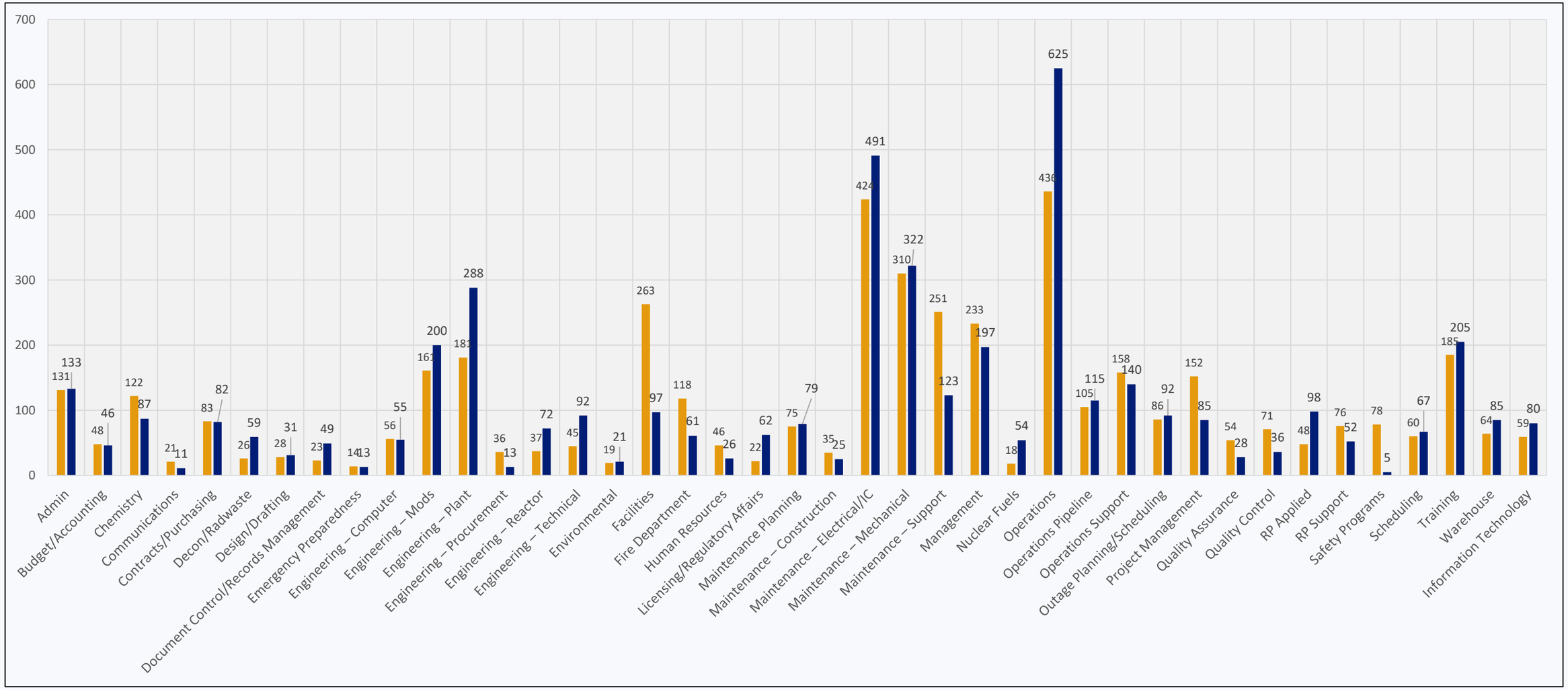
Site Headcount – Indeavor Functions



OPG

Benchmark

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Variance Analysis

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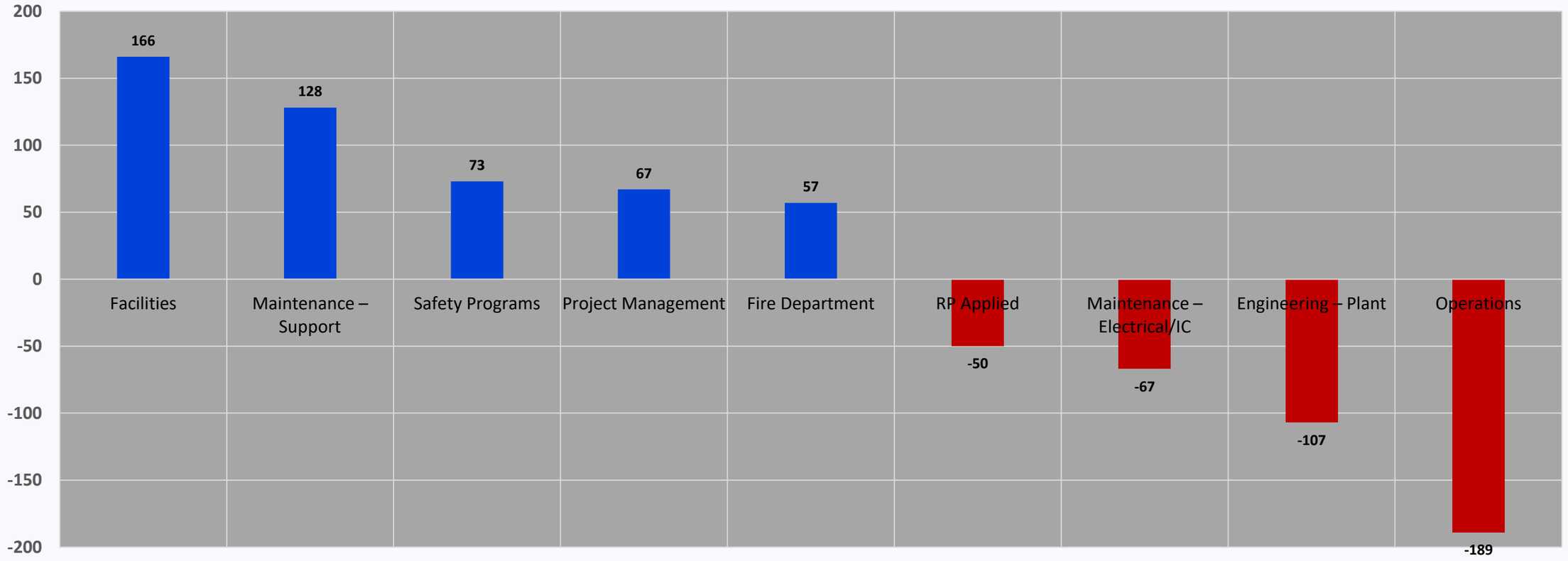
Headcount Variance by Function – Highlights

***5 Functions were above** the benchmark by 50+ headcount;*
***4 Functions were below** the benchmark by 50+ headcount.*



Above Benchmark

Below Benchmark

The 9 functions shown represent ~60% of the total headcount variance across all functions.

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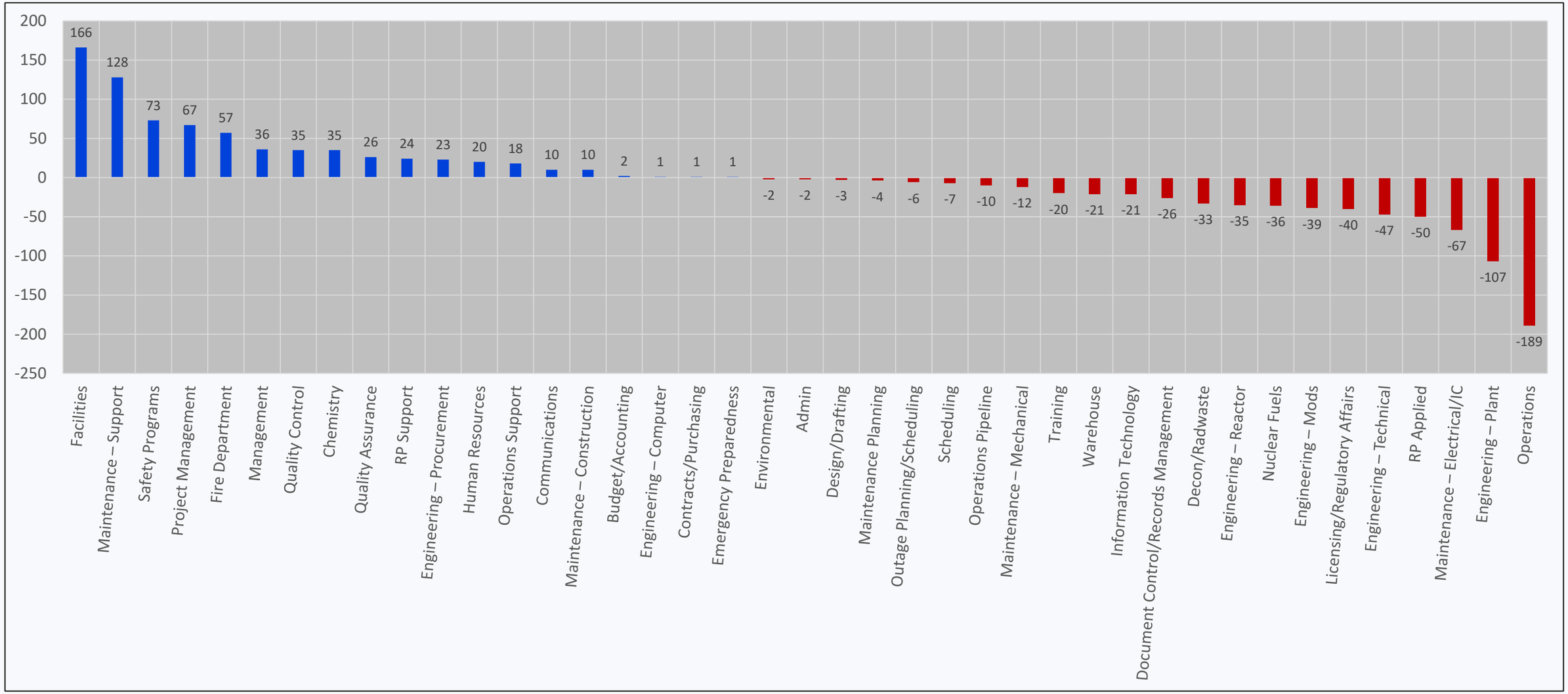
Headcount Variance by Function



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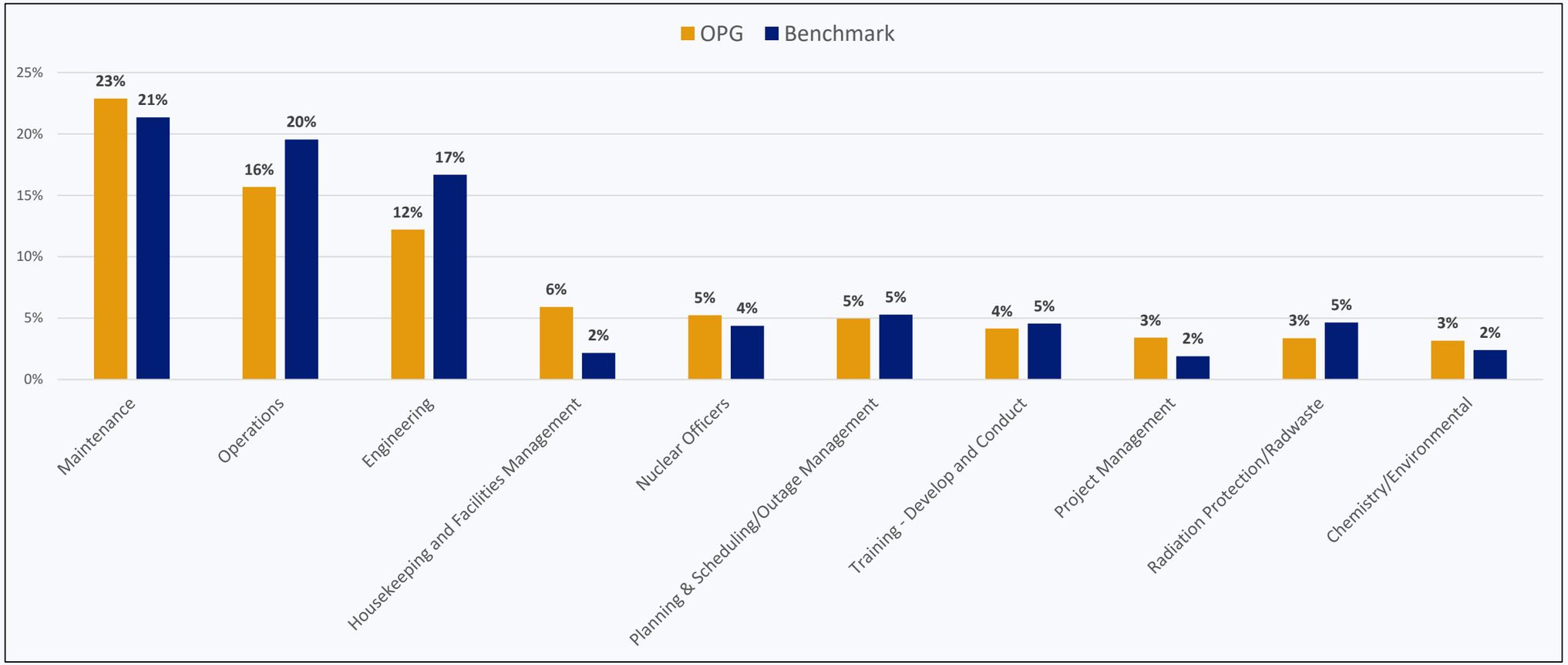
Overall EUCG Account % of Total Staffing



OPG

Benchmark

**Only the top 10 EUCG accounts are shown for visualization purposes. Ranked by the average of OPG and benchmark % of total staffing.*

Average breakdown of functions not shown is 1.6%

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Appendix

INDEAVOR

Appendix – A

EUCG Code	EUCG Account
AD01*	Admin
ENGTOT	Engineering
LP01	Security
LP03	Corrective Action Program and OE
LP02	Quality Assurance/Quality Control
LP04	Safety and Health
LP05	Licensing
LP06	Emergency Preparedness
LP07	Dedicated Fire Responders
MS01	Materials Management & Warehousing
MS02	Contracts & Purchasing
MS03	Procurement Engineering
NFTOT	Fuel Management
OP01	Operations
OP02	Chemistry/Environmental
OP03	Radiation Protection/Radwaste
SS01	Information Technology
SS02	Business Services
SS03	Records Management and Procedures
SS04	Human Resources
SS05	Housekeeping and Facilities Management
SS06	Communications and Community Relations
SS07	Nuclear Officers, Executives, Management Assistance and Industry Associations
TRTOT	Training - Develop and Conduct
WM01	Planning & Scheduling/Outage Management
WM02	Maintenance
WM05*	Project Management

**AD01 and WM05 are not official EUCG account codes, they are used only for data analysis purposes*

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Appendix – B

Indeavor Function	
Admin	Maintenance – Construction
Budget/Accounting	Maintenance – Electrical/IC
Chemistry	Maintenance – Mechanical
Communications	Maintenance – Planning and Support
Contracts/Purchasing	Management
Decon/Radwaste	Nuclear Fuels
Design/Drafting	Operations
Document Control/Records Management	Operations Pipeline
Emergency Preparedness	Operations Support
Engineering – Computer	Outage Planning/Scheduling
Engineering – Mods	Project Management
Engineering – Plant	Quality Assurance
Engineering – Procurement	Quality Control
Engineering – Reactor	RP Applied
Engineering – Technical	RP Support
Environmental	Safety Programs
Facilities	Scheduling
Fire Department	Training
Human Resources	Warehouse
Information Technology	
Licensing/Regulatory Affairs	

INDEAVOR

Appendix – C

EUCG Function	Indeavor Function	FTE Ratio
Admin	Admin	1.00
Engineering	Design/Drafting	0.03
Engineering	Engineering – Computer	0.09
Engineering	Engineering – Mods	0.31
Engineering	Engineering – Plant	0.39
Engineering	Engineering – Reactor	0.09
Engineering	Engineering – Technical	0.10
Security	Security Support	1.00
Corrective Action Program and OE	Corrective Action Program and OE	1.00
Quality Assurance/Quality Control	Quality Assurance	0.37
Quality Assurance/Quality Control	Quality Control	0.63
Safety and Health	Emergency Preparedness	0.23
Safety and Health	Safety Programs	0.77
Licensing	Licensing/Regulatory Affairs	1.00
Dedicated Fire Responders	Fire Department	1.00
Materials Management & Warehousing	Warehouse	1.00
Contracts & Purchasing	Contracts/Purchasing	1.00
Procurement Engineering	Engineering – Procurement	1.00
Fuel Management	Nuclear Fuels	1.00
Operations	Operations	0.61
Operations	Operations Support	0.19
Operations	Operations Pipeline	0.20
Chemistry/Environmental	Chemistry	0.89
Chemistry/Environmental	Environmental	0.11
Radiation Protection/Radwaste	Decon/Radwaste	0.21
Radiation Protection/Radwaste	RP Applied	0.34
Radiation Protection/Radwaste	RP Support	0.44
Business Services	Budget/Accounting	1.00
Records Management and Procedures	Document Control/Records Management	1.00
Human Resources	Human Resources	1.00
Housekeeping and Facilities Management	Facilities	1.00
Communications and Community Relations	Communications	1.00
Nuclear Officers, Executives, Management Assistance and Industry Associations	Management	1.00
Training - Develop and Conduct	Training	1.00
Planning & Scheduling/Outage Management	Maintenance Planning	0.34
Planning & Scheduling/Outage Management	Outage Planning/Scheduling	0.37
Planning & Scheduling/Outage Management	Scheduling	0.29
Maintenance	Maintenance – Construction	0.02
Maintenance	Maintenance – Electrical/IC	0.46
Maintenance	Maintenance – Mechanical	0.33
Maintenance	Maintenance – Support	0.19
Project Management	Project Management	1.00

INDEAVOR

Indeavor Function	OPG	Updated PWR Benchmark	HC Variance	% Variance
Admin	131	133	-2	-2%
Budget/Accounting	48	46	2	4%
Chemistry	122	87	35	40%
Communications	21	11	10	91%
Contracts/Purchasing	83	82	1	1%
Decon/Radwaste	26	59	-33	-56%
Design/Drafting	28	31	-3	-10%
Document Control/Records Management	23	49	-26	-53%
Emergency Preparedness	14	13	1	8%
Engineering - Computer	56	55	1	2%
Engineering - Mods	161	200	-39	-20%
Engineering - Plant	181	288	-107	-37%
Engineering - Procurement	36	13	23	177%
Engineering - Reactor	37	72	-35	-49%
Engineering - Technical	45	92	-47	-51%
Environmental	19	21	-2	-10%
Facilities	263	97	166	171%
Fire Department	118	61	57	93%
Human Resources	46	26	20	77%
Information Technology	59	80	-21	-26%
Licensing/Regulatory Affairs	22	62	-40	-65%
Maintenance - Planning	75	79	-4	-5%
Maintenance - Construction	35	25	10	40%
Maintenance - Electrical/IC	424	491	-67	-14%
Maintenance - Mechanical	310	322	-12	-4%
Maintenance - Support	251	123	128	104%
Management	233	197	36	18%
Nuclear Fuels	18	54	-36	-67%
Operations	436	625	-189	-30%
Operations Pipeline	105	115	-10	-9%
Operations Support	158	140	18	13%
Outage Planning/Scheduling	86	92	-6	-7%
Project Management	152	85	67	79%
Quality Assurance	54	28	26	93%
Quality Control	71	36	35	97%
RE Applied	48	98	-50	-51%
RP Support	76	52	24	46%
Safety Programs	78	5	73	1460%
Scheduling	60	67	-7	-10%
Training	185	205	-20	-10%
Warehouse	64	85	-21	-25%
Total	**4,458**	**4,502**	**-44**	**-1%**

Note 1: Safety Programs shows +1,460% because the PWR benchmark is very small (5 HC). PWR sites often use Safety Programs as a catch-all, and this low average is consistent with what we see in a broader PWR data set. Percentage variances for small functions should be read with caution.

SEC Interrogatory #165

Interrogatory

Reference:
F2-1-1, Attachment 5, p. 8

Question(s):

With respect to the Indeavor, *OPG Nuclear Staff Benchmarking* Report, the study excluded Purchased Services, which is a change from previous studies. Indeavor says: "Without the ability to interview benchmark sites and fully analyze PWR contract staffing, the data was excluded from both data sets."

a) [EB-2020-0290, F2-1-1, Attachment 6, p.11] Using the FTE categories used by Goodnight in previous studies, please explain what is included in the Purchased Services exclusion.

b) Please explain how its ability to interview benchmark sites and analyze PWR contract staffing differs from what Goodnight was able to do in previous studies?

c) On the same basis that it has calculated OPG FTEs in other functions, how many FTEs does OPG have in Purchased Services?

Response

a) Refer to Ex. L-F2-Staff-180.

b) *The following response was prepared by Indeavor:*

The question implies that Goodnight interviewed benchmark sites to collect contractor data as part of its OPG engagements. That is not how it worked. Goodnight maintained a proprietary Nuclear Plant Staffing Database as a standalone product, independent of any specific client engagement. Sites participated in the database voluntarily on an annual basis, and there was regular communication between Goodnight and participants to validate the data, including contractor staffing. The OPG benchmarking studies simply drew from that existing database. The detailed contractor data was available because it was already being collected as part of an established annual process that sites had participated in for years.

Goodnight ceased operations in 2021 and the database was closed. That annual reporting infrastructure no longer exists and cannot be recreated through a one-

off survey. Indeavor does not maintain a staffing database. When surveyed for the current study, peer sites would not provide their long-term contractor data without the ongoing relationship and mutual benefit that the Goodnight database provided. Purchased Services were excluded from both OPG and peers to maintain comparability.

c) Refer to Ex. L-F2-Staff-180.

SEC Interrogatory #167

Interrogatory

Reference:
F2-2-1, Tables 1a, 1b

Question(s):

Please provide the number of FTEs per function per year.

Response

Refer to Attachment 1 for OPG Nuclear Facilities Base OM&A FTEs per function per year for 2020-2031.

Refer to Attachment 2 for DNNP Facilities Base OM&A FTEs per function per year for 2026-2031.

Base OM&A - OPG Nuclear Facilities and Operations and Project Support FTEs by Function

Line No.	Function	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Actual	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	OPG Nuclear Facilities												
1	Darlington NGS	1,331.9	1,330.6	1,194.3	1,198.3	1,181.7	1,238.8	1,306.4	1,250.0	1,231.4	1,240.6	1,240.4	1,235.4
2	Pickering NGS	1,952.2	1,891.1	1,776.6	1,777.4	1,626.5	1,295.4	1,002.0	25.5	54.3	75.5	81.8	712.5
3	**Total OPG Nuclear Facilities**	3,284.1	3,221.7	2,970.9	2,975.7	2,808.2	2,534.3	2,308.5	1,275.5	1,285.6	1,316.1	1,322.2	1,947.9
	Operations and Project Support												
4	Enterprise Engineering	917.9	886.8	855.4	922.5	941.9	865.7	766.2	547.5	532.5	539.1	530.4	626.3
5	Integrated Fleet Management	785.5	721.9	717.2	783.5	856.0	761.2	805.7	634.4	630.0	620.9	636.9	694.4
6	Environment, Health & Safety	53.4	57.8	57.4	56.9	55.8	49.1	43.7	43.6	43.4	42.5	43.8	47.5
7	Enterprise Projects	67.0	67.1	79.4	77.5	71.8	36.7	28.5	23.1	23.0	23.8	22.8	23.2
8	Other Support	100.0	82.6	80.8	89.2	100.2	104.9	107.9	98.9	97.5	97.6	95.8	92.4
9	Low and Intermediate Level Waste	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	**Total Operations and Project Support**	1,923.9	1,816.2	1,790.3	1,929.6	2,025.7	1,817.6	1,752.1	1,347.5	1,326.4	1,323.9	1,329.7	1,483.9
	CRVA Eligible Costs												
11	Fuel Channel Life Extension Project	10.1	0.5	0.0	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Pickering Extended Operations	9.2	3.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Optimization of Pickering Shutdown	1.2	2.1	3.6	3.9	8.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0
14	**Total CRVA Eligible Costs**	20.5	6.3	3.6	4.2	8.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0
15	**Total Base OM&A**	5,228.5	5,044.1	4,764.8	4,909.5	4,842.1	4,352.1	4,060.5	2,623.0	2,612.0	2,640.0	2,651.9	3,431.7

Base OM&A - DNNP Facilities FTEs by Function

Line No.	Function	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	DNNP Facilities						
1	DNNP Facilities	0.0	0.0	0.0	0.0	18.4	101.8
2	**Total DNNP Facilities**	0.0	0.0	0.0	0.0	18.4	101.8
	Operations and Project Support						
3	Enterprise Engineering	1.7	1.8	1.9	2.0	11.4	42.5
4	Integrated Fleet Management	0.3	0.5	0.6	0.6	17.1	75.6
5	Environment, Health & Safety	1.4	2.0	2.4	2.5	2.8	2.5
6	Enterprise Projects	4.5	4.1	4.6	5.0	5.4	4.4
7	Other Support	3.2	4.1	4.5	3.8	7.0	13.3
8	Low and Intermediate Level Waste	0.0	0.0	0.0	0.0	0.0	0.0
9	**Total Operations and Project Support**	11.2	12.5	14.1	13.9	43.6	138.2
10	**Total Base OM&A**	11.2	12.5	14.1	13.9	62.0	240.0

SEC Interrogatory #168

Interrogatory

Reference:
F2-3-1

Question(s):

With respect to unallocated project budget:

a) [p.2] Please explain how the unallocated budget was determined and how the OEB can assess the reasonableness of those amounts where no supporting information, besides the project name, has been provided regarding the potential expenditures.

b) [F2-3-3, Table 4] For each project, please provide a detailed description, justification for the project, and the preliminary cost estimate.

Response

a) Refer to Ex. L-D2-SEC-061, part a), which also applies to Project OM&A.

b) Refer to Ex. L-D2-SEC-056, Attachment 4.

Board Staff Interrogatory #179

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Chart 4 / pp. 24-25
Ref 2: Exhibit F2 / Tab 1 / Schedule 1 / pp. 26-27 (Section 3.3)

Preamble:

At Reference 1, Darlington's non-normalized Non-Fuel Operating Cost per MWh target is $66.61 for 2027, which is more than double the industry median of $24.64 and more than triple the best quartile of $19.64. The normalized Non-Fuel Operating Cost per MWh and normalized Capital Cost per MW Design Electrical Rating (DER) targets for 2027-2031 are all marked N/A. Note 6 to Chart 4 states that "Value for Money targets are indicative and will be updated for final cost allocations reflected in this Application."

At Reference 2, OPG attributes elevated Darlington Total Generating Cost per MWh during the IR term to higher project-related investments, reduced generation from the Vacuum Building Outage in 2027, and emergent work associated with the Primary Moisture Separator Replacements and Turbine Rotors Replacement but does not disaggregate the cost impact of these individual factors

Question(s):

a) Please provide normalized Non-Fuel Operating Cost per MWh and normalized Capital Cost per MW DER targets for each year of the IR term. If they are not available, please explain.

b) Please provide a breakdown of the Darlington Non-Fuel Operating Cost per MWh target of $66.61 for 2027 into its major cost components (e.g., base OM&A, outage OM&A, project OM&A, support services allocations), and for each component identify the gap to the industry median.

c) Note 6 to Chart 4 states that Value for Money targets are "indicative." Please confirm when final Value for Money targets will be established. If the targets have since been established, please provide them.

Response

a) Normalized Non-Fuel Operating Cost per MWh and Normalized Capital Cost per MW DER targets for each year in the IR term cannot be provided. The normalization for these metrics is only performed to adjust for the impact of Darlington Refurbishment in accordance with ScottMadden's OPG Nuclear Cost Performance Benchmarking – Methodology to Adjust for Refurbishment and Validation of Implementation (Ex. F2-1-1, pp. 7-8). Since all Darlington Units have returned to service from refurbishment, such normalization is not applicable during the 2027-2031 IR term. As stated in Ex. F2-1-1, p. 10, OPG does not apply CANDU and age-related normalization, consistent with ScottMadden's methodology, to the sub-components of Total Generating Cost per MWh (i.e., Non-fuel Operating Cost per MWh or Capital Cost per MW DER).

b) Darlington's final Non-Fuel Operating Cost per MWh target for this business planning cycle is $67.07/MWh for 2027, as set out in part c) below. A breakdown of this target into the major cost components is provided in the table below. For clarity, the target reflects exclusions as per EUCG governance. Industry data is not broken down by the cost components below; therefore, a cost component comparison to the industry median is not possible.

2027 Major Cost Components related to Non-Fuel Operating Costs – Darlington	$ Amount per MWh
Darlington Base OM&A	37.25
Darlington Outage OM&A	11.97
Darlington Project OM&A	3.15
Allocation of Corporate Costs – Darlington	11.33
Allocation of Centrally Held Costs – Darlington	3.37
Total Non-Fuel Operating Costs – Darlington	**67.07**

c) Chart 1 below provides Darlington's final 2025–2031 Value for Money targets, which do not materially differ from the indicative targets provided in Chart 4 at Ex. F2-1-1, pp. 24-25). Consistent with past practice, the 2025–2031 Value for Money targets shown in Chart 4 were developed using support cost allocations determined through the previous year's business planning process and were therefore presented as indicative. The update to the Value for Money metrics was anticipated in OPG's 2025-2031 Business Plan, which indicated that the Value for Money targets were "indicative and will be updated once cost allocations and assumptions are finalized" (Ex. A2-2-1, Attachment 1, p. 39, footnote 4). The cost allocations based on the approved 2025–2031 Business Plan were subsequently finalized, in accordance with OPG's cost allocation methodology (Ex. F3-1-4) and are reflected in Chart 1 below.

Chart 1 – Annual Financial Targets for Darlington

Benchmarking Indicators	Best Quartile	Median Quartile	Third Quartile		Darlington Annual Targets						
					2025	2026	2027	2028	2029	2030	2031
Value for Money											
Normalized Total Generating Cost per Net MWh - Updated Methodology ($/MWh)	29.51	34.09	41.78		34.78	43.76	48.75	41.09	42.33	39.15	34.67
Normalized Total Generating Cost per Net MWh - Original Methodology ($/MWh)	27.95	33.51	42.57		37.52	59.72	82.08	50.90	55.27	48.81	44.13
Total Generating Cost per Net MWh ($/MWh)	33.44	39.66	49.23		72.18	85.43	107.77	68.11	74.34	66.90	62.39
Normalized Total Generating Cost per Unit - Updated Methodology ($/Unit)	257.91	284.3	328.93		240.83	301.07	345.63	293.11	300.97	280.12	250.30
Normalized Total Generating Cost per Unit - Original Methodology ($/Unit)	236.12	276.78	320.69		277.54	357.17	406.07	353.62	361.53	340.70	310.87
Total Generating Cost per Unit ($/Unit)	283.01	313.31	358.44		507.52	485.71	503.61	454.52	465.87	448.60	422.42
Normalized Non-Fuel Operating Cost per Net MWh ($/MWh)	N/A	N/A	N/A		37.78	49.76	N/A	N/A	N/A	N/A	N/A
Non-Fuel Operating Cost per Net MWh ($/MWh)	19.64	24.64	32.22		48.35	52.23	67.07	42.65	51.14	44.53	44.62
Fuel Cost per Net MWh ($/MWh)	6.11	6.68	7.44		5.02	6.05	6.49	6.80	7.33	7.80	8.19
Normalized Capital Cost per MW Design Electrical Rating ($/MW)	N/A	N/A	N/A		110.4	161.2	N/A	N/A	N/A	N/A	N/A
Capital Cost per MW Design Electrical Rating ($/MW)	33.87	60.01	107.3		150.71	175.85	182.11	141.84	113.24	111.21	73.84

** TGC/MWh and Non-Fuel Operating Cost per MWh exclude OPEB, Pension and Corporate Asset Service Fees to align with the industry standard.
*** Design Electrical Rating (DER)
Note 1: Normalization methodologies are applied as described in Ex. F2-1-1, Section 3.2.1

Board Staff Interrogatory #180

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / p. 11

Preamble:

At Reference 1, OPG states that the previous staff benchmarking studies included external purchased services (managed tasks), which are excluded from the current study due to the self-reported nature and data visibility from benchmarked peers.

Question(s):

a) Please provide the external purchased services FTE number that otherwise would be included in the current study for 2024 year.

Response

a) Chart 1 provides the external purchased services (managed tasks) FTEs, that were excluded from the current staff benchmarking study, in the same format used in EB-2020-0290, Ex. F2-1-1, Attachment 6, p. 11. In the course of responding to this interrogatory, it was determined that the 203 Oncore FTEs referenced in Figure 1 in Ex. F2-1-1, p. 13 is incorrect as this number represents the total Oncore vendor amount for the year, inclusive of both benchmarkable and non-benchmarkable amounts. The correct number of benchmarkable Oncore FTEs is 158 as shown in Chart 1 below.

Chart 1: 2024 External Purchased Services by Process Area

Process Area Summary	Oncore Hourly	Other Purchased Services	Total Oncore Hourly and Other Purchased Services
Administrative Services	-	-	-
Configuration Management	8	6	14
Equipment Reliability	12	14	26
Loss Prevention	21	21	42
Operate The Plant	-	11	11
Personnel Services	9	14	23
Plant Maintenance	98	68	166
Radiation Protection	2	1	3
Supply Chain	1	1	2
Work Management	7	14	22
Below the Line	-	2	2
Benchmarked Total	**158**	**152**	**310**

Board Staff Interrogatory #181

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / p. 12
Ref 2: Exhibit F4 / Tab 3 / Schedule 1 / Attachment 1, p.1

Preamble:

At Reference 1, OPG states that 4,458 OPG Nuclear staff were benchmarked and 2,386 were excluded from benchmarking consistent with the methodology applied in prior studies. The information is as of December 2024. OEB staff infer from these two values that the number of OPG Nuclear staff in 2024 was 6,844.

Reference 2 states that the number of direct nuclear facilities FTEs in 2024 was 7,507.3.

Question(s):

a) Please reconcile with difference between the value inferred by OEB staff from Reference 1 with the value at Reference 2.

Response

a) Chart 1 below reconciles the OPG FTE data provided to Indeavor for benchmarking purposes, to OPG Nuclear Facilities direct FTEs provided at Reference 2. In the course of responding to this interrogatory, it was determined that the 2,386 FTEs referenced at Ex. F2-1-1, p. 12 is incorrect and the number should have been 2,563, as shown below.

Chart 1 – Reconciliation of FTE Numbers

	2024 OPG FTEs
2024 Staff Benchmarked by Indeavor	4,458.0
2024 Staff Not Benchmarked by Indeavor	2,563.0
Total data provided for Benchmarking Study	**7,021.0**
Less: Augmented staff benchmarked	(386.0)
Plus: Adjustments to align with Electric Utility Cost Group (EUCG) staffing definitions, OPG Security policy, and timing differences[1, 2]	1,618.3
Less: Allocated Corporate Support Staff	(746.0)
2024 OPG Nuclear Facilities direct FTEs per Ex. F4-3-1, Attachment 1, p. 1, line 6	**7,507.3**

[1] Provided on an aggregated basis, as OPG is unable to disclose information separately Security Staff.
[2] Examples include Short Term Non-Regular Capital/Outage Labour, New Nuclear, Nuclear Waste & Decommissioning.

Board Staff Interrogatory #182

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Chart 2 - Comparison of OPG Nuclear Performance to Industry Benchmarks, p. 14

Preamble:

At Reference 1, there are eight metrics under the Reliability area, nine metrics under the Value for Money area and one metric under the Human Performance area.

Question(s):

a) Please clarify whether Darlington's best-quartile performance in 2023 on six of the Reliability metrics reflects any benefit of the completed refurbishments as of that time.

b) Please clarify whether Darlington's below median and below third quartile performance in 2023 on most Value for Money metrics is expected to improve post refurbishment.

Response

a) Completed refurbishments did not provide significant benefits to the six Reliability metrics for which Darlington achieved best-quartile performance in 2023. Rather, strong performance on the six Reliability metrics was attributable to other factors, as described in Ex. F2-1-1, Attachment 2, pp. 29-35 (e.g., Nuclear Performance Index ("NPI") was in first quartile due to excellent performance on all seven NPI safety sub-metrics, Unit Capability Factor performance was driven by reduced planned outage days in 2023, and backlogs improved as a result of continued station focus, maintenance efficiency, and improved schedule quality).

b) Yes, as per Ex. F2-1-1, pp. 26-27, Darlington's Value for Money metrics are expected to improve post-refurbishment. For example, Darlington's normalized total generating costs per megawatt-hour ("TGC/MWh") is expected to achieve second quartile performance toward the end of the IR term.

Board Staff Interrogatory #183

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Chart 3 – Annual Operational and Financial Targets for Pickering, pp. 20-22

Preamble:

At Reference 1, most metric target settings under Value for Money area are unavailable in Chart 3. Note 6 states "the Value for Money targets are indicative and will be updated for final cost allocations reflected in this Application."

Question(s):

a) Please provide the annual targets for the Value for Money metrics that are stated to be unavailable in Reference 1, if they have since become available.

Response

a) Due to the Pickering Refurbishment Program and resulting lack of forecast generation over the 2027-2030 period, Pickering's annual Value for Money metrics targets identified as unavailable in Ex. F2-1-1 (Chart 3, pp. 20-22) cannot be established for this period. In addition, given the significant diseconomies of scale associated with a single online unit for a partial year, OPG does not expect Value for Money targets to be meaningful measures of performance during 2031 and has not established such targets (Ex. A2-2-1, Attachment 1, p. 39, footnote 5). Normalized Non-Fuel Operating Cost per MWh and Normalized Capital Cost per MW DER are Darlington metrics used to normalize for the Darlington Refurbishment (refer to Ex. L-F2-Staff-179, part a)) and, in turn, are not applicable to Pickering.

   Consistent with past practice, the 2025-2026 Value for Money targets shown in Chart 4 (Ex. F2-1-1, pp. 20-21) were developed using support cost allocations determined through the previous year's business planning process and were therefore presented as indicative. The update to the Value for Money metrics was anticipated in OPG's 2025-2031 Business Plan, which indicated that the Value for Money targets were "indicative and will be updated once cost allocations and assumptions are finalized" (Ex. A2-2-1, Attachment 1, p. 39, footnote 4). The cost allocations based on the approved 2025–2031 Business Plan were subsequently finalized, in accordance with OPG's cost allocation methodology (Ex. F3-1-4).

Accordingly, the Value for Money targets have now been established. Chart 1 below provides Pickering's updated 2025-2026 Value for Money targets, which do not materially differ from the indicative targets previously provided.

Chart 1 – Annual Financial Targets for Pickering

Benchmarking Indicators	Best Quartile	Median Quartile	Third Quartile		Pickering Annual Targets						
					2025	2026	2027	2028	2029	2030	2031
Value for Money											
Normalized Total Generating Cost per Net MWh - Updated Methodology ($/MWh)	29.51	34.09	41.78		32.77	45.67	N/A	N/A	N/A	N/A	N/A
Normalized Total Generating Cost per Net MWh - Original Methodology ($/MWh)	27.95	33.51	42.57		42.06	57.25	N/A	N/A	N/A	N/A	N/A
Total Generating Cost per Net MWh ($/MWh)	33.44	39.66	49.23		71.57	101.57	N/A	N/A	N/A	N/A	N/A
Normalized Total Generating Cost per Unit - Updated Methodology ($/Unit)	257.91	284.3	328.93		131.81	131.20	N/A	N/A	N/A	N/A	N/A
Normalized Total Generating Cost per Unit - Original Methodology ($/Unit)	236.12	276.78	320.69		178.70	178.39	N/A	N/A	N/A	N/A	N/A
Total Generating Cost per Unit ($/Unit)	283.01	313.31	358.44		284.63	288.81	N/A	N/A	N/A	N/A	N/A
Normalized Non-Fuel Operating Cost per Net MWh ($/MWh)	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	N/A
Non-Fuel Operating Cost per Net MWh ($/MWh)	19.64	24.64	32.22		59.67	81.44	N/A	N/A	N/A	N/A	N/A
Fuel Cost per Net MWh ($/MWh)	6.11	6.68	7.44		5.15	5.75	N/A	N/A	N/A	N/A	N/A
Normalized Capital Cost per MW Design Electrical Rating ($/MW)	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	N/A
Capital Cost per MW Design Electrical Rating ($/MW)	33.87	60.01	107.3		34.71	79.25	N/A	N/A	N/A	N/A	N/A

** TGC/MWh and Non-Fuel Operating Cost per MWh exclude OPEB, Pension and Corporate Asset Service Fees to align with the industry standard.
*** Design Electrical Rating ("DER").
Note 1: Normalization methodologies are applied as described in Ex. F2-1-1, Section 3.2.1.

Witness Panel: Nuclear Operations and Nuclear Projects

Board Staff Interrogatory #184

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Chart 4 - Annual Operational and Financial Targets for Darlington, pp. 23

Preamble:

At Reference 1, Darlington's annual target is set as 0.0005 throughout 2031 on the Fuel Reliability (microcuries per gram) metric under Safety.

At Reference 1, Darlington's annual target is set as 0.50 throughout 2031 on the Reactor Automatic and Manual Trip Rate (# per 7,000 hours) metric under Safety.

Question(s):

a) Please confirm if a higher value in Fuel Reliability (microcuries per gram) metric means a lower performance, and that the annual target at 0.0005 means Darlington's performance would be expected to be below the third quartile throughout 2031.

b) Please confirm if a higher value in Reactor Automatic and Manual Trip Rate (# per 7,000 hours) metric means a lower performance, and that the annual target at 0.50 means Darlington's performance would be expected to be below the third quartile throughout 2031.

c) Please explain if the above-mentioned two metrics' performance are expected to improve to the third quartile or better beyond 2031.

Response

a) and b) Partially confirmed. As shown in Ex. F2-1-1, Attachment 2, pp. 19-22, higher values in the Fuel Reliability Index ("FRI") and Reactor Trip metrics mean a lower performance. However, annual targets set at 0.0005 microcuries per gram for FRI and 0.50 trips per 7,000 hours throughout the IR term would achieve maximum WANO NPI points ("Max NPI") (refer to Ex. F2-1-1, p. 23 and Ex. F2-1-1, Attachment 2, pp. 19-21). As discussed in Ex. F2-1-1, Attachment 2, p. 11, to benchmark performance, Max NPI is used to indicate best quartile performance for metrics that perform better than the Max NPI benchmark. If metric performance is not better than Max NPI, quartile benchmarks are used to benchmark performance.

c) As noted in parts a) and b), FRI and Reactor Trip metrics are expected to achieve Max NPI during the IR term. Information for this metric beyond 2031 is not available as it goes beyond the forecasted planning period that underlies this proceeding.

Board Staff Interrogatory #185

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Chart 4 – Annual Operational and Financial Targets for Darlington, p. 24

Preamble:

At Reference 1, Darlington's annual target is set as 95.3-96.8 throughout 2031 on the Unit Capability Rate (%) metric under Reliability.

Question(s):

a) Please confirm if a lower value in Unit Capability Rate (%) metric means a lower performance, and that the annual target at 95.3-96.8 means Darlington station's performance would be expected to be below the third quartile throughout 2031.

b) Please explain if the Unit Capability Rate (%) metric's performance is expected to improve to the third quartile or better beyond 2031.

Response

a) Confirmed. A lower Unit Capability Rate ("UCR") value indicates lower performance.

In preparing this interrogatory, OPG identified that the UCR set out in Ex. F2-1-1, for both Pickering and Darlington in Charts 3 and 4, were incorrectly stated. The correct UCR targets are set out in Chart 1 below.

Chart 1 – Corrected UCR Targets for Pickering and Darlington

	2026	2027	2028	2029	2030	2031
PN UCR	96.50	-	-	-	-	88.00
DN UCR	96.47	97.11	97.82	98.00	98.00	98.00

The corrected UCR targets reflect expected performance in the third quartile (97.35) for 2028 through 2031 for Darlington. For clarity, the corrected UCR target does not impact the production forecast.

b) The requested information is not available as it goes beyond the forecasted planning period that underlies this Application.

Board Staff Interrogatory #186

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Chart 4 - Annual Operational and Financial Targets for Darlington, pp. 24-25
Ref 2: Exhibit F2 / Tab 1 / Schedule 1 / p. 10

Preamble:

At Reference 1, there are eleven metrics under the Value for Money area, and nine metrics have annual targets in 2025-2031.

At Reference 1, two targets under Value for Money in 2027-2031 are unavailable in Chart 4. Note 6 says that the Value for Money targets are indicative and will be updated for final cost allocations reflected in this Application.

At Reference 2, OPG states that in the case of Darlington, this (refresh) analysis included costs associated with units in Refurbishment. Since 2017, OPG has calculated an adjustment for refurbishment costs based on the previously established methodology that continues to be applied until the Darlington Refurbishment Program (DRP) is completed.

Based on the References, OEB staff produced Table 1, comparing the original and updated normalization methodologies.

Table 1 – Comparison of Normalized Total Generating Cost (TGC) Methodologies ($/MWh)

	2027	2028	2029	2030	2031
Normalized Total Generating Cost per MWh – Updated Methodology	**51.58**	41.14	42.21	39.14	34.68
Normalized Total Generating Cost per MWh – Original Methodology	**81.36**	50.7	55.08	48.74	44.08
Difference between the original and updated methodology	**-29.78**	-9.56	-12.87	-9.6	-9.4

Question(s):

a) Please confirm that the values in Table 1 are correct. If not confirmed, please provide the corrected values.

b) Please confirm that the updated normalization methodology in annual TGC calculation does not include any refurbishment costs beyond 2026.

c) Please explain why the Normalized TGC/MWh metric value differs significantly in 2027 between the original methodology and updated methodology.

d) Please provide the 2027-2031 annual targets for the two Value for Money metrics that are stated to be unavailable in Reference 1, if they have since become available.

Response

a) OPG has updated Table 1 below to reflect Darlington's final 2025-2031 Value for Money metrics, as discussed and set out in Ex. L-F2-Staff-179, part (c):

Table 1 – Comparison of Normalized Total Generating Cost ("TGC") Methodologies ($/MWh)

	2027	2028	2029	2030	2031
Normalized Total Generating Cost per MWh – Updated Methodology	**48.75**	41.09	42.33	39.15	34.67
Normalized Total Generating Cost per MWh – Original Methodology	**82.08**	50.90	55.27	48.81	44.13
Difference between the original and updated methodology	**-33.33**	-9.82	-12.95	-9.66	-9.46

b) Confirmed.

c) The difference in 2027 between the original and updated Normalized TGC/MWh metric methodologies for Darlington is primarily due to the outage adjustment.

Under the original methodology, the outage adjustment was based on a Nuclear Outage Benchmarking Study conducted by ScottMadden and added an average incremental annualized outage days assumption by reactor/outage cycle to generation (refer to EB-2020-0290, Ex. F2-1-1, Attachment 5, pp. 11-12). For Darlington's 36-month outage cycle, this would produce an adjustment of 13 days

(approximately 1,096 GWh) being added to the generation annually, including 2027, resulting in normalized generation of 19.8 TWh for 2027.

Under the updated methodology, the outage adjustment developed by ScottMadden is based on historical EUCG data and benchmarks planned outage durations to the most efficient plant in the peer group with the lowest planned outage percentage (2.67%) (refer to Ex. F2-1-1, Attachment 4, pp. 11-12). For 2027, since Darlington's planned outage percentage is 31.42%, which is significantly higher than for other years in the IR term due to higher expected planned outage days and the Darlington Vacuum Building Outage, the adjustment adds a proportionately higher amount (9,666.2 GWh), resulting in a normalized generation of 28.4 TWh.

d) Refer to Ex. L-F2-Staff-179, part (a).

Board Staff Interrogatory #187

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / p. 33
Ref 2: Exhibit F2 / Tab 2 / Schedule 2 / pp. 3-4
Ref 3: Exhibit H1 / Tab 1 / Schedule 1 / pp. 52-53

Preamble:

At Reference 1, OPG states that it records, in the Pickering B Variance Account, the revenue requirement impact resulting from actual capital and non-capital costs incurred for extension activities. The Pickering B Variance Account also allows OPG to record costs incurred for preserving resources and supporting infrastructure to enable potential refurbishment and subsequent operation of the Pickering units beyond September 30, 2026.

At Reference 2, OPG states that planned Base OM&A costs in 2026 are $1,210.2 million, which is $588.5 million or 94.7% higher than the 2026 OEB-approved budget of $621.7 million. The reportable variances are largely due to Pickering Units 5-8 not ending commercial operation in 2025 as was assumed in EB-2020-0290.

Reference 3 describes and details the Pickering B Variance Account

Question(s):

a) Please provide, for the increased base OM&A costs in 2026 (i.e. $588.5 million or 94.7% higher than the 2026 OEB-approved budget of $621.7 million) the level of costs that would be recovered through additional revenues generated from the output of Pickering Units 5-8 during the period from January 1, 2026-September 30, 2026.

Response

a) OPG expects the revenues generated from the output of Pickering Units 5 to 8 from January 1, 2026-September 30, 2026 to exceed the forecasted increase in Base OM&A costs of $588.5 million during 2026.

Board Staff Interrogatory #188

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / p. 36
Ref 2: Exhibit F2 / Tab 1 / Schedule 1 / Table 1a

Preamble:

At Reference 1, OPG states that historical and bridge year amounts, identified in Reference 2 at Line 9, primarily relate to preparation for potential new nuclear generation. These costs are being recorded in the Nuclear Development Variance Account.

At Reference 2, Line 9 shows the 2025 budget amount at $62.1 million and 2026 budget amount at $136.4 million.

Question(s):

a) Please provide the 2025 actual amount for Other New Nuclear OM&A.

Response

a) The 2025 actual amount for Other New Nuclear OM&A is $39.4 million (refer to Ex. L-A1-CCC-001).

Board Staff Interrogatory #189

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Attachment 5, p. 8

Preamble:

At Reference 1, the table provides a list of job function categories that were excluded from the 2024 OPG nuclear staffing benchmarking methodology.

Question(s):

a) How many FTEs are in each of the excluded categories?

Response

a) Based on Indeavor's benchmarking methodology and EUCG data provided to Indeavor for benchmarking purposes, total OPG FTEs not benchmarked is 2,563 (refer to Ex. L-F2-Staff-181). Chart 1 below shows the breakdown of these FTEs based on the exclusion categories in Reference 1.[1] In addition, the External Purchased Services that were excluded from the staff benchmarking study (refer to Ex. L-F2-Staff-180) are included in Chart 1.

Chart 1 – OPG Nuclear Staff Benchmarking Exclusions by Function

Function	FTEs
Capital Staffing	1,084
Outage Execution Activities	399
Nuclear Waste and Decommissioning	10
CANDU Specific Activities	788
Total Exclusions by Function	**2,281**
Other [1]	282
Total EUCG Exclusions	**2,563**
Purchased Services (Managed Task)	310
Total Staff Benchmarking Exclusions including External Purchased Services	**2,873**

[1] Represents security support and other exclusions that do not fit into the above classifications.

[1] To remain compliant with OPG security policy, the FTE amount for OPG security staff cannot be specified and are additional to the FTE amounts shown in Chart 1 while security support FTEs have been included in the Other category in Chart 1.

Board Staff Interrogatory #190

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Attachment 5, p. 11
Ref 2: EB-2020-0290 Exhibit F2 / Tab 1 / Schedule 1 / Attachment 6

Preamble:

At Reference 1, Indeavor states that data provided at the Electric Utility Cost Group (EUCG) Account level was normalized using historical ratios to split the EUCG account groups into the respective Indeavor functions.

OEB staff notes that the question below is directed to Indeavor.

Question(s):

a) Indeavor: Please confirm that the normalization methodology described at Reference 1 is the same as that followed by Goodnight Consulting at Reference 2? If not confirmed, please explain.

Response

This response was prepared by Indeavor:

a) Confirmed, with the following clarification:

The normalization methodology used in the 2024 Indeavor benchmarking study is the same as that followed by Goodnight Consulting in the 2019 study — historical ratios were used to split EUCG Account-level data into the respective benchmarking functions. One additional step was required in the 2024 study: as the Goodnight Staffing Database no longer exists, PWR survey data provided at the EUCG Account level was allocated to the corresponding Indeavor (which are the same as what Goodnight Consulting previously used) functions using the historical FTE ratios before proceeding with the normalization. This additional step was necessary to replicate the same functional mapping that was previously handled directly through the Goodnight database. The underlying methodology and ratios are otherwise consistent with those applied in the 2019 study.

Board Staff Interrogatory #191

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Attachment 5, p. 21
Ref 2: EB-2020-0290 Exhibit F2 / Tab 1 / Schedule 1 / Attachment 6, p. 9

Preamble:

At Reference 1, Indeavor provides a list of job functions in the 2024 OPG nuclear staffing benchmarking.

At Reference 2, Goodnight Consulting provides a list of job functions in the 2019 OPG nuclear staffing benchmarking.

OEB staff notes that the question below is directed to Indeavor.

Question(s):

a) Indeavor: OEB staff compared the job functions in Indeavor's 2024 benchmarking and in Goodnight Consulting's 2019 benchmarking. Please explain the following differences:
   i. The "Information Technology" function is in the 2024 benchmarking but is not in the 2019 benchmarking,
   ii. The "Security Support" function is in the 2019 benchmarking but is not in the 2024 benchmarking,
   iii. The "Management Support" function is in the 2019 benchmarking but is not in the 2024 benchmarking.

Response

a) *The following response was prepared by Indeavor:*

   i. The Information Technology function was appropriately not included in the 2019 benchmarking because part of the function was outsourced at that time. Rather, this function was benchmarked via a different method external to the 2019 Goodnight benchmarking study, as noted in EB-2020-0290 Ex. F2-1-1, Attachment 6, p. 16. With the repatriation of Information Technology employees from New Horizon System Solutions to OPG in 2022 (refer to Ex. F3-1-1, p. 7), these employees are part of OPG headcount, and the IT function is now appropriately included in the 2024 nuclear staff benchmarking study.

ii. The Security Support function was not included in the 2024 benchmarking as OPG Security Support staff benchmarking data were excluded to remain compliant with OPG security policy, as noted in Ex. F2-1-1, Attachment 5, p. 8. Such benchmarking data were also not provided by benchmarking peers in 2024.

iii. The Management Support function is in fact included in the 2024 study within the broader "Management" function for benchmarking reporting purposes, as per the EUCG-to-Indeavor function mapping in Ex. F2-1-1, Attachment 5, p. 22, although it is not presented as a separate line item in the benchmarking results due to the de minimis size of this function.

Board Staff Interrogatory #193

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Table 2a

Preamble:

At Reference 1, the table shows nuclear facilities FTE information.

Question(s):

a) Please explain the difference in classification between "Term and Extended Temporary" staff and "Temporary" staff.

b) Please explain what the OPG Nuclear Non-Energy Direct staff covers (lines 41, 42, 43 and 44).

Response

a) Term employees are PWU-represented employees that can be hired instead of Regular employees in circumstances where employees are likely to be laid off as a result of the planned shutdown of Pickering (refer to Ex. F4-3-1, Section 5.1.1). Extended temporary employees are Society-represented employees that can be hired to avoid adding regular staff in circumstances where additional regular employees are likely to be laid off as a result of the planned shutdown of Pickering (refer to Ex. F4-3-1, p. 6, footnote 2). Temporary employees are hired for a fixed time period with a start and end date, which for clarity is not tied to the planned shutdown of Pickering. Temporary employees include students and other fixed term employees hired into PWU, Society or non-represented positions.

b) OPG Nuclear Non-Energy Direct staff are associated with producing a product or providing a service that is non-energy, which is discussed in Ex. G2-1-1.

Board Staff Interrogatory #194

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 2 / Schedule 1 / Table 2a
Ref 1: Exhibit F2 / Tab 2 / Schedule 1 / Table 2b

Preamble:

References 1 and 2 set out Base OM&A by resource type for OPG's nuclear facilities and for the Darlington New Nuclear Program (DNNP) facilities, respectively.

Question(s):

a) Please provide a few examples of the types of costs in the Other Purchased Services category and explain why Other Purchased Services makes up a higher percentage of Base OM&A for the DNNP facilities than for the OPG nuclear facilities.

b) Please provide the quantum of contracted labour costs to be procured through Other Purchased Services for the DNNP facilities in 2027-2031.

Response

a) Refer to Ex. F2-2-1, p.7, lines 5-8 for examples of the types of costs in the Other Purchased Services category for the OPG Nuclear Facilities Base OM&A. The simplified DNNP BWRX-300 design, digital technology and managed systems are designed to optimize labour resources, with staff trained and qualified on a wider scope of tasks and disciplines. As such, labour costs represent a smaller percentage of base OM&A costs in DNNP compared to OPG's nuclear facilities, which increases the percentage of purchased services work.

b) DNNP may purchase services to accomplish certain tasks. Purchased services typically include both labour and a mix of other items (e.g., equipment, materials, etc.) necessary to deliver the required service. OPG does not track purchased services on a labour only basis. Additionally, a number of such contracts are yet to be established as DNNP approaches operation. For these reasons, the quantum of contracted labour that is included under Other Purchased Services is not possible to separate.

Board Staff Interrogatory #195

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 2 / Schedule 1 / Attachment 1, p. 7
Ref 2: Exhibit F1 / Tab 2 / Schedule 1 / Attachment 1, p. 7

Preamble:

At Reference 1, OPG states that Renewable Generation Operations functions provide support for the Nuclear fleet, such as Energy Markets, with costs shown in Nuclear Base OM&A actuals and plan.

At Reference 2, OPG states that the Energy Markets team offers and optimizes OPG's generation assets in the IESO-administered electricity market, ensuring compliance with all legal, regulatory, environmental, and operational requirements.

Question(s):

a) Please provide, for each of 2027-2031, the amount of Renewable Generation Operations support costs allocated to Nuclear Base OM&A.

b) Please confirm that the historical and 2027 Renewable Generation Operations support costs that are allocated to Nuclear Base OM&A were not also allocated to the Hydroelectric businesses' revenue requirements. If not confirmed, please explain.

Response

a) The amount of forecast Renewable Generation Operations support costs allocated to OPG Nuclear and DNNP Facilities Base OM&A costs by year is provided in Chart 1:

Chart 1 – Renewable Generation Operations Allocated Support Costs ($M)

	2027	2028	2029	2030	2031	Total
OPG Nuclear Facilities	$6.3	$6.1	$6.4	$6.2	$6.3	$31.3
DNNP Facilities	$0.5	$0.6	$0.7	$0.9	$1.0	$3.7

b) Confirmed.

Board Staff Interrogatory #196

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 2 / Schedule 1 / Table 1a
Ref 2: Exhibit F2 / Tab 1 / Schedule 1 / Table 2a
Ref 3: Exhibit F2 / Tab 2 / Schedule 1 / Table 2a

Preamble:

At Reference 1, Base OM&A - OPG Nuclear Facilities table shows that the total Base OM&A increases from $840.4 million in 2027 to $1,225.4 million in 2031.

At Reference 2, Staff Summary - Subtotal OPG Nuclear Facilities OM&A (excluding DNNP LP) FTEs increases from 3,283.9 in 2027 to 3,882.6 in 2031.

At Reference 3, the Base OM&A - OPG Nuclear Facilities ($M) resource type table shows labour costs (Labour, Non-Regular Labour, Overtime and Augmented Staff) in Base OM&A.

Using the information in the References, OEB staff produced following table:

Table 1 – Base OM&A Change 2027-2031

	2027	**2031**	**% change**
Nuclear Facilities OM&A (excluding DNNP Facilities) FTE count - Ref 2 Line 6	**3,283.9**	**3,882.6**	**18.23%**
Labour ($ millions) - Ref 3 Line 1	570.03	860.12	50.89%
Non-Regular Labour ($ millions) - Ref 3 Line 2	10.07	10.36	2.81%
Overtime ($ millions) - Ref 3 Line 3	36.42	61.62	69.20%
Augmented Staff ($ millions) - Ref 3 Line 4	1.53	1.33	-12.78%
Sum of Labour costs within Base OM&A ($ millions):	**618.05**	**933.43**	**51.03%**

Total Base OM&A ($ millions)- Ref 1 Line 15	**840.4**	**1,225.4**	**45.80%**

Question(s):

a) Please confirm that the four categories of labour listed in Table 1 reflect all labour costs within Base OM&A. If not confirmed, please explain.

b) Please confirm that the values in Table 1 are correct. If not confirmed, please provide the corrected values.

c) Please explain why the increase in the sum of labour costs (i.e., 51.03%) is higher than the increase in FTE counts (i.e. 18.23%) between 2027 and 2031.

d) Please provide any non-compensation cost drivers which contribute to the total Base OM&A costs increase (i.e. 45.8%) from 2027-2031.

Response

a) Not confirmed. Labour, Non-Labour and Overtime are considered labour compensation costs within Base OM&A costs. Generally, augmented staff are brought in for specialized expertise on a fixed-term basis and/or to help manage peak workload periods (Ex. F2-4-1, p. 7, lines 13-23) and are not considered a labour cost.

b) The values in Table 1 are correct. However, Nuclear Facilities OM&A FTEs and Base OM&A labour costs are not equivalent, as Nuclear Facilities OM&A FTEs includes FTEs for Project OM&A and Outage OM&A in addition to the Base OM&A. Additionally, OPG has filed a revision at Ex. L-F2-Staff-199, correcting the FTE amounts in Reference 2, which affects the total Nuclear Facilities OM&A FTEs. The revised forecast Nuclear Facilities OM&A FTEs are 3,326.3 for 2027 and 3,931.6 for 2031.

c) The comparison between labour costs and FTEs using information from Table 1 is inaccurate for the reasons set out in part a) and b). Chart 1 is provided below to enable a more meaningful comparison between Nuclear Facilities Base OM&A FTEs and Nuclear Facilities Base OM&A labour costs between 2027 and 2031, which shows an increase of 30.8% in the Base OM&A FTEs compared to a 51.2% increase in the Base OM&A labour costs. The percentage increase in the labour costs is higher than the percentage increase in FTEs, primarily due to cumulative

wage escalation assumptions between 2027 and 2031 (Ex. L-F4-Staff-227), and higher overtime in 2031. Overtime does not contribute to the total number of FTEs.

Chart 1 – Base OM&A Change 2027 - 2031

OPG Nuclear Facilities Base OM&A (excluding DNNP Facilities)	2027 Plan	2031 Plan	% Change
Nuclear Facilities Base OM&A FTE count	**2,623.0**	**3,431.7**	**30.8%**
Labour (M$) - Ref. 3 Line 1	570.0	860.1	50.9%
Non-Regular Labour (M$) - Ref 3 Line 2	10.1	10.4	2.9%
Overtime (M$) - Ref 3 Line 3	36.4	61.6	69.2%
Sum of Labour costs within Base OM&A (M$):	**616.5**	**932.1**	**51.2%**
Total Base OM&A (M$)- Ref 1 Line 15	**840.4**	**1,225.4**	**45.8%**

d) The higher FTEs and overtime costs in 2031 reflect the temporary decrease in these cost levels in 2027 as Pickering Units 5-8 enter the four-unit refurbishment outage and begin to restore toward normal operating levels in 2031 when Pickering Unit 5 returns to service. For the same reason, as shown in Ex. F2-2-1 Table 2a, also contributing to this trend in the Nuclear Facilities Base OM&A costs is the temporary decrease in Materials and Other Purchased Services until Pickering Units 5 returns to service.

Board Staff Interrogatory #197

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Table 1a

Preamble:

At Reference 1, the Operating Costs Summary – OPG Nuclear Facilities ($M) table shows the Nuclear Facilities OM&A (excluding Darlington New Nuclear Program (DNNP) Facilities).

Question(s):

a) Please provide the planned external purchased service costs in 2027-2031 in the following OPG Nuclear Facilities OM&A categories:
   i. OPG Nuclear Facilities Base OM&A
   ii. OPG Nuclear Facilities Project OM&A
   iii. Pickering Cyclical Maintenance OM&A
   iv. Pickering Refurbishment OM&A

Response

a) Refer to Ex. L-F2-CCC-078.

Board Staff Interrogatory #198

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 2 / Schedule 2 / p. 2
Ref 2: Exhibit F2 / Tab 1 / Schedule 1 / Table 2a
Ref 3: Exhibit F2 / Tab 2 / Schedule 1 / Table 2

Preamble:

At Reference 1, OPG states that Planned Base OM&A costs in 2029 are $898.4 million, which is $47.8 million or 5.6% higher than the 2028 planned Base OM&A costs of $850.7 million. The higher OM&A costs include the impact of the 53rd fiscal week in 2029.

At Reference 2, Staff Summary - Subtotal OPG Nuclear Facilities OM&A (excluding DNNP LP) FTEs increase from 3,246.8 in 2028 to 3,317.7 in 2029.

OEB staff calculates that, at Reference 3, labour categories (Labour, Non-Regular Labour, Overtime and Augmented Staff) make up 75.2% of Base OM&A costs in the IR term.

OEB staff also calculates that the 53rd fiscal week, combined with the increase in FTEs could be expected to cause an increase in Base OM&A of approximately 3% between 2028 and 2029. That is:

- 53rd Fiscal Week adds approximately 2% (due to one extra week of compensation costs 1/52=2)
- OPG's projected FTE count increase adds approximately 2.1% (3,317.7/3,246.8 – 100%=2.1% compensation costs increase)

Applying the 2.0 + 2.1% increase to the labour categories' 75.2% contribution to Base OM&A results in an increase of approximately 3% in 2029 compared to 2028.

Question(s):

a) Please comment on the reasonableness of OEB staff's calculation that 2029 Base OM&A could be expected to be 3% higher than 2028 Base OM&A.

b) Please provide the 2028 to 2029 annual wage escalation and general inflation assumed in the Planned Base OM&A which results in the 5.6% Base OM&A costs increase from 2028 to 2029.

Response

a) Not confirmed. The calculated 3% is not a reasonable approximation of the Base OM&A costs increase between 2028 and 2029, as it does not consider wage escalation, which is provided at Ex. L-F4-Staff-227. Once wage escalation assumptions are added, the resulting approximation would be reasonable.

In addition, the FTEs in Reference 2 include all OPG Nuclear Facilities OM&A costs, whereas the costs at Reference 1 and 3 are planned Base OM&A costs only.

b) The 2028 to 2029 annual wage escalation assumptions are provided in Ex. L-F4-Staff-227 and general inflation assumed in the planned Base OM&A costs is provided in Ex. A2-2-1, Attachment 2, pp. 9-10.

Board Staff Interrogatory #199

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Table 2a

Preamble:

At Reference 1, Staff Summary - Regular and Non-Regular (FTEs) - OPG Nuclear Facilities table breaks out the FTEs accounted as OM&A and accounted as Capital.

Question(s):

a) Please provide the FTEs split between OM&A and Capital in Darlington Refurbishment Program's FTEs.

b) Please provide the FTEs split between OM&A and Capital in Pickering Refurbishment Program's FTEs.

c) Please provide the FTEs split between OM&A and Capital in Nuclear Provision FTEs.

Response

a) All DRP FTEs are Capital funded.

b) All PRP FTEs are Capital funded.

In the course of responding to this interrogatory, OPG identified that certain FTEs were incorrectly categorized under the PRP OM&A and should have been shown in the Nuclear Facilities OM&A and Nuclear Facilities Capital categories. A corrected version of Ex. F3-1-1, Table 18 is provided in Attachment 1, where lines 18 and 20-23 have been corrected to be included in lines 1, 3-6, 7 and 9-12. This also impacted Ex. F2-1-1, Table 2a, where lines 19, 21, 23-24 have been corrected to be included in lines 1, 3, 5 and 6 in the updated version of that table provided in Ex. L-F1-Staff 171, Attachment 1. These corrections do not impact the Applicants' proposed revenue requirements or other approvals sought in this Application.

c) Nuclear Provision FTEs are not split into OM&A and Capital, as they are not funded by either of those two categories and are instead funded by nuclear liabilities (refer to Ex. C2-1-1).

Numbers may not add due to rounding.

Filed: 2026-04-22
EB-2025-0297
Exhibit L
F2-Staff-199
Attachment 1

Staff Interrogatory #199 - Revised Ex. F3-1-1, Table 8
Allocation of Corporate Support Staff Summary - Regular and Non-Regular (FTEs) - OPG Nuclear Facilities

Line No.	Group	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Nuclear OM&A:												
1	**Regular Staff**	854.9	799.2	880.2	1,049.6	1,124.5	1,167.9	1,077.1	998.1	993.1	996.0	1,003.0	1,055.3
	Non-Regular Staff												
2	Term/ETE/PECO Temporary	57.4	76.1	79.2	61.9	53.0	39.0	33.3					
3	Temporary	146.9	156.0	168.5	186.2	152.1	102.5	73.4	55.4	55.5	53.2	54.9	58.0
4	EPSCA	24.6	25.3	22.1	21.6	15.7	27.1	28.1	23.1	23.1	23.1	23.0	26.9
5	**Total Non-Regular Staff**	229.0	257.3	269.8	269.7	220.8	168.6	134.7	78.5	78.5	76.2	78.0	85.0
6	**Subtotal Nuclear OM&A**	1,083.9	1,056.6	1,150.0	1,319.2	1,345.3	1,336.4	1,211.8	1,076.6	1,071.7	1,072.3	1,081.0	1,140.2
	Nuclear Capital:[1]												
7	**Regular Staff**	14.7	14.2	21.5	42.5	45.5	111.2	116.3	155.7	153.1	156.0	152.0	144.5
	Non-Regular Staff												
8	Term/ETE/PECO Temporary	2.6	1.3	1.1	2.7	5.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Temporary	1.0	0.0	0.0	10.8	11.1	0.8		3.2	3.2	3.2	3.2	3.2
10	EPSCA	10.7	10.2	1.0	2.8	1.7	0.9	0.9	0.9	0.9	0.9	0.9	0.9
11	**Total Non-Regular Staff**	14.3	11.5	2.1	16.3	18.4	1.8	0.9	4.1	4.1	4.1	4.1	4.2
12	**Subtotal Nuclear Capital**	29.0	25.7	23.6	58.8	63.9	112.9	117.2	159.8	157.2	160.1	156.1	148.6
	Darlington Refurbishment:												
13	**Regular Staff**	37.4	33.4	31.5	32.4	37.3	38.2	17.0	0.0	0.0	0.0	0.0	0.0
	Non-Regular Staff												
14	Temporary	10.6	12.2	9.3	10.2	6.9	4.0	0.0	0.0	0.0	0.0	0.0	0.0
15	EPSCA	6.7	8.9	7.8	7.2	8.0	6.0	0.0	0.0	0.0	0.0	0.0	0.0
16	**Total Non-Regular Staff**	17.3	21.1	17.2	17.4	14.9	10.0	0.0	0.0	0.0	0.0	0.0	0.0
17	**Subtotal Darlington Refurbishment**	54.7	54.5	48.7	49.9	52.2	48.2	17.0	0.0	0.0	0.0	0.0	0.0
	Pickering Refurbishment:												
18	**Regular Staff**	0.0	0.0	0.0	0.9	29.7	104.7	145.7	244.4	234.9	234.9	229.1	167.9
	Non-Regular Staff												
19	Term/ETE/PECO Temporary	0.0	0.0	0.0	0.0	2.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	Temporary	0.0	0.0	0.0	0.0	4.4	0.0	1.0	3.0	1.0	1.0	1.0	1.0
21	EPSCA	0.0	0.0	0.0	0.0	4.5	3.0	8.0	13.0	13.0	13.0	13.0	10.3
22	**Total Non-Regular Staff**	0.0	0.0	0.0	0.0	11.0	3.0	9.0	16.0	14.0	14.0	14.0	11.3
23	**Subtotal Pickering Refurbishment**	0.0	0.0	0.0	0.9	40.7	107.7	154.7	260.4	248.9	248.9	243.1	179.2
	Darlington New Nuclear Program:												
24	**Regular Staff**	0.0	0.0	9.9	14.0	21.9	33.3	0.0	0.0	0.0	0.0	0.0	0.0
	Non-Regular Staff												
25	Temporary	0.0	0.0	0.2	0.3	1.7	2.0	0.0	0.0	0.0	0.0	0.0	0.0
26	EPSCA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	**Total Non-Regular Staff**	0.0	0.0	0.2	0.3	1.8	2.0	0.0	0.0	0.0	0.0	0.0	0.0
28	**Subtotal New Nuclear DN Capital**	0.0	0.0	10.2	14.2	23.7	35.3	0.0	0.0	0.0	0.0	0.0	0.0
	Darlington New Nuclear & Other New Nuclear OM&A:												
29	**Regular Staff**	4.8	25.4	0.3	4.6	7.6	24.0	41.8	0.0	0.0	0.0	0.0	0.0
	Non-Regular Staff												
30	Temporary	0.4	2.1	0.0	0.2	0.3	1.0	1.0	0.0	0.0	0.0	0.0	0.0
31	**Subtotal Darlington & Other New Nuclear OM&A**	5.2	27.6	0.3	4.9	7.8	25.0	42.8	0.0	0.0	0.0	0.0	0.0
	Nuclear Provision:												
32	**Regular Staff**	16.3	14.5	16.1	15.3	27.6	65.5	59.1	58.1	56.5	49.1	50.2	50.4
	Non-Regular Staff												
33	Term/ETE/PECO Temporary	0.6	1.1	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Temporary	1.5	0.5	2.0	2.4	2.5	1.0	1.0	1.0	1.0	1.0	1.0	1.0
35	EPSCA	0.0	0.0	0.0	0.0	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	**Total Non-Regular Staff**	2.1	1.6	2.0	2.4	4.4	1.0	1.0	1.0	1.0	1.0	1.0	1.0
37	**Subtotal Nuclear Provision**	18.4	16.1	18.1	17.8	31.9	66.5	60.1	59.1	57.5	50.1	51.2	51.4
38	**Total Nuclear**	1,191.3	1,180.5	1,250.8	1,465.6	1,565.7	1,732.2	1,603.6	1,555.9	1,535.2	1,531.3	1,531.5	1,519.4

Notes:

1 Includes Asset Service Fee projects

Board Staff Interrogatory #200

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Table 1b
Ref 2: Exhibit F2 / Tab 1 / Schedule 1 / Table 2b

Preamble:

At Reference 1, the Operating Costs Summary - DNNP Facilities ($M) table shows the Darlington New Nuclear Program (DNNP) Facilities OM&A.

At Reference 2, the Regular and Non-Regular (FTEs) - DNNP Facilities table shows the DNNP Facilities OM&A Staff FTEs number.

OEB staff created the following table to compute year over year changes to DNNP staffing across 2027-2031.

Table 1 – DNNP Facilities OM&A Year over Year

	2027	**2031**	**YoY % change**
DNNP Facilities OM&A ($ millions) - Ref 1 table Line No. 4	50.2	167.6	**233.86%**
DNNP Facilities OM&A Staff FTEs number - Ref 2 table Line No. 6	144.9	238.5	**64.60%**

Question(s):

a) Please confirm that the values calculated in Table 1 are correct. If not confirmed, please provide the corrected values.

b) Please provide any non-compensation cost drivers that lead to the DNNP Facilities OM&A ($ millions) increase.

Response

a) Confirmed.

b) DNNP Unit 1 will not be operating in 2027 but is planned to be in commercial operation for a full year in 2031, which is the reason for the higher DNNP facilities OM&A costs in 2031 relative to 2027. The 2031 DNNP facilities OM&A costs reflect the full suite of Base and Outage labour and non-labour resources and expenditures necessary for the safe and reliable operation of a new nuclear generating facility. The resource type breakdown of DNNP facilities OM&A costs can be found at Ex. F2-2-1, Table 2b.

For clarity, non-compensation OM&A expenses for the DNNP facilities in 2031 include:

- $45.3M in planned contracting services for the 12-month cycle outage in 2031, which consists of refueling, inspection and maintenance activities. As explained at Ex. F4-2-1, Section 4.2, contracting services will be used for the maintenance scope of that outage;
- $30.1M in Base OM&A purchased services. Refer to Ex. L-F2-Staff-194 for additional information;
- $10.6M in materials costs; and
- $10.3M for planned costs including Canadian Nuclear Safety Commission licence fees, World Association of Nuclear Operators fees, and other costs such as Boiler Water Reactor engineering membership fees.

Board Staff Interrogatory #201

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Table 1b

Preamble:

At Reference 1, the Operating Costs Summary - DNNP Facilities ($M) table shows the Darlington New Nuclear Program (DNNP) Facilities OM&A.

Question(s):

a) Please provide the external purchased service costs treated as DNNP Facilities OM&A in 2026-2031, with breakdowns into Base, Outage and Operational Readiness OM&A.

Response

The requested information is provided in Chart 1 below.

Chart 1 - DNNP Facilities OM&A Purchased Services 2026 to 2031 ($M)

Line No.	DNNP Facilities Cost Category	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1	Base OM&A	0.5	0.3	0.4	0.5	11.8	30.1
2	Outage OM&A	0.0	0.0	0.0	0.0	0.0	45.3
3	Operational Readiness OM&A	7.5	10.7	11.2	7.7	1.9	0.0
4	DNNP Facilities Purchased Services OM&A	**8.0**	**11.0**	**11.6**	**8.2**	**13.8**	**75.4**

Refer to Ex. L-F2-Staff-194 and Ex. L-F2-Staff-200 for further discussion of DNNP facilities purchased services OM&A costs.

Board Staff Interrogatory #202

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 3 / Schedule 1 / Table 1
Ref 2: Exhibit F2 / Tab 1 / Schedule 1 / Table 2a

Preamble:

At Reference 1, Project OM&A Summary - OPG Nuclear Facilities ($M) table shows the 2020-2031 Project OM&A.

At Reference 2, the Staff Summary - Regular and Non-Regular (FTEs) - OPG Nuclear Facilities table shows the 2020-2031 OPG Nuclear Facilities Capital FTEs.

OEB staff created the following table showing year over year changes to OM&A.

Table 1 – Nuclear Facilities OM&A Year over Year

	2024	**2025**	**YoY % Change**
Total Project OM&A - OPG Nuclear Facilities (excluding Darlington New Nuclear Program (DNNP) Facilities) ($ millions) - Ref 1 table Line No. 16	107.9	75.6	**-29.94%**
OPG Nuclear Facilities Capital (excluding DNNP Facilities) FTEs - Ref 2 table Line No. 12	324.3	517.3	**59.51%**

Question(s):

a) Please confirm that the values in Table 1 are correct. If not confirmed, please provide corrected values.

b) Please provide 2025 actual Project OM&A as presented in the Reference 1 table if available.

c) Please explain why the Project OM&A costs trend down from 2024 to 2025 by 29.94% while the OPG Nuclear Facilities Capital FTEs sees an increase from 2024

to 2025 of 59.51%. To what extent is the difference in trends due to more project costs being capitalized rather than being expensed as OM&A?

d) Please clarify if OPG's capitalization policy on project costs has changed in the 2024-2025 period.

Response

a) Confirmed.

b) Refer to Ex. L-A1-CCC-001, which includes Ex. F2-3-1, Table 1 updated with 2025 year-end actual numbers.

c) The OPG Nuclear Facilities Project OM&A costs trending down from 2024 actual to 2025 budget by $32.3M is due primarily to Project #87908 Darlington Unit 1 Steam Generator Primary Side Clean, which incurred nearly all of its project spend in 2024 (Ex. F2-3-3, p. 3, lines 1-11). Other drivers for 2024 expenditures are noted in Ex. F2-3-2, Section 5.0. These drivers are not due to increased capitalization of costs.

The actual OPG Nuclear Facilities Project OM&A costs for 2025 were $63.1M, which is $12.5M below the 2025 budget and $44.8M lower than the 2024 actual. The 2025 actual costs were lower than budget primarily due to lower removal costs associated with capital projects and shifts in project schedules and associated expenses.

Actual 2025 OPG Nuclear Facilities Capital FTEs was 384.9, which represents an 18.7% increase from 2024 (Ex. L-A1-CCC-001). The increase in Capital FTEs from 2024 to 2025 is unrelated to Project OM&A costs decreasing from 2024 to 2025 and is instead tied to the increase in capital project expenditures in 2025 and the ramp up to support the 2026 capital portfolio. The increase in capital investment in 2025 is not due to more project costs being capitalized rather than being expensed as OM&A and OPG's capitalization policy has stayed constant between 2024 and 2025, as discussed in part d).

d) OPG's capitalization policy has not changed in the 2024-2025 period.

Board Staff Interrogatory #203

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 3 / Schedule 2 / Table 1
Ref 2: Exhibit F2 / Tab 3 / Schedule 2 / page 3

Preamble:

At Reference 1, the Comparison of Project OM&A - OPG Nuclear Facilities ($M) table lays out the 2020-2026 Project OM&A Actual/Budget vs. OEB-Approved difference.

At Reference 2, OPG states that planned project OM&A costs for 2027-2031 are $410.6 million. This value is $76.9 million (16%) lower than the actual expenditure amount of $487.4 million in the 2022-2026 term (2025 and 2026 being forecast). This decrease is primarily driven by decreased planned expenditures in Project OM&A (Portfolio) of $11.7 million and Non-Portfolio Projects of $65.2 million.

OEB staff created the following table showing Project OM&A year over year trends.

Table 1 – Project OM&A Year over Year

	2022	**2023**	**2024**	**2025**	**2026**	**2022-2026 term**
Total Project OM&A Including Adjustments ($ millions) - Actual - Ref 1 table Line No. 18, Actual columns	89.5	141.1	107.9	75.6	73.3	487.4
Total Project OM&A Including Adjustments ($ millions) - OEB-Approved - Ref 1 table Line No. 18, OEB-Approved columns	86.4	82.5	76.6	72.8	60.1	378.4
Project OM&A Actual over OEB-Approved ($ millions)	3.1	58.6	31.3	2.8	13.2	**109.0**

Question(s):

a) Please confirm that the values in Table 1 are correct. If not confirmed, please provide the corrected values.

b) Given the forecasted decrease in project OM&A in 2027-2031 term compared to 2022-2026 actual, please explain if the $109 million over OEB-Approved spending on project OM&A in 2022-2026 is due to pacing of 2022-2026 projects going ahead of original schedule, project OM&A scope change, or neither. If neither, please explain.

c) Please provide the estimated costs and in-service dates of each of the projects in Reference 3. If the sum of those projects' estimated costs differs from the $152.6 million 2027-2031 Plan for Portfolio Project (Unallocated) at Reference 1, please explain

Response

a) Confirmed.

b) The 2022-2026 Actuals / Budget variance to 2022-2026 OEB-Approved for Project OM&A cost is not due to pacing of 2022-2026 projects going ahead of original schedule or project OM&A scope changes. The primary drivers of the variance are the following new projects that were not in EB-2020-0290, which account for $75.3M (69%) of the variance:

Portfolio Projects (Allocated):

- #87908 Darlington Unit 1 Steam Generator Primary Side Clean (+$20.5M) (Ex. F2-3-3, p. 3, lines 1-11)

Non-Portfolio Projects:

- Fuel Channel Life Management Phase V Project (+$13.3M)
- FCLE Related Ongoing Costs[1] (+$26.8M) (Ex. F2-3-3, p. 2, lines 16-27)
- Darlington Steam Generator Primary Moisture Separators Replacement Projects (+$14.7M) (Ex. D2-1-3, p. 13, line 22 to p. 15, line 15)

For further information on variance drivers to OEB-Approved spend, refer to Ex. F2-3-2, Sections 4.0 and 5.0.

c) Following clarification sought from OEB staff, OPG understand that this question was provided in error and no response is required.

[1] Represents the Pickering Unit 8 Boiler Secondary Side Advancement Scale Conditioning.

Board Staff Interrogatory #204

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 3 / Schedule 2 / Table 1
Ref 2: Exhibit F2 / Tab 3 / Schedule 2 / p. 1
Ref 3: Exhibit F2 / Tab 3 / Schedule 3 / Table 4

Preamble:

Reference 1 states at line 24 that the 2027-2031 Plan for Portfolio Projects (Unallocated) is $152.6 million.

Reference 2 states that Portfolio Projects (Unallocated) is "the remaining budget available to cover the cost of projects that are progressing through the review and approval process but do not have a PMOC-approved budget or an approved BCS."

References 3 lists unallocated OM&A projects.

Question(s):

a) Please provide the estimated costs and in-service dates of each of the projects in Reference 3. If the sum of those projects' estimated costs differs from the $152.6 million 2027-2031 Plan for Portfolio Project (Unallocated) at Reference 1, please explain.

b) For the projects at Reference 3, are there business cases or similar documentation that supports the project need and cost estimates? If so, please provide them for those projects greater than $20 million. If not available, please describe the information provided to the business unit asset management governing body.

Response

a) Refer to Ex. L-F2-CCC-075, Attachment 1 for estimated costs of unallocated OM&A candidate projects. In-service dates are not applicable to OM&A projects and only applicable to capital projects. Potential project end dates have been provided in Attachment 1 (confidential) but, as noted in Ex. L-F2-CCC-075, cost and schedule information for unallocated projects are preliminary, high-level estimates and are subject to change through the annual business planning process.

   Ex. F2-3-3, Table 4 contains only Tier 1 (Projects >$20M) and Tier 2 (Projects >$5M and <$20M) OM&A candidate projects, which add up to $99.2M in the 2027-2031

IR term, and does not reconcile to $152.6M as the table does not include potential Tier 3 (Projects <$5M) OM&A projects and other unallocated funds. The other unallocated funds are, in part, included in recognition of the anticipated additional investments expected to be identified in support of Pickering second life operations as well as emergent projects. In later years of the business plan, in recognition of emerging work issues that require timely resolution, Darlington has other unallocated funds to support anticipated inspections that require project management oversight.

b) For projects greater than $20 million listed in Reference 3, the only project with a BCS is for Project 89223 – DN U2 Primary Heat Transport Pump Motors Oil Leak Repairs, which is provided at Attachment 1. For the remaining unallocated projects listed in Reference 3, refer to Ex. L-D2-SEC-056 Attachment 4.

Business Case Summary

Project #	89223	**BCS Document Number**	D-BCS-33130-10008
Project Title	89223 - DN UNIT 2 PHT-PM OIL LEAK REPAIRS		
Facility	D - DARLINGTON NGD	**Investment Classification**	Sustaining
Project Level (Scalability)	B	**Financial Classification**	62030 - OM&A - PROJECT
Release: Gate and Project Phase	G3 - Execution - (Full)	**Target Project Completion Date**	2030-May-31
Estimate Class (Current Request)	Class 3	**Estimate Class (Overall Project)**	Class 3

Recommendation

We recommend release of$34,643k, including [redacted] of contingency.

The Total Project Cost is estimated to be $34,643k, including [redacted] of total contingency.

This project will address and mitigate the risks associated with the 2-33130-PM1/2/3/4 DE bearing oil leaks, thereby relieving the on-going Operations/Maintenance burdens, eliminating the potential safety hazards, and ensuring the long-term motor reliability.

This release is to repair four (4) leaking Primary Heat Transport (PHT) Pump Motors (PM) in U2 during the D2721 outage. In order to accomplish this objective, four (4) available spare motors are required. Three (3) pump motors to be installed will be delivered from Project# 84415. One (1) remaining spare motor (R06) will be repaired and returned as a spare under this project, prior to the start of the outage in 2026.

Investment Cash Flows

Project Number	89223 - DN UNIT 2 PHT-PM OIL LEAK REPAIRS					**FAC**	62030 - OM&A - PROJECT		
$K	**LT YE last year**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**Future**	**Total**
Previous releases	0								0
Currently Requested	0	81	5,729	8,569	13,768	6,457	39		34,643
Total released to date	0	81	5,729	8,569	13,768	6,457	39		34,643
Future required	0								0
Total Project Cost	0	81	5,729	8,569	13,768	6,457	39		34,643
Ongoing Costs	0								0

Total OAR Approval	34,643.0

Approvals	**Signatures**	**Date**
The recommendation, including the identified ongoing costs, if any, represents the best option to meet the validated business need.		
Recommended by: Direct Report of Line Approver : Hassan Qadri Director Station Engineering Dir DN Station Eng	Hassan Qadri	2025-11-18
I concur with the business decision as documented in this BCS.		
Finance Approval : Maha Tam VP Ops & Projects Controllership	Maha Tam	2025-11-26

ONTARIO POWER GENERATION

Records File Information:
Retention Permanent

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OPG-FORM-0076-R006*

Business Case Summary

I confirm that this investment/project, including the identified ongoing costs, if any, will address the business need, is of sufficient priority to proceed, and provides value for money.		
Line Approval per OAR : **OAR Element : 1.1** **Allan Grace** **SVP Darlington**	Allan Grace	2025-11-26

EXECUTIVE SUMMARY – Project Overview

PHT motors perform the critical function of transferring heat from the fuel to the boilers for power generation or to a heat sink to provide cooling of the fuel. Oil seal leaks were identified on new Unit 1, 2 and 3 PHT Pump Motors during the first routine inspection after their return to service. Oil was observed leaking and pooling on stator windings, rotor, stator coolers and motor bus bars. Cleanup and repair cannot be performed in situ or at site as it requires full motor disassembly.

A risk assessment of the seal leak issue by OPG (NK38-CORR-33130-0794084) recommends that the problem be corrected early to preserve the life of the motors, before cumulative motor damage occurs. Oil leakage will degrade the motor stator winding insulation and increase motor operating temperatures resulting in premature motor failure, potentially leading to a forced Unit shutdown to replace the motor.

This project is to repair four (4) oil leaking motors in Unit 2 during the Darlington Nuclear Station U2 outage (D2721), as well as the repair of one (1) additional motor (R06) to support the execution of this work during outage. One of the spare motors intended for U2 outage (D2127) was installed in U4 to replace a motor (R06) having Resistance Temperature Detector (RTD) related issues. Therefore, there are only three (3) spares currently available for Unit 2. To support the outage and the replacement of the four (4) leaking motors in U2, the additional motor will be repaired for the RTD related issues in 2026 bringing the spare motor inventory to four (4).

While the project estimate includes costs related to the oil leak repairs, OPG is pursuing cost recovery through warranty claim with the manufacturer.

This project is proceeding directly to a full Execution Phase (Gate 3) release. This project has a similar scope as project# 84415, PHT motor oil leak repairs for Units 1 and 3. Project# 84415 is on track and has successfully completed 50% of the scope of work.

This release will fund the following scope of work:
1. Repair of one (1) PHT pump motor (R06).
2. Removal of the four (4) leaking PHT pump motors from U2 (M7, M8, M9 and M10).
3. Installation of pump motors. One (1) motor (R06) from 89223 and three (3) from 84415 (M6, M1, M2).
4. Completion of oil leak repair of the four (4) removed motors from U2.
5. Return four (4) repaired motors to the station as spares.

The key risks involved, and the mitigations applied with this project are:
1. OEM Support/ Long Lead/ Alternative Materials availability.
Mitigation: Work with legal and supply change for early resolution on warranty claims.

2. Discover issues during inspection assessments during repair which may result increase in cost and/or delay to schedule.
Mitigation: Work with the vendor to inspect the bearing pads at the early stage of the component inspection.

Business Need

For Project Level A or B

There are twenty-one (21) PHT Pump Motors at Darlington site. Sixteen (16) are needed for normal operations (4 per unit) and five (5) spares are to remain on site. Ten (10) of the PHT Pump Motors were replaced with redesigns and installed in Unit 1, 2 and 3.

Oil leaks from the drive-end (DE) bearing seals were discovered during the first internal inspections of the new motors. Oil is leaking and pooling on the inside of the motor shroud covering the motors internal components, including the stator windings, rotor, stator coolers, bus bars, air baffles, auxiliary junction box and associated wiring. Additional issues include oil foaming in the non-drive end (NDE) oil reservoir (oil level not visible) and oil leakage at the NDE of the motor (oil on top of motor).

One of the spare motors intended for U2 was installed in U4 to replace a motor having RTD related issues and, another motor (R01) can no longer be used as it is too old. Thus, there are now only three (3) spares instead of five (5). To support the outage and the replacement of the four (4) oil leaking motors in U2, the additional motor (R06) will be repaired for RTD related issues in 2026, bringing the spare motor inventory to four (4).

This project is to repair four (4) oil leaking motors in Unit 2 during the Darlington Nuclear Station U2 outage (D2721), as well as the repair of one (1) additional motor (R06) to support the execution of this work during outage.

Business Case Summary

Preferred Alternative:	Replace and Repair PHT Motors	For Project Level A, B or C

Description of Preferred Alternative

Replace four (4) oil leaking PHT pump motors in Unit 2, during D2721 outage. To support this, one (1) additional motor (R06) will be repaired for RTD related issues in 2026.

Scope of Work includes:
1. Repair of one (1) PHT pump motor (R06).
2. Removal of the four (4) leaking PHT pump motors from U2 (M7, M8, M9 and M10).
3. Installation of pump motors. One (1) motor (R06) from 89223 and three (3) from 84415 (M6, M1, M2).
4. Completion of oil leak repair of the four (4) removed motors from U2.
5. Return four (4) repaired motors to the station as spares.

Key Assumptions:
1. OEM support (technical, parts, etc.) will be available to support motor repairs/replacements, as well as spare parts.
2. OEM or equivalent parts will be available on time to support the motor repairs schedule.

Deliverables:

Previous Release: N/A

Current Release:

Deliverable Type	*Milestones*	*Associated Milestones (if any):*	*Target Date*
Procurement Process of Motor R06	Procurement Contracts Awarded/PO Issued	89223M1340	2026-03-26
Repair and return of a spare motor (R06) to support D2721 scope.	LLM_Long Lead Manufacturing Complete	89223M1580	2026-12-21
Replace 2-33130-PM1/2/3/4 with spares during D2721.	Available for Service and/or Ready For Service Completed	89223M1750	2027-11-30
Repair and return of removed/defective motors from U2 as spares.	Material / Equipment Available	89223M1551	2029-05-14
Project Closeout	Project Close Out Completed	89223M9998	2030-05-31

Future Release: N/A

Alternative 2:	**Base Case - No Project**	For Project Level A, B or Value-Enhancing

Not recommended as current PHT motor oil seal leakage issue will not be resolved. Continued operation with the oil leaks will not support safe and reliable continued operations of Darlington. This will pose production and safety risks going forward and will also expose the PHT pumps to the high risk of failure as a result of the degradation due to oil leakages.

Pros:
1. None.

Cons:
1. Failure of motors will lead to forced outage.
2. A catastrophically failed motor may not be repairable (additional new motors may have to be procured).

Alternative 3:	**Delay Work**	For Project Level A, B or Value-Enhancing

This alternative is not recommended. Defer PHT motor replacement and repair to scheduled upcoming outages. A delay will mean missing the next planned opportunity for repair and extending the project completion date.

Risks of delay:
1. Increased and more frequent maintenance to remove oil from inside the motor
2. DNGS has a limited ability to remove oil from an installed motor
3. Increased oil viscosity may clog stator vents and coolers, increasing motor operating temperatures
4. Oil contamination on windings may lead to degraded rotor/ stator insulation and premature winding failure
5. Cumulative damage / fouling of internal parts such as (coolers, rotor, stator windings, bearing oil passages, etc.)
6. Risk of premature motor failure and forced outage(s)
7. Work delayed until the next planned U2 outage, the year 2030

Pros:
1. Delay in Cost Spend.

Cons:
1. High Risk of motor failure leading to a forced outage.
2. Extended burden on Operations and Maintenance to operate the plant with defective motors.

Alternative 4:	**Procure New Motors for Replacement**	For Project Level A, B

Replace deficient motors with new motors with the upgraded design. The alternative is not recommended due to the longer lead time and higher costs.

Pros:
1. New Motors may have a longer operating life.

Cons:
1. Long lead time to procure new motors
2. Significantly higher cost of new motors (approx. $8.5M new vs $3.5M each to repair; replacement costs are similar)
3. Additional outages required.

Key Risk Assessment — For Project Level A, B or C

Risk Class	Description of Risk	Response Type / Actions / Final TCD	Residual Ranking
Quality	Discovery of QA non-compliance items.	Mitigate 75942 - Work closely with repair vendor to provide adequate oversight. 11/30/2029	Medium
Technical	Repair vendor not able to complete all 4 repairs in time for outage.	Mitigate 75944 - Keep the schedule align with vendor capabilities (2 motors repair at a time) 8/31/2028	Medium
Technical	Failures of one or more PHT motors during operation and unavailability of spares.	Mitigate 76096 - Keep a viable spare at site in case any operating motor fails. 11/28/2029	Low
Procurement - Materials	Discovery of damaged bearing pads in one of the 5 motors.	Mitigate 75601 - Discovery of damage bearing pads Work with the vendor to inspect the bearing pads at the early stage of the component inspection. 8/25/2029	Medium

ONTARIO POWER GENERATION

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Business Case Summary

Financial Evaluation		For Project Level A, B (with multiple feasible alternatives) or Value-Enhancing			
$K	**Alternative**	**Base Case (No Project)**	**Delay Work**	**Alternative 4**	**Alternative 5**
N/A					

Analysis of Financial Evaluation – Key Assumptions and Key Results:

A financial evaluation is not required for sustaining projects.

Qualitative Factors	For Project Level A or B

Completion of this project will positively impact the business drivers of the nuclear safety and financial performance by improving reliability, reducing maintenance burden, and supporting the long-term operation of DNGS.

Post Implementation Review (PIR) Plan (refer to OPG-GUID-00120-0007)

Is PIR Required?	Yes	**PIR Completion Date**	2031-05-31

PIR KPI's	**Current Baseline**	**Target Result**	**How to Measure?**	**Who will measure?**
Condition of Motors	There are four (4) PHT motors considered to be at moderate risk of failure in mid-term operation due to oil leakages (M07-M10).	Seal leaks are repaired and risk to continuous operation is low.	Scheduled routine online inspections of motors to ensure oil leaks have been mitigated.	Components Engineering

Definitions and Acronyms	
BCS	Business Case Summary
PHT	Primary Heat Transport
PMP	Project Management Plan
PM	Pump Motor
DNGS	Darlington Nuclear Generating Station
OPEX	Operating Experience
OEM	Original Equipment Manufacturers
OAR	Organizational Authority Register
FAT	Factory Acceptance Tests
SAT	Site Acceptance Test
CCF	Change Control Form
NICR	Non-Identical Component Replacement

Business Case Summary

APPENDICES

Appendix A1: Summary of Estimate										
Project Number	89223 - DN UNIT 2 PHT-PM OIL LEAK REPAIRS						**FAC**	62030 - OM&A - PROJECT		
$K	**LT YE last year**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**Future**	**Total**	**%**
0 - Cost Management		19	135	136	142	61			493	1
1 - Project Management	[redacted]									
2 - Inspection										
3 - Engineering										
4 - Procurement										
5 - Construction										
6 - Commissioning										
Closeout										
Subtotal										
Outside WBS										
Contingency										
Subtotal w/ Contingency										
Interest										
Other										
Total		81	5,729	8,569	13,768	6,457	39		34,643	100
Removal Costs (incl. above)										0

Appendix A2: Summary of Estimate – Notes			
Escalation Rate	**4.14**	**Interest Rate (going-forward)**	

Appendix A3: Summary of Estimate - In-Service Estimates				
$K	Only applicable to capital projects. In-Service amount shall include interest but exclude removal costs.			
Project#	**Date**	**Description**	**Amount**	**%**
N/A				
		Total:		

Prepared by		Reviewed and Endorsed by (Execution Authority)	
Renee Tipler Corpuz Assistant Project Leader DN Projects 1.2	2025-11-07	Perrik Le Dreff VP Major Projects Darlington Nuclear Projects	2025-11-17

Board Staff Interrogatory #205

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 4 / Schedule 1 / p. 1
Ref 2: Exhibit F2 / Tab 4 / Schedule 1 / Table 1

Preamble:

At Reference 1, OPG states that Darlington station has a 36-month planned "cyclical outage" schedule. OPG states that non-refurbishment work conducting on units during their refurbishment "effectively replaces" cyclical outages that would have otherwise been undertaken.

Reference 2 shows Outage OM&A for 2020-2031.

Question(s):

a) Please confirm that, for 2022-2026, the Darlington non-refurbishment "cyclical outage" OM&A is included under the "Darlington Outages" in Reference 2.

Response

a) Confirmed.

Board Staff Interrogatory #206

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 4 / Schedule 1 / pp. 1-2

Preamble:

At Reference 1, OPG states that Darlington New Nuclear Program (DNNP) facilities' refueling outages will initially be performed on a 12-month cycle followed by 24-month cycles. Pickering station has a 30-month planned outage schedule. Darlington station has a 36-month planned outage schedule.

Question(s):

a) Please clarify if the 24-month outage cycle cadence for DNNP is expected for the duration of the facility's life.

b) Please explain how OPG plans outage schedules efficiently to maximize utilization of outage OM&A resources.

Response

a) Following the initial 12-month outage for each unit, a 24-month outage interval for DNNP, required for fueling, is expected for the duration of the facility's life.

b) Refer to Ex. F2-4-1, Section 4.3.

In addition, nuclear outages are planned and executed using a Planned Outage Management (N-PROC-MA-0013) procedure, which provides a systematic approach for guiding an outage through its life cycle. This procedure includes resource management milestones to ensure adequate resources are available to plan and execute outages efficiently.

Board Staff Interrogatory #207

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 4 / Schedule 1 / p. 4

Preamble:

At Reference 1, OPG states that the Pickering Cyclical Maintenance program will primarily be executed by existing OPG operational staff.

Question(s):

a) Given that the Pickering Cyclical Maintenance is a new category in OPG's 2026-2031 OM&A budget, please provide the number of existing FTEs and any new hire FTEs whose costs will be accounted in Pickering Cyclical Maintenance OM&A in 2026-2031.

Response

a) See Chart 1 below for the FTE forecast associated with the Pickering Cyclical Maintenance OM&A budget. The FTE forecast is based on the workforce demand to execute the program, reflecting existing operational staffing levels for the equivalent work prior to Units 5-8 coming offline for refurbishment. New hires would be used to manage attrition of existing employees in the normal course as part of overall workforce management, where applicable, and are not separately forecast.

Chart 1 – Pickering Cyclical Maintenance – Annual FTEs

Year	2026	2027	2028	2029	2030	2031
Annual FTE	75	431	422	422	423	260

Board Staff Interrogatory #208

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 4 / Schedule 1 / pp. 4-5
Ref 2: Exhibit F2 / Tab 4 / Schedule 1 / Table 1

Preamble:

At Reference 1, OPG states that both Base OM&A and Pickering Cyclical Maintenance OM&A resources are required to carry out the ongoing inspection, maintenance and regulatory compliance activities at Pickering during the four-unit refurbishment outage.

At Reference 2, the Outage OM&A table (line 1 and 2) shows that Darlington recorded Outage OM&A during its refurbishment years (2020-2026). The table (line 4 and 5) also shows that Pickering will have zero Outage OM&A planned during its refurbishment years (2027-2030).

Question(s):

a) Please clarify if the Pickering Cyclical Maintenance OM&A is a re-classification of costs that would otherwise be recorded under Base OM&A and Outage OM&A.

b) Please explain if and why Outage OM&A definition is applied differently for Darlington station and Pickering station during their respective refurbishment years.

Response

a) Yes, Pickering Cyclical Maintenance OM&A costs would otherwise be recorded under Base OM&A and Outage OM&A costs if the Pickering units were not in refurbishment during this period.

b) The Outage OM&A costs classification is applied differently for Darlington and Pickering during their respective refurbishment years. Darlington's Outage OM&A costs included certain non-refurbishment outage scope (referred to as Darlington Cyclical Outages) for various inspection, maintenance and related activities that are otherwise associated with a planned outage but which were undertaken on the units while they were under refurbishment. OPG recorded such costs as Outage OM&A costs because some Darlington units were not in refurbishment at that time and continued to take some planned outages.

In contrast, all four Pickering units will be in refurbishment during the 2027-2030 period and none will be taking planned outages during that time. As a result and given that the scope of Pickering's costs must also include what would otherwise have been online maintenance work funded by Base OM&A costs for an operating unit, like there was at Darlington, OPG is not applying an Outage OM&A cost classification for Pickering during the 2027-2030 period. Instead, the costs of the various inspection, maintenance and related activities during this period, whether they would have been online maintenance or planned outage scope, are classified as Pickering Cyclical Maintenance OM&A costs. Pickering Cyclical Maintenance OM&A costs are further discussed in Ex. F2-4-1, Section 3.0.

Board Staff Interrogatory #210

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 4 / Schedule 1 / p. 11

Preamble:

At Reference 1, OPG states that the actual outage OM&A costs also include unbudgeted planned outages.

Question(s):

a) Please clarify if "unbudgeted planned outages" includes planned but under-budgeted outages.

Response

a) As defined in Ex. E2-1-1, Attachment 1, p. 3, an "unbudgeted planned outage" refers to an emergent outage that was not included in the approved nuclear outage and generation plan that underpins the business plan, but for which OPG had sufficient time to notify the IESO at least 28 days prior to the start date. It does not include regular planned outages that were under-budgeted.

Board Staff Interrogatory #212

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 5 / Schedule 1 / p. 7

Preamble:

At Reference 1, OPG states that since EB-2020-0290, OPG has increased the fuel procurement planning timeframe from five years to 15 years, due in part to market drivers such as increasing nuclear power demand, and supply and demand dynamics expected in the global uranium market.

Question(s):

a) Please provide the increased annual working capital amount arising from the extension of the fuel procurement planning timeframe from five years to fifteen years.

Response

Extending the procurement planning horizon from 5 to 15 years allows OPG to secure supply capacity for a longer period without increasing annual nuclear fuel inventory demand. Consequently, no additional working capital is required.

Board Staff Interrogatory #214

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 5 / Schedule 1 / p. 16

Preamble:

At Reference 1, OPG describes the Darlington New Nuclear Program (DNNP) facilities' nuclear fuel procurement supply chain and some procurements done in 2023-2025.

Question(s):

a) Please clarify where these 2023-2025 procured costs for DNNP facilities are being recorded.

Response

a) The DNNP nuclear fuel procurements undertaken in 2023-2025 were for deliveries beginning in 2026 onwards (the first of which are uranium hexafluoride deliveries in 2026). No fuel costs under these contracts were incurred in the 2023-2025 period.

Board Staff Interrogatory #216

Interrogatory

Reference:
Ref 1: Exhibit F2 / Tab 6 / Schedule 1 / p. 1
Ref 2: Exhibit F2 / Tab 2 / Schedule 1 / Table 2a
Ref 3: Exhibit F2 / Tab 4 / Schedule 1 / Table 2

Preamble:

At Reference 1, OPG states that the total OM&A purchase services expenditures for all contractors for the historical period (2020-2024) was $247.6 million in 2020, $300.5 million in 2021, $255.5 million in 2022, $287.4 million in 2023, and $275.6 million in 2024.

At Reference 2, Other Purchased Services actual amounts for 2020-2024 are included under Base OM&A.

At Reference 3, Other Purchased Services actual amounts for 2020-2024 are included under Outage OM&A.

OEB staff produced the following table showing other purchased services.

Table 1 – Other Purchased Services ($ millions)

	2020	**2021**	**2022**	**2023**	**2024**
Other Purchased Services - Base OM&A - Ref 2 table, Line 7	130.16	151.14	159.58	143.42	164.91
Other Purchased Services - Outage OM&A - Ref 3 table, Line 6	135.22	188.12	128.03	157.28	169.61
Total of Other Purchased Services, Ref 2 and Ref 3	**265.37**	**339.26**	**287.61**	**300.70**	**334.52**
Total OM&A purchase services expenditures, Ref 1	**247.6**	**300.5**	**255.5**	**287.4**	**275.6**

Question(s):

a) Please confirm that the values in Table 1 are correct. If not confirmed, please provide the corrected values.

b) Please explain why the values in the two “Total” rows in Table 1 are different.

Response

a) Confirmed.

b) The values in the Total of Other Purchase Services, Reference 2 and Reference 3 row reflects Base and Outage OM&A purchase services only and excludes Project OM&A purchase services expenditures. The Total OM&A purchase services expenditures at Reference 1 reflects Base OM&A, Outage OM&A and Project OM&A expenditures for those vendors whose total expenditures over the 2020-2024 (5 year) period exceed $20M, as per Section 8.2 of the Filing Requirements for Ontario Power Generation Inc. Therefore, the two “Total” row values in Table 1 are different.

Society Interrogatory #010

Interrogatory

Reference:
OEB staff interrogatory F2-Staff-180

Preamble:

OEB staff have requested the external purchased services FTE number that otherwise would be included in the Indeavor Nuclear Staffing Benchmarking Study for 2024.

Question(s):

a) Please provide the estimated total cost for these external purchased services FTE's. This should be the total billed cost, not the sum of an estimated labour rate for such.

Response

a) The estimated total cost for the requested external purchased services FTEs, provided at Ex. L-F2-Staff-180, is $88.8M, based on actual amounts paid.

Society Interrogatory #011

Interrogatory

Reference:
(1) OEB staff interrogatory F2-Staff-181
(2) Exhibit F4-3-1, Attachment 1, "Appendix 2K"

Preamble:

OEB staff have requested that OPG reconcile the difference in inferred total OPG Nuclear staff numbers both included and excluded from the Indeavor Nuclear Staffing Benchmarking Study for 2024 and reference (2) above.

Question(s):

a) If the interrogatory response to F2-Staff-181 concludes that there is an error in reference (2), please update this reference.

Response

a) Not applicable, as there was no error in Reference 2 per Ex. L-F2-Staff-181, and therefore no update is required.

Society Interrogatory #012

Interrogatory

Reference:
Exhibit F2-1-1, Attachment 5, OPG Nuclear Staff Benchmarking by Indeavor dated November 2025.

Preamble:

"OPG's 2024 staffing headcount is 4,458, which is 9.3% below the benchmark of 4,913." [Executive Summary p4]

Question(s):

a) Please breakdown both this OPG staffing headcount of 4458 and the variance of 455 (9.3%) by representation jurisdiction i.e. Management, SUP represented and PWU represented.

b) Does this staffing headcount underage indicate that OPG is understaffed as compared to this peer group?

c) What are the health and safety consequences of such understaffing in OPG as compared to this peer group?

Response

a) The OPG nuclear staffing benchmarking headcount of 4,458 has been broken down in Chart 1 below by represented group. OPG and Indeavor are not privy to the peer group information at this level of detail and therefore cannot provide the breakdown of the variance to benchmark by represented group.

Chart 1: OPG Nuclear Staffing Benchmarking Headcount Breakdown

	Total
Management	424
Society Represented	1,511
Power Workers Union (PWU) Represented	2,446
Augmented Staff	44
EPSCA	33
Total	**4,458**

Witness Panel: Nuclear Operations and Nuclear Projects.

b) The Nuclear Staffing Benchmarking Report, which has been revised as discussed in Ex. L-F2-SEC-164, part d), shows that OPG's nuclear staffing headcount variance is 44, or 1.0%, below benchmark.

OPG is not understaffed. Rather, based on the 2025 Indeavor nuclear staffing analysis, OPG has been able to maintain safe, reliable operations with 1.0% less staff compared to the benchmark. OPG's Building Talent for Today & Tomorrow initiative focuses on ensuring work programs are resourced appropriately in accordance with the 2025-2031 Business Plan while minimizing the organizational impacts associated with transition to the Pickering Refurbishment Program and Pickering and Darlington post-refurbishment operations (refer to Ex. F2-1-1, pp. 29-30).

c) As discussed in part b), OPG is not understaffed. Therefore, there are no health and safety consequences of being understaffed compared to the peer group. OPG's staffing levels are predicated on ensuring safe, reliable operations of the nuclear stations. Pickering and Darlington stations continue to demonstrate strong safety performance, achieving green ratings for all safety metrics in 2023. Darlington and Pickering continued to demonstrate first quartile performance in Total Recordable Injury Frequency ("TRIF"), with OPG achieving its best TRIF performance in the history of the company in 2023 since the company's inception in 1999 and having the best TRIF performance in 2023 compared to its peer group. (Ex. F2-1-1, p.15, lines 10-16).

AMPCO Interrogatory #105

Interrogatory

Reference:
F2-3-3 Table 1

Question(s):

a) Please provide the total project cost in EB-2020-0290 for: DN Primary Heat Transport Pump Motor Oil Leak Repair (Project #84415), Fuel Channel Life Extension Project (Project #80014) DN Irradiated Fuel Bay Stack Frames Project (Project #80067).

b) Please provide the final completion date in EB-2020-0290 for: DN Primary Heat Transport Pump Motor Oil Leak Repair (Project #84415), Fuel Channel Life Extension Project (Project #80014), DN Irradiated Fuel Bay Stack Frames Project (Project #80067), and DN U0 Switchgear Refurbishment (Project #84484).

c) Please confirm the Fuel Channel Life Extension Project (Project #80014) was completed in December 2025 at a cost of $63.6 million.

d) Please provide the actual completion date for PN U8 Boiler Secondary Side Advanced Scale Conditioning Project (Project #87117) and the original baseline total cost estimate. In the response, please indicate why a BCS is shown as n/a.

e) Please confirm DN U1 Steam Generator Primary Side Clean Project (Project #87908) was completed in December 2025 at a cost of $20.6 million.

f) Please provide the Project Over Variance Report for Project #84484.

Response

a) The requested total project costs as provided in EB-2020-0290 Ex. F2-3-3, Table 1 were:
- DN Primary Heat Transport Pump Motor Oil Leak Repair (Project #84415): $47.4M
- Fuel Channel Life Extension Project (Project #80014): $69.3M
- DN Irradiated Fuel Bay Stack Frames Project (Project #80067): $29.7M.

b) The requested final completion dates as provided in EB-2020-0290, Ex. F2-3-3, Table 1 were:

- DN Primary Heat Transport Pump Motor Oil Leak Repair (Project #84415): July 2025
- Fuel Channel Life Extension Project (Project #80014): December 2021
- DN Irradiated Fuel Bay Stack Frames Project (Project #80067): December 2022
- DN U0 Switchgear Refurbishment (Project #84484): December 2027.

c) Confirmed.

d) PN U8 Boiler Secondary Side Advanced Scale Conditioning Project (Project #87117) was completed June 2025.[1] The original cost estimate was $35.8M and the total project cost of the completed project was $26.8M. A standalone Business Case Summary ("BCS") for this project was not applicable, as this work was executed under the established Fuel Channel Life Extension Ongoing investment program, which covers expenditures for incremental work required to enable fuel channel and other major component (e.g., steam generators) operation to enable a nuclear station's beyond original design targets (refer to Ex. F2-3-3, p. 2).

e) Not confirmed. The field work for the DN U1 Steam Generator Primary Side Clean Project (Project #87908) was completed in May 2024. However, project closure report completion is ongoing, and the total project cost has not yet been finalized.

f) As required by OPG's governance, a Superseding BCS was prepared, which is provided at Ex. F2-3-3, Attachment 1, Tab 1, rather than a Project Over Variance Report. A project variance explanation for Project #84484 is provided at Ex. F2-3-3, pp. 3-6.

[1] In the course of preparing this response, OPG discovered an error in the date specified in Ex. F2-3-3, p. 2, line 23, which specified completion in December 2024.

AMPCO Interrogatory #106

Interrogatory

Reference:
F2-3-3 Table 2a, Table 2b, Table 2c

Question(s):

a) Please confirm all of the projects with a final completion date of 2025 to March 2026 have been completed.

b) Please provide the baseline approved cost and final completion date for each of the OM&A projects in Table 2a, Table 2b and Table 2c.

Response

a) Not confirmed. All projects with final completion dates of 2025 to March 2026 have been completed except for the following projects, which are all currently in close out:

Project # 84872 - DN PRECISE-D Scrape Tooling
Project # 87152 - PN Public Address System Core Upgrade
Project # 87187/87892 - PN Forebay Dredging

b) The total project cost and final completion date from the first Execution Business Case Summary is provided for each of the OM&A projects in Ex. F2-3-3 Table 2a, Table 2b and Table 2c in Attachment 1.

Line No.	Facility	Project Name	Project No.	1st Execution BCS Final Completion Date[1]	1st Execution BCS Total Project Cost ($M)[1]
		ONGOING PROJECTS FROM EB-2020-0290			
1	AIM	Inspection Qualification	66105	Dec-14	15.3
2	DN	DN Reduced HTS Pressure-Temperature Envelope Modifications	80016	Dec-19	11.7
3	DN	DN Aging Management Scope Defining Inspections	80110	Dec-18	9.9
4	PN	Pickering 58 Digital Control Computer Hardware Modernization	80135	n/a	n/a
5	DN	Darlington DCC/CP/SEM Computers Software Shipments	82825	Jun-27	8.6
6	DN	DN Fuel Handling Computer Software Release	82826	Jul-26	10.2
7	DN	DN Annunciation Modifications And Post-Accident Monitoring Configuration Management	83545	Dec-28	9.2
8	AIM	DN PRECISE-D Scrape Tooling	84872	Dec-21	5.3

		COMPLETED/DEFERRED/CANCELLED FROM EB-2020-0290			
9	DN	DN Boiler Blowdown Piping Replacement	31506	Jun-18	17.8
10	DN	DN GFP Sample Delay & Alternative PHT Sampling Point	31514	May-18	8.5
11	DN	DN PHT LRV Modifications (Waterhammer)	38933	Dec-25	21.6
12	PN	PN Instrumentation & Control Obsolescence	41024	Jun-16	5.6
13	PN	DCC Aging Management	62553	Dec-12	14.5
14	PN	PN Equipment Reliability Initiatives	80060	Dec-14	8.5
15	DN	DN New Primary Heat Transport Pump Seals	80071	Dec-17	16.6
16	DN	DN Aging Management	80079	Dec-16	8.2
17	DN	DN Annulus Spacer Life Management	83280	Dec-21	29.3
18	PN	Pickering Fuelling Machine Ram Seal Improvement	83302	Dec-19	14.6
19	DN	DN Civil Building Structure Repairs	83479	May-24	12.7
20	ENG	Asset Management Implementation	83824	Dec-19	9.4

21	DN	DN Resin Transfer Modification	84380	Dec-20	8.0
22	DN	DN Periodic Safety Review	84589	May-24	27.0
23	DN	DN PHT Pump Motor R01 Refurbishment	84766	Sep-23	8.7
24	DN	X-Lab Wireless Sensor Portfolio	84999	Mar-24	7.0
		PROJECTS NOT IN EB-2020-0290			
25	AIM	Matrix Inspection For Tubular Components	84850	n/a	n/a
26	AIM	Laser Induced Breakdown Spectroscopy Hydride Characterization Tool	86174	n/a	n/a
27	PN	Public Address System Core Upgrade	87152	Jan-25	6.9
28	DN	Fuel Channel Life Management Phase V Project	87175	Dec-27	14.6
29	PN	PN Forebay Dredging	87187/ 87892	Nov-24	20.2

Notes:

1 The designation of "n/a" means the project has not advanced to a First Execution BCS.

AMPCO Interrogatory #107

Interrogatory

Reference:
F2-3-3 Table 4

Question(s):

a) Please confirm all of the projects with a potential 2025 start date have started.

b) With respect to the DN U2 Primary Heat Transport Pump Motors Oil Leak Repairs Project (Project #89223), please provide:
   i. the potential expenditures in 2027
   ii. Please provide the forecast total cost of the project

c) With respect to the AIM End of Life Fuel Channel Component Retrieval Project (Project #89282), please provide:
   i. the potential expenditures in 2027
   ii. Please provide the forecast total cost of the project

Response

a) Not confirmed. Project #86299 has not started.[1]

b) Refer to Ex. L-F2-Staff-204, Attachment 2 for the Business Case Summary for Project #89223 - DN U2 Primary Heat Transport Pump Motors Oil Leak Repairs, which includes the following requested information for the project:
   i. Estimated expenditures for 2027 are $8.6M
   ii. Estimated total cost of the project is $34.6M.

c) Forecast total cost information is not yet defined and expenditures by year are not available for Project #89282 - AIM End of Life Fuel Channel Component Retrieval, as this is still an unallocated project. For estimated investment cost information, refer to Ex. L-F2-CCC-075, Attachment 1. As discussed in Ex. L-F2-CCC-075, the information provided is based on pre-Class 5 estimates that are subject to change.

[1] As noted in Ex. L-F2-3-Staff-204, Project# 89280 – DN Software Inventory Management 69000 was incorrectly included in Ex. F2-3-3, Table 4.

CCC Interrogatory #081

Interrogatory

Reference:
Exhibit F3, Tab 1, Schedule 1, Attachment 2, Table 1

Preamble:

The Hackett Group benchmarking study uses the categories of Finance, HR, ECS, IT, Procurement and Real Estate & Facilities Mgmt to benchmark OPG's corporate support costs.

Tables 1 presents OPG's corporate support costs using the categories Corporate & Technology Services, Real Estate, Supply Chain, Finance, Human Resources, and Corporate Centre.

Question(s):

a) Please recategorize Tables 1-4 so that they match the categories used by the Hackett Group in their benchmarking study, combining or disaggregating the categories in the Tables as necessary.

b) Please confirm that the benchmarking results do not account for the changes in support services costs from 2024 to 2031.

c) Please benchmark OPG's proposed 2031 corporate support costs, using forecast 2031 data as necessary.

Response

OPG assumes based on the question that the respective reference is intended to be Ex. F3-1-1, Table 1 and not Ex. F1-1-1, Attachment 2, Table 1.

a) OPG understands the question to be asking for a restatement of the historical and forecast cost information contained in Ex. F3-1-1 Table 1 in a manner that aligns to the taxonomy used by Hackett to perform the Corporate Support Benchmarking Study. OPG cannot provide this data as it has not conducted such an exercise and is unable to do so in the time available. This would require the same level of analysis of OPG's cost structure for each of the four additional historical years for nuclear and each of the eight additional historical years for regulated hydroelectric, and seven years of forecast information, as was necessary to develop the 2024

benchmarked costs, in line with Hackett's taxonomy. In addition, the benchmarking is performed by Hackett on a combined nuclear and regulated hydroelectric basis and as a result, the associated adjustments and recategorizations necessary to accord to Hackett's taxonomy have not been performed for each of the regulated businesses separately.

b) Confirmed.

c) Refer to part a).

In addition, the following response was prepared by The Hackett Group:

Hackett does not have the necessary data to provide an accurate benchmark comparison of OPG, or peers based on 2031 forecast data. That analysis was not included in the original scope of the OPG benchmark analysis and would be a departure from Hackett's benchmarking methodology. Hackett benchmarks are based on data collected from companies in the peer group based on current state performance. Developing a benchmark based on 2031 forecasts would require assumptions regarding future business drivers, potential organizational structures, technology adoption, and forward-looking macroeconomic changes. Hackett does not have the necessary data to do this comparison.

CCMBC Interrogatory #003

Interrogatory

Reference:
F3-1-1, page 48

Preamble:

"WTW undertook a comparison of OPG's wages to those provided by Bruce Power. The results of this comparison are captured in Attachment 4, and a summary is provided below in Figure 13. The analysis shows that Bruce Power's unionized wages are 24% higher for PWU represented positions and 9% higher for Society-represented positions. For licensed nuclear roles, such as the Control Room Shift Supervisor (Society), Bruce Power's unionized wages are up to 20% higher."

Question(s):

a) How many employees have left OPG for jobs with Bruce Power over the past five years?

b) Is OPG concerned that it may be losing employees to Bruce Power?

c) Did WTW undertake a comparison of OPG's pensions, benefits and OPEB's to those provided by Bruce Power? If the answer is yes, please file it. If the answer is no, please explain why not.

Response

a) OPG does not comprehensively track the requested information specific to Bruce Power LP; however, it is known that there have been employees in various functions who have left OPG for jobs with Bruce Power LP over the past five years.

b) OPG actively manages risks related to staff retention and continues to monitor the ongoing demand for employees skilled and trained in the energy sector, particularly the nuclear industry. The success of the Darlington Refurbishment Program has created additional market interest in OPG's employees in certain roles, and more broadly, energy sector development is contributing to increased competition for talent. While OPG competes with Bruce Power LP for talent, they are not the exclusive contributor to the increased labour market risk. Refer to Ex. F4-3-1, pp. 13-17, which further describes talent retention considerations for OPG.

c) No. The analysis presented in Ex. F4-3-1, Attachment 4 was based on publicly available information. As noted in Ex. L-F4-CCMBC-004, part (b), the detailed information required to complete a pension and benefits analysis of Bruce Power LP's pension and benefits information is not publicly available.

Minogi Corp Interrogatory #009

Interrogatory

Reference:

- **Exhibit F3, Tab 3, Schedule 1**
- **Exhibit A1, Tab 3, Section 1.1**

Question(s):

a) Please confirm if OPG proposes procurement related reporting, scorecards, or record-keeping in this proceeding.

b) If yes to a), please describe.

c) If no to a), please confirm OPG's ability to report annually at facility/project level on spend with Ontario, Canadian, local or First Nation rightsholder suppliers and provide details.

d) Please confirm plans to implement such report for 2027-2031.

Response

a) - d) OPG is not proposing separate procurement related reporting to the OEB.

OPG already maintains multiple internal and external mechanisms to document, track, and report on procurement-related activities and outcomes, including corporate procurement records maintained in accordance with internal governance and financial control requirements. Publicly available reporting includes OPG's Annual Reports (refer to Ex. A2-1-1) and OPG's Corporate Balanced Scorecard (refer to Ex. L-F4-AMPCO-124 for the 2025 scorecard). In addition, OPG reports on procurement-related economic empowerment initiatives through the Reconciliation Action Plan ("RAP") Updates (refer to the 2022 RAP Report on opg.com), which includes information on procurement activities involving Indigenous and First Nations businesses.

OPG maintains procurement-related record-keeping, reporting, and scorecard practices. OPG's procurement process includes documented evaluation criteria, weightings, and an evaluation methodology used to assess and score supplier submissions, and OPG retains procurement records to support contract award and contract administration.

Minogi Corp Interrogatory #010

Interrogatory

Reference:

- **Exhibit F3, Tab 3, Schedule 1**
- **Exhibit F2, Schedule 5**

Question(s):

a) Please confirm if procurement for on-site storage, repackaging, monitoring, upgrades, or site waste management services at Pickering and Darlington follows standard OPG processes; describe any specific strategies for extended scenarios.

b) For each of the categories identified in a), please confirm and describe assessments of suitability for local or First Nation rightsholder businesses.

Response

a) Confirmed. OPG is unclear what “extended scenarios” refer to; OPG’s procurement process is described in Ex. F3-3-1.

b) Refer to Ex. L-D3-MC-012.

Minogi Corp Interrogatory #011

Interrogatory

Reference:

- **Exhibit F3, Tab 1, Schedule 1**
- **Exhibit F3, Tab 1, Schedule 1, Attachment 1**
- **Exhibit A2, Tab 1, Schedule 1, Attachment 4**

Question(s):

a) Please identify 2023–present OPG public statements, commitments, policies, or strategies on First Nation rightsholder economic inclusion, procurement, or partnerships.

b) Please describe the influence of the OPG public statements, commitments, policies, or strategies identified in a) on application assumptions, forecasts, and/or reporting.

c) Please describe any goals or tracking for local/First Nation rightsholder procurement in 2027-2031.

Response

a) and c)
OPG's focus is on advancing Indigenous economic inclusion through procurement and partnerships with local/First Nation rightsholders. Progress is tracked annually using contract award and spend data, with specific metrics to identify participation by community-owned and rightsholder-affiliated suppliers to support delivery and accountability. OPG has embedded Indigenous economic participation into its sourcing and supplier management processes. This includes hosting procurement information sessions for Indigenous businesses and OPG staff, requiring Indigenous engagement plans as part of RFP submissions, evaluating supplier performance against Indigenous engagement commitments, and delivering a structured mentorship program that pairs Indigenous business leaders with senior OPG leaders. Together, these programs provide a consistent framework to enable, support, and track local and First Nation rightsholders economic inclusion in OPG's procurement. Refer to https://www.opg.com/reporting/ for more information.

The Application reflects the assumptions made in OPG's 2025-2031 Business Plan.

Minogi Corp Interrogatory #012

Interrogatory

Reference:

- **Exhibit F3, Tab 1, Schedule 1**
- **Exhibit A2, Tab 1, Schedule 1, Attachment 4**
- **Exhibit D3, Tab 1, Schedule 1**
- **Exhibit D2, Tab 1, Schedule 1**

Question(s):

a) Please identify treaty lands relevant to Pickering, Darlington, and waste facilities for OPG's procurement/community purposes.

b) Please confirm use of location, proximity, treaty, or rightsholder criteria in identifying businesses for outreach/procurement.

c) Please provide total annual Pickering and Darlington procurement spending (2020–present) that OPG considers suitable for local or First Nation rightsholder sourcing.

d) Please describe the methodology for suitability determination pursuant to the response to c).

Response

a) The Pickering Nuclear Generating Station (PNGS), the Pickering Waste Management Facility (PWMF), the Darlington Nuclear Generating Station (DNGS) and the Darlington Waste Management Facility (DWMF) are located within the Williams Treaties (1923) including the Gunshot Treaty (1787–88). The Western Waste Management Facility (WWMF) is located within the area covered by Treaty 45 ½ (the Saugeen Tract Purchase), signed in 1836.

b) Refer to Ex. L-D3-MC-005.

c) and d) OPG does not categorize or track procurement spending as being specifically suitable for local or First Nation rightsholder sourcing. Refer to Ex. L-F3-MC-009 and Ex. L-F3-MC-011 for information on OPG's procurement reporting and Indigenous economic inclusion. Further, Ex. L-D3-MC-005 describes OPG's procurement evaluation process and assessment of suppliers.

Minogi Corp Interrogatory #013

Interrogatory

Reference:

- **Exhibit F3, Tab 1, Schedule 1**
- **Exhibit F3, Tab 1, Schedule 1, Attachment 1**
- **Exhibit A2, Tab 2, Schedule 1**
- **Exhibit D3, Tab 1, Schedule 1**

Question(s):

a) Please confirm consideration of a procurement framework by 2026/2027-2031 for First Nation rightsholder participation near nuclear facilities.

b) If yes to a), please describe:

(i) the status of that consideration;
(ii) any proposed timeline;
(iii) any internal approvals required; and
(iv) any reporting or tracking metrics.

c) If no to a), please describe OPG's rationale for not considering such a procurement framework.

d) Please identify any legal, operational, and/or safety considerations for such a framework.

Response

a)-d) Refer to Ex. L-D3-MC-006, parts (a)-(c). OPG's procurement process is described in Ex. F3-3-1, including Section 7.0 entitled "Social License and Procurement".

SEC Interrogatory #173

Interrogatory

Reference:
F3-1-1, p. 6-7

Question(s):

With respect to The Hackett Group, Benchmarking Study:

a) Please detail all methodological changes between the study filed in this application and that filed in EB-2020-0290.

b) [p.8] For each of the peer group companies, please provide the percentage of their revenue that comes from, a) nuclear generation, b) hydroelectric generation, c) other generation, d) transmission and distribution, and e) other.

Response

This response was prepared by The Hackett Group:

a) Hackett confirms that the methodology in the current study is consistent with the study filed under EB-2020-0290. There are no methodological changes.

b) Hackett's database does not include revenue segmented by nuclear generation, hydroelectric generation, other generation, transmission & distribution, and other. Additionally, the companies in the peer group do not disclose revenue in those segments, so the requested revenue segmentation is not publicly available.

The companies used in the peer group share similar demand drivers, industry complexities, and geographic coverage as OPG. The demand drivers evaluated include revenue, number of operating locations, and employee headcount. The geographic scope was limited to North America to help ensure that peer organizations operate under comparable market conditions and face similar regulatory and competitive challenges. The peer group is comprised of 14 North America–based companies, of which 43% have nuclear power generation assets. The median revenue for the peer group is approximately $7B, generally in line with OPG's annual 2024 revenue of approximately $5.6B.

SEC Interrogatory #174

Interrogatory

Reference:
F3-1-1, Table 1

Question(s):

Please provide the number of FTEs by corporate cost function.

Response

Attachment 1, 2 and 3 reflect the Allocation of Corporate Support & Administrative OM&A FTEs for the Regulated Hydroelectric, OPG Nuclear Facilities, and DNNP Facilities, respectively. For clarity, Ex. F3-1-1 Table 1 includes OPG's unregulated business activities, which is outside the scope of this Application.

Numbers may not add due to rounding.

Attachment #1

Corporate Support & Administrative Groups OM&A FTE's - OPG Regulated Hydroelectric[1]

Line No.	Corporate Costs	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Actual	2026 Budget	2027 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Base OM&A								
1	Corporate & Technology Services	26.2	26.0	37.5	43.4	45.3	44.8	49.6	45.9
2	Real Estate	1.1	2.1	3.3	3.2	4.4	3.1	4.0	3.7
3	Supply Chain	12.0	9.9	9.8	8.9	11.9	18.3	16.6	16.3
4	Finance	37.1	26.8	26.2	26.9	35.4	33.9	38.0	37.0
5	Human Resources	26.7	24.6	29.5	31.2	31.3	26.4	25.6	21.3
6	Corporate Centre	26.5	26.6	25.0	28.4	34.8	24.3	22.9	21.8
7	**Total Base OM&A**	129.5	115.9	131.2	142.1	163.1	150.8	156.8	146.1
8	**Project OM&A**	2.1	1.7	1.8	2.2	3.7	7.9	7.2	7.5
9	**Total OM&A**	131.6	117.6	133.0	144.3	166.8	158.7	164.0	153.6

Notes:

1 Corporate Support & Administrative costs have been restated from EB-2020-0290 for organizational changes and transfers to/from Enterprise Operations and Enterprise Projects as described in Ex. F3-1-1.

Numbers may not add due to rounding.

Attachment #2

Corporate Support & Administrative Groups OM&A FTE's - OPG Nuclear Facilities[1]

Line No.	Corporate Costs	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Actual	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Base OM&A												
1	Corporate & Technology Services	312.4	303.6	397.3	493.9	519.4	441.6	447.6	377.2	372.0	372.2	375.9	399.3
2	Real Estate	206.9	218.7	191.3	200.3	189.8	185.3	198.8	197.1	198.6	201.5	207.8	200.5
3	Supply Chain	228.4	209.6	213.3	234.2	221.1	180.0	172.3	146.2	141.9	140.6	140.3	169.5
4	Finance	117.7	120.6	122.2	134.0	137.1	152.8	155.4	147.5	145.6	147.0	146.8	146.8
5	Human Resources	120.0	109.7	124.5	153.4	148.5	130.0	118.8	93.8	92.6	90.3	86.4	98.9
6	Corporate Centre	79.2	75.9	80.5	78.4	84.0	98.9	91.3	84.8	84.1	85.0	86.9	88.4
7	**Total Base OM&A**	1,064.7	1,038.1	1,129.0	1,294.3	1,299.8	1,188.6	1,184.2	1,046.7	1,034.7	1,036.7	1,044.1	1,103.4
8	**Project OM&A**	19.2	18.5	21.0	24.8	45.5	38.2	27.6	29.9	36.9	35.6	36.9	36.8
9	**Total OM&A**	1,083.9	1,056.6	1,150.0	1,319.2	1,345.3	1,226.9	1,211.8	1,076.6	1,071.7	1,072.3	1,081.0	1,140.2

Notes:

1 Corporate Support & Administrative costs have been restated from EB-2020-0290 for organizational changes and transfers to/from Enterprise Operations and Enterprise Projects as described in Ex. F3-1-1.

Numbers may not add due to rounding.

Attachment #3

Corporate Support & Administrative Groups OM&A FTE's - DNNP Facilities

Line No.	Corporate Costs	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	Base OM&A						
1	Corporate & Technology Services	21.4	24.3	26.5	23.0	20.5	17.9
2	Real Estate	7.0	10.1	10.3	10.2	6.8	10.2
3	Supply Chain	2.7	3.9	4.5	4.3	7.5	14.0
4	Finance	14.0	18.3	20.6	19.7	21.7	13.8
5	Human Resources	5.0	5.2	5.7	4.8	4.5	5.1
6	Corporate Centre	6.8	9.4	10.7	10.3	11.7	6.2
7	**Total Base OM&A**	56.9	71.2	78.3	72.4	72.8	67.2
8	**Project OM&A**	2.5	3.2	4.2	4.4	3.9	4.0
9	**Total OM&A**	59.3	74.4	82.5	76.9	76.7	71.2

Notes:

1 In preparing this interogatory response, the Applicants identified that approximately $1M in resources related to DNNP Factilities was inadvertently presented in respect of OPG Nuclear Facilities. This has no impact on the combined nuclear revenue requirements and is proposed to be corrected during the Payment Amounts Order process in this proceeding.

SEC Interrogatory #175

Interrogatory

Reference:
F3-1-1

Question(s):

With respect to Corporate & Technology Services:

a) [p.7] Please provide a copy of the analysis OPG used to determine it was better to repatriate 250 NHSS Staff as opposed to renewing its NHSS IT services agreement.

b) [Table 6] Please provide a breakdown of IT Support Costs.

Response

a) As discussed in Ex. F3-1-1, pp. 7-8, OPG concluded that outsourcing IT services was no longer cost-effective or flexible enough to meet rapidly evolving technology needs, particularly in areas such as AI, data analytics, and cyber security. The NHSS staff repatriation in 2022 contributed to overall improved IT resourcing flexibility and responsiveness to business needs. The financial analysis that was used to inform the decision identifies anticipated savings for each of three scenarios considered, including the preferred alternative (scenario 3). The financial analysis is provided in Attachment 1.

b) Refer to Attachment 2.

Filed: 2026-04-22
EB-2025-0297
Ex. L-F3-SEC-175
Attachment 1

Scenario Comparison (as of September 2021)

Status Quo Scenario: Do Nothing (Base Case) — Base Case

	2022 ($M)	2023 ($M)	2024 ($M)	Total ($M)
New Horizon Base Contract (estimate for 3 years) [1]	61.3	62.6	63.8	187.7
Total cost in Base OM&A	**61.3**	**62.6**	**63.8**	**187.7**

Scenario 1: PWU Repatriation with 3 year contract (2022-2024)

	2022 ($M)	2023 ($M)	2024 ($M)	Total ($M)
New Horizon Base Contract (estimate for 3 years) [1]	61.3	62.6	63.8	187.7
New ITSA contract with NHSS for 3 years	(33.8)	(33.8)	(33.8)	(101.4)
OPG PWU - IT Tech Staff - Base Labour (92 IT Tech @ approx. $139K/year/person)	(13.0)	(13.2)	(13.4)	(39.6)
OPG Management Hire to manage PWU staff (3 Senior Managers @ approx. $250k/year/person)	(0.7)	(0.8)	(0.8)	(2.3)
OPG Section Head Hire to supervise PWU staff (6 Section Heads @ approx. $200K/year/person)	(1.2)	(1.2)	(1.2)	(3.6)
Finance resource and non labour support (1 additional Finance HC to support CIO)	(0.2)	(0.2)	(0.2)	(0.7)
Estimated onboarding costs of NHSS staff (transition services costs from Capgemini and third party support)	(1.0)	-	-	(1.0)
Estimated software license costs for repatriated staff	(0.7)	(0.7)	(0.7)	(2.1)
Incremental savings to Base OM&A	**10.7**	**12.7**	**13.7**	**37.1**

Scenario 2: PWU Repatriation and Society Repatriation Feb 1, 2022 and Feb 1, 2024

	2022 ($M)	2023 ($M)	2024 ($M)	Total ($M)
New Horizon Base Contract (estimate for 3 years) [1]	61.3	62.6	63.8	187.7
New ITSA contract with NHSS (ending Feb. 1, 2024)	(33.8)	(33.8)	(2.8)	(70.4)
OPG PWU - IT Tech Staff - Base Labour (92 IT Tech @ approx. $139K/year/person)	(13.0)	(13.2)	(13.4)	(39.6)
OPG Management Hire to manage PWU staff (3 Senior Managers @ approx. $250k/year/person)	(0.7)	(0.8)	(0.8)	(2.3)
OPG Section Head Hire to supervise PWU staff (6 Section Heads @ approx. $200K/Year/person)	(1.2)	(1.2)	(1.2)	(3.6)
Finance resource and non labour support (1 additional Finance HC to support CIO)	(0.2)	(0.2)	(0.2)	(0.7)
Estimated onboarding costs of NHSS staff (transition services costs from Capgemini and third party support)	(1.0)	-	(0.5)	(1.5)
Society Base Labour (120 HC @ approx. $200k/year/person)	-	-	(24.3)	(24.3)
OPG Management Hire to manage Society IT staff (3 Senior Managers @ approx. $250K/year/person)	-	-	(0.8)	(0.8)
Estimated software license costs for repatriated staff	(0.7)	(0.7)	(0.7)	(2.1)
Early Retirement Allowance (potential negotiated labour costs, if required)	-	-	(5.9)	(5.9)
Incremental savings to Base OM&A	**10.7**	**12.7**	**13.2**	**36.6**

Scenario 3: PWU repatriation on Feb 1, 2022 and Society Early Repatriation Nov 1, 2022 (preferred scenario)

	2022 ($M)	2023 ($M)	2024 ($M)	Total ($M)
New Horizon Base Contract (estimate for 3 years) [1]	61.3	62.6	63.8	187.7
New ITSA contract with NHSS (ending Nov. 1, 2022)	(25.4)	-	-	(25.4)
OPG PWU - IT Tech Staff - Base Labour (92 IT Tech @ approx. $139K/year/person)	(13.0)	(13.2)	(13.4)	(39.6)
OPG Management Hire to manage PWU staff (3 Senior Managers @ approx. $250k/year/person)	(0.7)	(0.8)	(0.8)	(2.3)
OPG Section Head Hire to supervise PWU staff (6 Section Heads @ approx. $200K/Year/person)	(1.2)	(1.2)	(1.2)	(3.6)
Finance resource and non labour support (1 additional Finance HC to support CIO)	(0.2)	(0.2)	(0.2)	(0.7)
Estimated onboarding costs of NHSS staff (transition services costs from Capgemini and third party support)	(1.5)	-	-	(1.5)
Society Base Labour (92 HC for 2022 and 2023), 120 HC for 2024 onwards	(5.9)	(24.0)	(24.3)	(54.1)
OPG Management Hire to manage Society IT staff (3 Senior Managers @ approx. $250K/year/person)	(0.2)	(0.8)	(0.8)	(1.7)
Estimated software license costs for repatriated staff	(0.7)	(0.7)	(0.7)	(2.1)
Early Retirement Allowance (potential negotiated labour costs, if required)	(5.8)	-	-	(5.8)
Penalty (estimated early contract termination cost)	(4.6)	-	-	(4.6)
Incremental savings to Base OM&A	**2.2**	**21.7**	**22.5**	**46.4**

Notes:

1. Base contract cost estimate includes known requirements for enhancements, additional service requirements, application maintenance, and application removal costs. Under the assumption of historical costs plus inflation, scenario 3 is still the preferred option. No base contract costs are estimated after 2024.

Numbers may not add due to rounding.

Allocation of Corporate & Technology Services Base OM&A Costs - OPG Nuclear Facilities- Breakdown of IT Support Costs ($M)

Line No.	Costs	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	**Hardware / Software / Telecommunications**	28.4	34.9	43.3	48.9	55.0	54.1	61.2	65.4	69.6	75.7	82.1	92.7
2	**NHSS Base Costs**	49.4	48.6	30.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	**IT Support Costs:**												
4	Labour	18.0	19.9	32.9	57.7	61.0	58.4	58.7	56.5	57.5	60.6	62.0	66.6
5	Non-Regular Labour	0.4	0.6	1.6	1.1	0.7	1.0	0.6	0.3	0.3	0.3	0.3	0.3
6	Overtime	0.2	0.2	1.0	1.5	1.7	0.3	0.3	0.4	0.4	0.4	0.4	0.4
7	Augmented Staff	0.0	0.0	0.0	0.2	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.1
8	Materials	0.1	0.1	0.3	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Other Purchased Services	5.2	7.9	5.9	5.8	7.5	5.2	4.5	4.6	3.9	3.4	3.4	3.3
10	Other	0.9	0.1	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4
11	**Total NHSS and IT Support Costs**	74.3	77.3	72.2	67.0	72.5	65.2	64.4	62.1	62.5	65.1	66.6	71.3
12	**Shared Services**[1]	27.4	27.3	29.0	29.5	30.5	29.9	26.7	22.1	22.5	23.5	24.1	27.6
13	**Total**	130.1	139.6	144.5	145.4	157.9	149.2	152.3	149.6	154.5	164.4	172.8	191.5

Notes:

1 Includes Shared Financial Services (formerly in Finance), HR Service Centre and Payroll Services (both formerly in People & Culture now known as Human Resources), and Business Infrastructure Services (formerly in Real Estate) as described in Ex. F3-1-1

SEC Interrogatory #176

Interrogatory

Reference:
F3-1-3

Question(s):

Please provide a breakdown of forecast/actual costs related to this application regardless of the year they are incurred by category (expert witness/consultants, external legal counsel, intervenor and OEB costs, and other). Please also provide actual costs incurred by category as of the date of the filing of this application, as well as actuals for the EB-2020-0290 application by category.

Response

The breakdown of actual costs by category related to this Application, EB-2025-0297, and EB-2020-0290 are provided in Chart 1 below.

Chart 1
Regulatory Proceeding Costs - Regulatory Affairs Department ($K)

Group	EB-2020-0290 Actual	EB-2025-0297 Actual[1]	EB-2025-0297 Budget
Regulatory Proceeding Costs:			
Expert Witnesses/Consultants	7,526.1	2,983.7	2,361.7
Intervenor Cost Awards	1,060.4	0.0	2,850.0
Other	334.7	275.0	167.7
Total Regulatory Proceeding Costs	8,921.2	3,258.7	5,379.4
External Legal Costs	1,750.8	1,382.1	2,827.5

Regulatory proceeding costs for EB-2025-0297 include certain 2026 Budget and 2027 Plan costs as applicable to this proceeding. In the course of preparing this response, OPG identified that in EB-2020-0290, Ex. F3-1-3, p.7, line 11, 2019 Actual,

[1] Up to and including December 31, 2025

erroneously categorized $75.8k of Expert Witnesses/Consultants costs in Intervenor cost awards. This correction has been reflected in Chart 1 under EB-2020-0290 Actual.

CCC Interrogatory #095

Interrogatory

Reference:
Exhibit F4, Tab 4, Schedule 1, p. 10, Table 5b

Preamble:

IESO non-energy costs are charges applied to the withdrawal of energy from the IESO-controlled grid. These charges include transmission charges, the debt retirement charge up to April 2018, the rural and remote electricity rate protection charge, the IESO administration fee, uplift charges, and the Global Adjustment. These charges are not discretionary and apply to all energy withdrawals from the IESO-controlled grid. The charges are directly assigned to the specific regulated facilities.

Question(s):

a) How does OPG forecast IESO non-energy charges?

b) Table 5B exhibits some apparently large variations between OEB approved and actual IESO non-energy charges; what is the driver behind this variances, and are these variances trued up in some fashion, i.e. through a variance account, or are they variances that OPG bears the risk for?

Response

a) The forecast for IESO non-energy charges is based on OPG's future outlook for Global Adjustment (GA) and an estimate of applicable uplifts and fees derived from historical data, applied to OPG's projected energy consumption at a station level. OPG forecasts Global Adjustment using its proprietary modelling tools for forecasting electricity system costs, expected energy production and prices, future capacity additions and costs, as well as the cost of conservation and demand management initiatives. The GA is inversely proportional to energy market prices. As a result, the GA can vary month-to-month and year-to-year.

b) The variance between OEB-approved and actual IESO non-energy charges is mainly driven by differences between OPG's GA forecast and the actual GA rate. Global Adjustment can be impacted by wholesale market prices and their fluctuations due to factors such as demand, weather, fuel prices, and intertie transactions. In 2020 and 2021, actual IESO non-energy charges were greater than OEB-approved due to unforeseen decreases in demand and market prices from

the COVID-19 pandemic. In 2022-2024, actual IESO non-energy charges were lower than the OEB-approved levels due to impacts of the Comprehensive Electricity Plan which removed approximately 85 per cent of the costs from non-hydroelectric renewable contracts from the GA. Variances in non-energy charges expenses are not subject to deferral and variance account treatment or other true-up mechanisms.

Board Staff Interrogatory #230

Interrogatory

Reference:
Ref 1: Exhibit F4 / Tab 3 / Schedule 1 / pp. 27-28

Preamble:

The text in the four figures at Reference 1 is not readable.

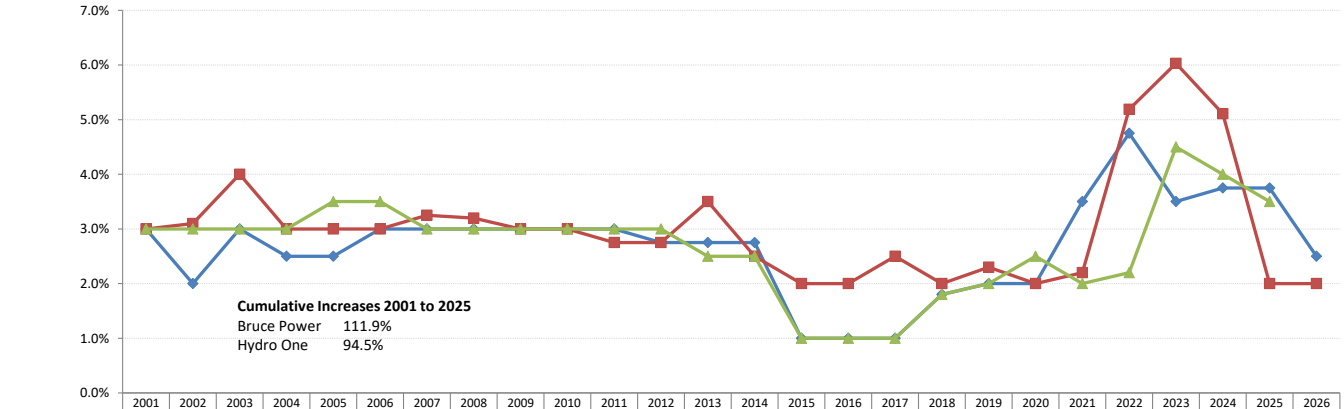
Question(s):

a) Please provide searchable, high-resolution versions of the figures at Reference 1

Response

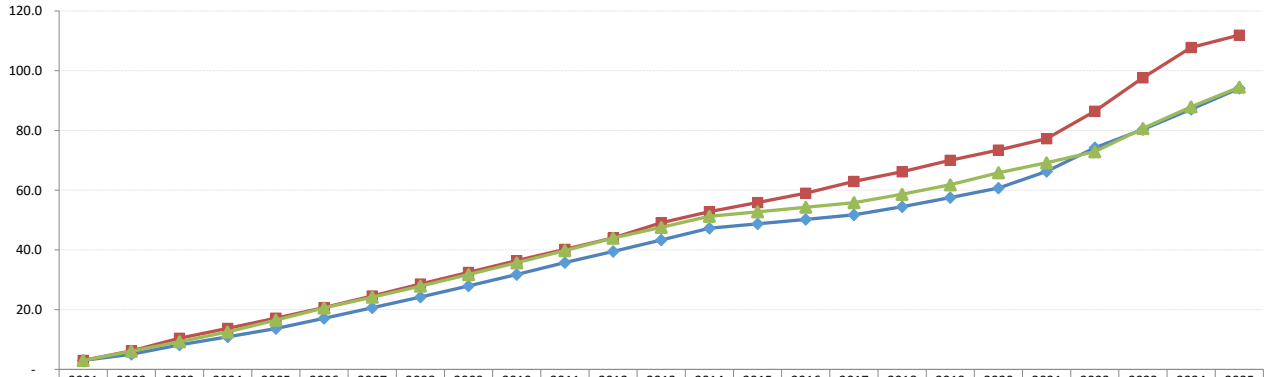
a) A searchable version of Figures 5 to 8 at Reference 1 is provided in Attachment 1.

Figure 5 - PWU Annual Salary Increases



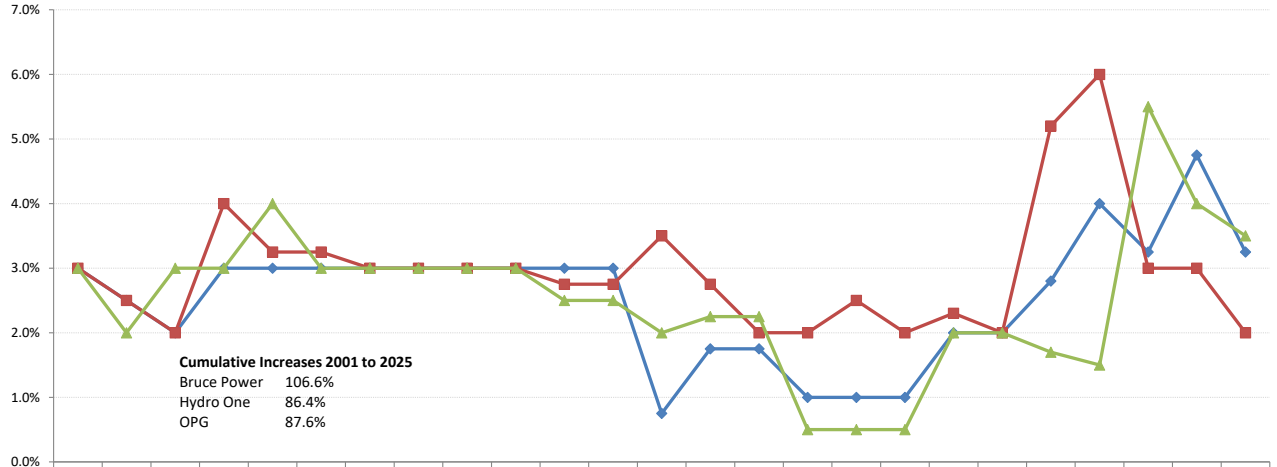
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
OPG	3.0%	2.0%	3.0%	2.5%	2.5%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	2.75%	2.75%	2.75%	1.0%	1.0%	1.0%	1.8%	2.0%	2.0%	3.50%	4.75%	3.50%	3.75%	3.75%	2.50%
Bruce Power	3.0%	3.1%	4.0%	3.0%	3.0%	3.0%	3.25%	3.2%	3.0%	3.0%	2.75%	2.75%	3.5%	2.5%	2.0%	2.0%	2.5%	2.0%	2.3%	2.00%	2.20%	5.19%	6.03%	5.11%	2.00%	2.00%
Hydro One	3.0%	3.0%	3.0%	3.0%	3.5%	3.5%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	2.5%	2.5%	1.0%	1.0%	1.0%	1.8%	2.0%	2.50%	2.00%	2.20%	4.50%	4.00%	3.50%	

Figure 6 - PWU Cumulative Salary Increases



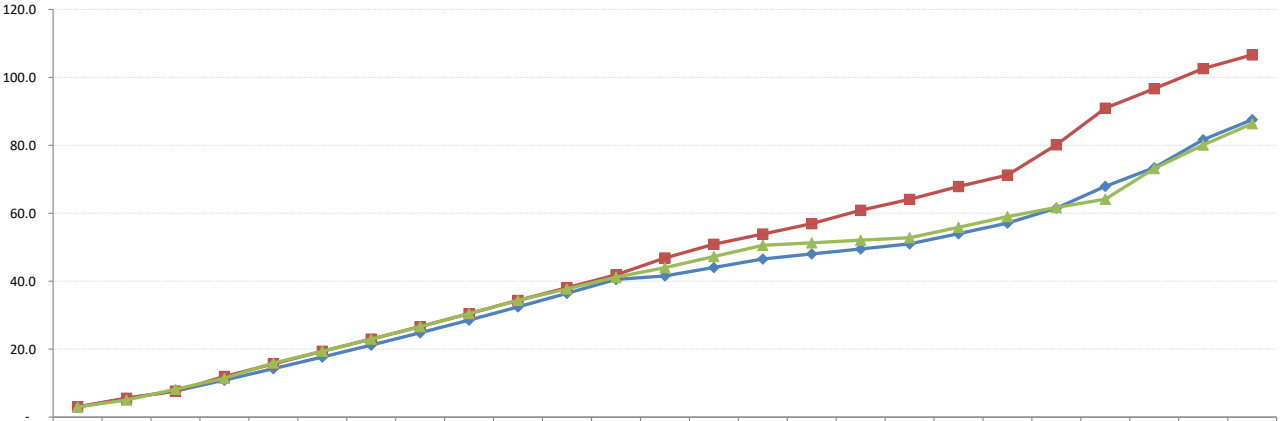
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
OPG	3.0	5.1	8.2	10.9	13.7	17.1	20.6	24.2	28.0	31.8	35.8	39.5	43.3	47.3	48.7	50.2	51.7	54.5	57.5	60.7	66.3	74.2	80.3	87.1	94.1
Bruce Power	3.0	6.2	10.4	13.8	17.2	20.7	24.6	28.6	32.4	36.4	40.2	44.0	49.1	52.8	55.9	59.0	62.9	66.2	70.0	73.4	77.2	86.4	97.7	107.8	111.9
Hydro One	3.0	6.1	9.3	12.6	16.5	20.6	24.2	27.9	31.7	35.7	39.8	44.0	47.6	51.3	52.8	54.3	55.8	58.6	61.8	65.9	69.2	72.9	80.7	87.9	94.5

Figure 7 - Society Annual Salary Increases



	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
OPG	3.0%	2.5%	2.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	0.75%	1.75%	1.75%	1.0%	1.0%	1.0%	2.0%	2.00%	2.80%	4.00%	3.25%	4.75%	3.25%
Bruce Power	3.0%	2.5%	2.0%	4.0%	3.25%	3.25%	3.0%	3.0%	3.0%	3.0%	2.75%	2.75%	3.5%	2.75%	2.0%	2.0%	2.5%	2.0%	2.3%	2.00%	5.20%	6.00%	3.00%	3.00%	2.00%
Hydro One	3.0%	2.0%	3.0%	3.0%	4.0%	3.0%	3.0%	3.0%	3.0%	3.0%	2.5%	2.5%	2.0%	2.25%	2.25%	0.5%	0.5%	0.5%	2.0%	2.00%	1.70%	1.50%	5.50%	4.00%	3.50%

Figure 8 - Society Cumulative Salary Increases



	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
OPG	3.0	5.6	7.7	10.9	14.2	17.7	21.2	24.8	28.6	32.4	36.4	40.5	41.6	44.0	46.6	48.0	49.5	51.0	54.0	57.1	61.5	68.0	73.4	81.7	87.6
Bruce Power	3.0	5.6	7.7	12.0	15.6	19.4	23.0	26.7	30.5	34.4	38.1	41.9	46.8	50.9	53.9	57.0	60.9	64.1	67.9	71.2	80.1	91.0	96.7	102.6	106.6
Hydro One	3.0	5.1	8.2	11.5	15.9	19.4	23.0	26.7	30.5	34.4	37.7	41.2	44.0	47.2	50.6	51.3	52.1	52.8	55.9	59.0	61.7	64.1	73.2	80.1	86.4

Society Interrogatory #014

Interrogatory

Reference:
(1) Exhibit F4-3-1, Attachment 1, "Appendix 2K"
(2) EB-2013-0321Decision With Reasons dated November 20, 2014 pps71,72,82
(3) Exhibit F4-3-1, Attachment 3, "Total Compensation Benchmarking Study prepared by Willis Towers Watson" p2 The total OPG count in 2024 is stated to be PWU 5407, Society 3866, Mgmt Group 1328 and OPG Total 10601.

Question(s):

a) Please update Reference (1) to show 2025 Actuals, and the latest projections for 2026 [if the 2025 Actuals are not immediately available, please update and provide them when available]. Also please provide an excel version of this update.

b) Please verify or update the values in the provided table below which are extracted from Appendix 2K.

c) Please update this table referred to in b) above to show 2025 Actuals, and the latest projections for 2026 [if the 2025 Actuals are not immediately available, please update and provide them when available]. Also please provide an excel version of this update.

d) In the OEB's Decision with Reasons in OPG's EB-2013-0321 application, the Board noted that "the percentage of employees that are managers has increased from approximately 10.5% in 2010 to 11.5% in 2015" (p71) and found that "OPG has not sufficiently justified the number of its management positions" (p72). As a consequence, the Board reduced OPG's OM&A costs to reflect a reduction to 10.5% management in total staffing (p.82).
   i. Please explain why Nuclear Facilities management staff are over 12% of total regular staff in each of 2027 to 2031.
   ii. What would the impact be on OM&A costs in each of 2027 to 2031 if Nuclear Facilities management staff were reduced to 10.5% of total regular staff?
   iii. Please explain why DNNP management staff are over 20% of total regular staff in each of 2027 and 2028 and between 19 and 18% in 2028 to 2031.
   iv. What would the impact be on OPG costs in each of 2027 to 2031 if DNNP management staff were reduced to 10.5% of total regular staff?
   v. How would OPG go about eliminating management staff in order to reach a management staff level of 10.5% of total regular staff?

e) For Nuclear Facilities, please provide the year over year reductions in SUP staff between year end 2025 and 2031 in absolute numbers as well as in percentage terms.

f) For Nuclear Facilities, please explain how OPG intends to go about eliminating roughly 750 SUP staff (a 20% reduction) over this six year period between year end 2025 and 2031? Will OPG offer severance packages to these staff whose employment will be terminated?

g) Please reconcile the difference between the value for 2024 OPG total staff provided in answer to b) above and Reference (3).

		Source:	Appendix 2k	F4-3-1 Attachment 1					
		2024	2025	2026	2027	2028	2029	2030	2031
Nuclear Facilities									
Management		1078.6	1276.9	1138.6	1042.2	1028.9	1016.2	1007.4	1018.7
SUP		3122.7	3639.7	3473.6	3250.9	3184.1	3141.7	3120.1	3087.5
PWU		3694.6	4184.3	4096.5	4141.2	4131.8	4164	4129.8	4116.9
Term/ETE/PECO Temp		719.1	279.2	248.5	7	7	7	0	0
EPSCA		458	358.2	231.8	433.9	551.9	487.3	402	320
	Total	9073	9938.3	9189	8875.2	8903.7	8816.2	8659.3	8543.1
	Total Reg	7895.9	9300.9	8708.7	8434.3	8344.8	8321.9	8257.3	8223.1
	Mgmt % Reg	13.66%	13.73%	13.07%	12.36%	12.33%	12.21%	12.20%	12.39%
	SUP % Reg	39.55%	41.28%	39.89%	38.54%	38.16%	37.75%	37.79%	37.55%
	PWU%Reg	46.79%	44.99%	47.04%	49.10%	49.51%	50.04%	50.01%	50.07%
DNNP									
Management		0	0	100	113.2	100.6	83.7	75.4	66.4
SUP		0	0	228.9	239.3	194.4	152.1	145.4	142.9
PWU		0	0	70.7	140.6	198.9	196.6	158.1	156
Term/ETE/PECO Temp		0	0	0	0	0	0	0	0
EPSCA		0	0	0	0	0	0	0.1	0.2
	Total	0	0	399.6	493.1	493.9	432.4	379	365.5
	Total Reg	0	0	399.6	493.1	493.9	432.4	378.9	365.3
	Mgmt % Reg	0.00%	0.00%	25.03%	22.96%	20.37%	19.36%	19.90%	18.18%
	SUP % Reg	0.00%	0.00%	57.28%	48.53%	39.36%	35.18%	38.37%	39.12%
	PWU%Reg	0.00%	0.00%	17.69%	28.51%	40.27%	45.47%	41.73%	42.70%
HydoElectric Facilities									
Management		155.6	164.5	165.9	162.1	160.4	158.4	160.7	161.3
SUP		506.5	604.8	619	635.3	629.8	624.4	626.4	621.7
PWU		753.5	856.6	911.4	914.5	921.6	933.2	925.8	928.1
Term/ETE/PECO Temp		0	0	0	0	0	0	0	0
EPSCA		0	0	0	0	0	0	0	0
	Total	**1415.6**	**1625.9**	**1696.3**	**1711.9**	**1711.8**	**1716**	**1712.9**	**1711.1**
	Total Reg	1415.6	1625.9	1696.3	1711.9	1711.8	1716	1712.9	1711.1
	Mgmt % Reg	10.99%	10.12%	9.78%	9.47%	9.37%	9.23%	9.38%	9.43%
	SUP % Reg	35.78%	37.20%	36.49%	37.11%	36.79%	36.39%	36.57%	36.33%
	PWU%Reg	53.23%	52.68%	53.73%	53.42%	53.84%	54.38%	54.05%	54.24%
OPG TOTAL									
Management		1234.2	1441.4	1404.5	1317.5	1289.9	1258.3	1243.5	1246.4
SUP		3629.2	4444.5	4321.5	4125.5	4008.3	3918.2	3891.9	3852.1
PWU		4448.1	5040.9	5078.6	5196.3	5252.3	5293.8	5213.7	5201
Term/ETE/PECO Temp		719.1	279.2	248.5	7	7	7	0	0
EPSCA		458	358.2	231.8	433.9	551.9	487.3	402.1	320.2
	Total	10488.6	11564.2	11284.9	11080.2	11109.4	10964.6	10751.2	10619.7
	Total Reg	9311.5	10926.8	10804.6	10639.3	10550.5	10470.3	10349.1	10299.5
	Mgmt % Reg	13.25%	13.19%	13.00%	12.38%	12.23%	12.02%	12.02%	12.10%
	SUP % Reg	38.98%	40.68%	40.00%	38.78%	37.99%	37.42%	37.61%	37.40%
	PWU%Reg	47.77%	46.13%	47.00%	48.84%	49.78%	50.56%	50.38%	50.50%

Response

a) Refer to Ex. L-F4-AMPCO-110, Attachment 1 for an excel version, including 2025 actuals. The latest 2026 projections available in the Appendix 2K level of detail are per the budget included in the pre-filed evidence.

b) and c)

Refer to Ex. L-F4-AMPCO-110, Attachment 1 for updated values and 2025 actuals. The latest 2026 projections available in the "Appendix 2K" level of detail are per the budget included in the pre-filed evidence.

d)

i. Nuclear Facilities management and supervisory staff are not over 12% of total Regular staff. Management Supervisory roles are, on average, approximately 10.0% of total Regular staff over the IR term. Refer to Ex. F4-3-1 Figure 4a and Ex. L- F4-SEC-189.

ii. It is not possible to determine the requested impact on OM&A costs in each of 2027 to 2031 absent additional specificity. A determinative response for any reduced OM&A costs would require elimination of work programs and would necessitate the Applicants to carefully assess impacts to production, safety, performance and delays to project execution, among other priorities.

iii. DNNP staffing requirements reflect project execution and transition from project execution toward a steady state operating Unit 1. As discussed at Ex. F2-2-1, pp. 3-4, overall, the BWRX-300 design, digital technology and managed systems are designed to optimize resource needs, with staff trained and qualified on a wider scope of tasks and disciplines. As such, represented positions comprise a proportionately smaller percentage of the total FTE complement.

iv. It is not possible to determine the requested impact on costs in each of 2027 - 2031 absent additional specificity. A determinative response for any reduced costs would require elimination of work programs and would necessitate the Applicants to carefully assess impacts to production delay and delays to project execution (schedule or scope) among other priorities.

v. OPG declines to comment on this speculative question. A determinative response for any reduced OM&A costs would require elimination of work programs and would necessitate the Applicants to carefully assess impacts to production, safety, performance and delays to project execution, among other priorities.

e) Refer to Chart 1 below.

Chart 1 - Nuclear Facilities (excluding DNNP LP) Society Regular and Non-Regular FTEs 2025-2031

Nuclear Facilities (excluding DNNP LP)	**2025 Actual**	**2026 Plan**	**2027 Plan**	**2028 Plan**	**2029 Plan**	**2030 Plan**	**2031 Plan**
Staff (Regular and Non-Regular)		**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**
Society	3,251.4	3,473.6	3,250.9	3,184.1	3,141.7	3,120.1	3,087.5
YOY Change		222.2	(222.7)	(66.9)	(42.4)	(21.6)	(32.6)
YOY % Change		6.8%	-6.4%	-2.1%	-1.3%	-0.7%	-1.0%

f) OPG does not expect a need to terminate employment for Society-represented employees supporting OPG's nuclear facilities and the DNNP facilities. FTEs related to both OPG's nuclear facilities and the DNNP facilities should be combined to assess any FTE trends over the IR term. On this basis, Society-represented Regular FTEs reduce by approximately 80 from 2025 to 2031.

g) The two references are not equivalent and cannot be reconciled.

Attachment 1 refers to FTEs for OPG's nuclear facilities and the DNNP facilities. Refer to Ex. L-F4-AMPCO-127 for a detailed definition of FTE.

Reference 3 includes OPG Regular and Term Employee incumbents in role as of April 1, 2024.

Regulated Facilities - Regular FTE as a percentage of Total Regular and Non-Regular FTE

Nuclear Facilities (Excl DNNP)	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
	FTE	**FTE**	**FTE**	**FTE**	**FTE**	**FTE**	**FTE**	**FTE**
Staff (Regular and Non-Regular)	**Actual**	**Actual**	**Plan**	**Plan**	**Plan**	**Plan**	**Plan**	**Plan**
Management	1,078.6	1,135.8	1,138.6	1,042.2	1,028.9	1,016.2	1,007.4	1,018.7
Society	3,122.7	3,251.4	3,473.6	3,250.9	3,184.1	3,141.7	3,120.1	3,087.5
PWU	3,694.6	3,863.9	4,096.5	4,141.2	4,131.8	4,164.0	4,129.8	4,116.9
Term/ETE/PECO Temporary	719.1	319.8	248.5	7.0	7.0	7.0	-	-
EPSCA	458.0	407.9	231.8	433.9	551.9	487.3	402.0	320.0
Total (Regular and Non-Regular)	9,073.0	8,978.8	9,189.0	8,875.1	8,903.6	8,816.2	8,659.2	8,543.2
Total Regular	7,044.3	7,531.2	8,023.5	8,089.9	8,040.6	7,989.1	7,966.4	7,930.4
Mgmt % Reg	15.3%	15.1%	14.2%	12.9%	12.8%	12.7%	12.6%	12.8%
Society % Reg	44.3%	43.2%	43.3%	40.2%	39.6%	39.3%	39.2%	38.9%
PWU % Reg	52.4%	51.3%	51.1%	51.2%	51.4%	52.1%	51.8%	51.9%
DNNP LP	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
	FTE	**FTE**	**FTE**	**FTE**	**FTE**	**FTE**	**FTE**	**FTE**
Staff (Regular and Non-Regular)	**Actual**	**Actual**	**Plan**	**Plan**	**Plan**	**Plan**	**Plan**	**Plan**
Management			98.3	110.3	96.1	75.3	61.6	45.9
Society			227.6	236.7	190.0	143.4	131.2	122.3
PWU			70.3	140.0	197.8	194.3	154.6	151.6
Term/ETE/PECO Temporary								
EPSCA			0.0	0.0	0.0	0.0	0.1	0.2
Total (Regular and Non-Regular)			396.2	487.1	484.0	413.1	347.3	319.9
Total Regular			371.9	463.2	461.4	395.1	336.6	316.1
Mgmt % Reg			26.4%	23.8%	20.8%	19.1%	18.3%	14.5%
Society % Reg			61.2%	51.1%	41.2%	36.3%	39.0%	38.7%
PWU % Reg			18.9%	30.2%	42.9%	49.2%	45.9%	48.0%
Hydroelectric Facilities	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
	FTE	**FTE**	**FTE**	**FTE**	**FTE**	**FTE**	**FTE**	**FTE**
Staff (Regular and Non-Regular)	**Actual**	**Actual**	**Plan**	**Plan**	**Plan**	**Plan**	**Plan**	**Plan**
Management	155.6	155.7	165.9	162.1	160.4	158.4	160.7	161.3

Society		506.5	548.9	619.0	635.3	629.8	624.4	626.4	621.7
PWU		753.5	801.8	911.4	914.5	921.6	933.2	925.8	928.1
Term/ETE/PECO Temporary									
EPSCA									
	Total (Regular and Non-Regular)	1,415.6	1,506.5	1,696.3	1,711.9	1,711.9	1,716.0	1,712.9	1,711.1
	Total Regular	1,317.8	1,406.5	1,575.1	1,586.7	1,581.6	1,579.0	1,584.8	1,585.1
	Mgmt % Reg	11.8%	11.1%	10.5%	10.2%	10.1%	10.0%	10.1%	10.2%
	Society % Reg	38.4%	39.0%	39.3%	40.0%	39.8%	39.5%	39.5%	39.2%
	PWU % Reg	57.2%	57.0%	57.9%	57.6%	58.3%	59.1%	58.4%	58.5%
OPG Regulated Facilities Total		**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
		FTE	**FTE**	**FTE**	**FTE**	**FTE**	**FTE**	**FTE**	**FTE**
Staff (Regular and Non-Regular)		**Actual**	**Actual**	**Plan**	**Plan**	**Plan**	**Plan**	**Plan**	**Plan**
Management		1,234.3	1,291.5	1,402.8	1,314.6	1,285.4	1,250.0	1,229.6	1,225.9
Society		3,629.2	3,800.3	4,320.2	4,122.9	4,003.9	3,909.4	3,877.7	3,831.5
PWU		4,448.0	4,665.7	5,078.2	5,195.6	5,251.2	5,291.5	5,210.1	5,196.6
Term/ETE/PECO Temporary		719.1	319.8	248.5	7.0	7.0	7.0	-	-
EPSCA		458.0	407.9	231.8	433.9	551.9	487.4	402.0	320.2
	Total (Regular and Non-Regular)	10,488.5	10,485.2	11,281.5	11,074.0	11,099.4	10,945.2	10,719.4	10,574.2
	Total Regular	8,362.0	8,937.7	9,970.5	10,139.8	10,083.6	9,963.2	9,887.8	9,831.5
	Mgmt % Reg	14.8%	14.5%	14.1%	13.0%	12.7%	12.5%	12.4%	12.5%
	Society % Reg	43.4%	42.5%	43.3%	40.7%	39.7%	39.2%	39.2%	39.0%
	PWU % Reg	53.2%	52.2%	50.9%	51.2%	52.1%	53.1%	52.7%	52.9%

Society Interrogatory #027

Interrogatory

Reference:
Exhibit F4-3-2 Pension and OPEB Costs

Question(s):

a) OPG uses an accrual basis for including its pension costs in rates, either as OM&A or capex. Please discuss any impacts on customers of OPG's decision to reduce its pension contributions, including the impact on its financing costs and intergenerational equity.

Response

a) OPG understands the question to refer to its decision to reduce registered pension plan contributions on account of the funding surplus, as discussed in Ex. F4-3-1, Section 7.0.1. As discussed in Ex. F4-3-2, Section 2.0, pension and OPEB costs for the regulated facilities have been calculated on an accrual basis of accounting for the purposes of the proposed revenue requirements.

The reduction in pension contributions has a small impact on customers, resulting in an estimated average increase of less than 0.1% in the impact of the Application on a typical monthly residential customer bill. The estimated revenue requirement impacts underpinning this calculation can be found in Ex. L-F4-PWU-012. The impacts reflect forecasted lower earnings on the pension asset component of the pension accrual costs as a result of the lower contributions over the IR term, together with the effects of such lower contributions on the regulatory income tax calculations

OPG has not identified any meaningful intergenerational equity considerations for customers with respect to its reduced pension contributions, as the payment amounts are proposed to reflect the accrual basis of accounting. As shown at Ex. F4-3-2, Chart 6 and Chart 7, taking into account the impact of the reduced pension contributions on account of the funding surplus, the forecasted pension accrual costs for OPG's prescribed facilities over the 2027-2031 period remain lower than the corresponding cash amounts. As discussed in Ex. H1-1-1, Section 5.12, the Pension and OPEB Forecast Accrual versus Actual Cash Differential Variance Account will continue to record interest on the difference between OPG's pension and OPEB accrual costs and cash amounts, asymmetrically in favour of ratepayers.

Society Interrogatory #028

Interrogatory

Reference:
Exhibit F4-3-2 Pension and OPEB Costs

Question(s):

a) Should OPG be required to increase its pension contributions as a result of the next pension actuarial assessment, please explain what, if any, the impacts would be to customers or to established variance accounts.

Response

a) This question is effectively the inverse of the one posed at Ex. L-F4-SUP-027. For the same reasons as discussed in Ex. L-F4-SUP-027, should OPG be required to increase its pension contributions during the 2027-2031 IR term relative to the forecast amounts underpinning the payment amounts approved in this proceeding, there would be a small reduction in the revenue requirement impacts associated with the pension and OPEB costs for OPG and DNNP LP's prescribed facilities and these amounts would be recorded in the respective Pension and OPEB Cost Variance Account as a future refund to customers.

As noted in Ex. L-F4-SUP-027, the forecasted pension accrual costs for OPG's prescribed facilities over the 2027-2031 period remain lower than the corresponding cash amounts. As discussed in Ex. H1-1-1, Section 5.12, the Pension and OPEB Forecast Accrual versus Actual Cash Differential Variance Account will continue to record interest on the difference between OPG's pension and OPEB accrual costs and cash amounts, asymmetrically in favour of ratepayers.