PRODUCTION FORECAST AND METHODOLOGY – REGULATED HYDROELECTRIC

1.0 PURPOSE

This evidence provides the production forecast for the regulated hydroelectric facilities and a description of the methodology used to derive the forecast. It also presents an overview of outage planning for the regulated hydroelectric facilities. Consistent with the OEB's letter dated September 17, 2024, issued in EB-2024-0136, OPG has included nine years of historical data for its regulated hydroelectric business below, for the period 2016-2024.

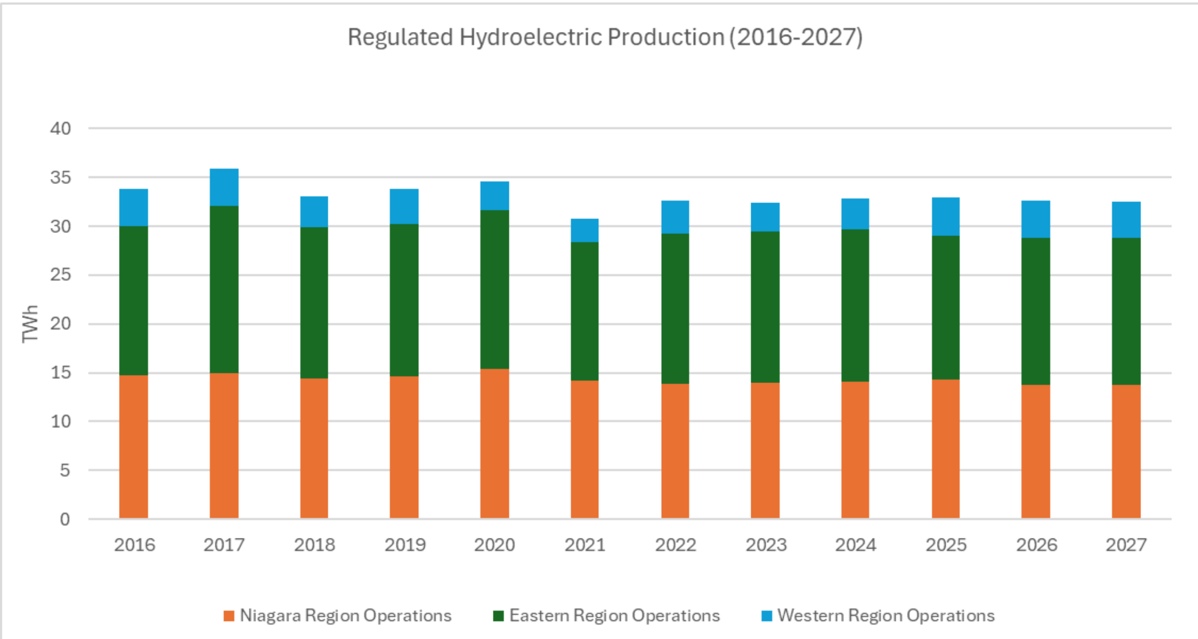
2.0 OVERVIEW

The actual regulated hydroelectric production for the years 2016-2024 and the forecast production for the bridge years (2025-2026) and test year (2027) is presented in Ex. E1-1-1, Table 1 and summarized below in Figure 1. OPG is seeking approval of a planned production forecast of 32.5 TWh in 2027 for the regulated hydroelectric facilities. Annual changes in production are primarily due to unit and water availability. Detailed analysis of year-over-year changes in actual and forecast production is provided in Ex. E1-1-2. Forecast monthly production data for the test period are presented in Ex. E1-1-1, Table 2.

The methodologies used to determine the flow and production forecasts for the Sir Adam Beck Complex, DeCew Falls generating stations, and R.H. Saunders GS are presented in Sections 3.2, 3.3, and 3.4, respectively. The forecast methodologies for the remaining regulated facilities are presented in Section 3.5.

A brief description of outage planning for the regulated hydroelectric facilities is presented in Section 4.0.

Figure 1 – Pre-SBG Spill Regulated Hydroelectric Production (2016-2027)



3.0 REGULATED HYDROELECTRIC PRODUCTION FORECAST

3.1 Forecast Methodologies

Hydroelectric production is impacted by water availability, which is affected by meteorological conditions, particularly precipitation and evaporation. OPG seeks to optimize the use of available water while meeting safety, environmental, applicable laws, and electrical system operational requirements. The forecast methodologies account for operational strategies used to maximize the use of available water for production and minimize hydroelectric spill (i.e., unutilized water).

Computer models are used to derive production forecasts for the 27 of the 54 regulated dispatchable hydroelectric stations that are connected to the IESO-controlled grid – a list of these stations is provided in Attachment 1.[1] Forecast monthly water flows, generating unit efficiency ratings, and planned outage information are used to convert forecast water availability into forecast energy production. These values are adjusted to reflect losses

[1] Calabogie GS is not dispatchable, but is modelled as part of the Madawaska River.

associated with electrical system operational requirements (e.g., regulation service, operating reserve, condense-mode operations, and system constraints) based on a historical impact assessment. The production forecast methodology used in this application was modified to also account for estimated losses that are not expected to be eligible for recovery in the Hydroelectric Surplus Baseload Generation Variance Account ("SBGVA").

For the other 27 regulated hydroelectric stations that are connected to local distribution systems and are non-dispatchable, OPG uses average historical production to determine the production forecast – a list of these stations is provided in Attachment 2.

The production forecast methodology has been updated to reflect spill that is not eligible for recovery under the SBGVA as described in Ex. E1-2-1, Section 4.3. With the exception of this change, there are no deductions made for global and local Surplus Baseload Generation ("SBG") where OPG expects that losses due to SBG will be addressed by the SBGVA as approved in EB-2010-0008 and modified in EB-2023-0336. This approach is consistent with the OEB's Decisions with Reasons in EB-2010-0008 and the forecasting approach in EB-2013-0321, which stipulated that no deductions are made for the impact of SBG. Details of the SBGVA are discussed further in Ex. E1-2-1 and Ex. H1-1-1.

3.2 Sir Adam Beck Complex Flow and Production Forecast

The models underlying the flow forecasting methodology for the Sir Adam Beck Complex have been updated since EB-2013-0321, though the methodology itself remains consistent. In December 2023, OPG fully transitioned from using the Hydrological Response Model for the Great Lakes and the Advanced Hydrological Prediction System[2] to the Residual Net Basin Supply ("RNBS") model maintained and run by the U.S. Army Corps of Engineers Great Lakes Hydraulics and Hydrology Office. The RNBS model is a statistical model which uses a long history of observations as a basis to forecast future conditions and uses.

[2] The Advanced Hydrologic Prediction System was superseded by the development of the Great Lakes Seasonal Hydrological Forecasting System ("GLSHFS") in 2017; while the data processing code was updated to standardize file formats, the underlying model components of the two systems were the same. The U.S. Army Corps of Engineers ceased providing the GLSHFS forecast as of December 1, 2023.

OPG uses the RNBS 50% (median) forecast of monthly average Niagara River inflow into the Grass Island Pool ("GIP"). The GIP is the section of the Niagara River upstream of the International Niagara Control Works and Horseshoe Falls which influences how much water is diverted through the tunnels and open cut canals to the hydroelectric generating stations. Short-term forecasts consider current Great Lake watershed conditions, seasonal precipitation outlooks, flows forecast by the U.S. Army Corps of Engineers RNBS model, and seasonal water availability trends. The flow forecast is adjusted to gradually align with long-term average conditions, using historical data analyses and comparing the forecast with other forecasting models, as a basis for this adjustment.

As with EB-2013-0321, the forecasted GIP inflows, along with the forecasted DeCew Falls diversion (detailed in Section 3.3), are inputs to the Niagara Utilization Monthly Model, which uses generating unit efficiency ratings, planned outage information, and forecasted regulation service[3] utilization to calculate the monthly energy production for the Sir Adam Beck complex.[4] Incremental production increases anticipated as a result of the Sir Adam Beck complex refurbishment projects completed by the test year have been incorporated into the forecasted energy production.

3.3 DeCew Falls Diversion Flow and Production Forecast

Water is diverted from the Welland Seaway Canal and routed to the DeCew Falls generating stations (DeCew 1 GS and DeCew 2 GS) for hydroelectric production. Forecasts of monthly DeCew diversion flow are prepared based on historical diversion flow, which is dependent on prevailing Lake Erie levels and considerations of planned Seaway Canal maintenance, planned unit outages at the DeCew generating stations, and flow variations, such as during major scheduled rowing regatta events held downstream of the generating stations.

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[3] Formerly referred to as Automatic Generation Control.
[4] No adjustment has been made to the Sir Adam Beck complex production forecast volumes to account for station service used by Niagara Hydrogen Centre.

Forecast DeCew diversion flows are used with unit availability information and generating unit efficiency ratings to calculate the monthly energy production forecast for the DeCew Falls generating stations.

3.4 St. Lawrence River Flow and R.H. Saunders GS Production Forecast

Prior to 2019, OPG used all available historic flows in its forecasting methodology for R.H. Saunders GS. Beginning in 2019, in order to align with changes to international standards and known watershed conditions, OPG transitioned to a 30-year[5] median in its forecasting methodology; this change reflects that flow trends on some river systems, including the St. Lawrence River, have remained consistent over time.

Monthly energy production for the R.H. Saunders GS is based upon St. Lawrence River flow and Lake Ontario water levels. R.H. Saunders GS planned outage information and generating unit efficiency ratings are used in conjunction with the expected flows and levels to calculate the monthly energy production forecast. The expected incremental production increases due to refurbishment projects at R.H. Saunders GS have been incorporated into the forecast energy production.

3.5 Production Forecast for the Remaining Regulated Hydroelectric Generating Stations

Energy production forecasts for the remaining 21 dispatchable regulated hydroelectric generating stations, located on nine river systems (see Attachment 1), are produced using computer models and are based upon the methodology documented in EB-2013-0321. Similar to the R.H. Saunders GS production forecast methodology described in Section 3.4, in 2019 OPG transitioned to a 30-year median in its forecasting methodologies for these regulated hydroelectric generating stations, consistent with changes to international standards. These models convert water availability to forecast energy production using generating unit efficiency ratings and planned outage information. The methodology used in this application has been modified from the one used in EB-2013-0321 to also account for spill due to unplanned

[5] In 2015, the World Meteorological Congress revised the definition of a climatological standard normal to the most recent 30-year period.

outages. OPG began tracking unplanned outage spill in 2019 to improve the accuracy of its hydroelectric forecasts for these stations and has used a five-year historical average to estimate associated losses.

Ottawa River flow may be augmented at times with water diverted from Québec to the Ottawa River basin upstream of Lake Temiskaming (referred to as the "Cabonga diversion"). The production forecasts for the four Ottawa River stations are based on historical median flow data that includes the Cabonga diversion flow. OPG benefits from additional energy produced at the four stations due to the Cabonga water. By agreement, a portion of the additional energy generated is returned to Hydro-Québec (referred to as "Cabonga payback"). Cabonga payback typically amounts to less than 1% of total production from the Ottawa River stations. The Eastern Region's production totals presented Ex. E1-1-1, Table 1 reflect the forecasted Cabonga payback amounts.

Energy production forecast methodologies for the remaining 27 non-dispatchable regulated hydroelectric stations (located on twelve river systems, see Attachment 2) remain unchanged from EB-2013-0321. These forecasts are based on historical mean monthly production values, adjusted to account for planned outages. These small generating stations are run-of-the-river and account for less than 5% of the total production from the remaining regulated hydroelectric facilities and less than 2% of total production from all regulated hydroelectric facilities. These 27 small stations are excluded from the Hydroelectric Water Conditions Variance Account (see Ex. H1-1-1).

The production impacts of redevelopment and refurbishment projects completed by the test year are reflected in forecast energy production.

4.0 OUTAGE PLANNING

OPG's hydroelectric outages are generally planned to conduct the following:

- Refurbishment, redevelopment, or concrete work
- Preventative maintenance
- Condition-based maintenance

- Inspection and testing

In addition to regularly scheduled maintenance outages, refurbishment and overhaul work is planned at select hydroelectric facilities (details on refurbishment projects are provided in Ex. D1-1-2). These major planned outages are accounted for in the 2027 test year production forecast, including anticipated incremental production increases.

In addition to planning outages around the key pillars of safety, environment, and applicable laws/regulations, OPG continues to optimize the timing and duration of its outages where possible. Outage optimization involves, but is not limited to:

- Scheduling outages[6] during periods of low water flow and/or demand to minimize the impact on generation. The normal cyclical patterns of river flow within a year are considered when scheduling outages in order to minimize hydroelectric spill.
- Seeking opportunities to reduce unit outage durations by nesting shorter maintenance/project outages within longer refurbishment outages where possible.
- Utilizing operational strategies (e.g., storing water where possible, running remaining online units at maximum gate) to maximize water usage and minimize hydroelectric spill. This helps to ensure optimal efficiency during planned outages.
- Collaborating with stakeholders, including Hydro One and the IESO, to coordinate outages. This bundling of work, where possible, helps reduce downtime and increase overall generation production.

[6] OPG outages are subject to assessment and final approval by the IESO as per Market Manual 7: System Operations, Part 7.4: IESO-Controlled Grid Operating Policies. The IESO has the discretion to reschedule, reject, or revoke an outage request if it risks operations or reliability of the IESO-controlled grid. See: <https://www.ieso.ca/-/media/Files/IESO/Document-Library/Renewed-Market-Rules-and-Manuals/market-manuals/system-operations/ieso-so-controlled-grid-operating-policies.pdf>.

ATTACHMENT 1

REGULATED STATIONS WITH MODELED PRODUCTION FORECASTS

River System	Generating Station
Niagara	Sir Adam Beck 1 Sir Adam Beck 2 Sir Adam Beck Pump Generating Station
Welland	DeCew Falls 1 DeCew Falls 2
St. Lawrence	R.H. Saunders
Madawaska	Mountain Chute Barrett Chute Calabogie Stewartville Arnprior
Ottawa	Otto Holden Des Joachims Chenaux Chats Falls
Abitibi	Abitibi Canyon Otter Rapids
Montreal	Lower Notch
Nipigon	Pine Portage Cameron Falls Alexander
Aguasabon	Aguasabon
Kaministiquia	Silver Falls Kakabeka Falls
English	Manitou Falls Caribou Falls
Winnipeg	Whitedog Falls

ATTACHMENT 2

REGULATED STATIONS WITHOUT MODELED PRODUCTION FORECASTS

River System	Generating Station
Montreal	Chute
Matabitchuan	Matabitchuan
Mississippi	High Falls
Rideau	Merrickville
Trent	Lakefield Auburn Seymour Ranney Falls Hagues Reach Meyersburg Sills Island Frankford Sidney
Beaver	Eugenia
Muskoka	Trethewey Falls Hanna Chute South Falls Ragged Rapids Big Eddy
Severn	Big Chute
South	Elliott Chute Bingham Chute Nipissing
Sturgeon	Crystal Falls
Wanapitei	Stinson Coniston McVittie

Numbers may not add due to rounding.

Table 1
Production Trend - Regulated Hydroelectric (TWh)

Line No.	Operating Region[1]	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget[3]	2026 Budget	2027 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	**Niagara Region**	12.0	11.3	12.0	12.4	12.2	12.5	12.7	13.2	13.7	14.3	14.0	13.8
2	**Eastern Region[2]**	14.2	16.1	14.8	14.8	15.3	14.0	15.1	15.3	15.5	14.8	14.8	15.0
3	**Western Region**	3.3	3.4	3.0	3.3	2.8	2.4	3.4	2.9	3.2	3.9	3.9	3.7
4	**Total**	29.5	30.7	29.8	30.5	30.3	29.0	31.1	31.4	32.5	33.0	32.8	32.5

Notes:
1 Operating Region descriptions effective 2021 (see Ex. A1-4-2).
2 Eastern Region totals reflect energy delivered to Hydro-Québec via R.H. Saunders GS and Chats Falls GS.
3 2016-2024 production values are net of SBG spill. 2025-2027 production values are on a pre-spill basis, i.e., there are no deductions made for SBG as per Ex. E1-1-1, Section 3.1.

Table 2
Monthly Production - Regulated Hydroelectric (TWh)
2027 Test Year

Line No.	Operating Region[1]	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	2027 Plan[3]:													
1	**Niagara Region**	1.2	1.1	1.3	1.1	1.1	1.1	1.2	1.1	1.1	1.1	1.2	1.2	13.8
2	**Eastern Region[2]**	1.3	1.2	1.3	1.5	1.7	1.3	1.1	1.0	0.9	1.1	1.2	1.3	15.0
3	**Western Region**	0.4	0.3	0.4	0.3	0.3	0.3	0.3	0.2	0.2	0.3	0.3	0.4	3.7
4	**Total**	2.9	2.7	2.9	2.9	3.2	2.7	2.6	2.4	2.2	2.4	2.6	2.9	32.5

Notes:
1 Operating Region descriptions effective 2021 (see Ex. A1-4-2).
2 Eastern Region totals reflect energy delivered to Hydro-Québec via R.H. Saunders GS and Chats Falls GS.
3 2027 production values are on a pre-spill basis, i.e., there are no deductions made for SBG as per Ex. E1-1-1, Section 3.1.

COMPARISON OF PRODUCTION FORECASTS – REGULATED HYDROELECTRIC

1.0 PURPOSE

This evidence presents period-over-period comparisons of total regulated hydroelectric production based on actuals for 2016-2024 and forecasts for the bridge period (2025-2026) and test year (2027), as detailed in Ex. E1-1-2, Table 1, and supports the approval of the regulated hydroelectric production forecast presented in Ex. E1-1-1.

Consistent with the OEB's letter dated September 17, 2024, issued in EB-2024-0136, OPG has included nine years of historical data for its regulated hydroelectric business below, for the period 2016-2024. As there is no OEB-approved regulated hydroelectric production information for 2015 onwards, OPG has provided only year-over-year variance analysis for the historical period (2016-2024), bridge period (2025-2026), and test year (2027).

2.0 PERIOD-OVER-PERIOD CHANGES – TEST YEAR

Hydroelectric production is impacted primarily by water availability, unit availability, or a combination thereof. As detailed in Ex. E1-1-1, historical median monthly flows are used for determining the monthly energy production forecast for many regulated generating stations, and a long-term average for the Sir Adam Beck and DeCew Falls facilities. Therefore, the year-over-year changes in the bridge period and test year are mainly attributed to forecast outage differences and forecast production increases expected from refurbishment and redevelopment projects. The production forecast is inclusive of outages to accommodate the ongoing refurbishment program and other life extension activities across the fleet, and also reflects anticipated energy from the completed refurbishment and redevelopment projects, as described in Ex. F1-1-1 and Ex. D1-1-2.

The forecast methodology for the 2027 test year accounts for operational strategies used to maximize the use of available water for production and minimize hydroelectric spill (i.e., unutilized water) as detailed in Ex. E1-1-1, Section 4.0.

2027 Plan versus 2026 Forecast

The total regulated hydroelectric production forecast for 2027 is 1% (0.3 TWh) lower than the forecast for 2026.

The total production forecast for Niagara Region in 2027 is 2% (0.2 TWh) lower than the forecast for 2026 primarily due to changes in unit availability. Variances in unit availability are due to differences in maintenance outage schedules and the reduced availability of Sir Adam Beck 2 GS due to the refurbishment program.

The total production forecast for Eastern Region in 2027 is 1% (0.1 TWh) higher than the forecast for 2026. Period-over-period variances in Eastern Region are due to differences in maintenance, refurbishment and redevelopment outage schedules and forecast production increases expected from refurbishment and redevelopment projects. The majority of this variance is due to the return to service of redeveloped stations, namely Coniston GS, Stinson GS, and Bingham Chute GS.

The total production forecast for Western Region in 2027 is 5% (0.2 TWh) lower than the forecast for 2026. Period-over-period variances in Western Region are due to differences in maintenance outage schedules, namely at Caribou Falls GS in 2027.

3.0 PERIOD-OVER-PERIOD CHANGES – BRIDGE YEARS

2026 Forecast versus 2025 Forecast

The total regulated hydroelectric production forecast for 2026 is 1% (0.2 TWh) lower than the forecast for 2025. Lower production at Niagara Region is partially offset by higher production from Eastern Region.

The total production forecast for Niagara Region in 2026 is 2% (0.3 TWh) lower than the forecast for 2025 primarily due to an expected reduction in flow in 2026, changes in unit availability, and impacts from Sir Adam Beck 1 GS and Sir Adam Beck 2 GS refurbishment programs. Niagara River flows are expected to return to long-term average in 2026, and continue into the test year and beyond. Niagara River flows are forecasted to reduce in 2026 compared to 2025 given the trend towards long-term average.

The total production forecast for Eastern Region in 2026 is 0.5% (0.1 TWh) higher than the forecast for 2025. Period-over-period variances in Eastern Region are attributed to differences in maintenance and refurbishment outage schedules, namely the return to service of Abitibi Canyon GS units from maintenance by 2026.

The total production forecast for Western Region in 2026 is 0.5% (0.02 TWh) lower than the forecast for 2025. Period-over-period variances in Western Region are attributed to refurbishment work at Cameron Falls GS and Manitou Falls GS, and the redevelopment of Kakabeka Falls GS.

4.0 PERIOD-OVER-PERIOD CHANGES – HISTORICAL YEARS

2025 Forecast versus 2024 Actual

The total regulated hydroelectric production forecast for 2025 is 1% (0.5 TWh) higher than 2024 actual production. Actuals up until and including 2024 are net of Surplus Baseload Generation ("SBG") losses. The 2025 budget year is on a pre-SBG spill basis as per Ex. E1-1-1, Section 3.1. Differences in production that are due to SBG conditions are captured after-the-fact in the Hydroelectric Surplus Baseload Generation Variance Account (see Ex. E1-2-1 and Ex. H1-1-1 for further SBG breakdowns).

The total production forecast for Niagara Region in 2025 is 4% (0.5 TWh) higher than the actual production in 2024. This is due to increased unit availability at DeCew Falls 1 GS and DeCew Falls 2 GS in 2025, resulting in a 0.5 TWh increase in DeCew Falls facility forecasted production. Sir Adam Beck 2 GS had 0.3 TWh of SBG in 2024, however this was offset by forecasted lower flow conditions in 2025.

The total production forecast for Eastern Region in 2025 is 5% (0.7 TWh) lower than 2024 actuals. This is due to lower forecasted flow conditions along the Ottawa and Montreal Rivers in 2025.

The total production forecast for Western Region in 2025 is 22% (0.7 TWh) higher than 2024 actuals due to higher forecasted flow conditions and fewer maintenance outages at Manitou Falls GS and Cameron Falls GS.

2024 Actual versus 2023 Actual

The total production for 2024 was 4% (1.1 TWh) higher than production for 2023. Production during 2024 was 5% (0.6 TWh) higher in Niagara Region, 1% (0.2 TWh) higher in Eastern Region, and 10% (0.3 TWh) higher in Western Region. Lower SBG conditions due to higher electricity demand contributed to this increased production.

Niagara River flow was comparable between 2024 and 2023; lower production losses due to reduced SBG spill and increased unit availability compared to 2023 resulted in higher production from Niagara Region. Higher unit availability at both Sir Adam Beck GS 1 and 2 is attributed to a decrease in maintenance outages and Hydro One Switchyard Project work in 2024.

Although Eastern river flows were lower in 2024, lower production losses due to reduced SBG spill compared to 2023 resulted in higher production from Eastern Region.

Higher flow conditions along Western river systems and lower production losses due to reduced SBG spill in 2024 resulted in higher production compared to 2023.

2023 Actual versus 2022 Actual

The total regulated hydroelectric production for 2023 was 1% (0.3 TWh) higher than 2022. Production during 2023 was 4% (0.5 TWh) higher in Niagara Region, 2% (0.2 TWh) higher in Eastern Region, and 13% (0.4 TWh) lower in Western Region.

Niagara River flow was comparable between 2023 and 2022. However, lower production losses due to reduced SBG spill compared to 2022 resulted in higher production from Niagara Region.

Higher flows along Eastern rivers, namely the Madawaska River, and lower production losses due to reduced SBG spill compared to 2022 resulted in higher production from Eastern Region in 2023.

Lower flow conditions in 2023 along Western river systems resulted in lower production in Western Region compared to 2022.

2022 Actual versus 2021 Actual

The total regulated hydroelectric production for 2022 was 7% (2.1 TWh) higher than 2021. Production during 2022 was 1% (0.1 TWh) higher in Niagara Region, 7% (1.0 TWh) higher in Eastern Region, and 40% (1.0 TWh) higher in Western Region. Higher flows across most of Ontario and lower SBG conditions due to higher electricity demand contributed to this increased production.

Although Niagara River flow conditions were lower in 2022, lower production losses due to lower SBG spill resulted in higher 2022 production from Niagara Region compared to 2021.

Higher total production from Eastern Region in 2022, compared to the 2021 production, is attributable to higher annual mean flow conditions across the Ottawa, Abitibi, and Montreal Rivers.

Higher annual mean flow conditions were observed along all Western Rivers, most notably along the English and Winnipeg rivers. Higher flow conditions in 2022 along Western Rivers and fewer refurbishments and maintenance outages, namely at Cameron Falls GS and Aguasabon GS, resulted in higher production from Western Region compared to 2021.

2021 Actual versus 2020 Actual

The total regulated hydroelectric production for 2021 was approximately 4% (1.3 TWh) lower than the actual production achieved in 2020. Production during 2021 was 3% (0.4 TWh) higher in Niagara Region, 8% (1.3 TWh) lower in Eastern Region, and 13% (0.4 TWh) lower in Western Region.

Although Niagara River flow was lower in 2021, lower production losses due to lower SBG spill compared to 2020 resulted in higher 2021 production from Niagara Operations.

Lower flow conditions in 2021 along the Eastern river systems and an increase in planned maintenance and project activities that had previously been deferred from 2020 due to the COVID-19 pandemic resulted in lower production for Eastern Region compared to 2020. Lower annual mean flow conditions were most notable along the Ottawa, St. Lawrence, and Montreal rivers.

Lower flow conditions in 2021 along the English and Winnipeg rivers and an increase in refurbishment and maintenance outages at Aguasabon GS resulted in lower production from Western Region compared to 2020.

5.0 PERIOD-OVER-PERIOD CHANGES – EXTENDED HISTORICAL YEARS

Pursuant to the OEB's letter dated September 17, 2024, issued in EB-2024-0136, OPG has included four additional years of historical data.

2020 Actual versus 2019 Actual

The total regulated hydroelectric production for 2020 was approximately 1% (0.3 TWh) lower than 2019 actual production. Lower production in 2020 reflected greater production losses due to higher SBG spill as a result of the impact of the COVID-19 pandemic on Ontario electricity demand. Production during 2020 was 2% (0.2 TWh) lower in Niagara Region, 4% (0.5 TWh) higher in Eastern Region, and 17% (0.6 TWh) lower in Western Region.

Although higher mean annual flows were observed along the Niagara River, total annual production in Niagara Region was lower in 2020 as a result of higher production losses due to higher SBG spill in 2020.

Higher mean flow conditions were observed in 2020 along the St. Lawrence River for the year. The second half of 2020 in particular saw increased flow conditions on the Ottawa, Madawaska, Abitibi and Montreal Rivers. Higher flow conditions year-over-year coupled with deferral of project and planned maintenance work due to the COVID-19 pandemic resulted in increased production from Eastern Region in 2020. This was partially offset by higher production losses due to higher SBG spill.

Lower total annual production from Western Region was observed in 2020 due to lower flow conditions along Western River systems and increased production losses due to higher SBG spill.

2019 Actual versus 2018 Actual

The total regulated hydroelectric production for 2019 was approximately 3% (0.8 TWh) higher than the actual production achieved in 2018. Production during 2019 was 3% (0.4 TWh) higher in Niagara Region and 13% (0.4 TWh) higher in Western Region. There were negligible year-over-year differences in actual production in Eastern Region.

Total annual production in Niagara Region was greater in 2019 due to higher flow conditions along the Niagara River compared to 2018. Lower production in 2018 also reflected greater production losses due to higher SBG spill.

Higher mean annual flow conditions were observed along all Eastern rivers in 2019. Higher mean annual flow conditions were offset by higher production losses due to SBG spill in 2019, resulting in negligible year-over-year differences in total production from Eastern Region.

Higher total annual production from Western Region was observed in 2019 primarily due to higher flow conditions along the Kaministiquia, English, and Winnipeg rivers. This was partially offset by production losses due to higher SBG spill.

2018 Actual versus 2017 Actual

The total regulated hydroelectric production for 2018 was approximately 3% (0.9 TWh) lower than the actual production achieved in 2017. Production during 2018 was 7% (0.7 TWh) higher in Niagara Region, 8% (1.3 TWh) lower in Eastern Region, and 12% (0.4 TWh) lower in Western Region.

Although Niagara River flow conditions between the two years were comparable, higher production losses due to higher SBG spill in 2017 resulted in higher production from Niagara Region in 2018.

Lower flow conditions in 2018 along the Madawaska and Ottawa Rivers resulted in lower production compared to 2017 in Eastern Region. This lower production was slightly offset by production along the St. Lawrence River which was comparable in flows and production to 2017.

Lower flow conditions in 2018 along Western river systems resulted in lower production in Western Region compared to 2017.

2017 Actual versus 2016 Actual

The total regulated hydroelectric production for 2017 was 4% (1.2 TWh) higher than the actual production achieved in 2016. Production during 2017 was 6% (0.8 TWh) lower in Niagara Region, 13% (1.9 TWh) higher in Eastern Region, and 3% (0.1 TWh) higher in Western Region.

Annual mean flow in 2017 for the Niagara River was higher than the 2016 flow conditions. However, production from Niagara Region was lower than in 2016 due to increased SBG spill at the Sir Adam Beck Complex as well as lower unit availability at DeCew Falls 2 GS due to a one-unit refurbishment.

Significantly higher total production from Eastern Region in 2017, compared to the 2016 production, is attributable to higher annual mean flow conditions across the Madawaska, Ottawa, and St. Lawrence Rivers.

Marginally higher total production for Western Region in 2017 compared to 2016 is attributable to higher unit availability and lower production losses due to lower SBG spill in 2017.

Numbers may not add due to rounding.

Table 1
Comparison of Production Forecast - Regulated Hydroelectric (TWh)

Line No.	Operating Region[1]	2016 Actual	(c)-(a) Change	2017 Actual	(e)-(c) Change	2018 Actual	(g)-(e) Change	2019 Actual	(i)-(g) Change	2020 Actual	(k)-(i) Change	2021 Actual	(m)-(k) Change	2022 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	**Niagara Region**	12.0	(0.8)	11.3	0.7	12.0	0.4	12.4	(0.2)	12.2	0.4	12.5	0.1	12.7
2	**Eastern Region[2]**	14.2	1.9	16.1	(1.3)	14.8	(0.0)	14.8	0.5	15.3	(1.3)	14.0	1.0	15.1
3	**Western Region**	3.3	0.1	3.4	(0.4)	3.0	0.4	3.3	(0.6)	2.8	(0.4)	2.4	1.0	3.4
4	**Total**	29.5	1.2	30.7	(0.9)	29.8	0.8	30.5	(0.3)	30.3	(1.3)	29.0	2.1	31.1

Line No.	Operating Region[1]	2022 Actual	(c)-(a) Change	2023 Actual	(g)-(e) Change	2024 Actual	(i)-(g) Change	2025 Budget[3]	(k)-(i) Change	2026 Budget	(k)-(i) Change	2027 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
5	**Niagara Region**	12.7	0.5	13.2	0.6	13.7	0.5	14.3	(0.3)	14.0	(0.2)	13.8
6	**Eastern Region**	15.1	0.2	15.3	0.2	15.5	(0.7)	14.8	0.1	14.8	0.1	15.0
7	**Western Region**	3.4	(0.4)	2.9	0.3	3.2	0.7	3.9	(0.0)	3.9	(0.2)	3.7
8	**Total**	31.1	0.3	31.4	1.1	32.5	0.5	33.0	(0.2)	32.8	(0.3)	32.5

Notes:
1 Operating Region descriptions effective 2021 (see Ex. A1-4-2).
2 Eastern Region totals reflect energy delivered to Hydro-Québec via R.H. Saunders GS and Chats Falls GS.
3 2016-2024 production values are net of SBG spill. 2025-2027 production values are on a pre-spill basis, i.e., there are no deductions made for SBG as per Ex. E1-1-1, Section 3.1.

HYDROELECTRIC INCENTIVE MECHANISM, SURPLUS BASELOAD GENERATION AND MAKE WHOLE PAYMENTS

1.0 PURPOSE

This evidence explains OPG's proposal for the continuation of changes to OPG's regulatory framework as a result of the implementation of IESO's Market Renewal Program ("MRP" or "Renewed Market"), as established and settled in EB-2023-0336, based on quantitative results from the first five months of OPG's experience in the Renewed Market. It also proposes changes to the sharing of Hydroelectric Incentive Mechanism ("HIM") revenues for the IR term. Additionally, as committed in EB-2023-0336, OPG has attached the Hydroelectric Surplus Baseload Generation Variance Account Study ("SBGVA Study") as Attachment 1.

2.0 OVERVIEW

In this application OPG is seeking the following approvals, as established and settled in EB-2023-0336, further supported by OPG's experience in the Renewed Market:

1. To continue to book amounts in the SBGVA based on the revised local and global Surplus Baseload Generation ("SBG") spill methodology, as described in Section 4.0;
2. To continue to be settled according to the revised HIM, which includes separate day-ahead and real-time incentives and uses locational prices based on daily average, as described in Section 5.0;
3. To continue the revised HIM adjustment for spill ("unintended benefit") as described in Section 5.0; and
4. To continue to retain Real-Time Energy Make Whole Payments as described in Section 6.0.

These approvals will continue the alignment of certain ratemaking methodologies related to production from OPG's prescribed hydroelectric generating facilities, as approved by the OEB, with the design and operations of the Renewed Market.

OPG is also seeking the approval to eliminate the sharing of HIM revenues above the threshold established in Ex. G1-1-1 as described in Section 5.0. This proposal is supported by a Market Surveillance Panel ("MSP") recommendation and is detailed in OPG's SBGVA Study as an outcome of one of the studied options. The proposed removal of HIM revenue sharing maintains OPG's incentives across all market outcomes to the benefit of ratepayers.

3.0 OVERVIEW OF THE RENEWED MARKET

While the Renewed Market introduced many operational changes,[1] the impacts on OPG's Regulated Framework addressed in this Exhibit are outlined in Chart 1 and are described further below.

Chart 1: Mapping of MRP Design Elements to Impacted OPG Regulated Framework Addressed in this Application

		Impacts to OPG Regulated Framework			
MRP Changes		SBGVA	HIM	Other Revenues	MWP/CMSC
Single Schedule Market	Uniform price to Locational Prices	☑	☑	☑	
	Eliminate Unconstrained schedule	☑		☑	☑
	Changes to MWP				☑
DAM & RTM	DAM & RTM Settlement		☑	☑	

3.1 Single schedule market ("SSM")

In the Legacy Market (referring to the market prior to MRP), the IESO used two dispatch algorithms: one to schedule and dispatch resources to meet demand and another to determine prices.[2] The dispatch setting "constrained" algorithm included transmission constraints and losses, while the "unconstrained", uniform price-setting algorithm did not. In comparison, the Renewed Market includes a single schedule optimization that utilizes the same dispatch algorithm for both dispatch scheduling and pricing. The Locational Marginal Prices ("LMP")

[1] A complete list of contemplated changes can be found in the IESO's high-level design documents: <https://www.ieso.ca/en/Market-Renewal/Energy-Stream-Designs/High-Level-Designs>.
[2] For purposes of this exhibit, a 'resource' refers to a single or group of generating units that connect to the IESO controlled grid at a specific node.

published in the Renewed Market incorporate the cost of congestion and losses to reflect the marginal cost of energy at each electrical node on the system. These prices typically reflect dispatch schedules received at each resource and are used for market settlement, subject to a floor price.

3.2 Financially binding Day-Ahead Market ("DAM") and Real-Time Balancing Market

Unlike the Legacy Market, where only non-quick start generators received a Day-Ahead guarantee via a day-ahead commitment process, the Renewed Market includes a financially binding Day-Ahead Market for all participants and balances deviations that occur between the day-ahead and real-time through a Real-Time Balancing Market. The IESO's stated benefits of a financially binding DAM include certainty for participating resources through a guaranteed schedule and price in the day-ahead timeframe and greater market scheduling certainty for the market operator by shifting scheduling of supply quantities to the day-ahead timeframe.[3] A real-time balancing settlement is used for deviations between a resource's day-ahead schedule and its real-time output based on the real-time LMP to incentivize market participants to respond to incremental, post day-ahead system changes.

3.3 Changes to Make Whole Payments ("MWP")

Make Whole Payments, a type of out-of-market compensation, ensure market participants are paid appropriately when resources are dispatched uneconomically in relation to their market payments. The Legacy Market used Congestion Management Settlement Credits ("CMSC") to keep market participants whole when a resource's constrained run schedule differed from the unconstrained schedule used in the uniform price setting run. As such, CMSCs facilitated revenue sufficiency for hydroelectric resources related to inefficient operation and in some instances forgone generation due to system constraints. In the Renewed Market, MWPs compensate hydroelectric resources for lost cost and lost opportunity cost in day-ahead and real-time. As the LMPs include the cost of congestion, according to the IESO's high-level

[3] IESO, Day-Ahead Market High-Level Design ("DAMHLD"), August 2019, p. 3 <https://www.ieso.ca/en/Market-Renewal/Stakeholder-Engagements/Market-Renewal-Day-Ahead-Market>.

design,[4] the transition to the single schedule market largely removes the underlying causes of divergence between dispatch and price that previously created the need for out-of-market payments. While MWPs are a part of both the day-ahead and real-time market, the circumstances that lead to MWPs in the Renewed Market are expected to be infrequent by design.

4.0 SURPLUS BASELOAD GENERATION

While both global SBG and local SBG can lead to hydroelectric spill, this section explains why global SBG conditions were used to quantify SBG spill when calculating SBGVA entries in the Legacy Market and why global SBG conditions can no longer be differentiated from local SBG conditions in the Renewed Market. This section details OPG's proposal to continue to quantify SBG spill and make entries to the SBGVA on a total SBG basis (i.e., include spill due to global and local SBG conditions).

4.1 Overview

In its 2012 Renewable Integration Stakeholder Engagement, the IESO described that SBG conditions can occur on both a global and local level, with global SBG defined as "a condition that occurs when Ontario's electricity production from baseload facilities, if not managed, would otherwise be greater than demand".[5] Local SBG was similarly defined as "a condition that occurs when a region's electricity production from baseload facilities, if not managed, would otherwise be greater than the local demand and the transmission system's ability to move the excess generation out of the area".[6] Both types of SBG conditions can cause hydroelectric spill at OPG's hydroelectric resources when storage is not available.

4.2 SBG Spill Calculation in the Legacy Market

As explained in Ex. E1-1-1, similar to all prior applications, OPG's hydroelectric production forecast has no deductions made for SBG and therefore its ability to recover its revenue

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[4] IESO, Single Schedule Market High-Level Design ("SSMHLD"), August 2019, p. 55 https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/ssm/SSM-High-Level-Design-Aug2019.ashx>.
[5] SE-91 Document "Surplus Baseload Generation (SBG)", August 7, 2012.
[6] *Ibid.*

requirement is reduced when SBG conditions occur.[7] To address the impact of SBG on OPG's regulated hydroelectric production, the OEB approved the SBGVA in EB-2010-0008 and each subsequent payment amounts proceeding.

As detailed in EB-2013-0321[8] and most recently set out in the EB-2020-0290 Payment Amounts Order, OPG calculated forgone production due to SBG in the Legacy Market by starting with the total volume of spill and subtracting the volume of spill due to water conveyance constraints, production capability, market constraints and contractual obligations.

SBGVA entries were then calculated using the volume of spill remaining after excluding the spill amounts incurred by OPG that were not attributable to the impact of SBG conditions based on a comparison of OPG's Gross Revenue Charge ("GRC") and the uniform price. The uniform price is an indicator of global SBG, as it does not consider the impact of congestion.

4.3 SBG Spill Calculation in the Renewed Market

As explained in EB-2023-0336, the Renewed Market's SSM necessitated an update to OPG's methodology for calculating forgone production due to SBG conditions. Specifically, the Renewed Market does not calculate and publish a uniform, "unconstrained" price, thereby eliminating OPG's ability to evaluate market conditions without the impact of local market constraints. As a result, OPG is unable to accurately distinguish between spill due to global and local SBG conditions as defined in IESO's Renewable Integration Stakeholder Engagement.

The use of a SSM also impacts the calculation of SBG-related spill. As described in Section 4.2, in the Legacy Market OPG isolated global SBG spill from other market constraints that can cause OPG to forgo generation, which at times included spill caused by local SBG. OPG assessed market constraints by comparing the constrained and unconstrained schedules published in the Legacy Market. This process ensured that forgone generation due to market

[7] Where OPG expects that losses due to SBG will be addressed by the SBGVA as approved in EB-2010-0008 and modified in EB-2023-0336.
[8] EB-2013-0321, Ex. E1-2-1, Section 3.2 and Ex. L-5.4-17 SEC-070.

constraints, including those related to local SBG, were not booked in the SBGVA, as they may also attract CMSC payments. The Renewed Market's use of a single schedule eliminates OPG's ability to identify spill attributable to market constraints as it also eliminates CMSC payments.

To address these changes, in EB-2023-0336 OPG proposed adjustments to the methodology used to calculate spill due to SBG conditions. OPG's proposal aligned with the structure of the Renewed Market while maintaining OPG's revenue sufficiency when impacted by surplus conditions outside of OPG's control. OPG's proposal was accepted at the conclusion of OPG's MRP application in EB-2023-0336 and implemented as proposed as of May 1, 2025, the go-live date of the Renewed Market.

OPG's methodology to calculate forgone production due to SBG maintains the process of starting with the actual volume of water spilled. OPG then removes spill related to water conveyance constraints, production capability constraints and contractual obligations. This methodology differs from the one used in the Legacy Market. Specifically, spill associated with market constraints is no longer removed as these amounts are unquantifiable in the Renewed Market. This remaining spill volume is considered as potential SBG spill. SBG conditions are generally expected to be present when the applicable real-time LMP for a given resource falls below its applicable GRC price threshold.[9] OPG's use of LMP as an indicator for SBG conditions could indicate the presence of global or local SBG conditions, unlike the uniform price in the Legacy Market, which signaled the presence of global SBG.

In the course of pre-implementation testing of OPG's proposed methodology using Legacy Market proxy LMPs (also known as Shadow Prices) OPG observed instances when the locational price did not fall below GRC while GRC-based generation was scheduled down and OPG incurred spill. OPG anticipated that LMPs in the Renewed Market could be subject to similar exceptions. After the implementation of the Renewed Market, OPG continued to

[9] Per IESO's SSMHLD, p. 8, footnote 4, the applicable LMP by location is based on the connection point (node) of a market participant supplier.

observe spill ineligible for SBGVA recovery. As noted in the IESO's *Update on Renewed Market Performance and Operations*: "LMP prices do not tell the whole story and cannot always be used to determine if an offer/bid should or should not have cleared the market at their submitted prices".[10] As such, while the Renewed Market introduced LMPs that generally reflect system conditions, certain operational and optimization constraints continue to result in spill outcomes that are not captured under the SBGVA framework. This impact is included as an adjustment to OPG's hydroelectric production forecast as reflected in Ex. E1-1-1, Section 3.1.

4.4 SBG Spill and Make Whole Payments

As explained in Section 3.3, the use of a Single Schedule in the Renewed Market eliminated CMSCs but continued the general use of MWPs in instances when the IESO takes out-of-market actions. OPG notes that MWPs related to lost opportunity resulting from the IESO taking out-of-market actions can coincide with the occurrence of SBG spill at its hydroelectric facilities. To prevent duplicate payment related to the same quantity of forgone generation, OPG's SBGVA methodology identifies instances when, on an hourly resolution, a resource books SBGVA amounts and receives a MWP from the IESO. OPG reduces the SBGVA entry associated with the respective resource by the value of the MWP received, ensuring the entry does not fall below zero dollars. OPG notes that for the first five months of the Renewed Market, the MWP associated reduction of OPG's SBGVA has been negligible.

4.5 SBG Spill Observations in the Renewed Market

Consistent with its OEB-approved EB-2023-0336 Settlement Proposal, OPG has presented SBGVA amounts from the five months in the Renewed Market as well as monthly data for the 2021-2025 period in Chart 2. This data demonstrates the expected persistence of seasonal patterns with higher SBGVA entries during freshet months. While OPG is unable to isolate spill that is attributable solely to the SBGVA methodology changes implemented under the Renewed Market, spill volumes observed to date have remained generally consistent on a

[10] IESO, Update on Renewed Market Performance and Operations https://ieso.ca/-/media/Files/IESO/Document-Library/engage/renewed-market/rmo-20250821-presentation-renewed-market-update.pdf>.

month-over-month basis with levels recorded since 2021. OPG expects that total SBG spill will continue to remain at these recently observed lower levels, subject to hydrological conditions.

Chart 2: SBG Spill Booked to SBGVA (MWh)[11]

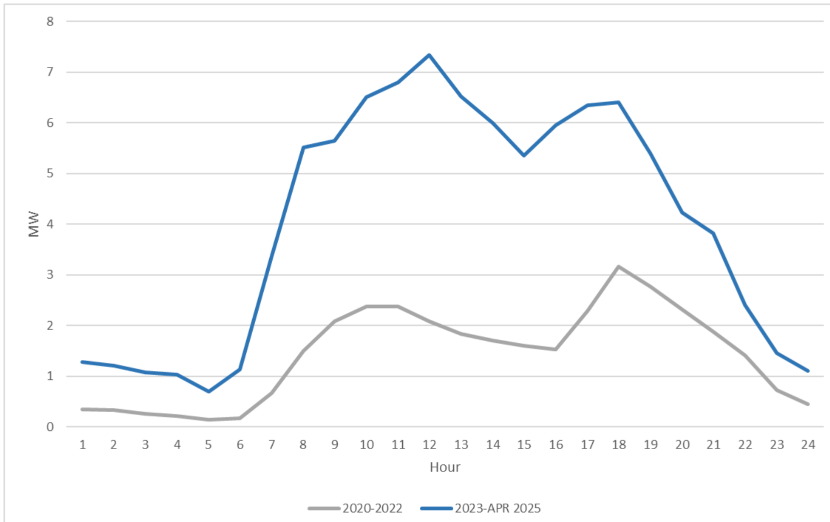
	2021	2022	2023	2024	2025	Average
January	195	51	54	3	5	61
February	118	72	152	15	0	72
March	258	74	85	20	48	97
April	399	276	199	77	131	216
May	299	353	289	44	**398**	278
June	134	283	31	68	**84**	121
July	108	32	1	13	**33**	37
August	32	30	18	9	**12**	20
September	130	77	9	17	**20**	58
October	99	65	92	17		68
November	48	216	40	49		88
December	62	62	6	17		37

4.6 Use of Sir Adam Beck Pump Generating Station ("PGS") During SBG Conditions

As demonstrated in the SBG and related PGS annual reporting and record-keeping requirement, Ex. H1-1-1 Attachments 3 and 4, and Chart 3 below, PGS utilization continues to increase since the SBGVA was last cleared.

[11] The SBGVA amounts associated with spill for May to September 2025 as presented in Chart 1 are subject to a monthly $0.6M reduction in accordance with the OEB-approved EB-2023-0336 Settlement Proposal, which is applicable until the effective date of the payment amounts order in this Application.

Chart 3 - Average Pumped Generating Station Output by Hour
(January 2020 - April 2025)



The number of coincident hours where SBGVA additions were made and the PGS was not pumping have decreased significantly since the 2020 high of 6,437, at 1,856 in 2023 and 1,006 in 2024. The value of SBGVA additions in coincident hours when the PGS was not operated in pump mode exclusively to prevent economic loss to OPG have also significantly decreased from the 2020 high of $11.5M to $0.7M in 2023 and $0.4M in 2024. OPG attributes the increase in PGS utilization and the concomitant decline in hours with SBGVA bookings when the PGS is not pumping to the absence of very high flows on the Niagara river and sufficient price spread in the market.

4.7 Conclusion

OPG proposes to continue to book amounts in the SBGVA based on the revised local and global SBG spill methodology as settled in EB-2023-0336 and described above. The continuation of this process is supported by data observed in the first five months of the Renewed Market. The SBGVA provides a mechanism for OPG to record the impacts of foregone generation not reflected in its forecast, and the entries are adjusted for interactions with Real-Time MWPs, ensuring no additional reductions are required.

5.0 HYDROELECTRIC INCENTIVE MECHANISM

This section sets out OPG's proposals related to the HIM. Sections 5.1-5.3 describe the HIM and OPG's proposal to continue the updates to the HIM methodology and the spill adjustment that align the HIM with the Renewed Market as settled in EB-2023-0336. Section 5.4 presents the customer benefit analysis associated with the HIM, and Section 5.5 outlines OPG's proposed revisions to HIM revenue sharing.

5.1 HIM Overview

The HIM was proposed and approved in EB-2007-0905 to provide OPG with an incentive to respond to market signals in a manner that also benefits consumers. Under the HIM, if in a given hour OPG produces more energy than a monthly average-based hourly volume, it receives market prices for this incremental amount of energy. If OPG's energy production is less than the hourly volume in a given hour, the amount payable to OPG is reduced by the production shortfall multiplied by the market price. Consumers benefit from the placement of hydroelectric energy in high priced hours, which typically reflects higher demand for electricity.

In EB-2010-0008, the OEB required OPG to address the interaction between HIM revenues and the SBGVA in its next application. In EB-2013-0321, the OEB directed OPG to include an offset to the HIM to reflect the interaction between the HIM and the SBGVA (known as the Unintended Benefit).

5.2 HIM Redesign for the Renewed Market

5.2.1 <u>Day Ahead and Real Time HIM</u>

In EB-2023-0336, OPG proposed revisions to the HIM with the objective of maintaining a similar design as the previously approved HIM while incorporating design features of the Renewed Market. Specifically, the redesigned HIM includes:

- A formula that incorporates a separate day-ahead ("DA") and real-time ("RT") incentive to reflect the new financially binding DA and RT balancing settlement design;
- Locational Market Price settlement;

- Daily production averaging to better align the HIM with daily market scheduling timeframes and operational storage horizons; and
- Continuation of a revised Unintended Benefit.

Figure 1 - Incentive Payment Calculation

$$\begin{aligned} Incentive\ Payment &= DA\ Incentive + RT\ Incentive \\ &= \sum_t \left(MW_{DA}(t) - MW_{DAavg}\right) \times LMP_{DA}(t) \\ &+ \sum_t \left(MW_{diff}(t) - MW_{diff,avg}\right) \times LMP_{RT}(t) \end{aligned}$$

Where:

$$MW_{diff}(t) = MW_{RT}(t) - MW_{DA}(t)$$

$$MW_{diff,avg} = MW_{RTavg} - MW_{DAavg}$$

Where:

$MW_{DA}(t)$: hourly production schedule from the IESO day-ahead market for each hour, *t*, of the day

MW_{DAavg}: average of hourly energy schedule from the IESO day-ahead market over the day

$LMP_{DA}(t)$: the day-ahead LMP for the resource for each hour, *t*, of the day

$MW_{RT}(t)$: net energy production supplied to the IESO real-time market for each hour, *t*, of the day

MW_{RTavg}: average of hourly net energy production over the day

$LMP_{RT}(t)$: the real-time LMP for the resource for each hour, *t*, of the day

OPG's HIM proposal provides an incentive for OPG to time-shift energy to high-price periods in the day-ahead timeframe in alignment the Renewed Market's financially binding DAM. The redesigned HIM also aligns with the RT Balancing Market as it provides OPG with an incentive to respond to real-time signals in the form of an incremental payment for further deviations from the day-ahead average. The use of daily averaging better aligns with the IESO's daily scheduling timeframe of resources in the Renewed Market and more closely reflects OPG's storage and time shifting capabilities. This redesigned HIM's day-ahead component is expected to be more material than the real-time one, which is consistent with the Renewed Market's intent of the Day Ahead being used to schedule most of the supply.[12]

5.2.2. Unintended Benefit

The Renewed Market does not change the potential interactions of SBG spill booked in the SBGVA and the HIM as outlined in EB-2013-0321. OPG's EB-2023-0336 application included a revised Unintended Benefit calculation that reflected the redesigned HIM and its use of a daily average and Locational Marginal Prices. Specifically, OPG proposed the following revised formula for the unintended benefit adjustment:

Figure 2: Revised Formula for Unintended Benefit Adjustment

$$Unintended\ Benefit\ Adjustment = \sum_t \left(MW_{Spill\ RTM}(t) - MW_{Spill\ RTM\ Avg}\right) \times LMP_{RTM\ Hourly}(t)$$

Where:

$MW_{Spill\ RTM}(t)$: hourly forgone production due to spill for each hour, t, of the real-time market day

$MW_{Spill\ RTM\ Avg}$: average of hourly spill over the real-time market day

$LMP_{RTM\ Hourly}(t)$: the real-time market LMP for the resource in the hour, t

5.3 HIM Analysis

5.3.1 HIM Results in the Renewed Market

Consistent with its OEB-approved EB-2023-0336 Settlement Proposal, OPG has presented HIM amounts from the five months in the Renewed Market in Chart 4.

[12] IESO, Day-Ahead Market High-Level Design ("DAMHLD"), August 2019, p. 3 <https://www.ieso.ca/en/Market-Renewal/Stakeholder-Engagements/Market-Renewal-Day-Ahead-Market>.

Chart 4 – HIM Payments in Market Renewal 2025 ($M)

	May	June	July	Aug	Sept
DA HIM	2.0	4.0	8.6	8.8	1.8
RT HIM	2.0	3.2	2.1	0.1	(0.3)
UIB	(4.7)	(0.8)	(0.6)	(0.1)	(0.2)
Net HIM	$(0.7)	$6.4	$10.1	$8.8	$1.3

These results capture the period immediately following the launch of the Renewed Market. OPG has taken a measured approach in interpreting these results alongside its longer-term modelled expectations of market operations. As the IESO noted in its update on Renewed Market performance and operations: the ability to draw conclusions at this point is still limited due to (1) short duration the renewed market has been in operation; (2) participants learning how the renewed market works and adjusting their strategies; and (3) experience in only two seasons.[13] OPG's observations include IESO's comments and contemplate a moderation of market outcomes as participants adjust their strategies and the IESO fine-tunes its systems based on real-life experience in the Renewed Market.

OPG's HIM observations are consistent with the overall expectation that the Day-Ahead HIM component would be higher than the Real-Time HIM, in keeping with the design of the Renewed Market. In the first month of the Renewed Market, OPG recorded negative HIM net revenue of $0.7M. This was mainly driven by high SBG spill that occurred during spring freshet which resulted in an unintended benefit adjustment that offset the DA and RT HIM payments earned during that period. In the following three summer months, OPG recorded a positive net HIM, followed by more moderate HIM revenues in September, which included a small negative RT HIM.

OPG expects an overall moderation of its HIM revenues as some of the early price volatility in the Renewed Market dampens with participants gaining experience in the new market. Further, as energy storage facilities continue to come online between 2025 and 2028, OPG expects

[13] https://ieso.ca/-/media/Files/IESO/Document-Library/engage/renewed-market/rmo-20250821-presentation-renewed-market-update.pdf

the increased arbitrage balancing supply to apply downward pressure on LMP price spreads, further moderating OPG's ability to earn HIM net revenues. Some of these assumptions are discussed further in Section 5.4, which details OPG's net HIM revenue forecast for 2027, the forward test year underpinning the regulated hydroelectric revenue requirement in this Application.

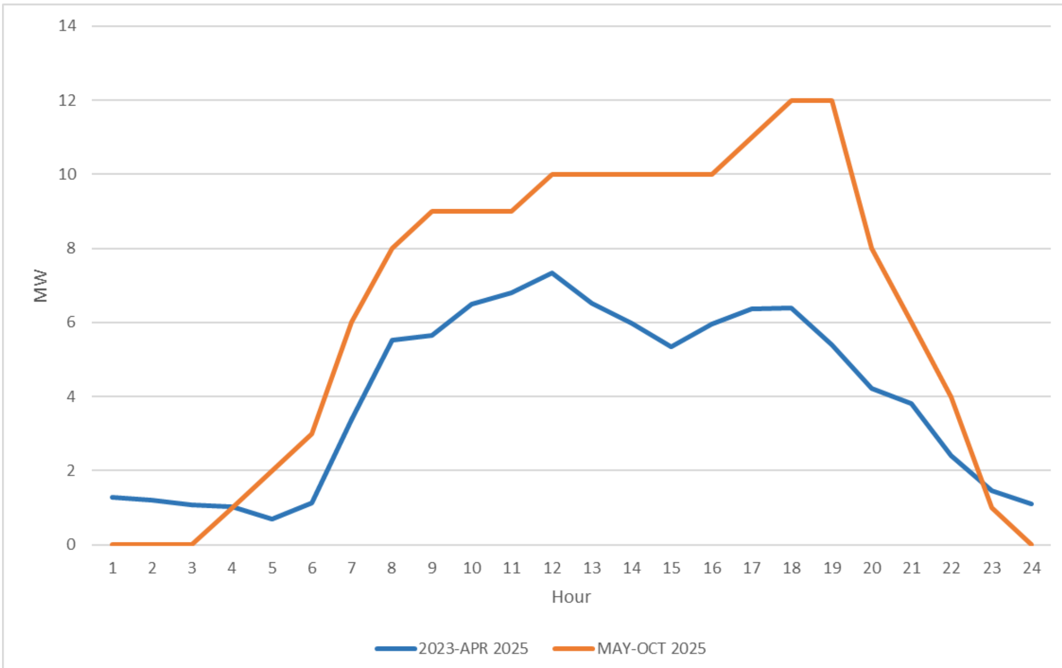
5.3.2 Impact of HIM on PGS Operating Decisions

The PGS supports the safe and efficient operation of the Sir Adam Beck complex while its time-shifting of water provides consumer benefit.[14] While the HIM approved in EB-2007-0905 was eventually applied to the additional hydroelectric stations prescribed in EB-2013-0321, its original design was specifically for the PGS to provide consumer benefit through incentivizing time shifting.

Chart 5 below illustrates that the HIM has continued to result in sustained high utilization of PGS in the first five months of the renewed market when compared to its utilization in the Legacy Market.

[14] EB-2023-0336, Ex. M1-1-1, Section 3.5 Customer Benefit.

Chart 5 - Average Pumped Generating Station Output by Hour
(2023 - October 2025)



These results indicate the continued adequacy of the incentive provided by the HIM for the PGS to time-shift water. Further discussion of the impact on HIM on PGS operating decisions in the renewed market can be found in Section 5.5.

5.4 HIM Forecast Customer Benefit

Consistent with OPG's prior applications, OPG has conducted modelling analysis to forecast the HIM benefits in the Renewed Market for the test year. OPG's models use locational prices and are based on OPG's understanding of the design of the Renewed Market through IESO design documents prior to this application. By comparing to a flatter scheduling profile, OPG's model demonstrates the value of time-shifting hydroelectric resources, a relatively low-cost generation source, which displaces the need for more expensive generation sources during high price periods, and minimize system needs to curtail other sources during low price periods.

Chart 6 illustrates OPG's modelled changes in customer costs arising from the relevant factors for the test period, demonstrating that the cost of the incentive provides a net consumer benefit. These figures represent "all-in" customer costs including changes in Global Adjustment payments which reflects OPG's understanding of Ontario's hybrid market, where some suppliers are settled based on contracts.

Chart 6 – HIM Customer Benefit Analysis

Line No.	**Customer Cost Changes ($M)**	**2026**	**2027***
1	Payments for Non-OPG Supplier Generation	(46)	(137)
2	Payments for OPG Generation (excluding incentive payment)	3	(13)
3	Payments for SBG-related Generation Curtailment	(7)	(3)
4	Export Revenues	2	2
5	**Change in Customer Cost excl. OPG Incentive (line 1+ line 2 + line 3 - line 4)**	**(52)**	**(154)**
6	**Additional Payments to OPG**		
7	DA HIM	19	19
8	RT HIM	7	4
9	Unintended Benefits Adjustment	(6)	(6)
10	**Total Additional Payments to OPG (line 7 + line 8 + line 9)**	**20**	**18**
11	**Net Customer Cost Change (line 5 + line 10)**	**$(32)**	**$(136)**

*Totals may not add due to rounding

OPG's assessment of consumer benefits from the HIM concludes that economic time-shifting of its regulated hydroelectric generation reduces modelled consumer costs before OPG incentive payments by $154M in the 2027 test year (See Chart 6, Line 5). The HIM-driven, incremental time-shifting of production results in a modelled net incentive payment to OPG of $18M (See Chart 6, Line 10), creating a $136M net consumer benefit (See Chart 6, Line 11).

The analysis accounts for the market effects of time shifting: the displacement of more expensive generation[15] (i.e., on-peak gas and imports) by hydroelectric production; increases in production and consequent GRC payments for additional on-peak generation at the regulated hydroelectric facilities; reduced payments for SBG-related forgone generation (as determined under OPG's proposal); and changes in exporter payments[16] made to the IESO for off-peak exports that result in changes in customer costs.

The higher customer benefit in 2027 relative to 2026 is due to forecasted increases in Ontario Zonal Prices. In 2027, OPG forecasts approximately 5 TWh of incremental demand relative to 2026, and no Pickering B generation after it comes offline for refurbishment in September 2026. Together, these factors are expected to increase reliance on gas-fired generation and imports. As a result, Ontario Zonal Prices are projected to rise, increasing the value of incremental time-shifted hydro production and the customer benefit in 2027.

Discussion on HIM forecasting can be found in Ex. G1-01-01, Section 7.0 HIM Revenue Requirement Adjustment.

5.5 Revisions to HIM Revenue Sharing

5.5.1 Impact of HIM Revenue Sharing on PGS Price Spread

OPG's SBGVA Study in Attachment 1 considered reasonable options to better incentivize OPG to minimize total system costs in consultation with stakeholders. As described in Section 3.3.3 of the study, OPG explored whether any changes to the HIM could meet this objective.

In the SBGVA Study, OPG noted that under the current HIM revenue-sharing regime, the price spread required to economically cycle the PGS would escalate when HIM revenues exceed the HIM threshold. While OPG's historic HIM revenues have not created such conditions, as

[15] The analysis accounts for impacts on generation costs resulting from displacement of generation but does not account for potential additional benefits related to carbon emission reductions.

[16] Sales of exports in the off-peak are typically made from contracted generation sources with contract prices that are independent of market prices. These volumes are effectively "take or pay". The consumer benefit arises from increasing the off-peak price for export sales so as to generate additional revenues that, in turn, reduce Global Adjustment payments by consumers.

the threshold is reset in the application, OPG believes it is important to pre-emptively address any structural barriers that may impede the operation of the PGS against the objective of reducing SBGVA entries and maximizing consumer benefit.

To illustrate the impact of sharing HIM revenues above the threshold, OPG calculated the spread required to economically cycle the PGS under two scenarios:

- **Scenario 1:** HIM net revenue sharing arrangement with 50% sharing of HIM net revenues above threshold; and
- **Scenario 2:** Alternative HIM net revenue sharing arrangement where 50% sharing above threshold is eliminated. This scenario is also reflective of PGS spread when the threshold has not been reached.

The PGS price spread is identical between both scenarios when OPG's HIM revenues are below the threshold. When the HIM revenues exceed the threshold, in both scenarios OPG continues to incur the same load charges, gross revenue charges, energy costs, and efficiency losses, but in Scenario 1 is limited to retaining only 50% of HIM net revenues to offset these costs. The resulting reduction in revenues must be recovered from the market for PGS operations to remain economic. This materially increases the spread required to justify time-shifting and, in practice, would impede the PGS's ability to shift generation, even though OPG has demonstrated that such operation provides a clear consumer benefit.

While OPG treats the sharing of forecast HIM revenues with customers as a fixed cost and does not build it into the variable cost formulas that guide market offers, once HIM net revenues exceed the threshold the obligation to share 50% effectively introduces an incremental variable cost that must be reflected in PGS offer decisions. OPG's proposal to remove the sharing of HIM revenues, ensures that PGS economics are consistent and not subject to a discrete change that impedes operations based on OPG's overall HIM revenues.

5.5.2 Market Surveillance Panel (MSP) Observations

As noted in the SBGVA Study, in its Monitoring Report 32[17] published on July 16, 2020 and a subsequent State of the Market Report 2022, the MSP expressed concern that the current revenue-sharing structure may be suppressing the efficiency benefits of the HIM. Specifically, in its Monitoring Report 32, the MSP recommended the OEB consider revisiting the sharing with consumers of HIM net revenue exceeding a threshold. The Market Surveillance Panel raised multiple arguments in support of the elimination of sharing. Consistent with OPG's analysis in Section 5.5.1, the MSP stated that the sharing is a dilution of OPG's incentive to time-shift production. The MSP also noted the lack of historical sharing of revenues on account of actual HIM revenues being lower than the threshold and raised the possibility that the sharing has had a negative impact on time-shifting.

The panel stated that eliminating or revising the revenue-sharing mechanism would give OPG a stronger, undiluted incentive to time-shift hydro production, which could improve overall market efficiency and benefit consumers through lower prices during peak periods. Additionally, although the revenue-sharing threshold has not been reached recently, because future market conditions will change, the Panel believes the HIM design should be robust for all plausible scenarios, ensuring OPG always has a clear incentive to operate efficiently.

5.6 Conclusion

Based on OPG's assessment, the enhanced HIM has demonstrated overall effectiveness in the Renewed Market. The majority of HIM revenues have been earned in Day Ahead and the PGS has operated in accordance with market signals. To position the HIM as a consistent driver for OPG to realize consumer benefits by time-shifting its flexible hydroelectric generation, OPG proposes to:

1. Establish a HIM forecast for 2027 (as described in Ex. G1-1-1);
2. Share 50% of the forecast HIM revenues with customers as an offset to the revenue requirement; and
3. Retain 100% of actual HIM revenues, including amounts above the forecast.

By eliminating the sharing of HIM revenues above the Hydroelectric Incentive Mechanism Variance Account threshold, OPG's proposal better aligns incentives with efficient market outcomes, provides customers with an upfront benefit through the forecast offset, and enhances OPG's ability to pursue cost-saving opportunities for ratepayers.

6.0 REAL-TIME ENERGY MAKE WHOLE PAYMENTS

This section explains MWPs in the Renewed Market and details OPG's proposal to continue to retain Real Time MWPs as payments that ensure OPG revenue sufficiency for events outside of its control.

6.1 Impacts of MRP on Make Whole Payments

According to the IESO's SSM high-level design, relative to the previous two schedule market, the need for MWPs in the new market is expected to be infrequent and immaterial.[17] This is due to the introduction of the single schedule market and locational marginal pricing which the IESO believes have eliminated the most significant cause of divergence between dispatch and price (congestion and losses) that resulted in out-of-market payments. CMSCs, the previous form of MWPs, have also been eliminated under MRP.

Conditions where resources are needed to be scheduled or dispatched out-of-merit that result in lost cost or lost opportunity requiring MWPs continue in the Renewed Market, albeit in a more limited way. Consequently, the introduction of a DAM and RTM have resulted in both DA MWPs and RT MWPs, for both Energy and Operating Reserve.

6.1.1 MWP Observations Since MRP Implementation

Chart 7 covers total make whole payments received by OPG's regulated hydroelectric facilities since market opening:

[17] SSMHLD, p. 50.

Chart 7 – OPG Regulated Hydroelectric MWPs ($M)

	May 2025*	June 2025	July 2025	Aug 2025	Sept 2025
RT Energy MWP	0.8	2.2	2.6	0.5	0.2
RT OR MWP	1.7	3.2	2.3	0.5	0.5
DA Energy MWP	0.0	0.0	0.0	0.0	0.0
DA OR MWPs	0.1	0.0	0.0	0.0	0.0
Total MWP	**$2.5**	**$5.4**	**$4.9**	**$1.0**	**$0.7**

*Total may not add due to rounding

As seen in Chart 7, the overall trend in MWPs points to a decrease in MWP magnitude since the start of the market. OPG is generally unable to isolate specific causes of instances when hydroelectric generators receive MWPs in day-ahead, which may be due to a variety of reasons, including constraint violations, co-optimization of energy with operating reserve, or the commitment of a non-quick start resource in the reliability pass of the DAM engine.[18] OPG notes that all day-ahead MWPs received by its regulated hydroelectric facilities in the Renewed Market have been immaterial as demonstrated in Chart 7.

Real-Time Energy and Operating Reserve comprise the majority of MWP revenues received by OPG's regulated hydroelectric resources in the Renewed Market. MWPs may occur in real-time for a variety of reasons, including special instructions related to constraint violations, multi-interval optimization, co-optimization with operating reserve, or emergency control actions. These dispatch instructions may be issued automatically by the IESO's optimized dispatch tools or manually by the control room in response to real-time operating conditions. In the Real Time Market, OPG's OR MWPs have exceeded Energy MWPs in four out of the five months in the Renewed Market. While OPG attributes this trend to a number of possible market factors including joint optimization and the introduction of an Operating Reserve Demand Curve, OPG has taken a measured approach in its expectation of how MWPs may develop as the Renewed Market matures. Operating Reserve MWPs ("OR MWPs") are part of OPG's Operating Reserve revenues, as discussed in Ex G1-1-1.

[18] SSMHLD, p. 50.

Similarly, while OPG received comparatively higher Energy MWPs in two summer months, its longer-term view is informed by IESO's expectation of these payments to be infrequent and immaterial as well as the IESO's recognition that certain aspects of the market may require fine tuning before reaching a steady state. On November 21, 2025, the IESO launched a stakeholder engagement that identified targeted corrections to the Market Rules that would be made to address specific circumstances under which unwarranted MWPs are calculated. While the engagement is still in preliminary stages, OPG expects the outcome of these changes to further lower MWPs.

Overall, OPG expects that day-ahead MWPs will remain immaterial and real-time MWPs will moderate with experience in the new market to levels that meet IESO's expectations of infrequency and low materiality.

6.2 Continuation of Current Treatment of Make Whole Payments

In EB-2023-0336, OPG proposed and received approval to retain Real-Time Energy MWPs consistent with the principle that OPG is compensated with respect to output generated at its regulated facilities in accordance with Section 78.1 of the *Ontario Energy Board Act, 1998*. OPG did not seek approval with respect to the treatment of Day-Ahead Energy MWPs as they form part of the Day-Ahead Market settlement and have no impact on OPG's actual output. OPG's proposal included an underlying assumption that OPG will receive OR MWPs – both Day-Ahead and Real-Time as part of its Operating Reserve revenues. During implementation, the IESO raised certain consideration regarding the calculation and settlement of MWPs, which led to OPG receiving all MWPs, including Day-Ahead Energy MWPs as presented in Chart 6. To fulfill its obligations under the OEB-approved EB-2023-0336 Settlement Proposal, OPG has been crediting all received Day-Ahead Energy MWPs in the Ancillary Services Net Revenue Variance Account, which records OPG's OR Day-Ahead and Real-Time MWPs.

OPG proposes that the treatment of Real-Time Energy MWPs under OPG's Regulated Framework as settled in EB-2023-0336 continue throughout the upcoming rate-setting period. Such payments are not reflected in the setting of payment amounts and would serve to compensate OPG for IESO dispatch related losses from inefficient operation or possible loss of production in the form of hydroelectric spill. OPG also expects to continue to receive Real-Time OR MWPs as part of its OR revenues. Given the insignificant Day-Ahead Energy and OR MWPs received in the first five months of the Renewed Market – $0.1M and $0.2M total, respectively – for administrative efficiency, OPG proposes to forgo receiving all Day-Ahead Energy and OR MWPs during the IR term.

LIST OF ATTACHMENTS

Attachment 1: Surplus Baseload Generation Variance Account Study

Surplus Baseload Generation Variance Account Study

Response to EB-2023-0336 Settlement Agreement

ONTARIO POWER GENERATION

1.0 Introduction and Purpose of Study

In EB-2023-0336, OPG applied to the Ontario Energy Board ("OEB") for approval to dispose of balances in several deferral and variance accounts, including the Surplus Baseload Generation Variance Account ("SBGVA"). In that application OPG also sought approvals to address impacts of the Independent Electricity System Operator's ("IESO") Market Renewal Program ("MRP") on its regulated framework, including revisions to calculation of amounts booked to the SBGVA. Specifically, OPG sought approval to record the financial impact of foregone production due to global and local surplus baseload generation conditions using locational marginal prices ("LMP").

Following a settlement conference, the parties reached an agreement on all issues in the proceeding, including the disposal of the SBGVA balances as of December 31, 2022. This agreement was documented in a Settlement Proposal filed with the OEB and was adopted through a Decision and Order.[1]

As part of the Settlement Proposal, OPG committed to conduct and file, as part of its next rebasing application, a study assessing options to reduce SBGVA amounts on a forward-looking basis:

> *OPG shall study options to reduce SBGVA amounts on a going forward basis and in light of the MRP with the aim of minimizing total electricity system costs to ratepayers including market payments and regulated payments, with assistance from the IESO as available and necessary. The study shall consider reasonable options to better incentivize OPG to minimize total system costs, utilizing the Sir Adam Beck Pump Generating Station ("PGS") to reduce spillage at OPG's hydroelectric facilities, and other structural changes, including changes that may require OEB approval. OPG shall fund a stakeholder process to obtain input on options to be considered in the study. OPG shall file its report as part of its next rebasing application for the prescribed facilities.*[2]

This study is in response to the OEB-approved Settlement Proposal. The study primarily considers options to reduce SBGVA amounts on a going forward basis by adjusting economic

[1] EB-2023-0336, Decision and Order, June 13, 2024.
[2] Ibid., page 5

factors to increase output at the existing PGS facility in its existing configuration. Results of the study should be viewed in the context of PGS's primary function within the Sir Adam Beck Complex, where it supports safety, operational efficiency and provides capacity by time-shifting water to the benefit of the ratepayer.[3]

2.0 Stakeholder & Rightsholder Engagement

On March 21, 2025, OPG hosted a Stakeholder and Rightsholder Engagement Process to inform the scope of this study. OPG circulated the meeting notes and materials for this session to participants on April 24 and May 27, respectively (see also Appendix A). Chart 1.0 below summarizes the action items assigned to OPG at that session (#1-4), as well as an action received from Environmental Defence via email following the stakeholder session (#5). The chart further describes how OPG has responded to each of those actions and provides a cross reference to where further details are provided within this study.

In September 2025, OPG met with the IESO to provide an overview of the study's findings and share a draft of the SBGVA study for feedback. The IESO has reviewed this report and provided their comments in Appendix B.

Chart 1.0: Action Items from Stakeholder and Rightsholder Engagement

#	Action Item	OPG's Response	Reference
1	Consider whether changes to the HIM would meet the study's objectives.	*Eliminating the requirement to share HIM net revenues[4] beyond a threshold would better incentivize OPG to time-shift water to the benefit of the ratepayer in all market conditions.*	See **Section 3.3.3** *The Hydroelectric Incentive Mechanism*
2	Consider the best available information available at the time of conducting the study, including the	*This study uses the most up-to-date market inputs available & assumptions are aligned with the*	See **Section 3.0**

[3] EB-2023-0336, M1-1-1, section 3.5 Customer Benefit
[4] Net of unintended benefit adjustment

	potential impact of tariffs on the system, if applicable.	*business plan that underpins OPGs EB-2025 application to the OEB.*	*Methodology & Study Options*
3	Consider whether and how Global Adjustment could be included as a factor in the evaluation of the study options.	*Impacts to Global Adjustment are calculated as part of OPG's analysis and incorporated into the results in this report.*	See **Section 3.0** *Methodology & Study Options*
4	Clearly link how each study option meets the study objective(s) outlined in the settlement agreement, including whether and how it reduces spillage, and what structural changes would or would not be required.	*Options 1 & 2 include sections to discuss the impacts on PGS utilization, SBG spill, Total Customer Cost (TCC), and implementation considerations. Option 3 analyzes the price spread required to economically time-shift water using the PGS under different HIM net revenue sharing scenarios. More frequent time-shifting of water has been demonstrated by OPG to be beneficial to the ratepayer.*	See **Section 3.3** *Study Options*
5	With respect to the GRC, Environmental Defence asks that OPG's analysis account for the fact that the GRC is returned to ratepayer pockets via the provincial government as it displaces other tax revenue.	*OPG's analysis shows reducing GRC payable by PGS yields incremental reduced total customer cost when combined with the removal of load charges. OPG has accounted for displaced GRC payments as a reduction in TCC benefit for the ratepayer.*	See **Sections 3.3.2.2** *Results and* **3.3.2.3** *Implementation*

3.0 Methodology & Study Options

OPG conducted this study in accordance with guiding principles ensuring that outcomes are consistent with the EB-2023-0336 Settlement Agreement and considering the authority and mandate of each of the OEB and the IESO. OPG first developed the necessary guiding principles of the study and then identified study options that adhered to these principles and presented both as part of the Stakeholder and Rightsholder Engagement Process.

3.1 Guiding Principles

The IESO is responsible for the reliability of Ontario's power system and the efficiency of the electricity market. In the early 2010s, the IESO established a "dispatch order for generation"[5] to optimize generation dispatch during SBG conditions by introducing floor prices for variable generation. As noted in the IESO stakeholder engagement that set these floor prices, OPG's hydroelectric offer strategy uses Gross Revenue Charge ("GRC")-based offers to reflect storage unavailability. OPG follows the IESO's dispatch in accordance with the IESO Market Rules.

Additionally, based on fundamental principles of rate regulation, OPG must be provided with a reasonable opportunity to recover its approved revenue requirement and should not be required to operate at an economic loss, due to system-level operating decisions or market outcomes that are beyond its control.

With consideration to the above, OPG created the following four guiding principles to help identify viable study options:

1. Recognize the IESO's fundamental role in managing SBG.
2. Recognize that the objective of IESO's dispatch scheduling and optimization algorithm is to "maximize the gains from trade to ensure consumers of electricity receive the highest value based on electricity supply offers.[6] OPG supports this objective by offering its resources economically into the IESO's market.

[5] IESO, Dispatch Order for Baseload Generation, A Discussion Paper for Stakeholder Engagement 91 (Renewable Integration), dated November 2, 2011
[6] 1. IESO Market Rules Chapter 7, ss 4.3.2

3. Ensure OPG is following IESO market signals and dispatches.
4. Maintain OPG's ability to recover its approved revenue requirement and not operate at an economic loss.

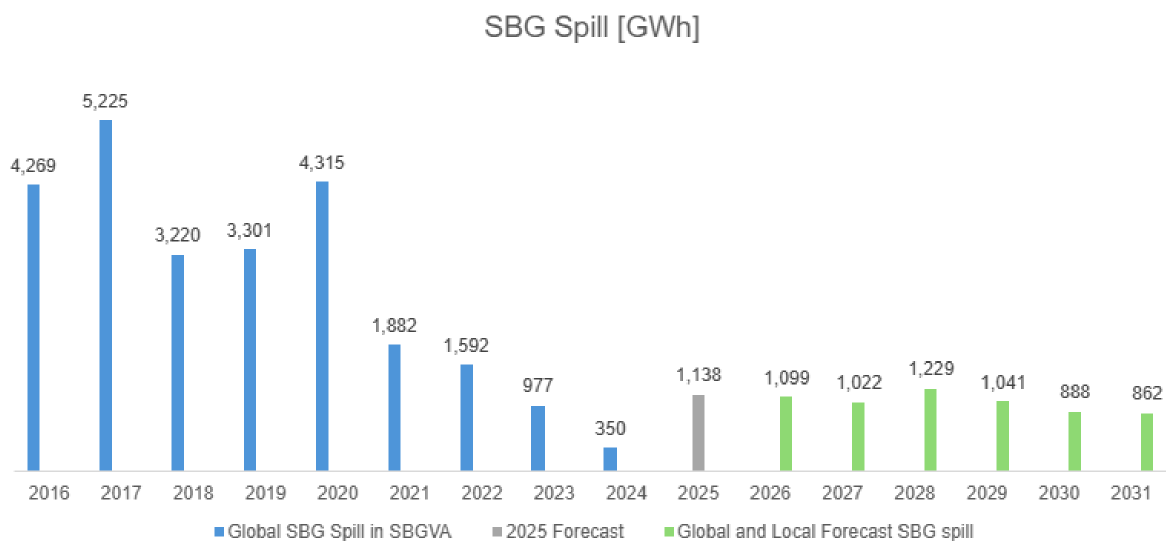
3.2 Surplus Baseload Generation in the Renewed Market

The IESO's Market Renewal Program ("MRP") replaced the previous two-schedule market with a single schedule market ("SSM") and introduced Locational Marginal Prices ("LMP"). Where SBG conditions were previously a global condition indicated by the Hourly Ontario Energy Price ("HOEP"), the replacement of HOEP with LMP under the Market Renewal Program eliminated OPG's ability to differentiate between global and local SBG conditions. As a result, OPG updated its methodology for making entries to the SBGVA, basing it on instances where a resource's LMP falls below the level of its GRC. This approach was approved by the OEB in EB-2023-0336[7] and forms the basis for OPG's forecast of SBG Spill (see Figure 1.0).

Using the EB-2023-0336 approved methodology, OPG projects total SBG spill to remain significantly below historical levels for the remainder of the study period. The reduction in forecast SBG spill is primarily due to changes in the supply and demand outlook in the province combined with expected efficiencies in the renewed market.

[7] EB-2023-0336 Decision and Order, issued June 13, 2024

Figure 1.0 - OPG Surplus Baseload Generation Spill: Historical Actuals and Forecast[8]



3.3 Study Options

This study examined the following three options based on the guiding principles outlined in Section 3.1:

1. Potential benefit of removing variable load charges applicable to PGS cycling;
2. Potential benefit of removing GRC applicable to PGS generation; and
3. Potential modifications to the HIM.

Options 1 and 2 focus specifically on the PGS and the economic considerations that could impact its utilization. These options assess economic reasons PGS does not cycle, which have been discussed in prior applications and are presented in OPG's PGS Reporting and Record-keeping Requirements. Other factors that limit PGS utilization (e.g., physical limitations, safety, equipment, or applicable law) were not considered in scope for this study.

Options 1 and 2 use an analytical framework designed to measure the impact of changes to PGS load charges and PGS GRC on PGS utilization, SBGVA additions, and TCC, when

[8] 2016-2024 shows actual SBG spill amounts included in SBGVA on a global basis. 2025 is an OPG forecast value based on global SBG conditions pre-MRP, and both global and local SBG conditions post-MRP. 2026-2031 OPG forecasts are based on both global and local SBG conditions.

compared to a base case.[9] The base case is a calculation of PGS utilization, SBGVA additions and TCC based on OPG's business plan. TCC is a calculation of all payments made by the IESO to generators including the impact of imports and exports, equal to market payments plus Global Adjustment costs. The negative TCC values in this report represent a reduction in customer cost while positive values represent an increase in customer cost.

Options 1 and 2 are calculated using the same assumptions as the base case, with only one independent variable changed: the load charge factor in PGS economics for option 1 ("The Load Charge Case"), and the GRC factor in PGS economics in option 2 ("The GRC Case").

Option 3 was identified as part of the Stakeholder and Rightsholder Engagement Process and considers whether changes to the HIM would meet the study's objectives. As described in section 3.3.3.4, the analytical framework to assess option 3 differs from the TCC based approach used for Options 1 and 2. For Option 3, the price spread required to economically cycle the PGS was calculated and compared under two HIM net revenue sharing scenarios.

3.3.1 Option #1: Potential benefit of removing variable load charges applicable to PGS cycling

The PGS is subject to variable load charges when operating in pump mode. Network Service Rate charge ("NSC") applies when the PGS operates in pump mode on weekdays between 7am and 7pm. If operated in pump mode during a NSC applicable hour, the PGS can incur significant NSC based on the NSC rate, the efficient operating point of a PGS pump, and the number of PGS pump units. As such, OPG does not operate the PGS in pump mode during NSC hours, unless it must do so for safety or operational reasons such as crossover control during periods of low diversion, equipment testing or rescue procedures.

The PGS operating in pump mode is also subject to the IESO Administration Charge in the form of a rate applied to the total PGS load in each month. Other market uplifts applicable to PGS load are subject to offsetting settlement reimbursements and are therefore excluded from

[9] The framework assumes the normally expected weather variations and unit commitments with no real-time price volatility owing to discrete events.

PGS economics. The NSC and IESO Administration Charges incurred by OPG are collectively referred to as the "PGS load charges" and are included as a single variable in the PGS economic formulas.

To determine the economics of generating with the PGS, OPG compares the breakeven generation price to the latest LMP. If that LMP is greater than the breakeven generation price, OPG concludes it is economic to generate. The formula for the breakeven PGS generation price is provided below, with the PGS load charges highlighted:

$$\frac{\begin{gathered}\textit{PGS Pump Efficiency} \times (\textit{Forecast Pump Price} + \underline{\textbf{\textit{PGS Load Charges}}}) + \\ \textit{Beck Gen Efficiency} \times (\textit{Forecast Pump Price} - \textit{Beck GRC}) + \\ (\textit{PGS Gen Efficiency} \times \textit{PGS GRC}) + (\textit{Beck Gen Efficiency} \times \textit{Beck GRC})\end{gathered}}{\textit{PGS Gen Efficiency} + \textit{Beck Gen Efficiency}}$$

To determine the economics of pumping with the PGS, OPG compares the breakeven pump price to the latest LMP. If that LMP is less than the breakeven pump price, OPG concludes it is economic to pump. The formula for the breakeven PGS pump price is provided below, with the PGS load charges highlighted:

$$\frac{\begin{gathered}\textit{PGS Gen Efficiency} \times (\textit{Forecast Gen Price} - \textit{PGS GRC}) + \\ \textit{Beck Gen Efficiency} \times (\textit{Forecast Gen Price} - \textit{Beck GRC}) + \\ (\textit{Beck Gen Efficiency} \times \textit{Beck GRC}) - (\textit{PGS Pump Efficiency} \times \underline{\textbf{\textit{PGS Load Charges}}})\end{gathered}}{\textit{PGS Pump Efficiency} + \textit{Beck Gen Efficiency}}$$

For the purpose of this study, OPG has examined the impact of PGS load charges on pumping and generating at the PGS.

3.3.1.1 Methodology

The results in Section 3.2.1.2 were derived by comparing the forecast values for PGS utilization, SBGVA additions, and TCC for the base case and Load Charge Case.[10]

[10] The analysis includes impact of battery energy storage systems expected to come online between 2025-2028.

3.3.1.2 Results

The results of the Load Charge Case compared to the base case are presented in Chart 2.0 and Chart 3.0 and discussed below.

Chart 2.0: Results of Option #1: Load Charge Case

	Incremental PGS Generation		Impact on SBG Spill	
	GWh	%	GWh	%
2026	4.1	11.4%	(5.3)	(1.7%)
2027	0.7	2.1%	(9.2)	(4.1%)
2028	0.6	3.6%	2.9	0.7%
2029	5.7	27.0%	(6.9)	(2.9%)
2030	3.6	16.7%	(2.1)	(2.7%)
2031	5.6	24.8%	(4.6)	(5.5%)
Total	**20.3**		**(25.2)**	
Average Annual	**3.4**		**(4.2)**	

Impact on PGS Generation

OPG's analysis indicates that removing variable load charges from PGS cycling economics would increase PGS generation by an average of 3.4 GWh annually, primarily due to the following two factors:

1. The PGS would be free to operate in pump mode at all hours of the day; and
2. The price spread required to economically cycle the PGS is reduced.

The inability to economically pump during NSC hours is the most significant impediment to incremental PGS cycling. As OPG does not operate the PGS in pump mode during NSC hours, the PGS is unable to pump during midday price dropouts which may allow the reservoir to be refilled before the evening peak.

Impact on SBGVA additions

The Load Charge Case results in 4.2 GWh average annual decrease of SBG spill when compared to the base case. This is primarily related to the incremental PGS pump mode operations during NSC hours, which reduced instances of on-peak SBG spill during those applicable hours.

Impact on Total Customer Cost

OPG's analysis also measures the impact on the TCC. The impact on TCC in the Load Charge Case compared to the base case is shown in Chart 3.0 and discussed below:

Chart 3.0: Option # 1 Impact to TCC: Load Charge Case

	2026	2027	2028	2029	2030	2031	Total	Annual Avg
Incremental Values:	$M	$M	$M	$M	$M	$M	$M	$M
(a) HIM payments to OPG	0.4	0.8	0.3	0.5	0.3	0.5	2.7	0.5
(b) SBGVA entries	0.1	(0.3)	0.3	(0.6)	(0.1)	(0.2)	(0.7)	(0.1)
(c) Imports and gas cost	(0.5)	4.1	0.7	(14.0)	(0.4)	0.3	(9.9)	(1.6)
(d) Incremental other costs	(0.2)	(0.5)	(0.2)	0.4	0.0	0.0	(0.6)	(0.1)
(e) Incremental export revenue	0.0	0.2	0.2	0.0	(0.1)	(0.0)	0.4	0.1
(f) Impact on TCC [a + b + c + d - e]	**(0.3)**	**3.8**	**0.8**	**(13.7)**	**(0.0)**	**0.6**	**(8.8)**	**(1.5)**

OPG's analysis of the Load Charge Case shows a cumulative $8.8M reduction in TCC over the study period when compared to the base case.

The largest contributor to the reduction in TCC in the Load Charge Case is the reduction in imports and gas generation. OPG's analysis demonstrates that incremental PGS utilization means a greater quantity of less expensive water is available to offset more expensive gas for more hours of the day when compared to the base case. This effect is especially prevalent in years where there are greater price spreads and more gas generation in the base case, as seen in 2029.

The other contributor to the reduction in TCC in the Load Charge Case is the reduction in SBG spill, as explained in the "Impact on SBGVA additions" section above.

The decrease in TCC related to reductions in imports, gas generation and SBG spill is partially offset by higher OPG HIM revenues associated with incremental on-peak generation at Sir Adam Beck 1 and 2 GS and the PGS.

3.3.1.3 Implementation

On March 27, 2025, the OEB issued a Decision and Order in EB-2022-0325 which ordered “transmission-connected energy storage facilities shall be exempt from transmission charges under any of the following circumstances: when scheduled to provide operating reserve, when providing reactive support, when providing regulation service, when responding to an IESO energy dispatch in the real-time electricity market, or when responding to an IESO directive in support of transmission system reliability.”[11]

OPG is in the process of determining the feasibility of implementing an NSC exemption for PGS by designating it as an energy storage facility. If the PGS receives the transmission charge exemption, the PGS would be available to pump in all hours of the day without incurring the NSC, and the load charge factor in the PGS economic formulas would be reduced. OPG expects a decision to be reached in 2026. OPG is also in the process of evaluating the feasibility of an IESO Administration Charge exemption for the PGS.

3.3.2 Option #2: Potential benefit of removing GRC applicable to PGS cycling

Gross Revenue Charge is calculated on an annual basis based on the actual production of any hydroelectric generating station in Ontario, including the PGS and the Sir Adam Beck complex. The GRC is a variable cost of generation and is expressed in the PGS economic decision making as a single value.

To determine the economics of generating with the PGS, OPG compares the breakeven generation price to the latest LMP. If that LMP is greater than the breakeven generation price, OPG concludes it is economic to generate.
The formula for the breakeven PGS generation price is provided below, with the GRC impacts highlighted:

[11] EB-2022-0325 Decision and Order, issued March 27, 2025, section 4.2 Implementation of Decision on Issue 5

$$\frac{\begin{gathered}\textit{PGS Pump Efficiency} \times (\textit{Forecast Pump Price} + \textit{PGS Load Charges}) + \\ \textit{Beck Gen Efficiency} \times (\textit{Forecast Pump Price} - \textit{Beck GRC}) + \\ (\textit{PGS Gen Efficiency} \times \underline{\textbf{\textit{PGS GRC}}}) + (\textit{Beck Gen Efficiency} \times \textit{Beck GRC})\end{gathered}}{\textit{PGS Gen Efficiency} + \textit{Beck Gen Efficiency}}$$

To determine the economics of pumping with the PGS, OPG compares the breakeven pump price to the latest LMP. If that LMP is less than the breakeven pump price, OPG considers it economic to operate in pump mode.

The formula for the breakeven PGS pump price is provided below, with the PGS GRC impacts highlighted:

$$\frac{\begin{gathered}\textit{PGS Gen Efficiency} \times (\textit{Forecast Gen Price} - \underline{\textbf{\textit{PGS GRC}}}) + \\ \textit{Beck Gen Efficiency} \times (\textit{Forecast Gen Price} - \textit{Beck GRC}) + \\ (\textit{Beck Gen Efficiency} \times \textit{Beck GRC}) - (\textit{PGS Pump Efficiency} \times \textit{PGS Load Charges})\end{gathered}}{\textit{PGS Pump Efficiency} + \textit{Beck Gen Efficiency}}$$

For the purpose of this study, OPG has examined what the impact GRC has on pumping and generating at the PGS.

3.3.2.1 Methodology

Option #2 was studied using the same methods, inputs, and assumptions as described in Section 3.2.

The GRC Case results in Section 3.2.2.2 below were derived through a separate analysis by setting the “PGS GRC” factor, as shown in the equations in Section 3.2.2, to zero. The forecast values for PGS utilization and SBGVA additions for the GRC Case were then compared to the base case and included in the charts in Section 3.2.2.2.

3.3.2.2 Results

The results of the GRC study case compared to the base case are presented in Chart 4.0 and discussed below.

Chart 4.0: Results of Option #2: GRC Case

	Incremental PGS Generation		Impact on SBG Spill	
	GWh	%	GWh	%
2026	2.6	7.2%	(0.5)	(0.2%)
2027	2.6	8.6%	0.1	0.1%
2028	1.2	6.8%	1.8	0.4%
2029	2.5	11.7%	(0.7)	(0.3%)
2030	0.9	4.3%	0.2	0.2%
2031	2.7	11.6%	0.2	1.1%
Total	**12.5**		**1.1**	
Average Annual	**2.1**		**0.2**	

While the GRC Case results in 2.1 GWh average annual increases in PGS generation compared to the base case, it does not result in SBG spill reduction. OPG notes that the analysis has accounted for decreased GRC payments to the provincial government as a reduction of TCC benefit. This additional TCC adjustment accounts for Environmental Defense's argument that higher GRC revenues for the provincial government offset other tax revenue and as such are not ultimately realized as final ratepayer savings.

In this GRC Case, the PGS was only able to operate in pump mode during non-NSC hours to avoid prohibitively high NSC. As such, the GRC Case resulted in a reduction in the price spread required to economically cycle the PGS, deriving only a marginal increase in PGS generation, with no significant TCC benefit when evaluated on its own (see Chart 5.0 below).

Chart 5.0: Option # 2 Impact to TCC: GRC Case

	2026	2027	2028	2029	2030	2031	Total	Annual Avg
Incremental Values:	$M	$M	$M	$M	$M	$M	$M	$M
(a) HIM payments to OPG	(0.0)	(0.1)	(0.2)	(0.1)	(0.1)	(0.2)	**(0.7)**	**(0.1)**
(b) SBGVA entries	0.0	0.1	0.2	(0.2)	0.0	0.0	**0.1**	**0.0**
(c) Imports and gas cost	(0.1)	0.1	0.0	0.8	0.1	(0.0)	**1.0**	**0.2**
(d) Other costs	(0.1)	(0.1)	(0.1)	0.2	0.0	(0.0)	**(0.1)**	**(0.0)**
(e) Export revenue	0.1	0.0	0.0	0.0	0.0	0.0	**0.2**	**0.0**
(f) Impact on TCC [a + b + c + d - e]	(0.2)	0.0	(0.2)	0.7	(0.0)	(0.2)	**0.1**	**0.0**
(g) Displaced GRC revenue	(0.2)	(0.2)	(0.1)	(0.1)	(0.1)	(0.1)	**(0.9)**	**(0.2)**
(h) Impact on TCC net of displaced GRC revenue [f - g]	**(0.0)**	**0.2**	**(0.1)**	**0.8**	**0.1**	**(0.0)**	**1.0**	**0.2**

3.3.2.3 Potential Benefit of Removing Variable Load Charges and GRC Applicable to PGS Cycling

OPG evaluated a scenario where both variable load charges and GRC applicable to PGS cycling were removed from the PGS formulas and observed the following results:

Chart 6.0: Combined Impacts of Option #1 and Option # 2

	Incremental PGS Generation		Impact on SBG Spill	
	GWh	%	GWh	%
2026	9.0	24.7%	(8.5)	(2.8%)
2027	3.4	11.2%	(9.4)	(4.2%)
2028	3.8	22.1%	(0.5)	(0.0%)
2029	7.3	34.6%	(6.0)	(2.5%)
2030	5.6	26.2%	(1.9)	(2.4%)
2031	8.6	37.6%	(9.0)	(10.7%)
Total	**37.7**		**(35.3)**	
Average Annual	**6.3**		**(5.9)**	

In this combined scenario, OPG calculated an incremental TCC savings net of GRC of $6.0M (see Chart 7) over the study period when compared to Load Charge Case alone. This more favourable result is driven by the reduced spread (from removing GRC) applied to PGS in all hours of every day and removal of pumping restrictions during NSC hours (from removing load charges).

Chart 7.0: Combined Impact of Option #1 and Option #2 to TCC

	2026	**2027**	**2028**	**2029**	**2030**	**2031**	**Total**	**Annual Avg**
Incremental Values:	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
(a) HIM payments to OPG	0.6	1.6	0.4	0.2	0.2	0.6	**3.6**	**0.6**
(b) SBGVA cost	(0.2)	(0.2)	0.1	(0.5)	(0.0)	(0.2)	**(1.1)**	**(0.2)**
(c) Imports and gas cost	(0.7)	3.6	0.1	(20.1)	(0.4)	0.3	**(17.2)**	**(2.9)**
(d) Other costs	(0.0)	(0.6)	(0.1)	0.3	(0.0)	(0.1)	**(0.5)**	**(0.1)**
(e) Export revenue	0.1	0.3	0.4	(0.1)	(0.1)	0.0	**0.7**	**0.1**
(f) Impact on TCC [a + b + c + d - e]	(0.4)	4.1	0.1	(19.9)	(0.2)	0.5	**(15.9)**	**(2.6)**
(g) Displaced GRC revenue	(0.3)	(0.2)	(0.1)	(0.2)	(0.2)	(0.2)	**(1.0)**	**(0.2)**
(h) Impact on TCC net of displaced GRC revenue [f - g]	**(0.2)**	**4.2**	**0.2**	**(19.8)**	**0.0**	**0.7**	**(14.8)**	**(2.5)**
(i) Impact to TCC of option 1 [Chart 3.0, line (f)]	(0.3)	3.8	0.8	(13.7)	(0.0)	0.6	**(8.8)**	**(1.5)**
(j) Incremental TCC reduction from GRC removal when combined with load charge removal [h - i]	**0.1**	**0.4**	**(0.6)**	**(6.1)**	**0.0**	**0.1**	**(6.0)**	**(1.0)**

OPG has accounted for the impact of removing GRC in the same manner as in section 3.3.2.2.

3.3.2.4 Implementation

OPG would require a GRC exemption for the PGS in order to exclude GRC from the economic decision making for PGS cycling. OPG will explore the feasibility of this option.

3.3.3 The Hydroelectric Incentive Mechanism

This section explores potential changes to the HIM that may satisfy the objective of reducing SBGVA amounts.

3.3.3.1 HIM Background

The HIM supports the efficiency of the wholesale electricity market by providing OPG's regulated hydroelectric generators with the appropriate driver to follow market signals while receiving a regulated payment for their output. While the HIM formula has necessarily evolved with the changing design of the Ontario electricity market since its initial approval in EB-2007-0905, this fundamental objective has not changed. This mechanism ultimately benefits customers by creating an economic driver for OPG to shift hydroelectric generation from low-price hours to high-price hours.[12]

Since the HIM was first approved in EB-2007-0905, OPG receives the applicable OEB-approved payment amount for the average hourly net energy produced ("hourly volume") from its regulated hydroelectric facilities. If OPG produces more energy than the hourly volume in a given hour, it is compensated at market prices for the incremental amounts of energy above this hourly volume. If OPG's actual energy production from its regulated hydroelectric facilities is less than the hourly volume in a given hour, the amount payable to OPG at the regulated hydroelectric payment amount is reduced by the production shortfall multiplied by the market price.

In EB-2010-0008, the OEB required that 50% of the forecast amount of HIM proceeds be returned to customers and incorporated this as a reduction to the revenue requirement. OPG was allowed to retain 50% of the HIM net revenue with any excess above the retained amount tracked in the Hydroelectric Incentive Mechanism Variance Account ("HIMVA") and shared equally between OPG and ratepayers. The OEB also required OPG to address the interaction between HIM revenues and SBGVA in its next application. In EB-2013-0321, the HIM was expanded to include the newly prescribed facilities, using the same formula. The OEB also increased the variance account threshold to reflect the inclusion of the newly regulated facilities,[13] a 50% revenue requirement offset and a 50% sharing of additional net revenues above the threshold. In the same decision, the OEB directed OPG to include an adjustment to the HIM to reflect the interaction between the HIM and the SBGVA (the unintended benefit).

In EB-2023-0336, OPG proposed an updated HIM formula to reflect the impact of MRP. OPG's HIM formula was adopted as part of a settlement agreement in this case and was implemented with the launch of the Renewed Market on May 1, 2025. OPG's HIM calculation is discussed further in Section 3.3.3.2.

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[12] EB-2023-0336, M1-1-1, section 3.5 Customer Benefit
[13] EB-2013-0321 Decision with Reasons, November 20, 2014, p. 13.

Under the current framework, OPG shares 50% of HIM net revenues with customers as established in EB-2010-0008 and EB-2013-0321. Under the HIM sharing approach, if the annual HIM net revenues exceed the pre-determined threshold, OPG records 50% of the HIM net revenues in the HIMVA as a credit to ratepayers. OPG's HIM net revenues have never exceeded the current applicable threshold that was established in EB-2013-0321.

3.3.3.2 HIM Calculation

The HIM is calculated using the following formula, established in EB-2023-0336:

$$
\begin{aligned}
Incentive\ Payment &= DA\ Incentive + RT\ Incentive \\
&= \sum_t \left(MW_{DA}(t) - MW_{DAavg}\right) \times LMP_{DA}(t) \\
&\quad + \sum_t \left(MW_{diff}(t) - MW_{diff,avg}\right) \times LMP_{RT}(t)
\end{aligned}
$$

Where:

$$MW_{diff}(t) = MW_{RT}(t) - MW_{DA}(t)$$

$$MW_{diff,avg} = MW_{RTavg} - MW_{DAavg}$$

Where:

$MW_{DA}(t)$: hourly production schedule from the IESO day-ahead market for each hour, *t*, of the day

MW_{DAavg}: average of hourly energy schedule from the IESO day-ahead market over the day

$LMP_{DA}(t)$: the day-ahead LMP for the resource for each hour, *t*, of the day

$MW_{RT}(t)$: net energy production supplied to the IESO real-time market for each hour, *t*, of the day

MW_{RTavg}: average of hourly net energy production over the day

$LMP_{RT}(t)$: the real-time LMP for the resource for each hour, *t*, of the day

An illustrative example of the HIM calculation for two hours is provided in Chart 8.0 below.

Chart 8.0: Illustrative Example for 2 hours of HIM Calculation including Adjustment for Unintended Benefit

Hour	Day-ahead Price	Day-ahead Schedule	Real-time Price	Real-time Output	SBG Spill	Daily Avg. Day-ahead Dispatch	Daily Avg. Real-time Output	Daily Avg. SBG Spill	Day-ahead HIM Payment	Real-time HIM Payment	Adjustment for Unintended Benefit
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
A	$5/MWh	0MW	$5/MWh	0MW	60	80MW	85MW	10MW	$(400)	$(25)	$250
B	$30/MWh	300MW	$40/MWh	300MW	0	80MW	85MW	10MW	$6,600	$(200)	$400

Sources for actual monthly calculation:

- **(a)** Published in IESO reports
- **(b)** Published in IESO reports
- **(c)** Published in IESO reports
- **(d)** OPG revenue meter data (utilized in settlement statements)
- **(e)** Per OEB approved SBG methodology
- **(f)** Daily simple average of (b) for all hours of the day
- **(g)** Daily simple average of (d) for all hours of the day
- **(h)** Daily simple average of (e) for all hours of the day
- **(i)** Calculated as: (b-f)*a
- **(j)** Calculated as: [(d-b)-(g-f)]*c
- **(k)** Calculated as: (e-h)*c

3.3.3.3 LMP Spread Required to Economically Cycle the PGS

Under the current HIM net revenue sharing arrangement, the price spread required to economically cycle the PGS will notably increase if actual HIM net revenues exceed the HIM threshold. To illustrate this, OPG calculated the spread required to economically cycle the PGS under two scenarios, summarized in Chart 9 below. Both scenarios assume that 50% of the forecast amount of HIM proceeds have already been returned to customers as a reduction to the revenue requirement, and that actual HIM net revenues have exceeded the threshold.

Scenario 1: HIM net revenue sharing arrangement with 50% sharing of HIM net revenues above threshold; and

Scenario 2: Alternative HIM net revenue sharing arrangement where 50% sharing above threshold is eliminated. This scenario is also reflective of PGS spread when the threshold has not been reached.

Section 3.3.1 provides the formulas governing PGS economics. The components of this formula were categorized as costs or revenues, as seen below.

Cost Components:
- Pump energy costs[14]
- Load charges
- GRC
- Adjustment for Incremental HIM Net Revenue Sharing*

Revenue Components:
- PGS revenue
- SAB revenue

*included once HIM net revenues exceed HIM threshold

Chart 9.0: Illustrative Calculations of Economic Price Spreads when HIM Net Revenues Exceed HIM Threshold

	Scenario 1 (50% HIM Sharing above threshold)	**Scenario 2 (No HIM Sharing)**
Energy Cost to SAB GRC	\$14.40	\$14.40
Revenue	Regulated Rate X Generation + (HIM Net Revenue X 50%)	Regulated Rate X Generation + HIM Net Revenue
Resulting Economic Offer Price	\$29.30	\$22.60
Economic Price Spread	\$29.30-\$14.40 = \$14.90	\$22.60-\$14.40 = \$8.20

In Scenario 1, OPG is required to share 50% of HIM net revenues on a variable basis with the ratepayer, while incurring the same amount of load charges, GRC, energy charges and efficiency losses. With OPG retaining only half of the incremental HIM net revenue, these costs must be recovered in the market to ensure OPG does not incur an economic loss when cycling the PGS. As such, a higher spread is required to economically cycle the PGS when the threshold is exceeded.

In Scenario 2, OPG continues to retain all HIM net revenues and does not need to adjust the economic spread for the PGS if HIM net revenues exceed the threshold. This scenario reflects the historical operation of the PGS as HIM net revenues have never exceeded the current

[14] Efficiency losses are inherently reflected in pump energy costs

applicable threshold that was established in EB-2013-0321. Compared to this Scenario 2, OPG estimates it would need to increase the spread by approximately 80%[15] when HIM net revenues exceed the threshold. Such an increase may impede the ability for PGS to time-shift under certain market conditions and will directionally lead to a higher SBG spill and reduced customer benefit.[16] OPG expects to reset its HIM forecast and associated threshold as part of its current application.

3.3.3.4 Market Surveillance Panel Monitoring Report 32 Summary

In its Monitoring Report 32[17] published on July 16, 2020 and a subsequent State of the Market Report 2022, the Market Surveillance Panel (MSP) expressed concern that the current revenue-sharing structure may be suppressing the efficiency benefits of the HIM. The MSP recommended “the OEB consider revisiting the sharing with consumers of net HIM net revenue exceeding a threshold” citing the following reasons:

- **Dilution of Incentive**: The Panel finds that sharing HIM net revenues above the threshold (i.e., the 50/50 split) reduces OPG’s incentive to time-shift production because OPG bears all the costs and risks but only receives half the benefit above the threshold. This could lead OPG to pass up profitable and efficient time-shifting opportunities, diminishing the intended efficiency gains of the HIM.
- **Recent Revenue Trends**: Actual HIM net revenues have consistently fallen short of the 2013 forecast used to set the sharing threshold. Since at least 2016, OPG has not generated enough incentive payments to cover the first 50% of the forecast, meaning the revenue-sharing provision has not been triggered in recent years.
- **Market Changes**: Factors such as flatter price curves, increased environmental regulations, and higher water levels have contributed to the decline in time-shifting, but the Panel cannot rule out that the revenue-sharing mechanism itself is a significant factor.

[15] Based on a pump energy cost of $14.40
[16] EB-2023-0336, M-1-1-1, section 3.5, Customer Benefit
[17] Market Surveillance Panel Report 32 - July 16, 2020

The panel stated that eliminating or revising the revenue-sharing mechanism would give OPG a stronger, undiluted incentive to time-shift hydro production, which could improve overall market efficiency and benefit consumers through lower prices during peak periods. Additionally, although the revenue-sharing threshold has not been reached recently, because future market conditions will change, the Panel believes the HIM design should be robust for all plausible scenarios, ensuring OPG always has a clear incentive to operate efficiently.

3.3.3.5 Changes to the HIM

OPG treats the sharing of the HIM net revenue forecast with the ratepayer as a fixed cost and as such, has not built it into the variable costs included in the economic formulas that govern how PGS is offered in the market. However, if HIM net revenues were to exceed the HIMVA threshold, the requirement to share 50% of HIM net revenues with the ratepayer represents an incremental variable cost that would have to be considered when offering the PGS to the market.

While the benefits of options 1 and 2 were analyzed by changing specific input variables and assessing changes in TCC, OPG cannot assess the benefits of removing the requirement to share HIM net revenues beyond the HIM threshold using the same method. As the probability of OPG's HIM net revenues exceeding the threshold differs over a large range of possible outcomes, OPG's model cannot deterministically produce an assessment of benefit. Instead, OPG relies on the conclusions from option 1, specifically that minimizing the price spread required to cycle the PGS increases PGS cycling which lowers TCC. OPG's analysis of a typical scenario demonstrates that including the marginal cost of sharing increases the spread required to cycle the PGS from $8.20 to $14.90[18]. This increase in spread can be demonstrated across the full range of pump energy prices as the overall need to earn more market revenues to offset the reduced marginal 50% HIM is consistent.

Based on the above, OPG concludes that eliminating sharing of HIM net revenues that exceed the HIMVA threshold would meet the study objectives by more effectively incentivizing OPG to engage in cost-saving opportunities for the ratepayer and would be consistent with MSP's Monitoring Report 32, which recommended that "… the OEB consider revisiting the sharing

[18] Based on a pump price of $14.40

with consumers of net HIM net revenue exceeding a threshold". OPG has thus proposed to eliminate sharing of HIM net revenues that exceed the HIMVA threshold in this application.

4.0 Conclusions

This study was undertaken in accordance with the OEB-approved Settlement Proposal in EB-2023-0336 to assess and recommend options to reduce SBGVA amounts on a forward-looking basis, with the aim of minimizing total electricity system costs to ratepayers. The analysis was conducted in the context of the MRP, with input from stakeholders and rightsholders, and with the support of the IESO as required. Stakeholder engagement played a critical role in shaping the study's scope and recommendations. Key action items from the engagement process were addressed, including ensuring the study's alignment with the latest market information, considering the impact of tariffs and Global Adjustment, and clearly linking each option to the study objectives.

The study evaluated three options: (1) removing load charges applicable to PGS cycling, (2) removing the GRC as a PGS pumping cost, and (3) modifying the HIM. Each option was assessed for its impact on PGS utilization, SBGVA reductions, and Total Customer Cost. Results from OPG's analysis are summarized in the following key findings:

- **Removing the Network Service Charge and IESO Administration Fees** as a PGS pump costs would increase PGS generation by 20.3 GWh and reduce SBG spill by 25.2 GWh over the study period, resulting in a forecast $8.8M reduction in Total Customer Costs. This would be achieved primarily by enabling more flexible, economic use of the PGS, particularly during hours currently restricted by the Network Service Rate charge. OPG is currently exploring the feasibility of implementing this option.
- **Removing GRC** as a PGS generation cost does not have a material impact on Total Customer Cost when done so in isolation, but when removed in addition to load charges, an incremental reduction in Total Customer Costs of $6.0M is calculated over the study period. OPG will explore the feasibility of this option.

- **Eliminating HIM sharing** above the established HIMVA threshold would provide a clear and consistent incentive for OPG to time-shift water, including if HIM net revenues are higher than the threshold. This proposed change is supported by the MSP as the Panel has previously stated that the current sharing mechanism may dilute OPG's incentive to time-shift hydro production for system benefit.

In conclusion, the options presented in this study offer pathways to reduce SBGVA amounts and total system costs, while respecting the operational realities of Ontario's electricity system. The findings demonstrate that targeted adjustments to PGS cost treatment and HIM net revenue sharing can improve incentives for OPG to time-shift generation in ways that lower spill and benefit ratepayers.

Ontario Power Generation (OPG) Stakeholder and Rightsholder Consultation – Surplus Baseload Generation (SBG) Study

→ Meeting Minutes

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1.0 Meeting Details

Date: March 21, 2025

Duration: 10:00 AM – 10:45 AM ET

Modality: Virtual (Microsoft Teams)

Facilitator: Ishma Zahur, Optimus SBR

2.0 Meeting Minutes

2.1 Introductions and Opening Remarks

Ishma Zahur from Optimus SBR welcomed attendees and introduced the Ontario Power Generation (OPG) staff present on the call, including Herman Mo (Senior Manager, Regulatory Affairs) and Saba Zadeh (Vice President, Regulatory Affairs). Ishma invited attendees to introduce themselves and outlined the agenda, which included:

1. A land acknowledgement
2. Purpose of the meeting
3. Facilitated discussion
4. Next steps

2.2 Purpose of the Meeting

Ishma explained that the meeting is part of OPG's commitment under the EB-2023-0336 settlement agreement. She highlighted that the agreement requires OPG to conduct and file a study assessing options to reduce Hydroelectric Surplus Baseload Generation Variance Account (SBGVA) amounts on a forward-looking basis. She emphasized that today's meeting is to gather input on options to be considered in the study. It was noted that two proposed study options were included in OPG's March 7 invitation and participants will have an opportunity to provide input on these. Ishma clarified that the study has not yet been conducted, and so there may be questions that OPG may not be able to answer at this stage. She also confirmed that feedback outside of the proposed options is welcome.

Ishma introduced Herman Mo from OPG to provide further context.

2.2.1 Presentation of Guiding Principles and Study Options

Herman outlined the following four guiding principles used to select OPG's proposed study options:

1. Recognizes the Independent Electricity System Operator's (IESO) fundamental role in managing Surplus Baseload Generation (SBG).
2. Recognizes that the objective of IESO's dispatch scheduling and optimization algorithm is to "maximize the gains from trade to ensure consumers of electricity receive the highest value based on electricity supply offers". OPG supports this objective by offering its resources economically into the IESO's market.
3. Ensures following IESO market signals and dispatch.
4. Maintains OPG's ability to recover its approved revenue requirement and not operate at an economic loss.

Herman explained that based on these principles, OPG proposes to study two scenarios related to reducing the price spread needed for economic cycling of the Sir Adam Beck Pump Generating Station (PGS). Currently the PGS is subject to variable load charges when it operates as a load, and to the Gross Revenue Charge (essentially a fuel cost for the water used for generation) when it operates as a generator. Both of these charges contribute to the market price spread required between pumping and generating so that OPG can recover these costs. Below are the two options that OPG proposes to study:

- Option 1: Study the potential benefit of removing variable load charges applicable to PGS cycling.
- Option 2: Study the potential benefit of removing Gross Revenue Charge ("GRC") applicable to PGS generation.

2.3 Facilitated Discussion

Ishma presented two discussion questions to participants:

1. What feedback or considerations for OPG do stakeholders and rightsholders have specific to the two options OPG proposes to study?
2. Do stakeholders and rightsholders have any other input for OPG outside of the two options OPG proposes to study?

2.3.1 Consideration of Additional Study Options

One participant questioned whether OPG had considered other study options that were ultimately not pursued beyond the two presented. In particular, OPG was asked why revisions to the Hydroelectric Incentive Mechanism (HIM) had not been included among the proposed study options.

OPG explained that a list of excluded options was not available but noted that the two selected options were identified based on the guiding principles. However, OPG confirmed it is open to considering additional suggestions and agreed to revisit whether incremental changes to the HIM could meet the study's objectives.

2.3.2 Evaluation Criteria and Ratepayer Impacts

There was discussion around how the proposed options would be evaluated and whether the study would analyze impacts on ratepayers.

OPG confirmed that the primary criterion, as defined in the EB-2023-0336 settlement agreement, is to reduce SBGVA amounts on a forward-looking basis, in light of the new market, with the aim of minimizing total electricity system costs to ratepayers. OPG confirmed that the study will demonstrate how each option satisfies that objective.

2.3.3 Scope of OPG's Control and IESO's Role

Stakeholders asked whether the study would also examine actions that the IESO could take to minimize SBG. Additionally, there were comments on how variable generation, such as wind generation and solar, influence SBG events.

OPG confirmed that the study will only focus on actions within OPG's control, in line with the first guiding principle.

2.3.4 Role of IESO in Supporting the Study

Some participants interpreted the settlement language—referring to IESO assistance—as an indication that OPG would engage the IESO on all scenarios, including those involving potential actions outside of OPG's control but within the IESO's purview and inquired whether either of OPG's proposed study options seeks to do that. Participants also suggested there may be options that fall within both OPG and IESO's shared control, and that collaboration could help enable such options. Furthermore, some participants understood the intent to be that while OPG can account for its own costs, it lacks visibility into total system costs. For example, when time-shifting generation using PGS, OPG may know how its own costs change, but not who is next in the dispatch order or how the shift would affect overall system costs. In such cases, participants suggested that OPG would require the IESO's assistance to gather the necessary data and model broader system cost impacts—believing this to be the primary reason for consulting the IESO as part of the study.

In response, OPG clarified that the study will focus on options within its control but emphasized the need to ensure that the proposed options do not conflict with the design of the new market. Since this is a forward-looking study, OPG's modelling will utilize OPG's assumptions and not be dependent on IESO data which would be commercially sensitive. Engagement with the IESO is intended as a check and balance—to confirm that OPG's proposals align with the IESO's framework. The study is not intended to examine options that fall entirely outside of OPG's control. OPG also reiterated that it will ensure the proposed options do not conflict with the IESO's principles or market rules.

2.3.5 Consideration of Tariffs

Participants raised the potential impact of tariffs, noting that although tariffs may only affect a small portion of OPG's operations, they are a growing concern among manufacturers and could become a factor that indirectly impacts the study.

OPG acknowledged this point and stated that the study would be based on the best available information at the time. OPG recognized if there is a known impact of tariffs, they may be considered in ongoing discussions.

2.3.6 Inclusion of Other Hydroelectric Facilities

Participants were interested to know if OPG is considering time-shifting opportunities beyond the PGS—such as other hydroelectric assets with time-shifting capability—and whether those were part of the study options.

OPG clarified that the HIM applies to PGS as well as other OPG hydroelectric assets. OPG stated that its review of changes to the HIM will include all hydroelectric resources subject to the incentive mechanism.

2.3.7 Global Adjustment as a Factor

Participants highlighted the distinction between minimizing system costs and minimizing Global Adjustment (GA) charges. They noted that even if a proposed option results in a reduction in total system costs, it does not necessarily translate into a benefit for some ratepayers due to the way GA is allocated.

OPG stated that the study will focus on minimizing total system costs, in accordance with the language in the settlement agreement. However, OPG acknowledged the point about GA and confirmed it will consider whether and how it could be included as an evaluation factor for the study options.

2.3.8 Market Renewal Program and Operational Considerations

Participants noted that the Market Renewal Program (MRP) has not yet come into effect, and the operation of the market in the future may differ from current expectations. Additionally, stakeholders raised the need to examine operational trade-offs between maximizing output through the Niagara tunnel and optimizing the use of the PGS facility.

In response, OPG confirmed that the study will be forward-looking and based on the best available information regarding how the new market is expected to operate. OPG clarified that the modeling will incorporate up-to-date physical attributes of the Beck complex, including the Niagara tunnel infrastructure. OPG also noted that it already optimizes operations across the entire Beck complex.

Following a prior comment that GA may change under MRP, one participant clarified that MRP affects only market prices and, therefore, only the quantum of GA would be impacted. OPG acknowledged this distinction and re-confirmed that it would consider whether and how GA could be included as a factor in the evaluation of study options.

2.3.9 Scope of Structural Changes

Referring to the settlement agreement language regarding the study, participants requested clarification on how OPG interpreted “structural changes” and whether this included potential future infrastructure changes (e.g., transmission) that may be required depending on how the plant continues to operate going forward.

OPG explained that the term encompasses a broad range of possibilities but clarified it has not considered capital investments or changes to physical assets. Instead, OPG believes the focus as being on regulatory or market mechanisms, including those requiring further approval by external entities such as those in OPG's two proposed options.

2.3.10 Jurisdiction and Feasibility of Proposed Options

Participants commented that the proposed options – removal of variable load charges and GRC – fall outside the OEB's jurisdiction. Participants suggested that OPG consider including options it can pursue unilaterally or with OEB approval, with the possibility there may be none, to ensure that actionable options are included in the final report.

In response, OPG agreed to consider the point raised.

2.3.11 Expectations for Final Report

Participants requested that the final report explicitly demonstrate how each proposed option meets the objectives outlined in the settlement agreement, including whether and how it reduces spillage, and what structural changes would or would not be required.

OPG confirmed that the final report will address how each option satisfies the settlement requirements, and that if an option requested by intervenors does not meet those requirements, the report will explain why. OPG also noted that both of its proposed options are intended to support increased PGS cycling, which could result in reduced spillage, and that this assumption would be validated during the modeling phase of the study.

2.4 Next Steps

Ishma thanked participants for their feedback and outlined the following next steps:

1. Meeting minutes will be issued and shared with attendees.
2. OPG will assess all feedback and incorporate it into the study design.
3. OPG will engage IESO as available and needed.
4. A final study report will be drafted.
5. The report will be filed as part of OPG's upcoming rate application.

3.0 Summary of Action Items

The table below captures the action items for OPG to consider following the meeting.

#	Action Item
1.	Consider whether changes to the HIM would meet the study's objectives.
2.	Consider the best available information available at the time of conducting the study, including the potential impact of tariffs on the system, if applicable.
3.	Consider whether and how Global Adjustment could be included as a factor in the evaluation of the study options.
4.	Clearly link how each study option meets the study objective(s) outlined in the settlement agreement, including whether and how it reduces spillage, and what structural changes would or would not be required.

4.0 Participant List

4.1 Attended

Organization / Affiliation	Stakeholder
Association of Major Power Consumers in Ontario (AMPCO)	Shelley Grice
Coalition of Concerned Manufacturers and Businesses of Canada (CCMBC)	Tom Ladanyi
Environmental Defense (ED)	Amanda Montgomery
Power Workers Union (PWU)	Bayu Kidane
Quinte Manufacturers Association (QMA)	Michael D. McLeod
School Energy Coalition (SEC)	Mark Rubenstein
Society of United Professionals (SUP)	Bohdan Dumka
Vulnerable Energy Consumers Coalition (VECC)	Mark Garner
Ontario Energy Board (OEB)	Chris Cincar
	Thomas Eminowicz
	Jeffrey Sauer
	Fiona O'Connell
On behalf of Minogi Corp., a wholly owned subsidiary of Mississaugas of Scugog Island First Nation ("MSIFN")	Daniel Vollmer
Six Nations Council	Peter Graham
Ministry of Energy (MOE)	Shehrzad Shehrzad
	Maya Super
Independent Electricity System Operator (IESO)	Phillip Chisulo
Ontario Power Generation (OPG)	Herman Mo, Senior Manager, Regulatory Affairs
	Saba Zadeh, Vice President, Regulatory Affairs

Organization / Affiliation	Stakeholder
	Other observing members
Optimus SBR	Ishma Zahur, Facilitator (Principal, Industries & Government Practice)
	Vrinda Oberoi, Note-taker (Senior Analyst, Industries & Government Practice)

4.2 Did Not Attend

Organization / Affiliation	Participant
Consumers Council of Canada (CCC)	Julie Girvan
Ontario Energy Board	Michael Millar
	Ritchie Murray
	Tina Li
	Musab Qureshi
	Theodore Antonopoulos
Chiefs of Ontario	Chris Hoyos

Appendix B

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Powering Tomorrow.

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November 24, 2025

Herman Mo
Senior Manager, Regulatory Affairs
Ontario Power Generation
1908 Colonel Sam Dr.
Oshawa, ON L1H 8W8

Dear Mr. Mo:

Re: Surplus Baseload Generation Variance Account (SBGVA) Study

In preparation for its 2027-2031 Payment Amounts for Prescribed Assets application, Ontario Power Generation (OPG) engaged the Independent Electricity System Operator (IESO) beginning in September 2024 regarding its requirement to prepare an SBGVA study.

In March 2025, OPG conducted a stakeholder session to gather input from stakeholders and rights holders on two proposed study options related to the SBGVA study, as well as to invite feedback on any additional considerations beyond the proposed options. This process allowed all participants – including the IESO – the opportunity to provide feedback on the options to be explored as part of the SBGVA study.

In September 2025, OPG met with the IESO to provide an overview of the study's findings and shared a draft of the 2025 SBGVA study**.** Following our review of the study, from a market efficiency perspective, the IESO acknowledges that the proposed options appear directionally appropriate. However, we would like to clarify that the IESO did not participate in the development or execution of the study and while the IESO has no concerns with OPG's analysis, we have not conducted an independent validation of the results.

If you have any questions or would like to discuss further, please let us know.

Sincerely,

Carrie Aloussis

Carrie Aloussis
Senior Manager, Regulatory Affairs

PRODUCTION FORECAST AND METHODOLOGY - NUCLEAR

1.0 PURPOSE

This evidence provides the production forecast for the OPG nuclear facilities and Darlington New Nuclear Program ("DNNP") facilities, and a description of the methodology used to derive the forecast. The nuclear generation forecast and methodology are substantively the same as in OPG's prior applications. Any changes are noted as applicable.

Altogether, the Application is seeking approval of a total nuclear production forecast of 128.6 terawatt-hours ("TWh") for the IR term. This includes:

- 126.2 TWh for OPG Nuclear Facilities (consisting of a plan of 18.7 TWh in 2027, 26.7 TWh for 2028, 25.1 TWh for 2029, 26.8 TWh for 2030, and 28.9 TWh for 2031), and
- 2.4 TWh for DNNP Facilities for 2030-2031 (consisting of a plan of 0.5 TWh in 2030 and 1.9 TWh in 2031).

2.0 NUCLEAR PRODUCTION METHODOLOGY AND PLANNING PROCESS

2.1 Methodology

Nuclear production planning and forecast methodology for this application remains substantively unchanged from EB-2020-0290 and broadly applies in the same manner for OPG nuclear facilities and DNNP facilities.

OPG nuclear facilities and DNNP facilities are designed as baseload generators. The annual nuclear production forecast for each is equal to the sum of the nuclear generating units' capacity multiplied by the number of hours in a year, less the number of hours for any planned outages, planned derates, forced production losses (i.e., unplanned outages and unplanned derates, as defined in Attachment 1 of this exhibit) and corrections for sources of generation losses (i.e., lake temperature, grid losses, and consumption (station service), as defined in Attachment 1).

The nuclear facilities and DNNP facilities production planning process is focused on establishing annual planned outage schedules and calculating variances to planned generation due to forced production losses. Outage durations are determined based on the scope of work defined for each outage while considering recent benchmarking efforts and industry best practices, with a commitment to continuously improve. The objective is to establish a realistic and accurate annual nuclear production forecast based on the generation and planned outage scope, and forced production losses with the following deliverables:

- A planned outage schedule for all stations that includes unit outage start dates, end dates, and durations based on the major elements and preventative maintenance comprising the scope of work that will be executed during each outage.
- Operational reliability targets such as Unit Capability Factor ("UCF"), Unit Capability Rate and the level of forced production losses based on forecast Forced Loss Rate ("FLR").
- Generation forecasts (in TWh) for individual nuclear units and an aggregated forecast for each station.

The generation and outage plan is an input to OPG's overall corporate business plan. As discussed in Ex. F2-4-1, outage resource requirements and cost estimates for the outage OM&A cost budget are also tied to the nuclear generation and outage plan.

2.2 Schedule

Planned outage schedules identify the number of days required for inspections and maintenance activities to ensure continued safe, reliable and long-term operation. The planned outage schedule is prepared, for OPG nuclear facilities, in accordance with OPG's aging and life cycle management programs and in for both OPG nuclear facilities and DNNP facilities, compliance with OPG's nuclear operating licenses issued by the CNSC, with consideration for Ontario's electricity grid system demand (i.e., IESO constraints). The planned outage schedule also incorporates "lessons learned" from past OPG outages and operating experience outside of OPG.

Planned outages are complex, involving many OPG divisions and groups working together. Outages require focus, expertise, high levels of coordination, training and includes a level of detail that exceeds that of many major construction projects (due to nuclear regulatory complexity and constraints in work execution). They require careful preparation and the safe execution of a well-developed plan that accounts for nuclear, radiological, and industrial safety, as well as the efficient achievement of production goals and cost controls. OPG's nuclear facilities typically involve more than twenty thousand work activities (i.e., tasks), involving many different types of resource personnel and hours of labour, sequenced in an optimal order to ensure safe, and effective execution while ensuring the fuel core is cool, controlled and contained at all times. In comparison, DNNP facilities' outage activities and durations are largely based on refueling requirements.

Planned outages consist of a combination of "routine" inspection, maintenance and "non-routine" activities specific to a particular outage. Examples of routine inspections are fuel channel, feeder, steam generator legal requirements and fitness for service to operate to the next planned outage and preventative maintenance. Non-routine activities include corrective and deficient maintenance, and replacements or modifications of the equipment or plant configuration that can only be done when the unit is shut down.

Planned outages must be submitted to and be "time-stamped" by the IESO. In most cases, OPG submits its nuclear outage schedule early in order to secure an early time-stamp date; this date determines the outage's advanced approval priority in the IESO's outage queue. In addition to this advance approval process, all outages must receive final approval from the IESO before they can begin. The IESO can deny approval of a planned outage start at any time up to the beginning of the outage. OPG works with the IESO to proactively address concerns regarding grid demand and planned nuclear outages.

Consistent with prior applications and now utilized also for the DNNP facilities, planned outage durations include a station-level allowance under the control of the site for uncertainty related to discovery work that is based on industry OPEX. Planned outage durations also include nuclear fleet-level allowance days under the control of the Chief Nuclear Officer to address risks to the completion of planned outages due to complexity in fleet level constraints (e.g., availability of Advance Inspection and Maintenance resources that service multiple organizations and outages).

3.0 OPG NUCLEAR FACILITIES

The period between the 2027-2031 IR term encompasses significant changes to the OPG nuclear line of business. Refurbishment of all Darlington units is expected to be complete in 2026, with all four units in-service throughout the entire IR term (see Ex. D2-2-1). These generation gains are offset by Pickering, with Units 1 and 4 having ended their commercial operation in 2024, and Units 5-8 being planned to shutdown on September 30, 2026 prior to transitioning into refurbishments (see Ex. D2-3-1). This will temporarily reduce nuclear production as there will be no generation from Pickering until the first Pickering refurbished unit, Unit 5, is planned to return to service in May 2031.

In addition to the major projects, as described in Ex. D2-1-2, this IR term also includes several significant, emergent equipment replacements and rehabilitations required to address reliability risks to Darlington's post-refurbishment operations, and which with impacts to the generation forecast. This includes the Darlington Steam Generator ("SG") Primary Moisture Separators ("PMS") Replacement projects. OPG has taken the opportunity to complete this emergent work where possible in the 2022-2026 IR term. This includes replacing the PMS in two SGs in Unit 3 and the PMS in all four SGs in Unit 1 during refurbishment windows to minimize post-refurbishment outage impacts. Replacements of the PMS in all four SGs on Unit 4 have been installed while the unit is under refurbishment. The PMS replacements on the remaining two SGs in Unit 3 are planned to be undertaken in a 2026 Darlington outage. As a result of this optimization effort, only one outage is needed during the 2027-2031 IR term to replace the PMS for all four SGs in Unit 2. See Ex. D2-1-3, Section 3.1.3 for further discussion on this project.

Concurrently, during the same Unit 2 Darlington PMS replacement outage in 2027, OPG will execute the Darlington Unit 2 Turbine Control and Auxiliary Systems Upgrade project that was deferred from 2025 to support grid reliability and manage resource constraints during concurrent nuclear outages. OPG has reviewed the challenges with regard to parallel execution of these significant work programs and built a strategy around key evolutions through existing work planning processes, allowing OPG to take one major outage instead of two. See Ex. D2-1-3, Section 3.1.3 for further discussion on this project.

OPG is also planning for Turbine Rotor Replacements for all four Darlington units starting in 2029, with three units' replacements being completed during the IR term in their respective planned outages. Once completed, this is forecasted to result in a planned uprate of 21 MW per unit, which is reflected in the nuclear production plan following each replacement. See Ex. D2-1-3, Section 3.1.3 for further discussion on this project.

Other major work planned includes Darlington Generator Stator Rewinds which were initially determined to be at low risk of requiring a rewind on Units 1 and 2 based on inspections performed prior to refurbishment. However, during a Unit 1 regular planned outage prior to refurbishment and in the refurbishment outage for Unit 2, scheduled inspections determined that there was increased degradation associated with generator stator winding conditions. As part of refurbishment, OPG conducted full/partial replacements of the stator winding wedges as a remedial action. While these less involved interventions were successful in enabling their return-to-service and mitigating near-term degradation, further assessments since have indicated signs of insulation degradation that cannot be managed by continued adjustments. As a result, OPG has determined that the Generator Stators in Unit 1 and Unit 2 will require an in-situ rewind in their respective planned outages in 2028 and 2030 respectively.

Another major non-routine work being planned at Darlington is Steam Generator ("SG") chemical clean on all four units. Based on build-up of boiler deposits in the SGs, a chemical clean is required continue to operate the SGs safely and reliably, maintaining the design and licensing bases. This commitment forms part of OPG's SG Life Cycle Management Plan as submitted to the regulator. Execution of SG chemical clean is planned in their respective planned outages for Unit 3 in 2026, Unit 2 in 2027, Unit 1 in 2028, and Unit 4 in 2029.

Major generation highlights of the 2027-2031 Plan (126.2 TWh):

- Reduction of 25.7 TWh compared to 2022-2026 OEB-approved Plan (151.9 TWh) primarily due to Pickering shutdown for Units 1 and 4 and Units 5-8 transition to refurbishment, offset by the return to service of all four Darlington units following their refurbishment.
- Darlington units post-refurbishment reflect improved performance:
  - Overall Darlington outage schedule efficiency efforts, including leveraging Canadian Nuclear Safety Commission ("CNSC") approved 36-months outage intervals and piloting planned outage duration improvements following refurbishment.
  - The 2027-2031 Plan reflects outage optimization efforts OPG undertook during the 2022-2026 IR term upon early return to service of Darlington Units, including extending a planned outage to support PMS replacements in 2026. These efforts have reduced the outages needed in the 2027-2031 Plan to execute the major equipment replacements and rehabilitations work described above.
  - Unit 4 post-refurbishment forecast FLR improvements at 6% and 4% for the first and second years respectively (versus 12% and 6% used in the EB-2020-0290 forecast). OPG has implemented initiatives to improve plant equipment reliability, fuel handling and lessons learned from prior unit refurbishments. An example is the Foreign Object Search and Retrieval program that has been included in Unit 4 refurbishment scope to minimize risk upon returning to service. This was a lesson learned from a Unit 3 outage, where foreign material in boilers resulted in a Boiler Tube Leak forced outage. These initiatives are addressed in Ex. F2-1-1.
  - Expectations of better outage execution performance as a result of outage improvement initiatives. Such initiatives are based on industry best practices to improve the outage planning process, outage tooling, scope of work assessments, and training. As an example, OPG is developing a Rapid Delivery Machine at Darlington, which will improve radiological safety for employees in all instances, as well as reduce durations of fuel channel inspection and vault maintenance campaigns by up to 10 days per outage whenever vault work is critical path. These improvements are incorporated into the generation forecast upon expected completion of the project.
  - Three out of four Darington units will have Turbine Rotor Replacements completed during the IR term, resulting in a net production increase of 0.6 TWh as a result of unit net electrical output rating increasing by 21 MW, which is built into production forecast.

  - Reduced equipment-related outages from 30 days to 15 days due to retirement of certain risks following the completion of Darlington Refurbishment Program ("DRP").
- Darlington Vacuum Building Outage (regulatory requirement) is scheduled in 2027, strategically overlapping with the Unit 2 outage to replace PMS and execute the Turbine Control and Auxiliary Systems Upgrade, reducing the overall planned outage days.

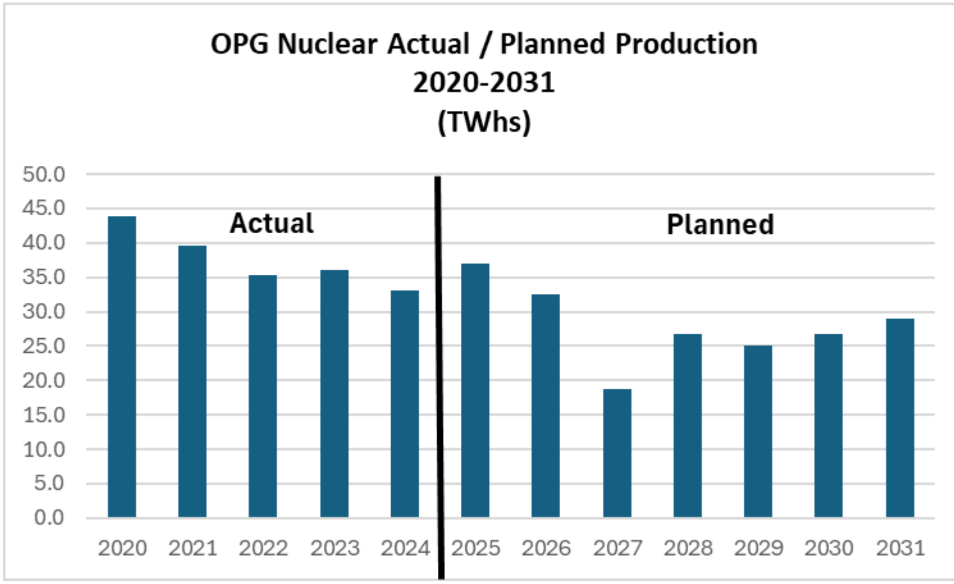
The actual nuclear production for 2020-2024 and the forecast for 2025-2031 are presented in Ex. E2-1-1, Table 1. The monthly nuclear production forecast for 2027-2031 is presented in Ex. E2-1-1, Table 2.

3.0 HISTORICAL RESULTS

In EB-2020-0290, OPG was planning to end commercial operations at Pickering during the 2022-2026 period. In September 2022, the Province of Ontario announced the extension of Pickering Units 5-8 operations from December 2025 to September 2026 ("extension period"). This will lead to approximately 11.4 TWh increase in generation for 2026. As discussed in Ex. H1-1-1, through the Pickering B Variance Account established under O. Reg. 53/05, OPG will record and return net revenues generated during the extension period that are earned from the output of the Pickering Units 5-8 to the ratepayers, subject to the OEB's review in a future application.

Overall, actual and planned nuclear production over the 2020-2031 period declines, with 2027 being the lowest, before rising towards the end of the IR term as shown in Chart 1.

Chart 1



The overall decline in nuclear production over the 2020-2029 period primarily reflects the impact of the DRP (up to 2026) and no Pickering generation starting October 1, 2026, with Units 1 and 4 having permanently shut down in 2024 and Units 5-8 planned to transition to refurbishment. Generation increase in 2030 is the result of one planned outage scheduled at Darlington (versus 2 planned outages in 2029) while 2031 is primarily attributable to Pickering Unit 5 returning to service post-refurbishment in May 2031.

The Planned Outage ("PO") days details over the years 2022-2024 are provided in Chart 2 below and are discussed under Ex. E2-1-2, Section 5.0.

Chart 2 – Planned Outage Durations[1,2]

	2022	2023	2024
Pickering Planned Outage Days (OEB-approved)	487.2	371.1	270.2
Pickering Planned Outage Days (Actuals)	393.8	355.6	283.0
Variance	**93.4**	**15.5**	**-12.8**
Darlington Planned Outage Days (OEB-approved)	73.0	112.2	55.0

Darlington Planned Outage Days (Actuals)	45.1	0.0 *	99.0
Variance	**27.9**	**112.2**	**-44.0**

[1] Includes Unbudgeted Planned Outages days. Excludes Planned Outage days for the Darlington Refurbishment Program.
[2] Does not reflect the EB-2020-0290 settlement adjustment for production forecast.
* Darlington PO deferred from 2023 to 2024

Darlington had fewer PO days compared to plan in 2022-2024 primarily due to not requiring a Unit 3 Post Refurbishment outage in 2023, combined with generation gains from lower number of unbudgeted planned outage days required. However, these generation gains were offset by a higher number of FLR days over those years (see Section 3.4, Chart 4), which are not factored into Chart 2. Pickering outage days show a declining trend as a result of Unit 1 and Unit 4 end of commercial operations. Pickering's 2022 PO days reflected a VBO and four POs. The variance is primarily attributable to one PO completed ahead of schedule and one PO that started later and was completed in early 2023 to mitigate execution overlap challenges of parallel execution of VBO.

Both stations have experienced equipment issues over the historical period, which led to the following unbudgeted planned outages (e.g., Equipment Aging Outage days):

Pickering Unbudgeted:

- Unit 7 unbudgeted PO was taken to address grayloc leak repairs (2022) – 5.9 days.
- Unit 5 unbudgeted PO to repair vault air conditioning units in order to prevent Forced Outage in summer months due to vault temperature limits (2023) – 13.5 days.
- Unit 8 unbudgeted PO to resolve oil ingress into the generator brush gear enclosure (2023) – 15.1 days.
- Unit 1 planned derate with an impact of 6.6 equivalent days lost to perform necessary inspection & maintenance on Fuel Handling equipment to ensure reliability (2023).
- Unit 5 unbudgeted PO to repair vault air conditioning units leaks (2024) – 21.9 days
- Unbudgeted POs (5 events) due to grid constraints or external factors with total impact of 20.6 days.

Darlington Unbudgeted:

- Unit 3 unbudgeted PO to address boiler tube leak (2024) – 7.1 days.
- Unit 2 had unbudgeted PO to address planned MW oscillation repairs during U2 Turbine Trip on Loss of Excitation window (2024) – 5.5 days.

3.1 Production Forecast Assumptions

The 2027-2031 production forecast considers recent historical results including the PO execution performance improvements realized since 2021 and incorporates the following key components:

- **Darlington units in operation post Darlington Refurbishment Program:** With the planned completion of DRP in 2026, the production forecast assumes that all Darlington units will be in operation through the entire IR term.
- **Pickering Shutdown of Units 1 and 4:** Pickering Units 1 and 4 ended commercial operation on October 1, 2024 and December 31, 2024 respectively. The production forecast therefore includes no generation from these units.
- **Pickering Units 5-8 Refurbishment:** The production forecast assumes that Pickering Units 5-8 will be taken offline at the end of September 2026 prior to transitioning into refurbishment in January 2027. The production forecast assumes that Unit 5 will return to service in May 2031 consistent with the Pickering Refurbishment Program's release quality estimate (see Ex. D2-3-1).
- **Pickering Post-Refurbishment Outages:** For Pickering Unit 5 returning to service in May 2031, one post-refurbishment outage has been scheduled to address equipment issues that are expected to emerge. As discussed in EB-2016-0152 and EB-2020-0290 with respect to the DRP, the need for these post-refurbishment outages is based on OPEX from other nuclear facilities that underwent major refurbishment. The need for these at outages at Pickering is underscored by the age of the units pre-refurbishment and the scope and execution complexity of the Pickering Refurbishment Program. The first post-refurbishment outage (55 days) is scheduled within six months following Unit 5 return to service, and is scheduled to be completed within 2031.
- **Pickering Planned Uprate:** The production forecast assumes that post-refurbishment, Unit 5 will return with a higher Maximum Continuous Rating ("MCR") capacity of 572 MW

compared with the current MCR of 540 MW as a result of improved turbine generator technology and thermal efficiency following refurbishment.

- **Planned Outage Cycles:** Maintaining a 36-month outage cycle for Darlington. Most of the PO durations during the IR term are longer than regular POs in order to complete major equipment replacements and rehabilitations to mitigate equipment reliability risks as discussed above. Other than the Unit 5 post-refurbishment outage, there will be no planned outages for Pickering during the rate term.
- **Equipment Risk Outages:** As discussed in Section 2.1 and Section 3.2.1, OPG has continued to observe equipment aging issues at both Pickering and Darlington that require equipment risk outages or unbudgeted planned outages to repair as it is not feasible or economical to proactively mitigate all possible modes of failure. In addition to this, OPG is also planning to undertake a significant amount of complex and significant modifications to replace and rehabilitate major equipment as discussed above, which may require equipment risk outages to address post-installation equipment issues. For these reasons, OPG has planned for equipment risk outages at Darlington to address equipment issues related to, (1) issues currently being tracked (Section 3.2.1 below), and (2) outages that may be required to address post-installation issues.
- **Darlington Vacuum Building Outage ("VBO") in 2027**: As per OPG's Power Reactor Operating Licence, the Darlington VBO has been scheduled for spring of 2027. This includes replacement of key Emergency Coolant Injection valves that can only be replaced during a VBO. OPG has leveraged lessons learned from the last Darlington VBO in 2015, the Pickering VBO in 2022 and industry best practices to refine outage scope and complexity.
- **Darlington FLR**: Darlington's unit post-refurbishment FLR targets are reduced to 6% and 4% for the first and second year respectively for Unit 1 and Unit 4, reflecting operating experience and lessons learned from Units 2 and 3. FLR was previously 12% and 6% in the first two years post-refurbishment. All Darlington units are expected to transition to post-refurbishment normal operations by 2028. The resultant station FLR varies between 2.9% to 2.0% per year (2.2% average) over the IR term, as discussed further in Section 3.3.
- **Pickering Post-Refurbishment**: Consistent with industry OPEX, higher FLR is expected immediately after Units return from refurbishment. The FLR target for Unit 5 is 12% in the

first year; which applies to the approximately 7.5 months following the Unit's return to service in May 2031. The FLR target for this first Pickering unit to undergo refurbishment has been set higher than the FLR target for Darlington Unit 4, which is the 4th unit returning to service.

3.2 Planned Outages

3.2.1 Schedule

The four Darlington Units are on a three year (36-month) planned outage cycle, which means that either one or two regular single unit planned outages occur each year for routine inspection and maintenance over the IR term. With Unit 4 expected to return to service in 2026, Darlington units are effectively reinstated to three-year (36-month) PO cycle interval over the entire IR term.

As noted above in Section 3.2 relating to equipment risk outages, while each station has an extensive preventive maintenance program that is realized through online or planned outage repairs, it is not feasible or economical to proactively mitigate all possible modes of failure. Unless there are safety concerns or regulatory limits requiring immediate action, OPG will take an equipment risk outage at an appropriate time to repair components that fail. As discussed in Section 2.1, OPG has undertaken unbudgeted planned outages and experienced forced outages due to the equipment issues at the Darlington and Pickering facilities. Such instances highlight the various equipment-related risks that OPG monitors under its Risk Management Program. In addition, as a result of the major equipment replacements and rehabilitation work during the IR term, there are risks associated with the performance of new equipment installations. Accordingly, OPG's outage plan for the IR term includes a 15-day equipment risk outage each year to address potential issues at Darlington. These outages are expected to be taken in response to specific active risks that OPG is currently tracking under the Risk Management Program or to address any issues associated with major equipment being placed in-service, namely:

- Darlington boiler tube leak
- Darlington low pressure service water system degradation
- Darlington fuel handling reliability issues

- Darlington MW oscillation repairs (experienced in 2024, as discussed above)
- Emergent post-installation equipment issues for major, complex and non-routine work, including SG PMS replacements, SG rewinds, Turbine Rotor Replacements, Turbine Control and Auxiliary Upgrade and non-routine steam generator cleanings.

The completion of the DRP has retired some aging-related risks. This has enabled a reduction in the expected equipment-risk related planned outages from 30-days duration during the 2022-2026 rate term to 15 days in this IR term as OPG continues to monitor active equipment issues at Darlington that were not addressed during refurbishment.

3.2.2 Vacuum Building Outage

The VBO is planned at a twelve-year frequency as approved by CNSC in Darlington's Power Reactor Operating Licence. The last VBO at Darlington was in 2015. As a result, OPG is required to conduct a VBO in 2027 which will result in all four-units being taken offline for nuclear safety purposes. OPG has scheduled the VBO during the extended Unit 2 outage in 2027, resulting in only incrementally taking three units offline.

In planning for the VBO, OPG has reviewed lessons learned and benchmarked other utilities. In addition, OPG is utilizing innovative technology and drones to perform some of the vacuum building inspection work and planning to initiate projects that would provide opportunities in future VBO's.[1] OPG's generation forecast reflects a planned duration of 45.9 days to execute the VBO. Any further scoping opportunities would require CNSC approval.[2] OPG will update its application should there be any material change related to the VBO duration.

There is no VBO scheduled for Pickering during the IR term.

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[1] See Project #84552 Darlington VBO Power Operated Valves Replacement Project in Ex. D2-1-3, Section 3.1.1.

[2] Subsequent to the establishment of the generation plan underpinning the 2025-2031 business plan, OPG has received CNSC approval for a one-day reduction to the VBO outage duration per unit (3 days total).

3.3 Forced Loss Rate

Forced production losses (i.e., unplanned outages and derates) are a source of variance to planned generation. OPG forecasts FLR targets that reflect the risk of forced production losses at Darlington and Pickering. The FLR targets are based on the plants' historical performance, any known improvements or component condition issues, initiatives to improve equipment reliability, and with consideration of post-refurbishment risks.

Pickering's FLR performance is set out in Chart 3 below:

Chart 3 – Pickering Forced Loss Rate

	2020	2021	2022	2023	2024	Avg.	10-Year Avg.
FLR- Actual (%)	2.7	6.2	1.8	2.8	2.6	**3.2**	**4.17**
OEB-Approved (%) [1]	5.0	5.0	3.5	3.5	3.5	**4.1**	**4.89**

[1] EB-2020-0290, Ex. E2-1-2, Table 1

Pickering's FLR performance has averaged 3.2% over the 2020-2024 period compared to an OEB-approved target of 4.1%. The Pickering FLR target remains at 3.5% until September 30, 2026, considering some equipment challenges that may emerge in the final years of operation prior to Units being taken offline for refurbishment. Considering operating experience from other nuclear fleets and industry, Pickering's Unit 5 FLR is set at 12% for the first-year post-refurbishment.

Darlington's FLR performance is set out in Chart 4 below:

Chart 4 – Darlington Forced Loss Rate

	2020	2021	2022	2023	2024	Avg.	10-Year Avg.
FLR-Actual (%)	1.5	3.5	7.5	1.4	12.1	**5.2**	**3.85**
OEB-Approved (%)[1]	4.2	3.0	2.1	1.2	6.0	**3.3**	**2.07**

[1] EB-2020-0290, Ex. E2-1-2, Table 1

Darlington's FLR performance has averaged 5.2% over the 2020-2024 period compared to an OEB-approved target of 3.3%. The high FLR in 2022 and 2024 was primarily attributable to a forced outages on Unit 2 (Turbine Stop Valve) and Unit 3 (Boiler Tube Leak) respectively.

With operating experience from Units 2 and 3 and leveraging lessons learned that have since been applied to subsequent units, Units 1 and 4 FLR targets were reduced to 6% and 4% for first and second year respectively post-refurbishment.

Notwithstanding the recent FLR performance at Darlington, and the need to execute major replacement and rehabilitation projects in support of post-refurbishment operations during the IR term, Darlington continues to target an improved FLR performance, set at 2.0% FLR over the 2028-2031 period once Units 1 and 4 enter their third year of post-refurbishment operations.

3.4 DNNP FACILITIES

The first of four DNNP facilities' units is planned to be commercially available and generating starting in October 2030. The 2027-2031 DNNP facilities' production forecast incorporates the following key components and assumptions:

- **DNNP Facilities Unit 1:** The production forecast includes 2.4 TWh generation from the first unit, which is planned to enter commercial operation in October 2030. Unit 1 is the only DNNP facilities unit operating during the IR term, generating for close to 15 months during the IR term. A mechanism has been established under O. Reg. 53/05 to account for any production variances as a result of differences between the actual in-service date and the OEB-approved forecast in-service date. See Ex. H1-1-1 for more information.
- **DNNP Facilities – Unit Rating:** Based on current design information, OPG is planning its generation forecast to include a MCR and net electrical rating of 327 MW and 315 MW respectively (includes 12 MW consumption).
- **DNNP Facilities – FLR:** Based on industry experience and considering the first of a kind nature of the project, the generation plan for the first SMR reflects lower availability with FLR of 12% for first year of operation, before reducing to 6% in the second year.

- **DNNP Facilities – PO Days:** With only one unit planned to be in operation during this IR period, the production forecast includes one 15-day outage to address equipment issues that are expected to emerge within the first six months of operation. In addition, there is a 50-day planned outage after its first year of commercial operations in the fall of 2031. The first outage currently includes initial re-fueling, prescribed inspection and maintenance, as well as potential additional regulatory inspections over first of a kind operations and first time start-up related activities. This outage is based on the available OPEX from industry peers (Tennessee Valley Authority and Boiling Water Reactor Owner’s Group data) including OPG’s nuclear fleet and extensive input from the original equipment manufacturer. After the initial PO, the SMR units are expected to be on a two year (24-month) PO cycle.

LIST OF ATTACHMENTS

ATTACHMENT 1

GLOSSARY OF OUTAGE AND GENERATION PERFORMANCE TERMS

The following evidence is substantially unchanged from that filed in EB-2013-0321.

Consumption Losses: The electrical service energy consumed by a station and used to supply the electrical load for ancillary equipment and related on-site processes.

Derate: A derate is where a unit is delivering a portion but not all of its full electrical power. Derates include:

- **Planned Derate:** A planned reduction in available power generation, scheduled with the IESO at least 28 days in advance.
- **Forced Derate:** An unplanned reduction in available power generation, which can include deratings due to equipment, safety, or environmental reasons.

Forced Extensions to Planned Outages: An extension to a planned outage which is not scheduled with the IESO at least 28 days in advance, and is unavoidable because the unit is not capable of safe operation at the scheduled outage completion time (e.g., an unexpected condition discovered during the scheduled outage which drives critical path).

Forced Loss Rate: Forced Loss Rate is a World Association of Nuclear Operators (“WANO”) indicator of performance reliability. Forced Loss Rate is a measure of the percentage of energy generation that a plant is not supplying to the electrical grid during non-planned outage periods, because of forced production losses, i.e., forced outages or unplanned derates. This indicator excludes forced production losses due to high lake water temperatures and forced extensions to planned outages.

Forced Outage: An unplanned electricity system component failure (e.g., immediate, delayed, postponed, startup failure) or other condition that requires the unit be removed completely from service immediately and, per WANO industry performance reporting guidelines, for which OPG did not provide at least 28 days advance notice to the IESO for the start of the outage.

Forced Production Losses: Lost production due to forced outages and forced derates.

Generation Losses: The total generation losses that are outside the control of plant management, equal to the sum of “Consumption Losses” + “Grid Losses” + “Lake Temperature Losses”.

Grid Losses: Generation losses due to a reduction in electrical power generation because the grid is unable to accept the available power (due to a problem outside of the station boundary) or because of demand limitations.

Lake Temperature Losses: High lake water temperature losses due to reduced condenser efficiency resulting in lower generation output.

Life Cycle Management: Life cycle management is the integration of safety management, ageing management and business management decisions, together with economic considerations over the life of a nuclear power plant in order to:

- Maintain an acceptable level of performance including safety.
- Optimize the operation, maintenance and service life of structures, systems, and components.
- Maximize returns on investment over the operational life of the nuclear power plant.
- Take account of strategies for life cycle funding (including decommissioning), fuel management, and waste management.

Maximum Continuous Rating: The design, or demonstrated higher, maximum power of a unit operating continuously (in MWs).

Planned Outage: An outage which has been scheduled with the IESO at least 28 days in advance of the start date. It is subject to final approval by the IESO, the starting time of which could be postponed up to the scheduled hour of shutdown. The schedule must include the planned completion date. The planned outage duration cannot be revised (increased or decreased) after the planned outage has commenced.

Unbudgeted Planned Outage: An emergent outage that was not included in the approved integrated 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. Although not included in the approved plan, the notice provided allows the outage to be categorized as "planned" for performance reporting purposes as per WANO industry guidelines.

Unit Capability Factor: A standard WANO indicator of performance reliability. Unit capability factor is the percentage of maximum energy generation that a unit is capable of supplying to the electrical grid, limited only by factors within the control of plant management. Unit capability factor is derived as the ratio of generation available from a unit over a specified time period divided by the maximum generation that the unit is able to produce under ambient conditions and at maximum reactor power during the same period. The available generation is reduced by planned and unplanned production losses deemed under station management's control. However, the derivation of available generation is not affected by losses due to events not under station management's control including environmental conditions (e.g., loss of transmission, lake water temperature derates, labour disputes, and potential low demand periods). While these events do impact production, they do not penalize unit capability factor as the units are considered available to produce at these times.

Unit Capability Rate: A standard indicator of performance reliability. 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. Unit Capability Rate, like UCF, is expressed as a percentage.

Numbers may not add due to rounding.

Table 1
Production Trend - Combined Nuclear (TWh)

Line No.	Prescribed Facility	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)
	OPG Nuclear Facilities												
1	**Darlington NGS**	23.4	18.5	13.9	14.6	11.7	21.1	21.1	18.7	26.7	25.1	26.8	27.1
2	**Pickering NGS**	20.5	21.1	21.4	21.5	21.3	15.8	11.4	0.0	0.0	0.0	0.0	1.9
3	**Total OPG Nuclear Facilities**	43.9	39.6	35.3	36.1	33.0	36.9	32.5	18.7	26.7	25.1	26.8	28.9
4	**DNNP Facilities**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	1.9
5	**Total**	43.9	39.6	35.3	36.1	33.0	36.9	32.5	18.7	26.7	25.1	27.3	30.9

Table 2
Monthly Production - Combined Nuclear (TWh)
IR Term

Line No.	Prescribed Facility	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	2027 Plan:													
	OPG Nuclear Facilities													
1	**Darlington NGS**	2.0	1.7	1.9	0.6	0.2	1.7	1.8	1.8	1.7	1.9	1.8	1.6	18.7
2	**Pickering NGS**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	**OPG Nuclear Facilities Subtotal**	2.0	1.7	1.9	0.6	0.2	1.7	1.8	1.8	1.7	1.9	1.8	1.6	18.7
4	**DNNP Facilities**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	**Total**	2.0	1.7	1.9	0.6	0.2	1.7	1.8	1.8	1.7	1.9	1.8	1.6	18.7
	2028 Plan:													
	OPG Nuclear Facilities													
6	**Darlington NGS**	2.0	1.8	1.9	1.8	2.4	2.4	2.4	2.4	2.4	2.5	2.5	2.2	26.7
7	**Pickering NGS**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**OPG Nuclear Facilities Subtotal**	2.0	1.8	1.9	1.8	2.4	2.4	2.4	2.4	2.4	2.5	2.5	2.2	26.7
9	**DNNP Facilities**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	**Total**	2.0	1.8	1.9	1.8	2.4	2.4	2.4	2.4	2.4	2.5	2.5	2.2	26.7
	2029 Plan:													
	OPG Nuclear Facilities													
11	**Darlington NGS**	2.2	1.7	1.9	2.5	2.5	2.4	2.4	2.3	1.8	1.9	1.8	1.6	25.1
12	**Pickering NGS**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	**OPG Nuclear Facilities Subtotal**	2.2	1.7	1.9	2.5	2.5	2.4	2.4	2.3	1.8	1.9	1.8	1.6	25.1
14	**DNNP Facilities**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	**Total**	2.2	1.7	1.9	2.5	2.5	2.4	2.4	2.3	1.8	1.9	1.8	1.6	25.1
	2030 Plan:													
	OPG Nuclear Facilities													
16	**Darlington NGS**	2.6	2.3	2.6	2.5	2.6	2.4	2.5	2.3	1.8	1.9	1.8	1.7	26.8
17	**Pickering NGS**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	**OPG Nuclear Facilities Subtotal**	2.6	2.3	2.6	2.5	2.6	2.4	2.5	2.3	1.8	1.9	1.8	1.7	26.8
19	**DNNP Facilities**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.2	0.5
20	**Total**	2.6	2.3	2.6	2.5	2.6	2.4	2.5	2.3	1.8	2.0	2.0	1.9	27.3
	2031 Plan:													
	OPG Nuclear Facilities													
21	**Darlington NGS**	2.6	2.2	1.9	1.9	1.9	1.8	2.5	2.5	2.4	2.6	2.5	2.3	27.1
22	**Pickering NGS**	0.0	0.0	0.0	0.0	0.2	0.3	0.3	0.3	0.3	0.3	(0.0)	0.1	1.9
23	**OPG Nuclear Facilities Subtotal**	2.6	2.2	1.9	1.9	2.1	2.2	2.8	2.8	2.7	2.9	2.5	2.3	28.9
24	**DNNP Facilities**	0.2	0.2	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.1	(0.0)	0.2	1.9
25	**Total**	2.8	2.4	2.1	2.0	2.3	2.4	3.0	3.0	2.9	3.0	2.5	2.5	30.9

COMPARISON OF PRODUCTION FORECASTS – NUCLEAR

1.0 PURPOSE

This evidence presents period-over-period comparisons of actual and forecast nuclear production for 2020-2031, in support of the approval of OPG's nuclear facilities' production forecast for the IR term. In addition, this evidence separately sets out the production forecast for the Darlington New Nuclear Program ("DNNP") facilities, the first unit of which will enter commercial operation during the IR term.

2.0 OPG NUCLEAR FACILITIES

2.1 Overview

Variances between actual and forecast production in the 2022-2026 term are primarily the result of the successful execution of the Darlington Refurbishment Program ("DRP"), including the implementation of lessons learned and unit over unit efficiencies, and the Province of Ontario's decision to extend Pickering Units 5-8 operations from 2025 to 2026.[1] Other reasons for variances are attributed to changes in the following: station planned outage ("PO") days,[2] forced outages ("FO"), planned or forced derates and unbudgeted POs. Variances may also arise due to station consumption, grid losses and impacts on thermal performance resulting from high lake water temperature.

Period-over-period variances are presented in Ex. E2-1-2, Tables 1a and 1b, and are explained below.

2.2 Period-Over-Period Changes – IR Term

As discussed in Ex. E2-1-1, Section 3.0, Pickering will be fully offline as of September 30, 2026. While Units 1 and 4 have ended commercial operation, Units 5-8 will transition to

[1] Under *Ontario Regulation 53/05*, OPG will return to ratepayers net revenues generated between January 1, 2026, to September 30, 2026, resulting from the extended operations of Pickering Units 5-8. See Ex. H1-1-1, Section 5.28, for information regarding the Pickering B Variance Account.

[2] PO days excludes a) outage days for Darlington units out of service during refurbishment, and b) outage equivalent planned derate days.

refurbishment, with Unit 5 returning to service towards the end of the IR term in May 2031. Until such point, there is no Pickering station generation during the IR term.

Also as discussed in Ex. E2-1-1, the DRP will conclude in 2026, with all four Darlington units operating throughout the IR term for the first time since 2016. Darlington's generation is impacted during this IR term by a four-unit vacuum building outage in 2027, and major equipment replacements and rehabilitations works requiring extended outages during the IR term as discussed below.

2027 Plan versus 2026 OEB-Approved

The 2027 Plan nuclear production of 18.7 terawatt-hours ("TWh") is 3.2 TWh lower than the 2026 OEB-approved plan production of 21.9 TWh. Since both the 2027 Plan and 2026 OEB-approved do not include any Pickering generation, the lower 2027 Plan production relative to 2026 OEB-approved is attributed to Darlington:

- Higher production in 2027 Plan compared with 2026 OEB-approved due to the completion of the DRP in 2026. The 2026 OEB-approved plan assumed that the last Darlington Unit 4 refurbishment would be complete in October 2026 (288 days).
- Lower production in 2027 Plan due to higher PO days (316.5 days) required primarily to execute major equipment replacements and rehabilitation associated with the Primary Moisture Separator ("PMS") Replacement on all four Steam Generators in Darlington Unit 2 in 2027, as well as the Unit 2 Turbine Control and Auxiliary Systems Upgrade ("TG Controls") project being executed in parallel. Both projects are described in Ex. D2-1-3, Section 3.1.3.
- Lower production in 2027 Plan due to planned Vacuum Building Outage ("VBO"; 45.9 days per unit (137.7 days total)) which necessitates shutdown of Units 1, 3, and 4. OPG has strategically overlapped the VBO with the above Unit 2 planned outage to optimize the outages.
- Higher production in 2027 Plan due to 19.5 fewer FLR equivalent days in 2027 Plan when compared with 2026 OEB-approved.
- Higher production in 2027 Plan compared with 2026 OEB-approved due to Unit 3 bulkhead derates not required upon refurbishment completion (savings of 15.1 equivalent days).

2028 Plan versus 2027 Plan

The 2028 Plan nuclear production of 26.7 TWh is 8.0 TWh higher than the 2027 Plan production of 18.7 TWh. The higher production of 2028 relative to 2027 is primarily due to 371.2 fewer PO days at Darlington as summarized below:

- Higher production in 2028 Plan compared with 2027 Plan as VBO (137.7 days impact) is completed in 2027.
- Two POs in 2028 totaling 141.5 days as compared to two POs in 2027 totaling 375.0 days for the extended outage duration associated with the Unit 2 PMSR and TG Controls PO.

2029 Plan versus 2028 Plan

The 2029 Plan nuclear production of 25.1 TWh is 1.6 TWh lower than the 2028 Plan production of 26.7 TWh. The lower production in 2029 relative to 2028 is due to Darlington having 72.7 more PO days than in 2028 as summarized below:

- Three POs in 2029 totaling 214.1 days as compared to two POs totaling 141.5 days in 2028.

2030 Plan versus 2029 Plan

The 2030 Plan nuclear production of 26.8 TWh is 1.8 TWh higher than the 2029 Plan production of 25.1 TWh. The higher production in 2030 relative to 2029 is primarily due to higher production at Darlington as summarized below:

- Two POs in 2030 totaling 139.2 days as compared to three POs totaling 214.1 days in 2029.

2031 Plan versus 2030 Plan

The 2031 Plan nuclear production of 28.9 TWh is 2.1 TWh higher than the 2030 Plan production of 26.8 TWh. The higher production in 2031 relative to 2030 is primarily due to the return of Pickering Unit 5 from refurbishment and impacts of unit uprates at Darlington as summarized below:

- Higher production from Pickering Unit 5 return to service post-refurbishment in May 2031 (+1.9 TWh).

2.3 Period-Over-Period Changes – Bridge Years

2026 Budget versus 2026 OEB-Approved

The 2026 planned nuclear production of 32.5 TWh is 10.5 TWh higher than the 2026 OEB-approved production of 21.9 TWh. The higher 2026 planned production is primarily due to a combination of the following:

- Lower production at Darlington relative to OEB-approved due to Unit 3 planned outage shifted from 2027 to 2026 and extended outage duration to conduct emergent work associated with the SG PMSR (-4.8 TWh).
- Higher production at Darlington due to planned early return to service of Unit 4 resulting in 183.0 fewer refurbishment days (+3.9 TWh).
- Higher production at Pickering due to Pickering Units 5-8 extended operation from January 1, 2026 to September 30, 2026 (+11.4 TWh).

2026 Budget versus 2025 Budget

The 2026 planned nuclear production of 32.5 TWh is 4.4 TWh lower than the 2025 planned nuclear production of 36.9 TWh. The lower 2026 planned production is primarily due to:

- Lower production at Pickering due to the planned shutdown of Units 5-8 on September 30, 2026 compared with entire year of production in 2025 (-4.4 TWh).

2025 Budget versus 2025 OEB-Approved

The 2025 planned nuclear production forecast of 36.9 TWh is 5.8 TWh higher than the 2025 OEB-approved production of 31.1 TWh. The higher 2025 planned production is primarily due to:

- Higher production at Darlington due to:
  - 107 fewer refurbishment days with Unit 1 having returned to service on November 27, 2024 versus OEB-approved assumption of April 18, 2025 (+2.2 TWh).
  - 182.0 fewer PO days due to shifting the Unit 2 Turbine Controls scope from 2025 to 2027 (see Ex. E2-1-1, Section 3.0 for further discussion) (+3.8 TWh).
  - 61 fewer post-refurbishment PO days attributed to Unit 3 (removal of 31-day post-refurbishment PO) and Unit 1 (reduced post-refurbishment PO from 55 days to 25 days) (+1.3 TWh). As a result of Unit 3's early return to service from refurbishment, a Unit 3

planned outage was shifted from 2027 into 2026, which eliminated the need for the Unit 3 post-refurbishment PO. Unit 1's reduced forecast for its post-refurbishment outage reflects operating experience from successful operation of Darlington Units 2, 3, and 1 post-refurbishments to-date.

- Lower planned production at Pickering primarily due to 80.0 additional planned PO days required to address Unit 6 equipment inspection and maintenance issues associated with life extension to September 31, 2026, partially offset by 5.0 fewer Equipment Aging Outage days (-0.8 TWh).
- Production Settlement adjustment (-0.9 TWh)

2025 Budget versus 2024 Actual

The 2025 planned nuclear production of 36.9 TWh is 3.9 TWh higher than the 2024 production of 33.0 TWh. The higher 2025 planned production is primarily due to:

- Higher planned production at Darlington (+9.4 TWh) due to:
  - 333 fewer refurbishment days (365 days in 2025 for Unit 4 compared to 698 days in 2024 for Units 1 and 4 combined);
  - 74 fewer PO days (25 days in 2025 planned production compared to 99 days in 2024); and
  - 41.2 fewer FLR equivalent days (38.6 days in 2025 planned production compared to 79.8 days in 2024).
- Lower planned production at Pickering (-5.5 TWh) primarily due to Units 1 and 4 end of commercial operations in 2024, with only Units 5-8 operating through 2025, partially offset by 172.7 fewer PO days in 2025 (110.3 PO days in the 2025 planned production compared to 283 PO days in 2024).

2.4 Period-Over-Period Changes – Historical Years

2024 Actual versus 2024 OEB-Approved

The 2024 actual nuclear production of 33.0 TWh is 1.1 TWh lower than the 2024 OEB-approved production of 34.1 TWh. The lower 2024 production is primarily due to a combination of the following:

- Lower production at Darlington due to 31.4 additional PO days in 2024 (86.4 days actual compared to 55 days in OEB-approved) reflecting a Unit 2 PO that was shifted from 2023 to 2024 to support grid reliability and manage resource constraints during concurrent nuclear outages (-0.7 TWh).
- Lower production at Darlington due to higher actual FLR of 12.1% compared to 6.0% OEB-approved (-0.9 TWh), primarily due to the following forced outages
  - 26.3 days to repair boiler tube leak in Unit 3;
  - 4.4 days to address circulating cooling water pump issues on Unit 3;
  - 32.7 days to address loss of excitation related issues on Unit 2; and
  - 11.1 days to repair boiler feed water suction pipe leaks on Unit 1.
- Higher production at Darlington due to 35 fewer refurbishment days with Unit 1 available for commercial operations on November 27, 2024 (698 days actual for Units 1 and 4 combined compared to 733 days in OEB-approved). This was driven by improvements in refurbishment schedules based on implementing prior unit lessons learned (+0.7 TWh),
- Higher production at Darlington as no derates were required during installation of the Bulkhead to isolate Unit 4 for refurbishment from the operating units as well as during the removal of the Bulkhead while bringing Unit 1 from refurbishment (+0.8 TWh).
- Production Settlement adjustment (-0.7 TWh).

2024 Actual versus 2023 Actual

The 2024 nuclear production of 33.0 TWh is 3.1 TWh lower than the 2023 production of 36.1 TWh. The lower 2024 production is primarily due to lower production at Darlington (-3.0 TWh):

- 99 higher PO days (99 days in 2024 and no PO days in 2023);
- 69.3 higher FLR equivalent days (79.8 days in 2024 compared to 10.5 days in 2023); and
- 32 fewer refurbishment days (698 days in 2024 for Unit 1 and 4 combined compared to 730 days in 2023 for Units 1, 3, and 4 combined).

2023 Actual versus 2023 OEB-Approved

The 2023 actual nuclear production of 36.1 TWh is 4.9 TWh higher than the 2023 OEB-approved production of 31.2 TWh. The higher 2023 production is primarily due to higher production at Darlington:

- Higher production at Darlington due to 108 fewer days required for refurbishment of Darlington units. Darlington Unit 3 was returned to service 166 days earlier than the OEB-approved plan as a result of the incorporation of significant operating experience and lessons learned from Unit 2 (+3.5 TWh). This was partially offset by the refurbishment of Darlington Unit 4 being advanced by 58 days to start immediately after Unit 3's return to service (-1.2 TWh).
- Higher production at Darlington due to fewer PO equivalent days, including a regular planned outage (82.2 days) that was shifted from 2023 to 2024 to support grid reliability and manage resource constraints during concurrent nuclear outages (+1.8 TWh).

2023 Actual versus 2022 Actual

The 2023 nuclear production of 36.1 TWh is 0.8 TWh higher than the 2022 production of 35.3 TWh. The higher 2023 production is primarily due to higher production at Darlington:

- Higher production at Darlington due to 45 fewer PO days in 2023 compared to 2022 (+0.9 TWh).
- Higher production at Darlington due to better FLR in 2023 compared to 2022 (+0.8 TWh).
- Lower production at Darlington due to 45 more refurbishment days at Darlington in 2023. There were 730.0 refurbishment days in 2023 with Unit 1 under refurbishment throughout the year (365 days) and Unit 4 refurbishment starting after Unit 3 returned to service. In comparison, there were 685.0 refurbishment days in 2022 as Unit 1 refurbishment began in February 2022 while Unit 3 refurbishment was already in progress (-0.9) TWh.

2022 Actual versus 2022 OEB-Approved

The nuclear production of 35.3 TWh in 2022 was 1.7 TWh higher than the 2022 OEB-approved production of 33.6 TWh. The higher 2022 production is primarily due to a combination of the following:

- Higher production at Darlington due primarily to:
  - 27.9 fewer PO days in 2022 compared to OEB-approved (+0.6 TWh);
  - Savings of 22.3 days as no derates were required during the installation of the Bulkhead to isolate Unit 1 for refurbishment from the operating units. This was the result

of implementation of Enriched Boric Acid project,[3] coupled with refurbishment schedule optimization based on lessons learned changes in operating unit fueling strategy (+0.5 TWh).

- Lower production at Darlington due to 40.6 more FLR equivalent days. Darlington's actual FLR was 7.5% versus 2022 OEB-approved of 2.1% (-0.8 TWh).
- Higher production at Pickering primarily due to 93.4 fewer PO days where regular PO were completed ahead of schedule with more efficient outage execution. One PO started later and was completed in early 2023 to mitigate execution overlap challenges of parallel execution of VBO (+1.2 TWh).

2022 Actual versus 2021 Actual

The 2022 nuclear production of 35.3 TWh is 4.3 TWh lower than the 2021 production of 39.6 TWh. The lower 2022 production is primarily due to a combination of the following:

- Lower production at Darlington due to 320.0 more refurbishment days in 2022. There were 365.0 refurbishment days in 2021 for Unit 3 compared with 685.0 refurbishment days in 2022 for Unit 3 during the entire year and Unit 1 refurbishment beginning in February (-6.7 TWh).
- Higher production at Darlington primarily due to 110.4 fewer PO days required in 2022 compared with 2021 (+2.3 TWh).

2021 Actual versus 2021 OEB-Approved

The 2021 nuclear production of 39.6 TWh was 4.2 TWh higher than the 2021 OEB-approved production of 35.4 TWh. The higher 2021 production is primarily due to a combination of the following:

- Higher production at Darlington due to 200.0 fewer refurbishment days. The OEB-approved production forecast reflected a six-month period when two units would be refurbished in parallel. Following revisions to the DRP schedule, this overlap began February 15, 2022 when Unit 1 began its refurbishment as opposed to June 15, 2021 (+4.2 TWh).

[3] The implementation of the Enriched Boric Acid project improves fueling reliability, allowing OPG to do longer maintenance windows on the fueling machine while a unit is operating.

- Lower production at Darlington due to 104.3 higher PO days. The OEB-approved production forecast reflected a post-refurbishment outage and a primary heat transport pump motor replacement mini outage, and no regular POs. In comparison, the 2021 Actual had two regular POs with 155.5 days. As a result of the revised DRP schedule, OPG had to move a Darlington Unit 1 outage from 2020 to 2021 and also add a PO in 2021 to support Unit 4 operation until its start of refurbishment (-2.2 TWh).
- Higher production at Pickering due to 227.3 fewer PO days. The Pickering VBO was moved to 2022 following Canadian Nuclear Safety Commission approval, accounting for 120.0 fewer PO days required at Pickering (+1.5 TWh).
- Higher production at Pickering due to the number of POs at Pickering being reduced from three to two due to the transition from a 24-month to a 30-month outage cycle (+1.3 TWh).

2021 Actual versus 2020 Actual

The 2021 nuclear production of 39.6 TWh is 4.3 TWh lower than the 2020 production of 43.9 TWh. The lower 2021 production is primarily due to a combination of the following:

- Lower production at Darlington primarily due to:
  - 122.5 higher PO days for 2021 (155.5 PO days) compared to 2020 (33 PO days) (-2.6 TWh).
  - 90 higher Darlington refurbishment days for 2021. Unit 3 was undergoing refurbishment for the entire 2021 compared with 275 refurbishment days in 2020 as Unit 2 completed refurbishment on June 4, 2020 and Unit 3 commenced refurbishment on September 3, 2020 (-1.9 TWh).
- Higher production at Pickering due to 114.6 fewer PO days for 2021 (335.5 PO days) compared with 2020 (450 PO days) (+1.4 TWh). This was partly offset by lower production at Pickering due to higher actual FLR for 2021 at 6.2% compared with 2020 FLR of 2.7% (-0.9 TWh).

2020 Actual versus 2020 OEB-Approved

The 2020 nuclear production of 43.9 TWh is 6.6 TWh higher than the 2020 OEB-approved production of 37.4 TWh. The higher 2020 production is primarily due to higher production at Darlington:

- Higher production at Darlington due to 91.1 fewer refurbishment days. In the 2020 OEB-approved production forecast, there was no gap between Unit 2 and Unit 3 refurbishments. Following revisions to the DRP schedule in response to the COVID-19 pandemic, there was a two-month gap between the return to service of Unit 2 and the start of the refurbishment of Unit 3 (+1.9 TWh).
- Higher production at Darlington due to the primary heat transport pump motor replacement mini outage included in EB-2016-0152 was cancelled as the work was completed in a prior year (+0.8 TWh).
- Higher production at Darlington from 150.2 fewer PO days due to a combination of the following:
  - The later return to service date for Unit 2 necessitated revisions to the outage schedule, which resulted in the rescheduling of the first Unit 2 post-refurbishment outage from 2020 to 2021 (+1.3 TWh); and
  - The shifting of the Unit 1 PO from September 2020 to February 2021 (+1.9 TWh);
  - Partly offset by a regulatory requirement to perform a single fuel channel replacement outage in advance of the Unit 3 refurbishment (-0.7 TWh).

3.0 DNNP FACILITIES

3.1 Overview

The first of four DNNP facilities' units is planned to be commercially available and generating starting in October 2030. Prior to this, there is no planned generation for the DNNP facilities. As such, there are no period-over-period comparison available for the historical or bridge years.

3.2 Period-Over-Period Changes – IR Term

2027 Plan versus 2026 OEB-Approved

There is no planned production from the DNNP facilities during this timeframe.

2028 Plan versus 2027 Plan

There is no planned production from the DNNP facilities during this timeframe.

2029 Plan versus 2028 Plan

There is no planned production from the DNNP facilities during this timeframe.

2030 Plan versus 2029 Plan

The 2030 DNNP facilities production forecast includes 0.5 TWh as DNNP facilities Unit 1 is planned to enter commercial operations in October 2030. There is no planned production during 2029 for the DNNP facilities.

2031 Plan versus 2030 Plan

The 2031 DNNP facilities production of 1.9 TWh is 1.4 TWh higher than 2030 Plan production of 0.5 TWh.

- There is higher production forecasted in 2031 with DNNP facilities' Unit 1 operating for a full year. This production increase is partly offset by the first PO at the DNNP facilities' Unit 1 as well as the warranty outage, both scheduled in 2031.

Table 1a
Comparison of Production Forecast - Combined Nuclear

Line No.	Business Unit	2020 OEB Approved[3]	(c)-(a) Change	2020 Actual	(g)-(c) Change	2021 OEB Approved[3]	(g)-(e) Change	2021 Actual	(k)-(g) Change	2022 OEB Approved	(k)-(i) Change	2022 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Darlington NGS											
1	**TWh**	17.7	5.7	23.4	(4.9)	16.6	1.9	18.5	(4.6)	13.4	0.5	13.9
2	**Unit Capability Factor (%)**	79.4	13.7	93.1	(10.4)	90.9	(8.3)	82.7	4.3	85.8	1.2	87.0
3	**PO Days[1,2]**	183.2	(150.2)	33.0	122.5	51.2	104.3	155.5	(110.4)	73.0	(27.9)	45.1
4	**Refurb PO Days**	366.0	(91.1)	274.9	90.1	565.0	(200.0)	365.0	320.0	685.0	0.0	685.0
5	**FEPO Days**	0.0	1.3	1.3	(1.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	**FLR (%)**	4.2	(2.6)	1.5	2.0	3.0	0.5	3.5	4.0	2.1	5.4	7.5
7	**FLR Days Equivalent**	38.1	(20.4)	17.7	15.3	25.0	8.1	33.0	22.0	14.4	40.6	55.0
	Pickering NGS											
8	**TWh**	19.6	0.9	20.5	0.6	18.8	2.3	21.1	0.3	19.8	1.6	21.4
9	**Unit Capability Factor (%)**	73.4	2.8	76.3	2.7	70.6	8.3	78.9	1.1	74.1	5.9	80.0
10	**PO Days[2]**	498.9	(48.9)	450.0	(114.6)	562.8	(227.3)	335.5	58.3	487.2	(93.4)	393.8
11	**Refurb PO Days**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	**FEPO Days**	0.0	13.0	13.0	(13.0)	0.0	0.0	0.0	1.1	0.0	1.1	1.1
13	**FLR (%)**	5.0	(2.3)	2.7	3.6	5.0	1.2	6.2	(4.4)	3.5	(1.7)	1.8
14	**FLR Days Equivalent**	84.9	(39.2)	45.6	69.1	81.4	33.4	114.7	(82.4)	58.9	(26.5)	32.3
	OPG Nuclear Facilities Totals											
15	**Unit Capability Factor (%)**	76.2	8.3	84.5	(3.8)	79.0	1.6	80.7	2.0	78.5	4.2	82.7
16	**PO Days[1,2]**	682.1	(199.1)	483.0	7.9	614.0	(123.1)	491.0	(52.1)	560.2	(121.3)	438.9
17	**FEPO Days**	0.0	14.3	14.3	(14.3)	0.0	0.0	0.0	1.1	0.0	1.1	1.1
18	**FLR (%)**	4.6	(2.5)	2.1	2.9	4.0	0.9	5.0	(0.8)	2.9	1.3	4.2
19	**FLR Days Equivalent**	122.9	(59.6)	63.3	84.4	106.3	41.4	147.7	(60.4)	73.2	14.1	87.3
20	**TWh before Adjustments**	37.4	6.6	43.9	(4.3)	35.4	4.2	39.6	(4.3)	33.2	2.1	35.3
21	**OEB/Settlement Adjustments[4]**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	(0.4)	0.0
22	**TWh including Adjustments**	37.4	6.6	43.9	(4.3)	35.4	4.2	39.6	(4.3)	33.6	1.7	35.3
	DNNP Facilities											
23	**TWh**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	**Unit Capability Factor (%)**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25	**PO Days[2]**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
26	**FEPO Days**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	**FLR (%)**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	**FLR Days Equivalent**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	**Total TWh Including Adjustments**	37.4	6.6	43.9	(4.3)	35.4	4.2	39.6	(4.3)	33.6	1.7	35.3

Line No.	Business Unit	2022 Actual	(e)-(a) Change	2023 OEB Approved	(e)-(c) Change	2023 Actual	(i)-(e) Change	2024 OEB Approved	(i)-(g) Change	2024 Actual	(k)-(i) Change	2025 Budget
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Darlington NGS											
30	**TWh**	13.9	0.7	9.6	5.0	14.6	(3.0)	12.0	(0.3)	11.7	9.4	21.1
31	**Unit Capability Factor (%)**	87.0	10.0	78.1	18.9	97.0	(22.4)	81.8	(7.2)	74.6	19.6	94.2
32	**PO Days[1,2]**	45.1	(45.1)	112.2	(112.2)	0.0	99.0	55.0	44.0	99.0	(74.0)	25.0
33	**Refurb PO Days**	685.0	45.0	838.0	(108.0)	730.0	(32.0)	733.0	(35.0)	698.0	(333.0)	365.0
34	**FEPO Days**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	**FLR (%)**	7.5	(6.1)	1.2	0.2	1.4	10.6	6.0	6.1	12.1	(8.5)	3.6
36	**FLR Days Equivalent**	55.0	(44.5)	5.9	4.6	10.5	69.3	38.0	41.8	79.8	(41.2)	38.6
	Pickering NGS											
37	**TWh**	21.4	0.1	21.2	0.3	21.5	(0.2)	21.4	(0.1)	21.3	(5.5)	15.8
38	**Unit Capability Factor (%)**	80.0	0.6	79.4	1.3	80.7	2.6	83.3	(0.0)	83.3	5.8	89.1
39	**PO Days[2]**	393.8	(38.2)	371.1	(15.5)	355.6	(72.6)	270.2	12.8	283.0	(172.7)	110.3
40	**Refurb PO Days**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
41	**FEPO Days**	1.1	0.9	0.0	2.0	2.0	(2.0)	0.0	0.0	0.0	0.0	0.0
42	**FLR (%)**	1.8	1.0	3.5	(0.7)	2.8	(0.2)	3.5	(0.9)	2.6	0.9	3.5
43	**FLR Days Equivalent**	32.3	18.1	63.1	(12.6)	50.5	(4.4)	66.8	(20.7)	46.1	1.1	47.2
	OPG Nuclear Facilities Totals											
44	**Unit Capability Factor (%)**	82.7	4.0	79.0	7.7	86.7	(6.8)	82.8	(2.9)	79.9	12.1	92.0
45	**PO Days[1,2]**	438.9	(83.3)	483.3	(127.7)	355.6	26.4	325.2	56.8	382.0	(246.7)	135.3
46	**FEPO Days**	1.1	0.9	0.0	2.0	2.0	(2.0)	0.0	0.0	0.0	0.0	0.0
47	**FLR (%)**	4.2	(1.9)	2.8	(0.6)	2.2	4.0	4.4	1.8	6.3	(2.7)	3.6
48	**FLR Days Equivalent**	87.3	(26.4)	69.0	(8.0)	61.0	64.9	104.8	21.1	125.9	(40.1)	85.8
49	**TWh before Adjustments**	35.3	0.8	30.8	5.3	36.1	(3.1)	33.4	(0.4)	33.0	3.9	36.9
50	**OEB/Settlement Adjustment[4]**	0.0	0.0	0.4	(0.4)	0.0	0.0	0.7	(0.7)	0.0	0.0	0.0
51	**TWh including Adjustments**	35.3	0.8	31.2	4.9	36.1	(3.1)	34.1	(1.1)	33.0	3.9	36.9
	DNNP Facilities											
52	**TWh**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
53	**Unit Capability Factor (%)**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
54	**PO Days[2]**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
55	**FEPO Days**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
56	**FLR (%)**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
57	**FLR Days Equivalent**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
58	**Total TWh Including Adjustments**	35.3	0.8	31.2	4.9	36.1	(3.1)	34.0	(1.1)	33.0	3.9	36.9

Notes:
1 PO days excludes planned outage days for units out of service during refurbishment.
2 PO days excludes planned outage equivalent days for planned derating of units or staggered unit shutdown.
3 OEB Approved amounts are per EB-2016-0152, Ex. E2-1-2, Table 1, and approved in the Decision and Order, pp. 11-13.
4 Production Settlement Adjustment Amounts per OPG Settlement Proposal, Filed 20210716, Table 17 - 2022-2026 Settled Production Forecast (TWh), p. 25.

Numbers may not add due to rounding.

Table 1b
Comparison of Production Forecast - Combined Nuclear

Line No.	Business Unit	2025 OEB Approved	(c)-(a) Change	2025 Budget	(g)-(c) Change	2026 OEB Approved	(g)-(e) Change	2026 Budget	(i)-(g) Change	2027 Plan	(k)-(i) Change	2028 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Darlington NGS											
1	**TWh**	13.5	7.5	21.1	(0.0)	21.5	(0.4)	21.1	(2.4)	18.7	8.0	26.7
2	**Unit Capability Factor (%)**	68.2	26.0	94.2	(18.2)	89.4	(13.4)	76.0	(13.1)	62.9	25.7	88.6
3	**PO Days[1]**	268.0	(243.0)	25.0	261.7	59.1	227.6	286.7	226.0	512.7	(371.2)	141.5
4	**Refurb PO Days**	472.0	(107.0)	365.0	(260.0)	288.0	(183.0)	105.0	(105.0)	0.0	0.0	0.0
5	**FEPO Days**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	**FLR (%)**	6.4	(2.8)	3.6	(0.1)	4.3	(0.7)	3.5	(0.6)	2.9	(0.7)	2.2
7	**FLR Days Equivalent**	46.2	(7.6)	38.6	(0.9)	46.8	(9.1)	37.7	(10.4)	27.3	1.5	28.9
	Pickering NGS											
8	**TWh**	16.6	(0.8)	15.8	(4.4)	0.0	11.4	11.4	(11.4)	0.0	0.0	0.0
9	**Unit Capability Factor (%)**	93.2	(4.1)	89.1	(2.1)	0.0	87.1	87.1	(87.1)	0.0	0.0	0.0
10	**PO Days[2]**	35.0	75.3	110.3	0.5	0.0	110.8	110.8	(110.8)	0.0	0.0	0.0
11	**Refurb PO Days**	0.0	0.0	0.0	368.0	0.0	368.0	368.0	1,092.0	1,460.0	4.0	1,464.0
12	**FEPO Days**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	**FLR (%)**	3.5	0.0	3.5	(0.0)	0.0	3.5	3.5	(3.5)	0.0	0.0	0.0
14	**FLR Days Equivalent**	49.4	(2.1)	47.2	(12.9)	0.0	34.3	34.3	(34.3)	0.0	0.0	0.0
	OPG Nuclear Facilities Totals											
15	**Unit Capability Factor (%)**	79.7	12.3	92.0	(12.5)	89.4	(9.9)	79.5	(16.6)	62.9	25.7	88.6
16	**PO Days[1,2]**	303.0	(167.7)	135.3	262.2	59.1	338.4	397.5	115.2	512.7	(371.2)	141.5
17	**FEPO Days**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	**FLR (%)**	5.0	(1.4)	3.6	(0.0)	4.3	(0.8)	3.5	(0.6)	2.9	(0.7)	2.2
19	**FLR Days Equivalent**	95.6	(9.8)	85.8	(13.8)	46.8	25.2	72.0	(44.7)	27.3	1.5	28.9
20	**TWh before Adjustments**	30.2	6.7	36.9	(4.4)	21.5	10.9	32.5	(13.8)	18.7	8.0	26.7
21	**OEB/Settlement Adjustments[3]**	0.9	(0.9)	0.0	0.0	0.4	(0.4)	0.0	0.0	0.0	0.0	0.0
22	**TWh including Adjustments**	31.1	5.8	36.9	(4.4)	21.9	10.5	32.5	(13.8)	18.7	8.0	26.7
	DNNP Facilities											
23	**TWh**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	**Unit Capability Factor (%)**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25	**PO Days[2]**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
26	**FEPO Days**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	**FLR (%)**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	**FLR Days Equivalent**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	**Total TWh Including Adjustments**	31.1	5.8	36.9	(4.4)	21.9	10.5	32.5	(13.8)	18.7	8.0	26.7

Line No.	Business Unit	2028 Plan	(c)-(a) Change	2029 Plan	(e)-(c) Change	2030 Plan	(g)-(e) Change	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Darlington NGS							
30	**TWh**	26.7	(1.6)	25.1	1.8	26.8	0.3	27.1
31	**Unit Capability Factor (%)**	88.6	(5.1)	83.5	5.1	88.6	0.1	88.7
32	**PO Days[1]**	141.5	72.7	214.1	(74.9)	139.2	0.0	139.2
33	**Refurb PO Days**	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	**FEPO Days**	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	**FLR (%)**	2.2	(0.2)	2.0	(0.0)	2.0	0.0	2.0
36	**FLR Days Equivalent**	28.9	(4.0)	24.9	1.5	26.4	0.0	26.4
	Pickering NGS							
37	**TWh**	0.0	0.0	0.0	0.0	0.0	1.9	1.9
38	**Unit Capability Factor (%)**	0.0	0.0	0.0	0.0	0.0	67.0	67.0
39	**PO Days[2]**	0.0	0.0	0.0	0.0	0.0	55.0	55.0
40	**Refurb PO Days**	1,464.0	(4.0)	1,460.0	0.0	1,460.0	(230.0)	1,230.0
41	**FEPO Days**	0.0	0.0	0.0	0.0	0.0	0.0	0.0
42	**FLR (%)**	0.0	0.0	0.0	0.0	0.0	12.0	12.0
43	**FLR Days Equivalent**	0.0	0.0	0.0	0.0	0.0	21.0	21.0
	OPG Nuclear Facilities Totals							
44	**Unit Capability Factor (%)**	88.6	(5.1)	83.5	5.1	88.6	(2.8)	85.8
45	**PO Days[1,2]**	141.5	72.7	214.1	(74.9)	139.2	55.0	194.2
46	**FEPO Days**	0.0	0.0	0.0	0.0	0.0	0.0	0.0
47	**FLR (%)**	2.2	(0.2)	2.0	0.2	2.2	1.2	3.4
48	**FLR Days Equivalent**	28.9	(4.0)	24.9	1.5	26.4	21.0	47.4
49	**TWh**	26.7	(1.6)	25.1	1.8	26.8	2.1	28.9
	DNNP Facilities							
50	**TWh**	0.0	0.0	0.0	0.5	0.5	1.4	1.9
51	**Unit Capability Factor (%)**	0.0	0.0	0.0	88.0	88.0	(15.3)	72.7
52	**PO Days**	0.0	0.0	0.0	0.0	0.0	64.9	64.9
53	**FEPO Days**	0.0	0.0	0.0	0.0	0.0	0.0	0.0
54	**FLR (%)**	0.0	0.0	0.0	12.0	12.0	(0.6)	11.4
55	**FLR Days Equivalent**	0.0	0.0	0.0	9.1	9.1	25.2	34.3
56	**Total TWh Including Adjustments**	26.7	(1.6)	25.1	2.3	27.3	3.6	30.9

Notes:
1 PO days excludes planned outage days for units out of service during refurbishment.
2 PO days includes staggered shutdown days in 2026.
3 Production Settlement Adjustment Amounts per OPG Settlement Proposal, Filed 20210716, Table 17 - 2022-2026 Settled Production Forecast (TWh), p. 25.