BUSINESS PLANNING AND BENCHMARKING - REGULATED HYDROELECTRIC

1.0 PURPOSE

This evidence presents the business planning, performance measures, and benchmarking for OPG's regulated hydroelectric business and provides a summary of the regulated hydroelectric operating costs from OPG's 2025-2031 Business Plan (the "Plan") in support of the Application.

In accordance with the rate-setting proposal for the regulated hydroelectric facilities, as described in Ex. A1-3-2, forecast information for the test year (2027) is provided for all operating cost exhibits, and forecast information for the full forecast period (2027-2031) is provided for capital-related exhibits.

2.0 OVERVIEW

This Application is based on the Plan, which in respect of the regulated hydroelectric business, was prepared reflecting the business planning process outlined in Ex. A2-2-1 and Section 3.0 below. The Application reflects significant changes in OPG's regulated hydroelectric operations since the last rebasing in EB-2013-0321 and supports OPG's mandate to provide safe and reliable hydroelectric power in line with the energy objectives of the Province of Ontario as described in Ex. A2-2-1. Highlights of the Plan as it pertains to the regulated hydroelectric operations include:

- Increased capital investment necessary to sustain an aging fleet, with a focus on turbine-generator refurbishment projects (Section 3.2.1) and civil infrastructure projects (Sections 3.2.3.1, 3.2.4, and 3.2.5);
- Redevelopment of select regulated hydroelectric stations, including increasing forecasted production (Section 3.2.2);
- Strategic resource planning, including increased headcount (Section 3.3) and programmatic vendor contracts to effectively support a growing work program (Section 3.2.1); and
- A Renewable Generation Excellence Plan that focuses on enhancing safety, operational performance, and future readiness through targeted initiatives and ongoing improvements at the hydroelectric stations (Section 3.4.1).

Overall, the planned investments will support both near-term and longer-term energy supply objectives:

- Providing Ontario with a clean and reliable source of baseload and peaking electricity for both everyday energy needs and periods of high seasonal demand; and
- Ensuring supply adequacy and stability to support meeting Provincial demand forecasts, including during nuclear station refurbishments.

The Plan, as it relates to the regulated hydroelectric facilities, is discussed in Section 3.0 and includes a description of historical and planned Operations, Maintenance and Administration ("OM&A") and capital expenditures. OPG's regulated hydroelectric operations are carried out by the Company's Renewable Generation ("RG") organization, as further described in Ex. A1-4-2 and Ex. F1-2-1.

3.0 REGULATED HYDROELECTRIC BUSINESS PLAN

The Plan reflects, as it relates to the regulated hydroelectric facilities, increased OM&A and capital expenditures to continuously improve safety, uphold regulatory compliance, preserve aging assets, sustain the existing fleet capacity while increasing forecasted production where opportunity exits, and improve equipment reliability. The Plan was prepared as described in Ex. A2-2-1 and Section 3.1 below.

The Plan reflects a significant evolution in OPG's regulated hydroelectric business since EB-2013-0321, including organizational changes (Ex. F1-2-1) and increased capital investment. This is necessary to meet the objectives stated above, and to support meeting the overall projected growth in Ontario's net energy demand of 65% by 2050.[1] At the same time, while it continues to exhibit overall strong reliability and cost performance compared to peers, OPG's regulated hydroelectric fleet now has an average age of approximately 90 years (ranging from 2-127 years old). The Plan reflects the increased investment necessary to manage the risks, sustain these assets, and maintain reliable operations for the longer term.

[1] IESO, Annual Planning Outlook: 2026 Demand Forecasts & 2027 Demand Scenario, November 2025, p. 6.

3.1 Regulated Hydroelectric Business Planning Process

3.1.1 Gap-Based Business Planning Process

The business planning cycle for OPG's RG business is undertaken annually as part of the overall OPG business planning process (Ex. A2-2-1). This cycle is focused on establishing strategic direction and performance targets for the RG business, in alignment with OPG's enterprise-wide objectives, and identifying the initiatives and resources required to achieve these targets.

OPG uses a gap-based business planning process for the RG business which consists of the following steps:

- **Performance Review**: Process of comparing actual performance to the previously approved business plan in order to identify areas to sustain or improve performance.
- **Setting Strategic Direction**: Process of goal alignment by establishing the level of performance and targets to sustain performance or drive continuous improvement within the business planning period.
- **Gap Closure Planning**: Process of planning gap closure initiatives as required to achieve targeted performance. The strategic initiatives to support gap closures are highlighted in the RG Excellence Plan as discussed in Section 3.4.1.
- **Developing Detailed Business Plan:** Process where generation, financial, and resource plans are developed based on the approved corporate strategic direction, performance targets, priorities, and resources, ensuring integration with corporate business planning processes.
- **Performance Reporting**: Continuous performance management reporting to ensure effective monitoring and execution of the approved business plan with careful consideration of safety, environment, financial, operational, and project performance.

Once the detailed business plan is developed and approved, OPG tracks performance against targets on a scorecard.

3.1.2 Auditor General Value for Money Audit

During 2022, the Office of the Auditor General of Ontario ("OAGO") conducted a Value for Money audit of OPG's Management and Maintenance of Hydroelectric Generating Stations. The OAGO recognized OPG as a reliable provider of hydroelectric power to the province, highlighting further opportunities for improvement, including the importance in maintaining its hydroelectric assets given the forecasted increase in energy demand. The audit also outlined recommendations to enhance OPG's maintenance planning and management systems, most of which have now been fully implemented or substantially progressed and the resources for which are included in the Plan. In December 2024, the OAGO released a Follow-Up Report on its 2022 Value for Money Audit, and identified OPG as one of the three auditees, out of the total of 16 auditees, that made the most progress toward fully implementing the recommended actions.

3.2 Key Business Plan Focus Areas

The business plan expenditures reflect investments in the following key focus areas, discussed in Sections 3.2.1-3.2.6 below: turbine-generator overhaul and refurbishment projects, redevelopment projects, portfolio projects, the Sir Adam Beck 1 canal rehabilitation and the Abitibi Canyon GS concrete and sluiceway rehabilitation. Details on OPG's initiatives to explore expansion opportunities at its existing regulated hydroelectric stations are provided in Section 3.2.6.

3.2.1 Turbine-Generator Overhaul and Refurbishment Projects

While hydroelectric facilities enjoy operating lifespans that generally exceed other generating technologies, they require cyclical renewal to ensure continued optimal performance. With the age of OPG's regulated hydroelectric assets averaging 90 years, many degraded components are at or approaching end-of-life and require significant investment during the forecast period to ensure that the assets can continue to help meet the province's energy needs for future decades. The Plan reflects these important investments, which accounts for $2,193.6M of capital expenditures on refurbishment projects in the 2027-2031 forecast period. These investments are necessary to address the aging condition of the fleet and the need to sustain asset performance. Without this investment, the reliability and generating capacity of these assets will decline.

Overall, for the 53 regulated hydroelectric refurbishment projects that are expected to come into service during the 2027-2031 forecast period, OPG expects to sustain approximately 1,500 MW of the existing regulated hydroelectric fleet capacity and add an estimated incremental capacity of approximately 50 MW; further highlighting the importance of ensuring these assets meet the province's energy needs. This includes turbine-generator refurbishments at OPG's three largest hydroelectric generating stations (Sir Adam Beck 1 GS, Sir Adam Beck 2 GS,[2] and R.H. Saunders GS),[3] supported by recent announcements from the Province of Ontario and reaffirmed in the 2025 Integrated Energy Plan.[4]

Major work on turbine-generator units falls into two categories: overhauls and refurbishments. Overhaul projects are typically required every 25-30 years and involve significant OM&A maintenance activities to sustain reliable operations of the turbine-generator equipment and related systems. Refurbishment projects are capital investments aimed at extending useful life of the equipment. Components may be refurbished, replaced, or upgraded. Refurbishments may also include design improvements that increase forecasted production. The scope and timing of refurbishment work is unique for each generating unit at a station and typically depends on the age and condition of the component, refurbishment/overhaul history, and any additional work necessary to sustain reliability. The scope of an overhaul or refurbishment project typically consists of the following components:

- Main powertrain components of the generating unit, such as generator (rotor and stator) windings, field poles, generator shaft, thrust bearing, upper and lower guide bearings.
- Turbine runner, headcover, seals, embedded components, wicket gates, operating ring, servomotors, bushings and linkages, turbine bearing and stationary and rotational alignment.

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[2] Province of Ontario, News Release: *Ontario Refurbishing Hydroelectric Stations in Niagara*, April 16, 2024 <https://news.ontario.ca/en/release/1002338/ontario-supports-plan-to-safely-continue-operating-the-pickering-nuclear-generating-station>.
[3] Province of Ontario, News Release: *Ontario Refurbishing Hydroelectric Station in Cornwall*, May 10, 2024 <https://news.ontario.ca/en/release/1004572/ontario-refurbishing-hydroelectric-station-in-cornwall>.
[4] "Energy for Generations: Ontario's Integrated Plan to Power the Strongest Economy in the G7", Ministry of Energy and Mines, p.9, 40, 54.

- Minor generator auxiliary systems, such as turbovent, cooling water radiators and controls, and minor control and instrumentation changes.
- Civil work that may include scroll case, draft tube, and discharge ring.

The specific scope of work on a component will determine if it is categorized as an overhaul or refurbishment, in accordance with OPG's capitalization policy (see Ex. D4-1-1). For example, a runner weld repair is considered overhaul (OM&A) scope, while a runner replacement would be refurbishment (capital) scope. The refurbishment or overhaul outage is often used to perform additional work, such as upgrading generation control equipment (governors and exciters) and installing new equipment for technology modernization, including sensors for online monitoring and diagnostics.

Overhaul and refurbishment project funding and outage requirements are identified during RG's business planning cycle, and the projects are prioritized in accordance with overall asset management processes (as described in Ex. D2-1-1) based on defined criteria, including but not limited to asset condition, risk, and value. Project scheduling and timing requires coordination with external stakeholders (such as Hydro One and the IESO) to minimize production losses where possible, while considering geographical and seasonal constraints. Regional factors are also considered, such as resource availability, materials delivery time, installation, and commissioning requirements.

At the same time as OPG needs to undertake this work, the global demand for hydropower supply chains and contractors is expected to surpass the already high levels of generation capacity added over the past 20 years. This will put significant pressure on the hydropower industry and create a market constrained by limited supply capacity. To mitigate this anticipated risk and facilitate the execution of its refurbishment program, OPG completed a competitive process with qualified large hydroelectric Original Equipment Manufacturers ("OEM") and implemented the Renewable Generation Programmatic Collaboration Agreement ("RG PCA") strategic initiative. The RG PCA is aimed at securing OEM execution capacity by way of long-term collaboration agreements with two hydroelectric OEMs, GE Renewable Energy Canada Inc. ("GE") and Andritz

Hydro Canada Inc. This initiative secures the specialized resources and stability OPG requires to meet the forecasted refurbishment workload in the tightening market, as well as the benefits of unit-over-unit project efficiencies expected within or across facilities with similar characteristics. While the primary objective of the RG PCA initiative is to address the anticipated OEM capacity challenges, it will seek to leverage potential additional opportunities, such as:

- Early OEM engagement
- Optimal project solutions
- Increases to unit efficiency, output, or capacity (MW)
- Resource stability
- Cost optimization
- End-to-end system assessments
- Integration of lessons learned

One of the cornerstones of the RG PCA initiative is to facilitate early OEM engagement. Each OEM has been allocated a group of refurbishment projects for various stations and units, with assignments based on work continuity and geographical proximity (such as shared river systems) to support more consistent project execution and efficient use of resources. OPG and the OEMs will adopt a similar “OneTeam” approach used at the Darlington Refurbishment Program to facilitate collaboration in refurbishment performance.

For each refurbishment project, lessons learned are identified for the purpose of continuous improvement. In addition, lessons learned are shared through team collaboration, refurbishment forums, and the Refurbishment Oversight Committee. The application of these insights inform the planning and execution of upcoming refurbishment activities, supporting unit-over-unit improvements in efficiency and project performance.

Details of the regulated hydroelectric refurbishment projects are provided in Ex. D1-1-2, Section 3.2.1.

3.2.2 Station Redevelopment Projects

The primary goal of a redevelopment is to extend operations for stations where investment is necessary to address a population of deteriorated and otherwise end-of-life assets. This includes the replacement of a significant portion of the generating station equipment, which may also include the replacement of existing civil infrastructure (partial or full). For some redevelopment projects, there may be opportunities to add incremental generation capacity. Without these planned redevelopments, OPG would ultimately need to decommission[5] these stations.

In support of the 2025 Integrated Energy Plan,[6] OPG is redeveloping five regulated hydroelectric stations in the 2027-2031 forecast period: one currently in the development phase (Bingham Chute GS) and four currently in the execution phase (Kakabeka Falls GS, Matabitchuan GS, Coniston GS, and Stinson GS). Capital expenditures for these redevelopment projects are expected to total $911.0M, with an expenditure of $176.0M in the 2027-2031 forecast period. The first redeveloped Coniston GS unit is expected to come into service in late 2026. All of the remaining planned redevelopment projects are expected to come into service during the forecast period. These investments will extend the life of these facilities by an additional 80-90 years and sustain approximately 43 MW of the existing regulated hydroelectric fleet capacity and add an estimated incremental 13 MW of capacity. Further details on redevelopment projects are provided in Ex. D1-1-2, Section 3.2.2.

OPG is continuing to explore options for other small regulated hydroelectric assets that are nearing end of life, including possible redevelopment projects. Funding to support these preliminary assessments is captured in Project OM&A, as detailed in Ex. F1-3-1, Section 3.2.

[5] Ongoing costs to maintain site infrastructure and water control structures would still be required if the station was decommissioned.
[6] "Energy for Generations: Ontario's Integrated Plan to Power the Strongest Economy in the G7", Ministry of Energy and Mines, Chapter 2.

3.2.3 Portfolio Projects

OPG plans to invest $1,581.3M capital in the 2027-2031 forecast period, and $90.7M Project OM&A in the 2027 test year in regulated hydroelectric portfolio projects. Major categories of work for the portfolio in the period include investments in concrete and dam restoration and rehabilitation projects, regulatory commitments and contractual obligations (such as large infrastructure projects on joint works assets), and other portfolio projects including: electrical and protection and controls upgrades, cranes and lifting devices, and gates, which are further detailed below.

3.2.3.1 Concrete and Dam Restoration and Rehabilitation Projects

The business plan includes funding to address concrete deterioration through rehabilitation and restoration projects. Examples of such capital projects include Otto Holden GS Refurbish Stop Log Sluice Piers and Aguasabon Dam Rehabilitation. Further details on concrete rehabilitation capital projects are provided in Ex. D1-1-2.

Over time, civil structures deteriorate due to various environmental factors such as thermal expansion-contraction, water seepage, freeze-thaw damage, corrosion of reinforcements, and abrasion. An additional cause of deterioration is the unexpected expansion of concrete due to long-term chemical reactions, specifically Alkali Aggregate Reaction (“AAR”).[7] The presence of AAR in the concrete causes deterioration to occur more rapidly than would normally be experienced for the age of the infrastructure. This can disrupt the operation of sluicegates, affect the crucial alignment of generators in dams, and potentially lead to structural concrete cracking. Concrete structures are monitored and inspected regularly through equipment reliability, dam safety, or bridge inspection programs. Any discovered deficiencies or risks are reported and mitigated, as necessary, through maintenance or capital investments.

[7] AAR is a reaction between alkali hydroxides and certain concrete aggregates. This reaction causes the expansion of the altered aggregate, leading to accelerated concrete deterioration, spalling, and loss of strength.

Examples of OPG's stations and structures showing signs of AAR include the R.H. Saunders GS and Otto Holden GS (see Figure 1), Manitou Falls GS, Pine Portage GS, and Chat Falls GS. There is no cure for AAR; ongoing restoration, guided by engineering assessments and monitoring, is required. OPG has installed civil and mechanical instrumentation and continues to monitor generator air gaps, runner clearances, spillway gate and/or log operations and other potentially affected equipment to assess if remedial action is required.

In 2018, concrete restoration was completed at the Chats Falls GS to address AAR and freeze-thaw damage. At the R.H. Saunders GS, concrete growth has impacted the integrity of critical structural members and has also led to deformation of the concrete around the generating unit. This deformation impacts the runner clearances, an issue being addressed through the restoration program. To relieve AAR stress, slot cutting was performed to re-establish expansion joints in the concrete between the units, allowing for concrete expansion while minimizing impact to components. Slot cutting is completed before unit refurbishments to maximize refurbishment benefits. In addition to mitigating the impact on the generating units, OPG is undertaking modifications of impacted structural members and repairs to maintain the integrity of the powerhouse.

Figure 1 – AAR Illustrative Examples

Left: Spalling concrete and exposed rebar at Otto Holden GS. Right: Spalling and cracked concrete column at R.H. Saunders GS.

3.2.3.2 Regulatory Commitments and Contractual Obligations

OPG has regulatory and contractual obligations that form part of the work program and are included in the business plan. This includes dam and public safety obligations, environmental obligations with Fisheries and Oceans Canada ("DFO"), the Ministry of Environment, Conservation and Parks ("MECP") and the Ministry of Natural Resources ("MNR"), IESO requirements, and contractual obligations with partners through joint works agreements (such as New York Power Authority), as described in Ex. A1-4-2.

The 2019 amendments to the *Fisheries Act*[8] include prohibitions on killing fish by means other than fishing[9] and causing the harmful alteration, disruption or destruction of fish habitat.[10] As a result of these amendments, both existing and newly built, or redeveloped, hydroelectric stations are required to obtain authorizations from the DFO. This authorization requirement applies to all of OPG's regulated hydroelectric generating stations, and the authorization process involves studies, stakeholder engagement, Indigenous consultations, and long-term monitoring. Once

[8] *Fisheries Act*, R.S.C. 1985, c. F. 14, as amended by S.C. 2019, c. 14.
[9] *Ibid*., s. 34.3.
[10] *Ibid*., s. 35.

initiated, the authorization process for each station may take up to three years to successfully complete.

While OPG mitigates impacts on fish through compliance with Water Management Plans set by MNR or under agreements with the MECP for stations that have compliance requirements under an *Endangered Species Act* (Ontario), OPG will also pursue authorizations for stations under redevelopment. Additional applications for authorizations at existing stations are anticipated during the forecast period for a Base OM&A cost of $5.7M; this funding reflects the costs necessary to seek the authorizations. Although the DFO authorization conditions are currently unknown, they are expected to include construction or alteration of fish habitat and/or potential facility alterations. Investments to address DFO compliance activities in the 2027-2031 forecast period have been included in the unallocated portfolio (Ex. D1-1-2, Table 5b).

The American eel is considered "endangered" under current provincial legislation in Ontario.[11] Under Section 11.1 of O. Reg. 242/08 of the *Endangered Species Act, 2007*, OPG has a formal agreement with the MECP which establishes an implementation plan to minimize adverse effects on the American eel that includes examining potential options to improve passage for migrating eels at the R.H. Saunders GS. Additionally, a pilot project is planned for execution in 2027-2028 at the Iroquois Dam on the St. Lawrence River and, pending successful implementation and acceptance by the MECP, a full-scale design and deployment project has been included in the unallocated portfolio (Ex. D1-1-2, Table 5a). The American eel was also under consideration to be listed as a "threatened" species under the federal *Species at Risk Act*. On December 2, 2025, the Government of Canada announced that the American eel was not to be listed, and that the best way to conserve the species was to manage the species and its habitat under the *Fisheries Act* through "adaptive management approaches".[12] The DFO will continue to implement measures aimed at minimizing the negative impacts of habitat alteration and improving the species' migration passages. OPG will continue to monitor any DFO compliance activities, as specific

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[11] Ontario Regulation 230/08: *Species at Risk in Ontario List*, Schedule 2. (n.d.). Government of Ontario. <https://www.ontario.ca/laws/regulation/080230>

[12] Government of Canada, News Release: Government of Canada commits to adaptive management approach to conserve and protect American Eel, December 2, 2025. <Government of Canada commits to adaptive management approach to conserve and protect American Eel - Canada.ca>

adaptive management activities and/or actions have not yet been explicitly identified. This may result in additional activities at certain regulated facilities such as R.H. Saunders G.S.

As the potential cost or impact to OPG's hydroelectric operations resulting from existing or future regulations pertaining to the American eel are currently unknown (and therefore not included in the business plan), OPG proposes capturing any future costs associated with potential provincial and/or federal regulatory impacts in a new deferral account. Further details are discussed in Ex. H1-1-1, Section 7.1.2.

3.2.3.3 Other Portfolio Projects

The balance of the regulated hydroelectric portfolio projects primarily consists of the following categories of work:

- Electrical and protection and controls upgrades which generally includes AC and DC station service equipment, breaker and switchgear, transformer and battery replacements;
- Cranes and lifting devices, which generally includes replacement of powerhouse cranes, many of which are original to the stations and required ahead of the turbine-generator refurbishment projects to mitigate the risk of delays to these extensive programs. This also includes head gate and sluice gate hoists and superstructures that are essential for protecting assets and maintaining proper water levels around dams;
- Gates, which generally include sluice gates, head gates, sectional gates and trashracks;
- Sustaining building/infrastructure work on aging powerhouses to ensure their integrity and ability to house the generating equipment, which generally includes roof replacements and structural work; and
- Other sustaining investments, such as work on non-concrete dams, surge tanks, and public safety booms, network upgrades, and the Northwest Operations Work Centre.

3.2.3.4 Unallocated Projects

OPG employs a portfolio management approach to capital investments for the nuclear business and for digital technology projects, which includes an unallocated portfolio based on the candidate projects identified through a prioritization process during business planning. The RG business has now aligned the management of its capital and OM&A project portfolios with the rest of the Company, as described in Ex. D2-1-1. This includes the use of unallocated portfolio funding in the Plan, as approved by OPG's Board of Directors, based on the expectation of future projects but with the recognition that they have not yet been fully scoped or approved. The alignment of the RG business to this approach in part reflects the more extensive capital program as well as a longer business planning horizon of up to seven years, compared to EB-2013-0321. Similar to OPG's other lines of business, the proportion of a project portfolio that is unallocated naturally tends to increase further into the forecast period, as later projects have yet to complete scoping and engineering required for a business case summary ("BCS") to be developed and approved. As discussed in Ex. D2-1-1, RG reviews the project portfolios as part of the business planning process and prioritizes projects for execution.

3.2.4 Sir Adam Beck 1 GS Canal Rehabilitation

The business plan includes funding in 2027-2029 for the first two phases of major work on the 100+ year-old canal that supplies water from the Welland and Niagara Rivers to the Sir Adam Beck generating complex, passing through the City of Niagara Falls. The canal has experienced canal wall deterioration, debris accumulation, and weed growth causing a reduction in flow to the Sir Adam Beck generating complex. The investment will ensure the capability to isolate and drain the canal, which will facilitate future rehabilitation work on the canal liner and associated structures. Isolation capability is also required to enable maintenance on non-OPG structures along the canal, such as the Highway 420 culvert. Further details on the SAB1 Canal Rehabilitation are provided in Ex. D1-1-2, Section 3.2.4.

3.2.5 Abitibi Canyon GS Concrete and Sluiceway Rehabilitation

The business plan includes funding for the rehabilitation of the Abitibi Canyon GS concrete structures and sluiceway in Northeastern Ontario. Concrete degradation on the upstream and downstream faces includes surface scaling, spalling, cracking, staining and delamination. All exposed downstream and upstream faces are affected; therefore, isolated repairs are no longer feasible for maintaining the long-term integrity of the structures. These investments include funding to address concrete deterioration, improve sluiceway and superstructure equipment reliability, and addressing equipment risks at this 92-year-old, 349 MW station. The higher expenditures in later years of the plan account for the anticipated size and complexity of these works, including dam repairs and upstream concrete rehabilitation, the specific scope for which is being developed.

3.2.6 Regulated Hydroelectric Expansion Opportunities

In keeping with the Province's 2023 Powering Ontario's Growth report[13] and the 2025 Integrated Energy Plan,[14] OPG continues to identify opportunities to increase generation at its existing regulated hydroelectric facilities. One such initiative is the proposed addition of a new 33 MW generating unit at the existing Chats Falls GS. This work is currently in the initiation phase, following an initial evaluation which determined there is sufficient excess inflow in the Ottawa River for the addition of a generating unit. By leveraging the existing powerhouse and transmission infrastructure, the project is expected to be more economical and the permitting requirements more streamlined than a new hydroelectric station. Subject to completing the necessary planning, the current forecast assumes that the project commences execution in 2028 and is completed beyond the 2027-2031 forecast period. Chats Falls GS is jointly owned by OPG and Hydro-Québec and its costs are shared between the two organizations in accordance with the OPG/Hydro-Québec O&M Agreement (described in Ex. A1-4-2). It is anticipated that project costs and future revenues will be shared via the existing partnership by both organizations. There are no forecast in-service amounts for this project during the 2027-2031 period.

3.3 Staffing Levels to Support Key Business Plan Focus Areas

Renewable Generation forecasts a full-time equivalent ("FTE") workforce of approximately 1,520 in 2027 that is expected to remain stable throughout the 2027-2031 forecast period. FTEs have increased consistently over the historical period, reflecting the addition of personnel across project management, operations, maintenance, engineering and training functions to effectively support capital and OM&A work programs, strategic initiatives, continued safe and reliable operation of the facilities and major capital projects ongoing over the period, such as the Sir Adam Beck 1 GS

[13] Province of Ontario, Powering Ontario's Growth: Ontario's Plan for a Clean Energy Future, July 7, 2023.
[14] "Energy for Generations: Ontario's Integrated Plan to Power the Strongest Economy in the G7", Ministry of Energy and Mines, p.56.

and Sir Adam Beck 2 GS refurbishment programs. The details of the FTEs are shown in Ex. F1-1-1, Table 2b.

3.4 Continuous Improvement Initiatives

3.4.1 RG Excellence Plan

The RG Excellence Plan sets the strategic initiatives and improvement plans, reviewed annually, aimed at enhancing safety, operational performance, and future readiness across the RG organization. The plan is structured around three main categories: People, Plant, and Future, each with specific goals, key focus areas, and measures of success.

In the **People category**, the primary goal is to drive a strong safety culture. Key focus areas include promoting clear and simple safety messaging, working with vendor partners to enhance safety. Success will be measured through safety incident rates and engagement results. To address the changing workforce supporting the key business plan focus areas described in Section 3.2, RG is focused on developing and sustaining employee proficiency including a training program to develop new leaders within the business. The primary focus of this program is to reinforce key leadership behaviours and skills, accelerating their development as leaders in the organization to influence the workforce.

The **Plant category** aims to maximize equipment performance, with key focus areas such as advancing the equipment reliability program and strengthening asset planning consistency. Success will be gauged through plant reliability metrics, including Availability Factor, discussed in Section 4.3 below. Another goal within this category is to strengthen work planning and execution, focusing on streamlining maintenance strategies and work management practices in support of the Enterprise Asset Management ("EAM") system modernization (described in Ex. D3-1-1, Section 2.1.2). Measures of success for this goal include work management performance and project milestone adherence.

Lastly, the **Future category** seeks to facilitate future development by building training programs, ensuring a proficient workforce through succession planning and knowledge sharing, and supports the EAM modernization efforts. Success measures will include training completion metrics and succession planning readiness. Further details on RG's staffing and training initiatives are provided in Ex. F1-2-1.

3.4.2 Technology Based Improvements

Renewable Generation has also implemented several initiatives aimed at opportunities to use technology to drive efficiency and improvement, in keeping with OPG's digital strategy (as described in Ex. D3-1-1). Some of these initiatives include:

1. Improving equipment reliability by progressing the installation of new sensors on key equipment and components, while also leveraging existing instrumentation. By using both new and current data sources, OPG is able to detect and address equipment issues earlier, which is one of the enablers from shifting from traditional time-based maintenance programs to more advanced condition-based maintenance strategies. As additional sensors are installed and more data is gathered and trended, analytics and artificial intelligence/machine learning models (built from historical and real-time information) are expected to further improve overall asset performance.
2. Reviewing work management and preventative maintenance strategies across the fleet to drive consistency, where practical and appropriate, and also to improve quantity and quality of data needed to ensure integrated processes and reliable data across the fleet.
3. Implementing PowerBI reporting, including transitioning manual metrics, where possible, into automated reporting. Online reporting dashboards provide managers with the ability to see up-to-date operational and cost information to facilitate timely resource and cost-management decision-making.

4.0 REGULATED HYDROELECTRIC KEY PERFORMANCE METRICS

OPG measures the performance of its regulated hydroelectric operations across four main outcomes: Safety, Environment, Reliability, and Cost Effectiveness. The measures of performance for each outcome are described in Sections 4.1-4.4 below, along with the historical performance and performance targets for the bridge (2025-2026) and forecast (2027-2031) periods, where applicable.

4.1 Safety

Total Recordable Injury Frequency ("TRIF") is defined as the number of injuries that result in fatalities, lost time, restricted work or medical treatment per 200,000 hours worked. Electricity Canada ("EC") is OPG's main benchmark for evaluating safety performance within Canada. EC implemented a change from All Injury Rate ("AIR") to TRIF as TRIF is more widely accepted and utilized by most industries outside of the electrical utility sector. In 2018, OPG replaced AIR with TRIF as a measure for evaluating health and safety performance to align with EC. Chart 1 describes RG's historical All Injury Rate/TRIF 2016-2024 performance. Chart 2 describes the 2025-2031 forecasted TRIF performance targets.[15]

Chart 1 – Renewable Generation All Injury Rate / Total Recordable Injury Frequency (2016-2024 Actuals)

		2016	2017	2018	2019	2020	2021	2022	2023	2024
All Injury Rate/Total Recordable Injury Frequency	Actual	1.82	2.05	1.68	1.32	1.21	1.02	1.56	0.46	0.77
	Target	1.32	1.23	1.23	1.21	1.21	1.21	1.21	1.20	1.11

Note: Low AIR/TRIF is good.

There was a notable improvement in safety performance, particularly in 2023 (0.46) and 2024 (0.77), which were RG's best and second-best performance years since OPG's inception. The general downward trend in TRIF over the years reflects successful safety initiatives and efforts to reduce injuries, including increasing supervisory presence in the field, safe work planning, expanding corrective action tracking and targeting specific areas (such as hand injuries) that have historically led to recordable events.

[15] TRIF performance is measured at the RG fleet level; as such, values include regulated hydroelectric and unregulated station performance.

Chart 2 – Renewable Generation Total Recordable Injury Frequency (2025-2031 Targets)

		2025	2026	2027	2028	2029	2030	2031
Total Recordable Injury Frequency	Target	1.05	1.00	0.95	0.90	0.85	0.80	0.75

Note: Low AIR/TRIF is good.

OPG is committed to safety, as demonstrated by its progressively lower TRIF targets. However, the expansion of the work program across RG introduces greater operational complexity, a larger workforce, and a broader range of activities, all of which present additional challenges to sustaining and advancing safety performance. OPG remains dedicated to achieving its ambitious TRIF targets through strengthened safety initiatives. To further support continuous improvement, the RG Excellence Plan (Section 3.4.1) includes initiatives to further strengthen safe work planning, pre-job briefing skills, and tailboard best practices.

4.2 Environment

Renewable Generation has historically utilized an Environmental Performance Index ("EPI") to assess the environmental performance of its fleet.[16] EPI is a composite, weighted index that incorporates multiple measures, including the number of environmental spills, regulatory infractions, and the implementation of other environmental initiatives such as the Polychlorinated Biphenyl ("PCB") equipment removal program. Results also account for third-party spills and infractions in instances where OPG is designated as Constructor.[17] Chart 3 provides a summary of the historical EPI performance for all of OPG's hydroelectric facilities.

Chart 3 – Renewable Generation Historic Environmental Performance Index (%, 2016-2024 Actuals)

		2016	2017	2018	2019	2020	2021	2022	2023	2024
Environmental Performance Index (%)	Actual	100	98	96	100	100	83	100	94	99
	Target	80	80	80	80	80	80	80	80	80

Note: High EPI is good.

[16] Environmental performance is measured at the RG fleet level; as such, targets and values include regulated hydroelectric and unregulated station performance.

[17] Role of Constructor is defined under the *Ontario Occupational Health and Safety Act* and administered by the Ministry of Labour, Immigration, Training and Skills Development, previously known as the Ministry of Labour.

OPG's regulated hydroelectric facilities have consistently demonstrated strong environmental performance, as reflected in the EPI results. In 2021, while EPI remained above target (actual 83 versus target of 80), a temporary decrease was observed due to an increase in spills and infractions. In response to this decline, RG successfully implemented corrective actions and performance quickly improved. Renewable Generation implements robust programs to prevent category A or B spills, has maintained an ISO 14001-certified Environmental Management System since 2020, and tracked and removed all known PCB-containing equipment as per legislated requirements.[18] In addition to the EPI calculation, OPG further demonstrates its commitment to the environment through key biodiversity initiatives. The Wildlife Habitat Council has recognized the Niagara Region, the R.H. Saunders GS, and the hydroelectric facilities along the Ottawa/Madawaska River for their various biodiversity programs.

The removal of PCB-containing equipment was completed in 2025. As a result, the composite weightings previously applied to the EPI metric will no longer apply. Beginning in 2026, RG is revising its environmental performance metric to track and report the number of spills and regulatory infractions under a new measure, Total Recordable Environmental Events ("TREE"). As OPG has historically tracked annual spills and infractions as part of the EPI metric, historical TREE values can be back-cast to trend performance; these values are provided in Chart 4. From 2016 to 2024, TREE performance was consistently better than target, with the number of spills and infractions lower than the established thresholds, even as targets became more stringent over the years.

Chart 4 – Total Recordable Environmental Events (2016-2024 Actuals)

		2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Recordable Environmental Events	Actual	11	4	9	5	8	11	8	7	7
	Target	18	17	15	14	14	14	14	13	12

Note: Low TREE is good.

[18] Government of Canada. (2008). *PCB Regulations (SOR/2008-273)*. *Canadian Environmental Protection Act, 1999*. https://laws-lois.justice.gc.ca/eng/regulations/SOR-2008-273/index.htm

The 2025 TREE target is set at 11, and for 2026 through 2031 the TREE target is set, and will be maintained, at 10 annually as shown in Chart 5. This recognizes that, as the implementation of the work program described in this exhibit expands across RG, achieving this target will become increasingly challenging. OPG remains committed to maintaining strong environmental performance despite the anticipated growth in activity.

Chart 5 – Total Recordable Environmental Events (2025-2031 Targets)

		2025	2026	2027	2028	2029	2030	2031
Total Recordable Environmental Events	Target	11	10	10	10	10	10	10

Note: Low TREE is good.

4.3 Reliability

Reliability performance is assessed using two metrics, Availability Factor (“Availability”) and Equivalent Forced Outage Rate (“EFOR”). Historical performance for the period 2016-2024 as well as business plan targets for 2025-2031 are outlined below. Both Availability (Section 4.3.1) and EFOR (Section 4.3.2) are calculated on a weighted basis, using each regulated hydroelectric unit’s Maximum Continuous Rating (“MCR”).[19] The EFOR metric, in particular, is influenced by the number of hours a unit operates.

Consequently, the overall reliability performance of the regulated hydroelectric fleet is primarily driven by 12 stations with both high MCR and a five-year average generation of greater than 500GWh. Together, these 12 stations account for approximately 87% of all regulated hydroelectric generation. Given their substantial influence on fleet-wide results, the historical performance and targets of these 12 stations are highlighted in Charts 6-9, alongside the performance and targets of each Region and the overall regulated hydroelectric fleet.

[19] MCR is the maximum electrical power output that can be continuously generated, provided adequate inflow is available. The unit is assumed to be operating at unity power factor and at the indicated reference gross head. MCR observes generator and turbine limitations.

4.3.1 Availability

Availability is the percentage of a given operating period (typically 8,760 hours in a year) in which a generating unit is available without any outages. This metric does not account for the availability of water and is therefore independent of hydrological constraints.[20] Unit hours that are not spent in outage states are weighted by the respective unit's MCR. Outages caused by external factors such as severe weather, fish spawning, active wildfires, and Hydro One equipment outages are not considered. Chart 6 presents historical and target Availability performance for the years 2016-2024.

Chart 6 – Regulated Hydroelectric Historic Availability (%, 2016-2024)

Station	Station Age		2016	2017	2018	2019	2020	2021	2022	2023	2024
DeCew Falls 2 GS	81	Actual	88.9%	45.5%	47.6%	61.0%	93.4%	93.7%	96.1%	78.2%	54.5%
		Target	85.3%	45.2%	84.6%	94.2%	93.8%	96.2%	96.9%	82.6%	67.1%
Sir Adam Beck 1 GS	103	Actual	73.2%	78.0%	91.1%	81.6%	92.7%	88.1%	94.1%	92.8%	93.2%
		Target	82.3%	81.1%	88.1%	84.4%	86.0%	75.0%	81.7%	86.6%	92.2%
Sir Adam Beck 2 GS	71	Actual	95.2%	96.3%	95.6%	93.5%	96.0%	96.4%	94.7%	94.6%	95.8%
		Target	93.8%	92.2%	95.2%	97.0%	96.6%	95.8%	92.1%	89.7%	95.4%
Niagara Region (5 Stations)	**90 (average)**	Actual	84.7%	85.8%	88.4%	86.2%	91.7%	91.2%	91.8%	90.0%	89.6%
		Target	85.4%	84.4%	91.4%	91.4%	92.7%	90.3%	88.5%	87.2%	91.9%
Cameron Falls GS	105	Actual	96.2%	97.0%	98.9%	79.9%	99.4%	89.0%	97.7%	96.3%	78.8%
		Target	97.1%	92.4%	89.4%	90.3%	94.8%	90.0%	97.5%	91.2%	82.6%
Pine Portage GS	75	Actual	94.9%	96.4%	96.0%	99.0%	86.0%	94.3%	95.9%	91.4%	88.0%
		Target	95.1%	95.2%	91.7%	97.8%	88.2%	92.9%	98.3%	91.4%	97.2%
Western Region (27 Stations)	**95 (average)**	Actual	92.3%	87.6%	87.6%	90.1%	88.0%	80.3%	88.3%	84.3%	85.3%
		Target	92.2%	90.2%	89.0%	90.7%	83.5%	84.6%	92.2%	87.2%	91.7%
Abitibi Canyon GS	92	Actual	92.4%	96.4%	86.5%	91.9%	71.5%	94.2%	71.0%	62.1%	71.4%
		Target	90.5%	93.4%	90.2%	85.2%	78.1%	75.3%	74.6%	68.4%	64.1%
Chats Falls GS	94	Actual	88.0%	87.8%	89.7%	95.3%	92.9%	90.5%	79.7%	87.4%	86.7%
		Target	90.4%	87.3%	87.4%	91.4%	88.9%	89.1%	95.2%	93.6%	89.4%
Chenaux GS	75	Actual	93.2%	90.6%	81.6%	80.0%	97.9%	73.1%	81.5%	80.5%	82.4%
		Target	90.2%	91.4%	86.3%	88.2%	89.7%	87.3%	93.6%	89.1%	84.4%
Des Joachims GS	75	Actual	90.6%	90.1%	78.3%	78.5%	79.4%	78.1%	81.7%	82.3%	90.0%
		Target	91.8%	90.8%	86.9%	80.9%	77.2%	77.6%	68.7%	83.8%	81.7%
Otter Rapids GS	64	Actual	97.3%	95.5%	90.2%	94.2%	91.8%	90.7%	93.7%	88.9%	80.8%
		Target	93.0%	93.0%	88.7%	85.9%	92.8%	91.5%	93.1%	83.5%	72.9%
Otto Holden GS	73	Actual	88.8%	90.1%	76.5%	77.4%	76.9%	80.8%	76.8%	80.0%	87.1%
		Target	89.6%	88.3%	95.1%	73.5%	70.5%	66.6%	59.9%	80.5%	81.2%
R.H. Saunders GS	67	Actual	90.8%	92.8%	94.5%	89.0%	95.5%	92.4%	89.4%	85.6%	82.7%
		Target	91.0%	90.2%	91.3%	85.0%	90.5%	92.5%	89.2%	91.3%	85.5%
Eastern Region (22 Stations)	**83 (average)**	Actual	91.1%	89.6%	84.0%	86.1%	87.2%	88.3%	85.0%	82.4%	82.1%
		Target	89.1%	88.5%	87.7%	85.1%	84.3%	83.9%	82.6%	85.9%	82.8%
All 54 Regulated Hydroelectric Stations	**90 (average)**	Actual	89.0%	88.0%	86.0%	86.6%	88.8%	88.4%	87.8%	85.4%	85.2%
		Target	88.1%	87.3%	89.2%	88.0%	87.3%	86.2%	85.8%	86.6%	87.1%

Note: High Availability is good.

[20] Hydroelectric generation is intrinsically linked to the amount of water in reservoirs or rivers as this determines the potential for electricity generation. If water levels are low or flow rates are insufficient, a station may not be able to generate power, even if it is technically available in terms of equipment.

Overall Regulated Hydroelectric Performance

When analyzing trends in Availability, it is important to distinguish whether unavailability is driven by planned or forced outages, as each factor has different implications for operational reliability and asset management. Unavailability across the regulated hydroelectric fleet is consistently attributed more to planned activities than forced outage events.

Between 2016-2024, approximately 70% of total unavailability was attributable to planned outages, demonstrating that the majority of unavailability was anticipated and proactively managed, rather than resulting from unexpected equipment failures. The regional distribution of weighted planned outage hours over this period was as follows: Eastern Region accounted for 61%, Niagara Region 28%, and Western Region 11% of the total planned outage-related unavailability. The remaining 30% of unavailability during this period was attributable to forced outages. Notably, forced outages peaked in 2019, primarily driven by large stations such as R.H. Saunders GS and Sir Adam Beck 1 GS.

Forecasted Availability Targets

Chart 7 provides the annual Availability targets for the 2025-2031 period. Availability targets are directly informed by the forecasted multi-year outage plan and historical forced outage and operation hours. As discussed earlier, there is an increased number of maintenance and refurbishment projects planned during the forecast period to address aging infrastructure and to sustain long-term reliability. These planned outages are essential for proactively managing asset health and minimizing the risk of forced outages in the future. As a result, the forecasted Availability targets have been adjusted to reflect the expected impact of these necessary planned outages. With this approach, performance metrics remain transparent and achievable, given the known scope of work. While this results in lower short-term Availability targets, it represents a deliberate strategy to support the long-term sustainability and reliability of the regulated hydroelectric fleet. OPG expects to return to higher Availability levels once this critical period of asset renewal is complete.

Fleet annual targets remain above the five-year (2019-2023) historical median industry benchmark of 82.6% as referenced in Section 5.2. Additionally, the RG Excellence Plan (Section 3.4.1) aims to sustain Availability by enhancing outage planning processes and shortening unit-over-unit refurbishment outages, where possible.

Chart 7 – Regulated Hydroelectric Availability (%, 2025-2031 Targets)

Station	Station Age	2025	2026	2027	2028	2029	2030	2031
DeCew Falls 2 GS	81	94.1	90.9	96.0	94.0	95.7	67.0	76.3
Sir Adam Beck 1 GS	103	86.5	84.4	83.1	85.3	84.6	88.7	94.2
Sir Adam Beck 2 GS	71	94.8	95.2	84.4	83.9	83.5	83.8	83.9
Niagara Region (5 Stations)	**90 (average)**	**89.9**	**90.8**	**84.3**	**83.8**	**83.4**	**82.8**	**84.1**
Cameron Falls GS	105	84.3	79.3	97.0	93.7	95.1	92.0	98.2
Pine Portage GS	75	92.3	99.1	93.9	97.6	72.7	98.5	78.6
Western Region (27 Stations)	**95 (average)**	**87.9**	**89.3**	**84.0**	**81.7**	**85.1**	**89.8**	**83.2**
Abitibi Canyon GS	92	80.5	93.1	90.9	87.0	89.4	82.0	75.2
Chats Falls GS	94	90.3	91.8	87.1	84.9	84.4	85.2	94.3
Chenaux GS	75	83.5	89.1	89.7	82.8	79.6	79.3	80.9
Des Joachims GS	75	94.7	82.5	83.9	90.3	91.2	95.0	89.8
Otter Rapids GS	64	71.2	72.8	71.7	62.4	81.6	82.0	82.3
Otto Holden GS	73	83.8	81.2	75.0	78.7	80.2	75.8	82.8
R.H. Saunders GS	67	84.1	87.6	85.7	84.2	84.3	79.7	82.0
Eastern Region (22 Stations)	**83 (average)**	**85.7**	**84.7**	**83.4**	**84**	**85.9**	**84.4**	**83.5**
All 54 Regulated Hydroelectric Stations	**90 (average)**	**87.5**	**87.4**	**83.8**	**83.7**	**84.9**	**84.4**	**83.7**

Note: High Availability is good.

4.3.2 Equivalent Forced Outage Rate

EFOR is an indicator of generating unit reliability measured by the ratio of time the unit was forced out-of-service (completely or partially) to the total time the unit was operating and forced out-of-service (completely or partially). Unit hours are weighted by MCR.

Increases to planned outage hours or states when the unit is available but not operating will reduce the total potential operating hours, thereby increasing the relative impact of any forced outages on the metric. This relationship is a significant consideration when interpreting reliability performance data. Additionally, a forced outage or derate[21] does not always result in a loss of electricity generation as water may not be available. In other instances, alternative units at the same station may be dispatched to maintain production.

Chart 8 presents EFOR performance over 2016-2024 for the aggregate of the 54 regulated hydroelectric generating stations, as well as each Region. Chart 8 also highlights the performance of the 12 highest generating stations because of their substantial influence on fleet-wide results.

Chart 8 – Regulated Hydroelectric Historical EFOR (%, 2016-2024)

Station	Station Age		2016	2017	2018	2019	2020	2021	2022	2023	2024
DeCew Falls 2 GS	81	Actual	0.3%	0.5%	0.5%	11.3%	3.6%	5.3%	1.7%	2.0%	1.0%
		Target	2.5%	2.1%	1.7%	1.8%	1.6%	1.6%	1.9%	2.2%	1.8%
Sir Adam Beck 1 GS	103	Actual	8.6%	6.4%	0.4%	15.7%	4.7%	2.6%	0.8%	0.7%	1.6%
		Target	3.5%	3.2%	3.6%	4.1%	3.7%	3.9%	4.0%	3.3%	3.3%
Sir Adam Beck 2 GS	71	Actual	0.6%	0.2%	2.0%	2.9%	2.2%	1.0%	2.4%	0.4%	1.3%
		Target	0.4%	0.4%	0.4%	0.4%	0.4%	0.6%	0.8%	0.9%	0.9%
Niagara Region (5 Stations)	**90 (average)**	**Actual**	**2.1%**	**2.5%**	**2.9%**	**8.4%**	**5.1%**	**4.6%**	**4.6%**	**3.5%**	**4.2%**
		Target	**1.3%**	**1.2%**	**1.3%**	**1.4%**	**1.4%**	**1.9%**	**2.3%**	**2.5%**	**2.5%**
Cameron Falls GS	105	Actual	0.2%	0.3%	0.5%	1.0%	0.4%	3.5%	0.1%	0.5%	3.0%
		Target	0.9%	0.7%	0.6%	0.8%	0.9%	0.9%	0.5%	0.5%	0.5%
Pine Portage GS	75	Actual	1.3%	2.6%	0.8%	0.4%	0.2%	0.5%	0.5%	0.4%	14.0%
		Target	0.8%	0.6%	0.7%	1.2%	1.4%	1.3%	0.7%	0.6%	0.6%
Western Region (27 Stations)	**95 (average)**	**Actual**	**2.1%**	**6.5%**	**4.0%**	**2.7%**	**4.2%**	**7.1%**	**4.9%**	**2.3%**	**10.0%**
		Target	**1.8%**	**1.8%**	**2.0%**	**2.5%**	**2.5%**	**2.9%**	**2.0%**	**2.4%**	**2.4%**
Abitibi Canyon GS	92	Actual	1.4%	0.4%	8.6%	1.1%	7.3%	3.1%	2.7%	1.1%	2.1%
		Target	3.1%	3.0%	2.8%	2.4%	2.4%	1.8%	2.4%	2.4%	2.4%
Chats Falls GS	94	Actual	4.1%	3.3%	1.8%	0.9%	1.2%	1.4%	1.5%	0.4%	0.5%
		Target	1.1%	1.1%	1.6%	1.6%	1.7%	1.6%	1.6%	1.6%	1.6%
Chenaux GS	75	Actual	3.2%	0.5%	3.0%	2.8%	0.7%	0.6%	2.2%	2.1%	0.6%
		Target	0.4%	0.7%	1.1%	0.9%	1.0%	1.7%	1.7%	1.6%	1.6%
Des Joachims GS	75	Actual	1.9%	1.3%	0.2%	0.5%	5.1%	0.8%	0.6%	1.7%	0.2%
		Target	0.7%	0.8%	1.0%	0.9%	1.0%	1.2%	1.7%	1.5%	1.4%
Otter Rapids GS	64	Actual	0.5%	0.3%	0.4%	2.1%	2.7%	6.1%	2.9%	3.1%	2.9%
		Target	3.9%	3.7%	3.2%	2.8%	2.8%	1.7%	1.7%	2.1%	2.0%
Otto Holden GS	73	Actual	1.9%	2.9%	3.3%	3.5%	10.0%	2.8%	1.0%	1.0%	0.8%
		Target	0.4%	0.5%	0.7%	0.7%	0.7%	1.7%	2.0%	2.1%	2.1%
R.H. Saunders GS	67	Actual	4.4%	4.6%	1.2%	9.8%	2.0%	0.4%	5.1%	3.5%	3.2%
		Target	0.4%	0.4%	0.6%	0.9%	1.0%	1.9%	2.1%	2.2%	2.2%
Eastern Region (22 Stations)	**83 (average)**	**Actual**	**2.7%**	**3.2%**	**5.2%**	**6.1%**	**6.5%**	**1.8%**	**3.6%**	**2.6%**	**5.6%**
		Target	**1.9%**	**2.0%**	**2.0%**	**2.1%**	**2.1%**	**2.6%**	**3.1%**	**3.0%**	**3.0%**
All 54 Regulated Hydroelectric Facilities	**90 (average)**	**Actual**	**2.4%**	**3.3%**	**4.2%**	**6.7%**	**5.7%**	**3.5%**	**4.1%**	**2.9%**	**5.5%**
		Target	**1.6%**	**1.7%**	**1.7%**	**1.8%**	**1.8%**	**2.3%**	**2.7%**	**2.6%**	**2.7%**

Note: Low EFOR is good.

[21] A derate is a reduction of a generating unit's capacity. The generating unit can run but cannot run at MCR. Derates can be planned or unplanned.

Overall Regulated Hydroelectric EFOR Performance

The overall fleet EFOR performance fluctuated during the 2016-2024 period, ranging from 2.4% to 6.7% and often exceeding targets, which have remained consistently lower (1.6%-2.7%), reflecting higher-than-expected forced outages at larger capacity stations, especially in 2019, 2020, and 2024. Over the 2016-2024 historical period, Eastern Region accounted for 46% of the total weighted forced outage hours, primarily due to forced outages at R.H. Saunders GS. Niagara Region represented 43% of forced outage hours, largely attributed to Sir Adam Beck Pump GS. Western Region contributed the remining 11% of forced outage hours, with Manitou Falls GS being the primary contributor within the Region.

EFOR performance of the largest capacity stations, Sir Adam Beck 1 GS, Sir Adam Beck 2 GS, R.H. Saunders GS, and Des Joachims GS, has remained generally stable over the historical period. Sir Adam Beck 1 GS and R.H. Saunders GS experienced challenges in 2019, contributing to a notable fleet-wide increase in EFOR that year. R.H. Saunders GS also experienced challenges in 2022 with some improvements observed in 2023 and 2024.

Forecasted EFOR Targets

Target setting for EFOR is conducted through a review of historical performance data,[22] including forced outage hours, in conjunction with the forecasted multi-year outage plan. Historical EFOR data specific to each station is used to project the expected impact of forced outage hours. Historical available but not operating hours specific to each station is used to project the impact of such hours on the estimated operating hours. The forecasted outage plan for each station is incorporated to account for the influence of planned outages on estimated operating hours. Operating hours are estimated using the planned outage schedule, projected forced outage hours, and available but not operating hours. These estimated operating hours provide the foundation for establishing EFOR performance targets, as presented in Chart 9.

[22] To set EFOR targets, OPG reviews the past 10 years of historical data for each station, such as EFOR, available but not operating hours, and forced outage hours. The highest and lowest annual values are excluded, and the average is calculated using the remaining eight years. This approach helps to set targets that reflect typical performance while minimizing the impact of unusual years.

The EFOR targets for the 2025-2031 period, ranging from 3.2% to 3.6%, are higher than the historical period, reflecting the anticipated increase in both planned outages and forced outage hours resulting from the condition of aging equipment across the regulated hydroelectric fleet. As many units approach refurbishment and overhaul milestones, a higher incidence of equipment-related outages is expected, which will reduce overall operating hours. In addition to accounting for the expected increase in planned outages, the elevated targets are intended to account for these forecasted equipment-related challenges, so that performance expectations remain realistic and aligned with the current state of asset health and the planned work program schedule.

Despite the above challenges, the regulated hydroelectric fleet targets remain below (i.e., more stringent) than the benchmarked five-year (2019-2023) industry median of 4.05% (see Section 5.2). In addition to undertaking planned investments to refurbish and rehabilitate aging assets, the RG Excellence Plan (Section 3.4.1) further aims to sustain EFOR performance by focusing efforts to advance key areas of equipment reliability and improving work management.

Chart 9 – Regulated Hydroelectric Equivalent Forced Outage (%, 2025-2031 Targets)

Station	Station Age	2025	2026	2027	2028	2029	2030	2031
DeCew Falls 2 GS	81	3.2	2.0	1.9	2.0	2.0	2.2	1.8
Sir Adam Beck 1 GS	103	3.7	3.5	3.3	3.4	3.4	3.4	3.4
Sir Adam Beck 2 GS	71	1.4	1.4	1.3	1.4	1.4	1.4	1.4
Niagara Region (5 Stations)	**90 (average)**	**3.1**	**3.5**	**3.5**	**3.4**	**3.4**	**3.5**	**3.3**
Cameron Falls GS	105	0.4	0.7	0.8	0.8	0.8	0.8	0.8
Pine Portage GS	75	0.5	0.8	0.8	0.8	0.9	0.9	0.9
Western Region (27 Stations)	**95 (average)**	**2.4**	**3.0**	**3.0**	**3.0**	**3.0**	**3.0**	**3.0**
Abitibi Canyon GS	92	2.7	2.9	2.7	2.7	2.7	2.7	2.7
Chats Falls GS	94	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Chenaux GS	75	2.4	2.5	2.5	2.4	2.5	2.5	2.5
Des Joachims GS	75	1.8	1.7	1.7	1.7	1.7	1.7	1.7
Otter Rapids GS	64	2.0	2.3	2.2	2.0	2.1	2.1	2.1
Otto Holden GS	73	2.8	2.9	2.9	2.8	2.8	2.7	2.8
R.H. Saunders GS	67	3.4	4.0	4.0	3.9	3.9	3.9	3.9
Eastern Region (22 Stations)	**83 (average)**	**3.5**	**3.9**	**3.9**	**3.9**	**3.9**	**3.9**	**3.9**
All 54 Regulated Hydroelectric Facilities	**90 (average)**	**3.2**	**3.6**	**3.6**	**3.6**	**3.6**	**3.6**	**3.6**

Note: Low EFOR is good.

4.4 Regulated Hydroelectric Cost Effectiveness

4.4.1 Unit Energy Cost

OM&A Unit Energy Cost ("UEC") is a measure of financial productivity. It measures the OM&A costs per unit of energy produced (MWh), calculated as the total OM&A costs (Base and Project), divided by the annual regulated hydroelectric generation.

By focusing on Base and Project OM&A costs, the UEC calculation excludes capital costs, gross revenue charge and any other expenses not directly related to operations, maintenance, and administration. The gross revenue charge (see Ex. F1-4-1) is excluded because it is determined by provincial regulation and therefore not within the direct control of OPG. Chart 10 shows UEC for the historical 2016-2024 period.

Chart 10 – Regulated Hydroelectric Historical Unit Energy Cost ($/MWh, 2016-2024)

	2016	2017	2018	2019	2020	2021	2022	2023	2024
Regulated Hydroelectric Unit Energy Cost ($/MWh)	8.10	8.10	8.70	8.50	8.50	10.00	9.60	10.20	10.00
Target as per Business Plan	N/A	8.70	8.30	8.40	8.70	8.80	9.20	9.30	11.00

Note: SBG, NYPA water transactions and related Gross Revenue Charge are excluded from UEC.

UEC increased from $8.10/MWh in 2016 to $10.00/MWh in 2024, representing an approximate 23% increase over this period. This upward trend in UEC is primarily attributable to investments related to unit overhauls and removal costs associated with capital projects, labour cost escalation, and post-COVID inflationary impacts.

Chart 11 shows the forecast regulated hydroelectric UEC for the 2025-2027 period. UEC is forecast to increase over the period, rising from $11.01/MWh in 2025 to $13.20/MWh in 2027. This increase reflects the following:

- A planned increase in Project OM&A costs associated with overhauls and removals of aging infrastructure (described in Ex. F1-3-1).
- A reduction in forecast production beginning in 2026 due to:
  - The return of Niagara River flows to their long-term average (described in E1-1-2), which is projected to continue into 2027.

- An increase in outages necessary to complete major projects such as refurbishments, particularly at large-capacity generating stations (e.g., Sir Adam Beck 1 GS, Sir Adam Beck 2 GS, and R.H. Saunders GS), as well as the ongoing maintenance program (as described in Section 3.2).

Chart 11 – Regulated Hydroelectric Unit Energy Cost Forecast ($/MWh, 2025-2027)

	2025	2026	2027
Regulated Hydroelectric Unit Energy Cost ($/MWh)	$11.01	$11.51	$13.20

Note: SBG, NYPA water transactions and related Gross Revenue Charge are excluded from UEC.

The combination of increased OM&A costs and reduced production drives the upward trend in UEC. These projections are intended to maintain an appropriate balance between supporting grid reliability and ongoing operational needs, and executing the necessary investments associated with managing an aging fleet.

4.4.2 Total Generation Cost

Total Generating Cost ("TGC") is defined as the total cost of operating the regulated hydroelectric facilities, encompassing operations, maintenance and administration (OM&A), fuel (water) and sustaining[23] capital, divided by total generation (MWh). To mitigate the impact of year-over-year fluctuations in capital expenditures, TGC is measured as a three-year historical average.

As illustrated in Chart 12, TGC increased from $22.40/MWh in 2016 to $32.00/MWh in 2024, representing an approximate 43% increase over this period. This upward trend is primarily attributable to higher capital investments related to turbine-generator refurbishment projects, labour cost escalation, and post-COVID inflationary impacts.

Chart 12 – Regulated Hydroelectric Total Generation Cost Performance ($/MWh, 2016-2024)

	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Generation Cost ($/MWh)	22.40	23.00	23.60	24.10	25.30	27.60	28.70	31.00	32.00

[23] Redevelopment projects are excluded from TGC.

5.0 REGULATED HYDROELECTRIC SAFETY AND RELIABILITY BENCHMARKING

OPG recognizes the value of cost and performance benchmarking, both for identifying areas of strength and for highlighting challenges that inform business planning and continuous improvement initiatives. Benchmarking within the hydroelectric sector presents unique challenges due to several factors, including:

- Limited stable peer groups
- Considerable variations in asset capacity factors (i.e., MW)
- Differences in asset age (equipment and life cycle considerations)
- Diverse operating contexts (geographical area, regulatory regimes, water availability, etc.)

Unlike other segments of the electricity industry, hydroelectric facilities exhibit considerable variability due to these and other factors, making direct, “apples-to-apples” comparisons difficult. As a result of these inherent differences in station and utility profiles, hydroelectric benchmarking efforts generally focus on isolating reasonably comparable peer groups and/or making adjustments for uncontrollable differences. These approaches can reduce the size of the peer population and may introduce assumptions into the benchmarking analysis. Hydroelectric benchmarking is therefore generally used to guide understanding of general performance trends or relative positioning, not as an absolute measure of performance. Unique factors of significance (peaking versus baseload station, regulatory constraints, grid supporting role for frequency regulation, etc.) that impact reliability and associated investment requirements should also be taken into consideration when assessing performance. The value of hydroelectric benchmarking performance also needs to be appropriately balanced with the engineering assessments that inform investment requirements to sustain future performance.

OPG’s regulated hydroelectric stations are benchmarked for safety, reliability, and cost performance. Three main data sets for hydroelectric benchmarking are used:

- Electric Utility Cost Group (“EUCG”)
- EC (formerly Canadian Electrical Association)
- Edison Electric Institute (“EEI”)

5.1 Total Recordable Injury Frequency Benchmarking

OPG is committed to the safety of its employees. Safety performance is benchmarked through industry associations in Canada and the United States. These associations collect safety performance data annually from their members who report their injury statistics based on standardized guidelines.

OPG participates in the annual EEI Safety Survey which is an industry-leading benchmarking tool. A varying number of utilities participate in the EEI safety benchmarking including Duke Energy, Tennessee Valley Authority, and Pacific Gas and Electric Company. Aggregated results for OPG's renewable generation facilities[24] are compared to the aggregated results of the hydroelectric utilities in the entire group.

Furthermore, OPG participates in Safety Surveys with participants from EUCG and National Hydropower Association. Participating utilities include entities such as Hydro-Québec, New Brunswick Power, Tennessee Valley Authority, and Duke Energy. Aggregated results for OPG's renewable generation stations are compared to the aggregated results of the hydroelectric utilities in the entire group.

OPG also participates in EC's safety benchmarking. Participants include utilities such as Manitoba Hydro, SaskPower, Nova Scotia Power, and British Columbia Hydro. Aggregated results for OPG's renewable generation stations are compared to the aggregated results of a subset of all EC member organization with more than 1,500 employees.

In 2023, the most recent benchmarked year, RG's TRIF was 0.46. This performance ranks in the first quartile of EC utilities and second quartile in both EEI and EUCG benchmarking. Training and awareness programs have been established to ensure the safety of employees. To sustain good benchmarking performance, RG will continue to advance safety performance by promoting clear safety messages, championing continuous improvement in work protection and corrective action culture, and strengthening safe work planning and best practices.

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[24] Includes both regulated and unregulated facilities.

5.2 Reliability Benchmarking

OPG has been participating in the EUCG Hydroelectric Productivity Committee benchmarking program (cost and reliability) since 2006. The EUCG benchmarking initiative includes a broad cross-section of Canadian and American utilities, with past and current participants such as New Brunswick Power, Hydro-Québec, Pacific Gas and Electric Company, U.S. Army Corps of Engineers, U.S. Bureau of Reclamation, Tennessee Valley Authority, Seattle City Light, Chelan County Public Utility District, Duke Energy, and Bonneville Power Authority. As noted above, the composition of participating utilities often varies from year to year, which can present challenges in establishing consistent, long-term comparative trends.

EUCG organizes its reliability benchmarking using standardized categories to facilitate comparisons among hydroelectric generating stations. EUCG's key reliability metrics include Availability[25] and Forced Outage Rate ("FOR").[26] For comparability, EUCG classifies generating stations according to their installed capacity (MW), using the following categories:

- Greater than 500MW
- Between 100 and 500MW
- Between 30 and 100MW
- Under 30MW

This categorization facilitates more meaningful benchmarking by enabling comparisons between facilities of similar scale.

The most recent benchmarking results, as shown in Chart 13 below, compare Availability and FOR performance across various station capacity categories against industry quartiles. As there can be broad fluctuation in a single year, an aggregate of the last five years (2019-2023) of EUCG

[25] The definition of "Availability" as used in the context of EUCG benchmarking differs from the "Availability Factor" referenced in the Performance section of this report. Specifically, the Availability metric as applied in EUCG benchmarking does not account for derates, whereas the Availability Factor in the Performance section does include the impact of derates.

[26] Forced Outage Rate ("FOR") is the percentage of time the generating station is forced out of service due to unexpected equipment failures or other unplanned events, relative to the total time the unit is operating. It differs from EFOR in that it does not include derates.

benchmarking data is considered to smooth out year-to-year fluctuations and provide a more representative measure of performance. The data set consists of 15 member utilities, including OPG. All data is blind, meaning the identities of the specific utilities providing data are not disclosed to participants. Of OPG's 54 regulated hydroelectric stations, two stations under 30MW capacity (Calabogie GS and Nipissing GS) are not included in the data set as they were not in-service during the period.

Chart 13 – Regulated Hydroelectric Availability and Forced Outage Rate Benchmarking Results Aggregate Five-Year (2019-2023) Performance

Station	Average OPG Station Age	Number of OPG Stations	OPG Capacity (MW)	Availability EUCG Median	OPG Availability Results	FOR EUCG Median	OPG FOR Results
All Stations <30MW	101	28	174	82.27%	82.72%	5.28%	14.70%
All Stations 30-100MW	76	9	766	85.45%	85.30%	2.39%	2.66%
All Stations 100-500MW	73	12	2609	85.39%	83.37%	5.11%	5.40%
All Stations >500MW	80	3	3102	83.15%	93.26%	3.13%	2.61%
OPG Regulated Hydroelectric Facilities	**90**	**52**	**6651**	**82.60%**	**87.53%**	**4.05%**	**4.05%**

Note: High Availability is Good. Low FOR is Good.
For the purposes of EUCG Benchmarking, Chat Falls GS full station capacity is considered in this table (192MW).

Availability Benchmarking Results

OPG's regulated hydroelectric fleet demonstrates strong operational performance, ranking very closely to the first quartile (EUCG first quartile 87.65% vs. OPG actual 87.53%) for the 52 benchmarked stations. Facilities with capacities greater than 500MW exhibit particularly robust availability, with actual performance of 93.26% significantly outperforming the industry median of 83.15%. Stations with capacities under 30MW and those in the 30-100MW range perform near the industry median with actual availability rates of 82.72% and 85.30%, compared to the median benchmarks of 82.27% and 85.45%, respectively. Generating stations within the 100-500MW category are positioned in the third quartile with an actual availability of 83.37% versus a median of 85.39%. Overall, the fleet's performance reflects a high standard of reliability and operational excellence, particularly among the largest stations.

Forced Outage Rate Benchmarking Results

For stations with greater than 500MW capacity, the regulated hydroelectric FOR is 2.61%, indicating performance is better than industry median (3.13%) for these stations. When considering all regulated hydroelectric stations, FOR is 4.05%, which places it at industry median (4.05%). FOR performance at stations in the 30-100 MW range (actual 5.40% versus median 5.11%), and the 100-500MW range (actual 2.66% versus median 2.39%) was slightly below the median. Stations under 30MW show a larger gap in performance from median (actual 14.70% versus median 5.28%), which resulted in third quartile performance. However, stations under 30MW capacity represent only 2.6% of OPG's total regulated hydroelectric capacity in the dataset.

These results demonstrate that the largest stations in OPG's regulated hydroelectric fleet are performing at or above the industry median for reliability and, on average, the entire fleet is performing at the industry median. Diligent maintenance and execution of unit refurbishments and replacement of aging equipment is necessary to sustain performance over time.

5.3 REGULATED HYDROELECTRIC COST BENCHMARKING

As discussed in Ex. A1-3-2, OPG has performed total cost benchmarking through a third party, London Economics International LLC ("LEI"). This benchmarking, provided as Ex. A1-3-2, Attachment 3, performed an econometric analysis comparing the total cost performance of OPG's regulated hydroelectric facilities to comparable industry peers in North America. LEI's econometric analysis controls for factors[27] that may impact costs and may differ across utilities. Similar to OPG's internal benchmarking, LEI utilized data from EUCG to compare OPG's efficiency to other North American utilities[28] using both OPG's OM&A-only spending, and OM&A plus sustaining capital ("OM&A + SC").

[27] These factors were determined by LEI to be prices of inputs, station capacity, control room staffing, number of active units, and time.

[28] As noted in Ex. A1-3-2, Attachment 3, LEI excluded some utilities from the dataset as they had not provided valid data for some of the expense categories or other independent variables for the entire study timeframe. The final comparable dataset included 253 stations owned/operated by 13 hydroelectric operators, including OPG.

LEI's findings, shown in Charts 14 and 15, indicate that OPG is a cost-efficient hydroelectric generator compared to the peer group. Specifically, OPG ranked 3rd (1st quintile) for OM&A and 4th (second quintile) for OM&A + SC, showing that, on average, OPG's expenditures for the regulated hydroelectric facilities are lower than other utilities.

Chart 14 – LEI's Findings: Relative Efficiency Ranking (OM&A)

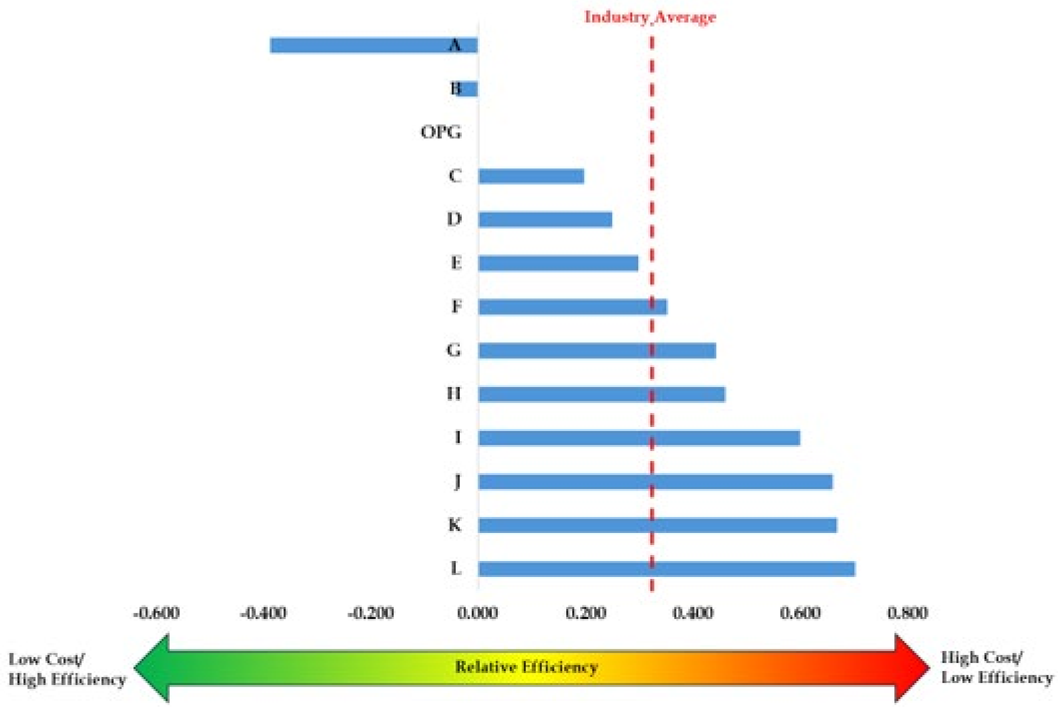
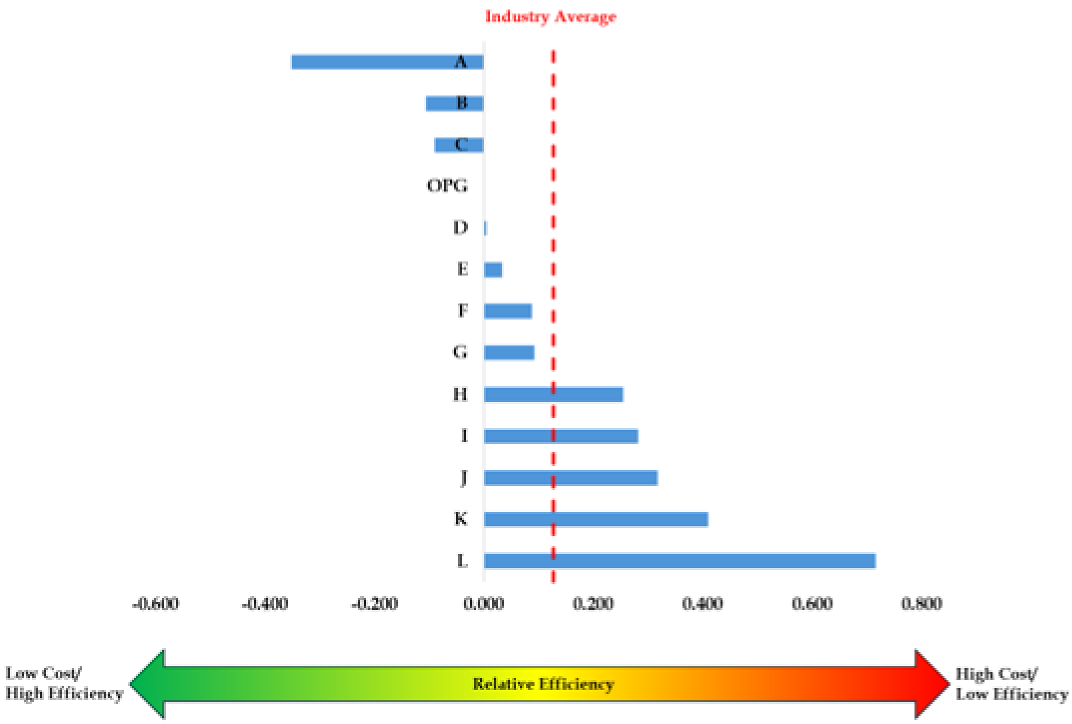


Chart 15 – LEI's Findings: Relative Efficiency Ranking (OM&A + SC)



Combined with the reliability benchmarking results discussed above, LEI's econometric total cost benchmarking analysis demonstrates that OPG continues to be an efficient hydroelectric generator while maintaining levels of reliability consistent with industry median, despite the challenges associated with sustaining an aging fleet. OPG will continue to strive for efficient operations while executing the work program necessary to sustain its regulated hydroelectric assets for future decades.

Numbers may not add due to rounding.

Table 1
Operating Costs Summary - Regulated Hydroelectric ($M)

Line No.	Cost Item	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	OM&A:												
1	**Base OM&A**	205.8	208.1	205.6	203.4	204.5	205.4	215.5	236.5	251.2	264.3	274.2	286.2
2	**Project OM&A**	39.0	42.3	53.8	54.3	53.6	81.1	74.1	75.3	68.3	92.6	90.5	127.0
3	**Allocation of Corporate Costs**	51.0	48.4	47.1	47.1	38.4	38.7	39.9	45.3	50.0	50.7	54.0	55.3
4	**Allocation of Centrally Held Costs**	44.6	26.2	29.2	24.1	15.9	28.8	8.0	(12.0)	12.6	1.6	(0.7)	5.6
5	**Asset Service Fee**	6.8	7.5	7.1	9.1	8.6	10.6	13.7	15.0	16.0	18.7	21.5	25.2
6	**Total OM&A**	347.2	332.5	342.8	338.1	321.1	364.6	351.1	360.0	398.1	427.9	439.4	499.3
7	**Gross Revenue Charge**	312.7	319.7	319.2	324.5	323.4	315.7	330.3	336.7	348.6	357.2	354.3	352.2
	Other Operating Cost Items:												
8	**Depreciation and Amortization**	145.2	140.2	145.9	147.3	148.1	153.4	162.7	173.1	174.1	190.8	194.8	215.4
9	**Income Tax**	17.4	10.3	87.7	77.5	93.0	87.9	103.8	60.2	(3.3)	68.8	37.6	27.3
10	**Property Tax**	0.9	0.9	0.9	1.0	1.1	1.1	1.0	1.1	1.1	1.1	1.0	2.1
11	**Total Operating Costs**	823.4	803.6	896.6	888.5	886.7	922.6	948.8	931.0	918.6	1,045.8	1,027.0	1,096.3

Table 2a

Regulated Hydroelectric Staff Summary - Regular and Non-Regular (FTEs) [1] - 2016-2019

Line No.	Group[2]	2016 Actual	2017 Actual	2018 Actual	2019 Actual
		(a)	(b)	(c)	(d)
1	**Regular Staff**	980.2	963.6	1,026.0	1,024.4
2	**Non-Regular Staff**	35.2	44.3	52.6	48.8
3	**Total Regulated Hydroelectric**	1,015.4	1,008.0	1,078.6	1,073.2

Notes:

1 Staff FTEs include staff deployed on Base OM&A, Project OM&A, and capital projects.

2 Consistent with OPG's letter dated June 11, 2024, issued in EB-2024-0136, data is provided at the regulated hydroelectric level for 2016-2019.

Table 2b

Regulated Hydroelectric Staff Summary - Regular and Non-Regular (FTEs)[1] - 2020-2031

Line No.	Group	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Regulated Hydroelectric Capital:												
1	**Regular Staff**	186.0	203.2	194.7	202.0	244.4	340.7	362.6	374.6	380.5	379.8	369.6	364.2
	Non-Regular Staff												
2	Temporary	6.1	7.3	7.8	13.6	13.5	36.1	64.8	72.9	73.9	79.3	77.9	77.8
3	**Total Regulated Hydroelectric Capital**	192.1	210.5	202.5	215.6	258.0	376.8	427.4	447.5	454.4	459.1	447.5	442.0
	Regulated Hydroelectric OM&A:												
4	**Regular Staff**	855.0	822.0	831.1	840.4	908.8	1004.7	1027.0	1028.3	1018.7	1020.8	1037.5	1041.7
	Non-Regular Staff												
5	Temporary	44.2	60.4	74.4	91.4	69.8	46.9	48.1	45.7	50.3	51.9	44.0	41.9
6	**Total Regulated Hydroelectric OM&A**	899.2	882.4	905.5	931.8	978.6	1,051.6	1,075.0	1,074.0	1,069.0	1,072.7	1,081.5	1,083.6
7	**Total Regulated Hydroelectric**	1,091.4	1,093.0	1,108.0	1,147.4	1,236.6	1,428.3	1,502.4	1,521.5	1,523.4	1,531.8	1,529.0	1,525.6

Notes:
1 Staff FTEs include staff deployed on Base OM&A, Project OM&A, and capital projects.

BASE OM&A COSTS – REGULATED HYDROELECTRIC

1.0 PURPOSE

This evidence presents the regulated hydroelectric base operations, maintenance, and administration ("OM&A") costs for the historical period (2016-2024), bridge period (2025-2026), and test year (2027), and the Full Time Equivalent ("FTE") information supporting the planned regulated hydroelectric work program for the 2027-2031 forecast period, as described in Ex. F1-1-1. All costs outlined in this evidence represent those that have been allocated to the regulated hydroelectric business either through the approved allocation methodology of support costs to the operating regions, or allocation of costs within regions that also include unregulated assets, as described in Section 3.2 of this exhibit. Details on OPG's overall cost allocation methodology are described in Ex. F3-1-4.

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, for the period 2016-2024. Where applicable, OPG has restated the presentation of actual (2016-2024). Base OM&A costs and FTEs for subsequent organizational changes including transfers to/from Renewable Generation ("RG") and Support Services groups to provide an appropriate basis of comparison with forecast period information. These transfers are further described in Ex. F3-1-1 and Attachment 1 to this schedule.

2.0 OVERVIEW

The regulated hydroelectric Base OM&A expenses by Operating Regions and Operations and Project Support for the historical period (2016-2024), bridge period (2025-2026), and test year (2027) are provided in Ex. F1-2-1, Table 1.[1] OPG is requesting approval of Base OM&A expense of $286.2M in 2027; by region, these amounts reflect Base OM&A expenses of $84.2M for Niagara Region, $147.1M for Eastern Region, and $55.0M for Western Region.

[1] Data is presented at the overall regulated hydroelectric level for 2016-2019 and at the Regional level from 2020 onwards.

Base OM&A expenses fund routine, day-to-day operations, maintenance, and other activities for the regulated hydroelectric stations, and activities within the Operations and Project Support functions in support of the regulated hydroelectric business. Total Base OM&A expenses remained relatively flat from 2016-2021, with subsequent increases in 2022 to 2024 reflecting labour cost escalation reflecting bargaining process outcomes including, as a result of the repeal of the *Protecting a Sustainable Public Sector for Future Generations Act* ("Bill-124"), as discussed in Ex. F4-3-1, Section 6.2, and increased resourcing to support the growing work program and regulated hydroelectric project portfolio. In 2025-2026, total Base OM&A expenses increase primarily due to higher resourcing necessary to support the increased work program described in Ex. F1-1-1, meet regulatory compliance needs, and training to support future workforce demands.

Total Base OM&A expenses are expected to increase over the historical period to the 2027 test year. This is primarily attributable to labour cost increases to support the increased work programs contemplated in the forecast period (see Ex. F1-1-1 for further information).

3.0 REGULATED HYDROELECTRIC BASE OM&A

Base OM&A funds the operations and maintenance of the regulated hydroelectric stations, in support of:

- Safe and environmentally responsible operation of the regulated hydroelectric generating stations and water control structures;
- Continued production of electricity from operating regulated hydroelectric units;
- Execution of maintenance activities necessary to sustain the reliability of the regulated hydroelectric assets;
- Fulfillment of regulatory compliance commitments, including applicable legislative requirements, Ontario Regulatory Compliance Program which includes IESO market rules, North American Electric Reliability Corporation standards and Northeast Power Coordinating Council directives, and OPG's contractual obligations; and
- Developing skills and maintaining existing competencies, ensuring employees are equipped to manage, operate, and maintain the regulated hydroelectric facilities safely and reliably.

OPG's regulated hydroelectric facilities are managed within the broader RG business unit. An overview of the current organizational structure of the RG business unit is provided in Attachment 1 to this schedule, along with a brief description of organizational changes since EB-2013-0321. While the functions of the RG business unit are common to both regulated and unregulated facilities, the costs described in this exhibit relate solely to the regulated facilities as determined in accordance with the methodology described in Section 3.2. Common costs associated with Operations and Project Support functions described in this exhibit similarly relate solely to the regulated facilities as determined in accordance with the methodology described in Ex. F3-1-4.

3.1 Detailed Description of Base OM&A Expenses by Function and Resource Type

Base OM&A cost information for the historical period (2016-2024), bridge period (2025-2026), and test year (2027) is presented in Ex. F1-2-1, Table 1. Base OM&A costs are broken into two categories: Operating Regions, which describe costs for functions within RG directly associated with electricity production (operations and maintenance) and Site and Support Services (which includes all common support and other costs incurred for the hydroelectric facilities that are not directly related to electricity production), and Operations and Project Support, which describe costs associated with functions within RG and enterprise-wide that support the entire regulated hydroelectric business.

Details of forecast Base OM&A costs by function and region for 2027 are presented in Ex. F1-2-1, Table 11. This table shows that Maintenance accounts for approximately 55% of the regulated hydroelectric Base OM&A costs in the test year, reflecting the level of effort required to maintain an aging fleet and support the safe, reliable, and environmentally sound operation of these facilities.

As shown in Ex. F1-2-1, Table 1, within the Operations and Project Support function, the largest forecast expenditures in the 2027 test year are attributable to Enterprise Engineering (46%). These costs primarily support asset management and front-end planning activities, dam safety, and operations and maintenance to sustain reliability of the regulated hydroelectric assets. Exhibit F1-2-1, Table 1 shows an increase in forecast Base OM&A costs for the test year, which is primarily attributable to higher staffing levels to support the increased work program (see Ex. F1-1-1) and labour cost escalation (see Ex. F4-3-1).

Base OM&A cost information is presented by standard OPG resource types in Ex. F1-2-1, Table 2. The resource types are as follows:

1. **Labour:** The salary and benefits cost of OPG full-time regular staff consisting of management and Society of United Professionals and Power Workers' Union represented employees. Base OM&A labour costs are derived using standard labour rates for job families within RG. In addition to base salary and statutory benefits (e.g., Employment Insurance, Canada Pension Plan), these standard labour rates include a component for pension and other post-employment benefits earned by employees for current service (discussed in Ex. F4-3-1 and Ex. F4-3-2) as well as a component for current employee health, dental, and other benefits provided during employment.

2. **Non-Regular Labour**: The salary and any applicable benefits cost of OPG non-regular staff consisting of employees hired for a fixed period of time with a start and end date. Incremental short-term labour resources utilized by hydroelectric regional operations groups are primarily temporary staff. These resources are deployed to address peak workload demands, seasonal operational requirements, and to provide coverage for short-duration staff absences or vacancies.

3. **Overtime:** The cost of incremental pay for work outside of core hours, for example during outages (planned and forced) or emergent work to address public safety, dam safety, or equipment reliability. Overtime is only applicable per the respective collective agreements for Society of United Professionals and Power Workers' Union represented employees.

4. **Augmented Staff:** Costs for external personnel providing specialized expertise (e.g., engineering) to supplement internal capability and/or to fill temporary vacancies.

5. **Materials:** The costs of all consumables, replacement parts, and associated transportation service costs supporting station operations (e.g., ongoing maintenance and repair work).

6. **Other Purchased Services:** The costs of specialized external services, primarily for construction and maintenance services supporting work programs, such as shoreline erosion services, environmental assessments, programs such as eel and fishery monitoring, and elevator and HVAC inspections. A discussion of the trend in Other Purchased Services for the 2027 test year is provided below; historical data is provided in Ex. F1-5-1.

7. **Other:** Costs for miscellaneous items include, but are not limited to:
   - Lease and fuel costs of transport work equipment (cars, trucks, cranes, boats, all-terrain vehicles, backhoes, etc.) including vehicle rental/lease fuel, licenses, vehicle registration, and maintenance and repairs;
   - Payments to external companies for utilities (electricity, oil, gas, water, etc.) consumed in owned or leased facilities including leased land, buildings, offices, warehouses, or other facility rentals;
   - Staff reimbursement of training courses, travel, meals, accommodations, and costs related to moving and relocation of redeployed staff; and
   - License fees for certification or licensing of buildings, plants, components or processes, such elevator licensing fees at buildings across the fleet.

   Where formal cost-sharing agreements with external parties (e.g., NYPA, Hydro-Québec, etc.) exist, the costs recovered are offset against OPG costs in this category.

3.2 Renewable Generation Regional Cost Allocation Methodology

For the RG regional common costs, OPG continues to use a standardized allocation methodology to allocate costs for regions that include both regulated and unregulated stations. As in EB-2013-0321, the methodology used to allocate such Base OM&A costs varies depending on the nature of the cost at each specific organizational level[2] as described below and outlined in F1-2-2, Tables 1a and 1b:

- Operations: for Eastern and Western Regions, common direct costs (such as those for staff at control centres supporting regulated and unregulated assets) are allocated using the stations' Maximum Continuous Ratings ("MCR").[3] Niagara Region has two subsets of operators:
  - Operators supporting stations in Niagara (Sir Adam Beck and DeCew Falls generating stations). These costs are entirely allocated to the regulated business.
  - Operators supporting small unmanned hydroelectric stations in the Gravenhurst and Campbellford areas (within Western Region, as described in Ex. A1-4-2, Section 2.2), one of which is unregulated. These costs are allocated based on the stations' MCRs.
- Maintenance: for base maintenance costs OPG plans costs direct to facilities or groups of facilities, where reasonably possible. Where use of a cost driver is required, OPG continues to use station capacities (i.e., MCR) for the applicable facilities within each Region or each Work Centre as the basis for allocation.
- Site and Support Services: common direct costs are allocated to facilities within the Region using station MCR. Where costs are specifically identifiable (such as capacity payments) they are directly charged to the station where the work is performed.

3.3 Base OM&A Trends

Total Base OM&A costs are forecasted to increase from $205.8M in 2016 to $286.2M in 2027, representing an average 3% per year increase.

Total labour (regular, non-regular, overtime) as a percentage of Base OM&A expenses is expected to remain stable between the historical and bridge periods (2016-2026) and the test year (2027) at just under 80%.

[2] Job function descriptions within each organization are provided in Attachment 1 to this schedule.
[3] MCR is the maximum electrical power output that can be continuously generated, provided adequate inflow is available. The unit is assumed to be operating at unity power factor and at the indicated reference gross head. MCR observes generator and turbine limitations.

Materials and other purchased service costs are expected to remain stable throughout the bridge and test years. Material costs are approximately an average of 8% of the total Base OM&A historical and bridge periods (2016-2026) expenditures and are forecast to decrease to approximately 7% in 2027. Other purchased services are forecasted to remain stable at approximately 11% of Base OM&A costs. Other miscellaneous costs were approximately 3% in the historical and bridge periods and are forecasted to be approximately 2% of total Base OM&A costs in 2027.

An explanation of reportable year-over-year variances in Base OM&A costs by function is provided in Ex. F1-2-2.

3.4 Regulated Hydroelectric Staff Summary

The OM&A FTEs associated with regulated hydroelectric facilities for the historical, bridge, and forecast period are detailed in Ex. F1-1-1, Tables 2a and 2b. OM&A FTEs have increased by approximately 20% from 2020 to the 2027 test year, with staffing levels forecast to remain relatively stable over the 2027-2031 forecast period. Increases are primarily driven by the need to support key work programs and initiatives, including the following job functions:

- General labourers, and civil and control maintenance job functions to address maintenance backlog and equipment reliability for the aging fleet;
- Mechanical and electrical job functions related to the Sir Adam Beck 1 GS and Sir Adam Beck 2 GS refurbishment programs;
- Protection & Control job functions;
- Programming job functions to support asset and investment management, front-end planning, and project performance;
- Engineering to support work management, equipment reliability, and asset management;
- Training functions to support the training backlog for existing staff and update training programs in preparation for future staffing demands;
- Security functions across select stations with increased public and safety risks; and
- Management support to lead large work programs and project portfolios driven by the refurbishment program, dam safety, and civil work.

3.5 Key Focus Areas

To drive continuous improvement and deliver on business commitments, RG has established the RG Excellence Plan (see Ex. F1-1-1, Section 3.4.1). The plan aims to enhance safety, operational performance, and future readiness across the RG organization. A strategic investment in supporting the workforce is called out in this plan, with key priorities during the forecast period including driving a strong safety culture and sustaining employee proficiency. Targeted training programs aim to accelerate development of new and emerging leaders to lead the workforce through change in support of the Enterprise Asset Management modernization (described in Ex. D3-1-1, Section 2.1.2). RG's approach also includes partnerships with external educational institutions and organizations to provide specialized training in knowledge areas such as dam safety and hydroelectric operations to address potential skill gaps and ensure business continuity into the future. Other focus areas aim to maximize equipment performance including emphasizing consistency in asset planning and maintenance strategies.

LIST OF ATTACHMENTS

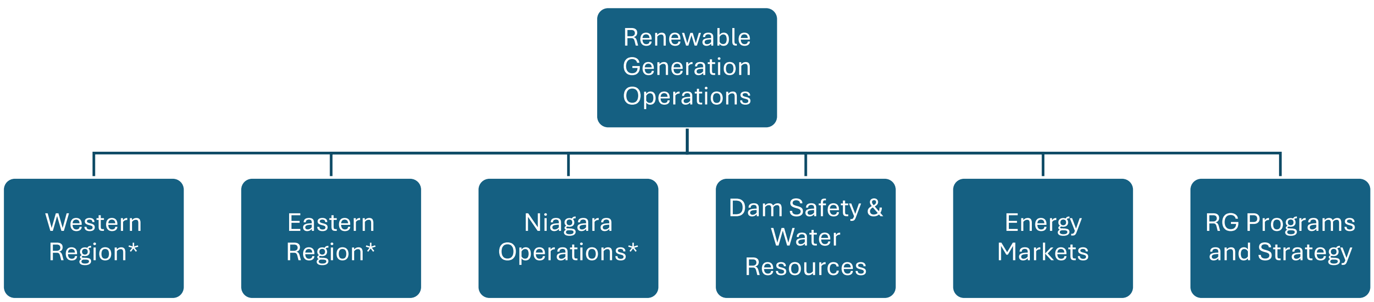
Attachment 1: Renewable Generation Organizational Structure

RENEWABLE GENERATION ORGANIZATIONAL STRUCTURE

1.0 RENEWABLE GENERATION ORGANIZATION DESCRIPTION

1.1 Organization Chart

Figure 1
Renewable Generation Organization Chart



*manages both regulated and unregulated facilities

Since EB-2013-0321, OPG has made a number of organizational changes to the Renewable Generation ("RG") organization to optimize and reflect its business needs. The following major organizational changes have been implemented since EB-2013-0321, and are reflected in the Ex. F tables:

- The Central Hydro Plant Group was consolidated into the remaining regional operations groups (effective 2021, as described in Ex. A1-4-2);
- The Hydro-Thermal Operations ("HTO") Central Support organization was eliminated, with the following functions centralized[1]:
  - Engineering support was centralized to Enterprise Engineering
  - HTO Project Execution was centralized to Enterprise Projects
  - Emergency Preparedness moved to Integrated Fleet Management

[1] As described in EB-2020-0290, Ex. A2-2-1, Section 3.0.

- Remaining legacy HTO Central Support functions (RG Programs and Strategy, Dam Safety and Water Resources) aligned under the SVP, Renewable Generation

- Energy Markets transferred from corporate Support Services to RG
- Electricity Sales & Trading and Integrated Revenue Planning transferred from Commercial Operations and Environment to RG within Energy Markets.

1.2 Detailed Description of Base OM&A by Function

1.2.1 Operating Regions

Renewable Generation's 54 regulated hydroelectric generating stations and associated water control structures are organized into three operating regions: Eastern, Western, and Niagara (see Ex. A1-4-2). The Operating Regions' base OM&A costs by function are:

- Operations
- Maintenance
- Site and Support Services

Operations

The primary function of the Operations Group is to ensure operations of the generating stations, equipment, and related infrastructure meet or exceed all safety, regulatory, and environmental requirements. This includes, but is not limited to, control room operations, employee and contractor work protection, water management (dam operations, water level monitoring, ice breaking operations, log operations, snow surveys), and daily oversight and compliance with dam safety, public safety and regulatory requirements. Operations costs also include OPG's portion of joint works operations costs for those stations subject to Joint Works Agreements (as described in Ex. A1-4-2).

Maintenance

This includes all work associated with hydroelectric facilities' direct maintenance to ensure normal, safe, and environmentally-sound operation. Maintenance plans are established in a maintenance management system and are used to prioritize and schedule work execution.

The maintenance work program also includes OPG's portion of maintenance joint works costs for those stations subject to Joint Works Agreements (as described in Ex. A1-4-2).

Site and Support Services

Site and Support Services within the regional operations groups include all common support activities for hydroelectric facilities that are not directly related to electricity production. This includes Production Support Staff, Vice Presidents Regional Operations, Compliance Management, Drafting, and Project Management. In addition to the costs incurred within the regional operations groups, certain other costs incurred to support the regulated hydroelectric facilities are provided on a centralized basis in Operations and Project support group costs.

1.2.2 Operations and Project Support

Operations and Project Support provide common or specialized services to the regions or facilities, including:

- Enterprise Engineering
- Integrated Fleet Management
- Environment, Health & Safety
- Enterprise Projects
- Other Support

The following sections provide descriptions of the various Operations and Project Support groups; the methodology for cost allocation to regional operations groups or facilities is described in Ex. F3-1-4.

Enterprise Engineering

Enterprise Engineering supports regulated hydroelectric operation by providing civil, mechanical, and electrical engineering support to the Operating Regions or facilities to ensure dam safety, reliable operations, project and program support, and specialized inspection services. The key functions include:

- Advanced Inspection and Maintenance (formerly Inspection and Reactor Innovation): this team is accountable for providing specialty inspection and maintenance services (e.g., vibration monitoring and analysis, non-destructive examinations, etc.) to supplement those carried out by station staff, where the nature of the skills or equipment required makes the work more effectively managed as a centralized function. The direct costs associated with the provision of inspection and maintenance services are included in OM&A costs.
- Central Engineering:
    - RG Station Engineering: this team supports safe operation through disposition of equipment issues, equipment failure investigations and root cause analyses, and resolution of longer-term operational challenges. It also provides modification and design basis control, program execution support (such as dam and public safety inspections, risk management, etc.), and project and asset management support.
    - RG Engineering Services: this team provides specialist civil, mechanical, electrical, and protection and controls engineering support to the RG fleet. This includes programs coordination and management (such as Reliability Compliance Program and Dam Safety Program), project engineering support, training development and delivery, internal governance development, and interface with external organizations such as Hydro One and IESO.
    - RG Engineering Strategy and Oversight: this team provides strategic planning and oversight for engineering programs across the fleet, including equipment reliability, risk management, design management and conduct of engineering, and support of fleet asset management and initiatives.
    - Enterprise Engineering Strategy and Support: this team provides data analytics and supports data-driven decision making (including the Monitoring and Diagnostics Centre), and engineering staffing strategies.

<u>Integrated Fleet Management</u>

Integrated Fleet Management provides two functions supporting the regulated hydroelectric business: Enterprise Learning and Security and Emergency Services.

- Enterprise Learning, which provides all training analysis, design, development, implementation, and evaluation activities to ensure staff are qualified to safely operate, maintain, and engineer RG facilities. This group also provides training administration and facilities support, such as Learning Management System administration, software application development, and training facility management.
- Security and Emergency Services, which addresses requirements regarding security design, refurbishment, existing facility lifecycles and any potential new assets. Specific specialized security services are also provided within the following functions: Security Clearances, Security Threat and Risk Assessment, Investigations as well as facility security and access control. The Enterprise Emergency Management team protects the health and safety of employees and the public by limiting the impact of internal and external hazards, and the associated potential events leading to damage to the environment, OPG assets, reputation, and operational continuity.

Environment Health & Safety

The Environment, Health & Safety ("EHS") organization develops and maintains EHS managed systems, programs and initiatives that support all employees in the company. The group provides expertise and operational support to OPG operations, facilities, projects, and functions to meet EHS compliance obligations. It acts to minimize EHS risks and impacts, and advises management of environmental issues, health and safety hazards, and prevention of workplace injuries in support of a strong safety culture. The group reports on OPG's environmental and health & safety performance, and performance and seeks opportunities for EHS to promote leadership and innovation. Finally, it provides assessment and specialist support in the areas of aquatic and terrestrial biology, contaminated land and groundwater, air and water emissions, waste and spills management, safe work planning, permits and approvals, impact assessments, regulations, licenses, orders to comply, climate change-related impacts and legislative monitoring.

<u>Enterprise Projects</u>

Enterprise Projects includes RG Major Projects and the Enterprise Project Management Office ("EPMO") which includes Project Controls and the Construction Centre of Excellence.

RG Major Projects is responsible for major renewable generation project planning, development and execution for larger projects such as redevelopment projects and major concrete rehabilitation (refer to Ex. F1-1-1 and Ex. D1-1-2 for further detail on these projects).

The EPMO is responsible for oversight of the processes, tools and project expertise necessary to deliver successful projects; serves as a source for best practices, training programs and an organizational focus for improving project performance across all portfolios. EPMO also provides project controls resources for all projects.

<u>Other Support</u>

Office of the Senior Vice President, Renewable Generation Operations

Costs associated with the Office of the SVP Renewable Generation, Operations include various expenses incurred by the RG SVP such as travel, administrative support, and membership costs in various hydroelectric associations, such as the International Hydropower Association and Canadian Hydropower Association.

Dam Safety and Water Resources

While the regional operations groups are responsible for dam operations and maintenance, as described in Section 1.2.1 above, the Dam Safety and Water Resources team provides program oversight and guidance on dam safety, public safety, and emergency management at OPG's dam sites as well as water management technical support to all regions in RG.

The department also provides support for water management policy and planning, operational water management, licensing and tenure, water agreements, climate change, decision support and information systems.

Renewable Generation Programs and Strategy

RG Programs and Strategy is responsible for driving performance improvements and supporting various strategic aspects of RG Operations (fleet business planning, staffing strategy for RG Operations and Maintenance, fleet improvement initiatives, etc.), as well as providing support in the administration and oversight of the Conduct of Operations, Conduct of Maintenance and Work Management RG programs that are executed by the regional operations groups.

RG Programs and Strategy also leads improvement efforts and drives consistency in critical aspects of RG's operations, including work management, conduct of operations, and conduct of maintenance, including work protection. The team also provides continuous improvement oversight through the corrective action process across RG. This department drives the development, implementation, and periodic review and update of RG's Excellence Plans.

Energy Markets

The Energy Markets team offers and optimizes OPG's generation assets in the IESO-administered electricity market, ensuring compliance with all legal, regulatory, environmental, and operational requirements. The team collaborates with Hydro One and the IESO to position OPG's generation and ancillary services for maximum value and system support. Energy Markets develops and implements market offer strategies, approved by senior management, in line with OEB regulations and IESO market rules. This includes outage planning and strategies to optimize production based on market signals, manage generation risks, and engage in interconnected market electricity trading. Energy Markets also derives OPG's generation and revenue forecasts, and monitors and provides advice and analysis on potential changes to the IESO administered market.

Numbers may not add due to rounding.

Table 1
Base OM&A - Regulated Hydroelectric ($M)

Line No.	Item	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Operating Region[1,2]												
1	Niagara Region	n/a	n/a	n/a	n/a	44.5	44.6	47.4	52.6	56.1	58.3	58.7	61.1
2	Eastern Region	n/a	n/a	n/a	n/a	78.7	78.2	83.0	91.3	97.5	102.7	107.9	111.6
3	Western Region	n/a	n/a	n/a	n/a	26.7	29.1	30.0	34.0	35.5	39.2	39.4	40.4
4	**Total Operating Regions**	156.0	156.1	150.7	148.8	149.9	151.9	160.4	177.9	189.1	200.2	206.0	213.2
	Operations and Project Support												
5	Enterprise Engineering	26.9	28.6	30.5	31.3	29.6	27.7	30.3	28.3	29.0	30.8	31.9	33.7
6	Integrated Fleet Management	6.4	7.0	5.0	5.1	5.1	4.7	4.5	8.2	8.0	8.7	8.7	9.9
7	Environment, Health & Safety	4.3	3.9	3.8	3.7	4.6	5.3	4.6	4.4	5.1	4.5	5.4	6.3
8	Enterprise Projects	2.2	2.2	2.4	1.5	1.7	2.0	2.1	3.1	2.9	3.3	3.5	2.9
9	Other Support	10.0	10.3	13.2	13.0	13.7	13.9	13.6	14.6	17.1	16.8	18.7	20.4
10	**Total Operations and Project Support**	49.8	52.0	54.9	54.6	54.6	53.5	55.0	58.6	62.1	64.1	68.1	73.1
11	**Total Base OM&A**	205.8	208.1	205.6	203.4	204.5	205.4	215.5	236.5	251.2	264.3	274.2	286.2

Notes:
1 Operating Region descriptions effective 2021 (see Ex. A1-4-2).
2 Consistent with OPG's letter dated June 11, 2024 issued in EB-2024-0136, data is provided at the regulated hydroelectric level for 2016-2019.

Table 2
Base OM&A - Regulated Hydroelectric ($M)

Line No.	Resource Type	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan	2027 Percentage[1]
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	**Labour**	147.7	146.6	146.5	143.5	146.7	142.5	146.4	157.8	169.9	188.0	201.5	208.3	72.8%
2	**Non-Regular Labour[2]**	3.6	4.3	4.5	4.0	4.6	5.6	7.3	9.4	7.6	5.3	5.0	5.3	1.8%
3	**Overtime**	6.6	8.7	9.3	9.9	8.3	10.4	12.3	13.8	15.2	13.6	13.5	13.9	4.9%
4	**Augmented Staff**	0.9	1.5	1.0	0.6	0.3	0.5	0.4	0.4	0.4	0.0	0.0	0.1	0.0%
5	**Materials**	14.8	15.3	15.3	15.0	16.4	16.7	18.8	17.5	19.9	19.0	19.8	20.8	7.3%
6	**Other Purchased Services**	23.1	24.4	19.9	21.6	20.9	24.3	26.2	31.1	32.0	31.8	27.8	31.1	10.9%
7	**Other**	9.1	7.3	9.1	9.0	7.4	5.6	4.3	6.6	6.2	6.6	6.6	6.8	2.4%
8	**Total Base OM&A**	205.8	208.0	205.6	203.5	204.5	205.4	215.5	236.5	251.2	264.3	274.2	286.3	100.0%

Notes:
1 2027 Percentage = 2027 Resource Costs divided by 2027 Base OM&A.
2 Non-Regular Labour includes costs for temporary staff.

Table 3

Regulated Hydroelectric Base OM&A by Function ($M)

Actual - Calendar Years Ending December 31, 2016 - 2019[1]

Line No.	Function	2016 Total	2017 Total	2018 Total	2019 Total
		(a)	(b)	(c)	(d)
	Operating Regions				
1	Operations & Maintenance	134.8	137.7	134.0	132.0
2	- Operations	20.9	21.4	22.6	21.5
3	- Maintenance	114.6	117.1	111.4	110.5
4	Site and Support Services	20.5	17.6	16.7	16.8
5	**Total Operating Regions**	156.0	156.1	150.7	148.8
6	**Operations and Project Support**	49.8	52.0	54.9	54.6
7	**Total Base OM&A**	205.8	208.1	205.6	203.4

Notes:

1 Consistent with OPG's letter dated June 11, 2024, issued in EB-2024-0136, data is provided at the regulated hydroelectric level for 2016-2019.

Numbers may not add due to rounding.

Table 4
Regulated Hydroelectric Base OM&A by Function ($M)
Actual - Calendar Year Ending December 31, 2020

Line No.	Function	Niagara Region	Eastern Region	Western Region	Total
		(a)	(b)	(c)	(d)
	Operating Regions				
1	Operations & Maintenance	39.7	68.2	23.5	131.4
2	- Operations	9.4	8.7	4.3	22.3
3	- Maintenance	30.3	59.5	19.2	109.0
4	Site and Support Services	4.8	10.5	3.2	18.5
5	**Total Operating Regions**	44.5	78.7	26.7	149.9
6	**Operations and Project Support**	16.0	26.8	11.8	54.6
7	**Total Base OM&A**	60.5	105.5	38.5	204.5

Numbers may not add due to rounding.

Table 5
Regulated Hydroelectric Base OM&A by Function ($M)
Actual - Calendar Year Ending December 31, 2021

Line No.	Function	Niagara Region	Eastern Region	Western Region	Total
		(a)	(b)	(c)	(d)
	Operating Regions				
1	Operations & Maintenance	40.1	68.9	25.7	134.7
2	- Operations	9.8	9.5	3.9	23.2
3	- Maintenance	30.3	59.4	21.8	111.5
4	Site and Support Services	4.6	9.3	3.3	17.2
5	**Total Operating Regions**	44.6	78.2	29.1	151.9
6	**Operations and Project Support**	14.9	26.8	11.8	53.5
7	**Total Base OM&A**	59.5	105.1	40.9	205.4

Numbers may not add due to rounding.

Table 6
Regulated Hydroelectric Base OM&A by Function ($M)
Actual - Calendar Year Ending December 31, 2022

Line No.	Function	Niagara Region	Eastern Region	Western Region	Total
		(a)	(b)	(c)	(d)
	Operating Regions				
1	Operations & Maintenance	41.4	74.1	27.4	142.9
2	- Operations	10.5	9.9	4.7	25.1
3	- Maintenance	30.9	64.2	22.7	117.7
4	Site and Support Services	6.1	8.9	2.6	17.6
5	**Total Operating Regions**	47.4	83.0	30.0	160.4
6	**Operations and Project Support**	17.2	27.6	10.2	55.0
7	**Total Base OM&A**	64.6	110.6	40.2	215.5

Numbers may not add due to rounding.

Table 7
Regulated Hydroelectric Base OM&A by Function ($M)
Actual - Calendar Year Ending December 31, 2023

Line No.	Function	Niagara Region	Eastern Region	Western Region	Total
		(a)	(b)	(c)	(d)
	Operating Regions				
1	Operations & Maintenance	46.1	82.2	31.5	159.8
2	- Operations	11.0	11.0	5.7	27.7
3	- Maintenance	35.1	71.2	25.8	132.2
4	Site and Support Services	6.5	9.1	2.5	18.1
5	**Total Operating Regions**	52.6	91.3	34.0	177.9
6	**Operations and Project Support**	18.3	28.5	11.8	58.6
7	**Total Base OM&A**	70.9	119.8	45.8	236.5

Table 8
Regulated Hydroelectric Base OM&A by Function ($M)
Actual - Calendar Year Ending December 31, 2024

Line No.	Function	Niagara Region	Eastern Region	Western Region	Total
		(a)	(b)	(c)	(d)
	Operating Regions				
1	Operations & Maintenance	49.7	89.8	32.6	172.1
2	- Operations	11.5	10.9	5.3	27.8
3	- Maintenance	38.2	78.9	27.3	144.3
4	Site and Support Services	6.5	7.7	2.9	17.0
5	**Total Operating Regions**	56.1	97.5	35.5	189.1
6	**Operations and Project Support**	19.8	28.0	14.3	62.1
7	**Total Base OM&A**	75.9	125.5	49.8	251.2

Numbers may not add due to rounding.

Table 9
Regulated Hydroelectric Base OM&A by Function ($M)
Budget - Calendar Year Ending December 31, 2025

Line No.	Function	Niagara Region	Eastern Region	Western Region	Total
		(a)	(b)	(c)	(d)
	Operating Regions				
1	Operations & Maintenance	50.3	92.9	36.2	179.4
2	- Operations	13.3	11.6	5.1	29.9
3	- Maintenance	37.0	81.3	31.2	149.5
4	Site and Support Services	8.1	9.8	2.9	20.8
5	**Total Operating Regions**	58.3	102.7	39.2	200.2
6	**Operations and Project Support**	20.8	31.7	11.6	64.1
7	**Total Base OM&A**	79.1	134.4	50.8	264.3

Table 10
Regulated Hydroelectric Base OM&A by Function ($M)
Budget - Calendar Year Ending December 31, 2026

Line No.	Function	Niagara Region	Eastern Region	Western Region	Total
		(a)	(b)	(c)	(d)
	Operating Regions				
1	Operations & Maintenance	51.0	97.0	36.4	184.4
2	- Operations	12.5	12.5	5.3	30.3
3	- Maintenance	38.5	84.5	31.1	154.1
4	Site and Support Services	7.7	10.9	3.0	21.7
5	**Total Operating Regions**	58.7	107.9	39.4	206.0
6	**Operations and Project Support**	21.6	33.2	13.3	68.1
7	**Total Base OM&A**	80.4	141.0	52.7	274.2

Table 11
Regulated Hydroelectric Base OM&A by Function ($M)
Plan - Calendar Year Ending December 31, 2027

Line No.	Function	Niagara Region	Eastern Region	Western Region	Total
		(a)	(b)	(c)	(d)
	Operating Regions				
1	Operations & Maintenance	52.7	99.9	37.2	189.8
2	- Operations	13.4	13.0	5.5	31.8
3	- Maintenance	39.3	86.9	31.8	158.0
4	Site and Support Services	8.4	11.7	3.2	23.3
5	**Total Operating Regions**	61.1	111.6	40.4	213.2
6	**Operations and Project Support**	23.1	35.4	14.6	73.1
7	**Total Base OM&A**	84.2	147.1	55.0	286.2

COMPARISON OF BASE OM&A COSTS – REGULATED HYDROELECTRIC

1.0 PURPOSE

This evidence presents period-over-period comparisons of Base OM&A costs for the regulated hydroelectric facilities based on actuals for 2016-2024 and forecasts for the bridge period (2025-2026) and test year (2027), as detailed in Ex. F1-1-1, Table 1 and F1-2-1, Table 1, and supports the approval of the regulated hydroelectric Base OM&A costs presented in Ex. F1-2-1.

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 hydroelectric business below, for the period 2016-2024. As there is no OEB-approved regulated hydroelectric Base OM&A cost information for 2015 onwards, OPG has provided year-over-year variance analyses for the historical period (2016-2024), bridge period (2025-2026), and test year (2027).

OPG has restated the presentation of actual (2016-2024) Base OM&A costs for organizational changes including transfers to/from Renewable Generation ("RG"), Operations and Project Support groups, and Corporate Support groups to provide an appropriate basis of comparison with forecast period information (these transfers are further described in Ex. F1-2-1, Attachment 1 and in Ex. F3-1-1).

Exhibit F1-2-2, Tables 1a and 1b provide the actual, budget, and forecast regulated hydroelectric Base OM&A expenditures by functional area for the 2016-2027 period. Details about operating regions' operations, maintenance and site support service activities are provided in Ex. F1-2-1. Operations and Project Support costs are allocated to operating regions using the methodology described in Ex. F3-1-4.

Net reportable variances and period-over-period changes by category of expense (10% or greater at the function level, subject to a minimum materiality limit of $1M) are discussed below.

2.0 PERIOD-OVER-PERIOD CHANGES – TEST YEAR

2027 Plan versus 2026 Budget

Planned Base OM&A costs in 2027 are $286.2M, which is $12.1M or 4% higher than the 2026 planned Base OM&A costs of $274.2M.

The reportable variances by category of expense are as follows:

- Integrated Fleet Management ($1.2M or 14% increase): due to the cost of moving training equipment related to the assumed exit of the 800 Kipling lease that currently houses the RG Training Centre. As discussed in Ex. D3-1-1, OPG will lease and fit out a new RG Training Centre as the current lease at 800 Kipling Ave. is not expected to extend past 2026.

3.0 PERIOD-OVER-PERIOD CHANGES – BRIDGE YEARS

2026 Budget versus 2025 Budget

Planned Base OM&A costs in 2026 are $274.2M, which is $9.9M or 4% higher than the 2025 budget amount of $264.3M.

The reportable variances by category are:

- Other Support ($1.9M or 11% increase): primarily due to higher staffing levels to ensure transfer of critical knowledge and skillsets due to expected attrition.

2025 Budget versus 2024 Actual

Planned Base OM&A costs in 2025 are $264.3M, which is $13.1M or 5% higher than 2024 actual amount of $251.2M.

The reportable variances by category of expense are as follows:

- Site and Support Services ($3.8M or 22% increase), primarily due to an increase in staffing levels to support project planning and asset management for the increased regulated hydroelectric work program, and from previously unfilled vacancies.

4.0 PERIOD-OVER-PERIOD CHANGES – HISTORICAL YEARS

2024 Actual versus 2023 Actual

Actual Base OM&A costs in 2024 were $251.2M, which was $14.7M or 6% higher than 2023 actual amount of $236.5M. All regulated hydroelectric organizations were impacted by higher labour cost escalation in 2023 reflecting collective bargaining process outcomes including as a result of *Protecting a Sustainable Public Sector for Future Generations Act* ("Bill 124") as discussed in Ex. F4-3-1. Another contributor to the increase in Base OM&A costs is the impact of the 53rd fiscal week in 2024.[1]

The reportable variances by category of expenses are as follows and are inclusive of the aforementioned higher labour cost escalation, with additional drivers of variance identified below where applicable:

- Other Support ($2.5M or 17% increase): due to higher staffing levels to support the preparation and implementation of the IESO's Market Renewal initiative, support compliance with the North American Electric Reliability Corporation reliability standards and increased support for RG performance reporting, business planning, and OEB payment amounts application preparation.

2023 Actual versus 2022 Actual

Actual Base OM&A costs in 2023 were $236.5M, which was $21.0M or 10% higher than 2022 actual amount of $215.5M. All regulated hydroelectric organizations were impacted by higher labour cost escalation in 2023 reflecting collective bargaining process outcomes including as a result of Bill 124, as discussed in Ex. F4-3-1.

The reportable variances by category of expenses are as follows and are inclusive of the aforementioned higher labour cost escalation, with additional drivers of variance identified below where applicable:

- Operations and Maintenance ($17.0M or 12% increase):
  - Operations ($2.5M or 10% increase): no other reportable variance

[1] Annual labour cost budgets are calculated on a weekly basis times the number of weeks in the fiscal calendar year; most years have 52 weeks, but some years, like 2024, have 53 numbered weeks.

  - Maintenance ($14.4M or 12% increase): due to higher maintenance costs primarily at R.H. Saunders GS and Sir Adam Beck 1 GS and Sir Adam Beck 2 GS due to environmental remediation (e.g., lead paint and asbestos removal), storm response clean-up, and additional joint works expenditures (see Ex. A1-4-2).
- Integrated Fleet Management ($3.7M or 82% increase): due to increased staffing levels in security, and training to support increased work program and address training backlogs.
- Enterprise Projects ($1.0M or 51% increase): due to higher staffing levels to support the increased regulated hydroelectric project portfolio.

2022 Actual versus 2021 Actual

Actual Base OM&A costs in 2022 were $215.5M, which was $10.1M or 5% higher than 2021 actual amount of $205.4M.

There are no reportable variances by category of expense.

2021 Actual versus 2020 Actual

Actual Base OM&A costs in 2021 were $205.4M, which was $0.9M or 0.5% higher than 2020 actual amount of $204.5M.

There are no reportable variances by category of expense.

5.0 PERIOD-OVER-PERIOD CHANGES – EXTENDED HISTORICAL YEARS

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

2020 Actual versus 2019 Actual

Actual Base OM&A costs in 2020 were $204.5M, which was $1.1M or 0.5% higher than 2019 actual amount of $203.4M.

The reportable variances by category of expense are as follows:

- Site and Support Services ($1.7M or 10% increase): primarily due to increased Base OM&A labour costs from fewer staff working on projects due to the COVID-19 pandemic.

2019 Actual versus 2018 Actual

Actual Base OM&A costs in 2019 were $203.4M, which was $2.2M or 1% lower than 2018 actual amount of $205.6M.

There are no reportable variances by category of expense.

2018 Actual versus 2017 Actual

Actual Base OM&A costs in 2018 were $205.6M, which was $2.5M or 1% lower than the 2017 actual amount of $208.1M.

The reportable variances by category of expense are as follows:

- Integrated Fleet Management ($2.0M or 29% decrease): primarily due to reductions in staffing levels in training functions.
- Other Support ($2.9M or 28% increase): primarily due to a difference in reporting of Hydro One share awards expense under collective agreements for represented staff, whereby the 2017 expense was charged to centrally held costs rather than Base OM&A costs and higher Hydro One share awards expense under collective agreements for represented staff.

2017 Actual versus 2016 Actual

Actual Base OM&A costs in 2017 were $208.1M, which was $2.4M or 1% higher than 2016 actual amount of $205.8M. A contributor to the increase in Base OM&A costs is the impact of the 53rd fiscal week in 2017.[2]

[2] Annual labour cost budgets are calculated on a weekly basis times the number of weeks in the fiscal calendar year; most years have 52 weeks, but some years, like 2017, have 53 numbered weeks.

The reportable variances by category of expense are as follows:

- Site and Support Services ($2.9M or 14% decrease): due to expenditures to reconstruct and subsequently divest two Niagara region bridges in return for release from the associated future maintenance liabilities.

Table 1a

Comparison of Regulated Hydroelectric Base OM&A by Function ($M)[1]

Line No.	Business Unit	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
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Operating Regions[2]											
1	Operations & Maintenance	134.8	2.9	137.7	(3.7)	134.0	(1.9)	132.0	(0.7)	131.4	3.3	134.7
2	- Operations	20.9	0.5	21.4	1.2	22.6	(1.0)	21.5	0.8	22.3	0.9	23.2
3	- Maintenance	114.6	2.5	117.1	(5.7)	111.4	(0.9)	110.5	(1.5)	109.0	2.5	111.5
4	Site and Support Services	20.5	***(2.9)***	17.6	(0.9)	16.7	0.1	16.8	***1.7***	18.5	(1.3)	17.2
5	**Total Operating Regions**	156.0	0.1	156.1	(5.4)	150.7	(1.9)	148.8	1.0	149.9	2.1	151.9
	Operations and Project Support											
6	Enterprise Engineering	26.9	1.7	28.6	1.9	30.5	0.8	31.3	(1.7)	29.6	(1.9)	27.7
7	Integrated Fleet Management	6.4	0.6	7.0	***(2.0)***	5.0	0.1	5.1	(0.0)	5.1	(0.4)	4.7
8	Environment, Health & Safety	4.3	(0.4)	3.9	(0.1)	3.8	(0.1)	3.7	0.9	4.6	0.6	5.3
9	Enterprise Projects	2.2	0.0	2.2	0.2	2.4	(0.9)	1.5	0.1	1.7	0.4	2.0
10	Other Support	10.0	0.3	10.3	***2.9***	13.2	(0.3)	13.0	0.7	13.7	0.2	13.9
11	**Total Operations and Project Support**	49.8	2.3	52.0	2.9	54.9	(0.3)	54.6	0.0	54.6	(1.1)	53.5
12	**Total Base OM&A**	205.8	2.4	208.1	(2.5)	205.6	(2.2)	203.4	1.0	204.5	0.9	205.4

Line No.	Business Unit	2021 Actual[1]	(c)-(a) Change	2022 Actual	(e)-(c) Change	2023 Actual	(g)-(e) Change	2024 Actual	(i)-(g) Change	2025 Budget	(k)-(i) Change	2026 Budget
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Operating Regions[2]											
13	Operations & Maintenance	134.7	8.1	142.9	***17.0***	159.8	12.3	172.1	7.3	179.4	5.0	184.4
14	- Operations	23.2	1.9	25.1	***2.5***	27.7	0.1	27.8	2.2	29.9	0.4	30.3
15	- Maintenance	111.5	6.2	117.7	***14.4***	132.2	12.2	144.3	5.1	149.5	4.6	154.1
16	Site and Support Services	17.2	0.3	17.6	0.5	18.1	(1.1)	17.0	***3.8***	20.8	0.9	21.7
17	**Total Operating Regions**	151.9	8.5	160.4	***17.5***	177.9	11.2	189.1	11.1	200.2	5.9	206.0
	Operations and Project Support											
18	Enterprise Engineering	27.7	2.6	30.3	(2.0)	28.3	0.7	29.0	1.8	30.8	1.1	31.9
19	Integrated Fleet Management	4.7	(0.1)	4.5	***3.7***	8.2	(0.2)	8.0	0.7	8.7	(0.0)	8.7
20	Environment, Health & Safety	5.3	(0.7)	4.6	(0.2)	4.4	0.7	5.1	(0.6)	4.5	0.9	5.4
21	Enterprise Projects	2.0	0.0	2.1	***1.0***	3.1	(0.2)	2.9	0.5	3.3	0.2	3.5
22	Other Support	13.9	(0.2)	13.6	0.9	14.6	***2.5***	17.1	(0.3)	16.8	***1.9***	18.7
23	**Total Operations and Project Support**	53.5	1.6	55.0	3.5	58.6	3.5	62.1	2.0	64.1	4.0	68.1
24	**Total Base OM&A**	205.4	10.1	215.5	21.0	236.5	14.7	251.2	13.1	264.3	9.9	274.2

Notes:

1 Bold italic font indicates variance of 10% or greater and subject to miniumum materiality threshold of $1M.

2 Operating Region descriptions effective 2021 (see Ex. A1-4-2).

Table 1b

Comparison of Regulated Hydroelectric Base OM&A by Function ($M)[1]

Line No.	Business Unit	2026 Budget	(c)-(a) Change	2027 Plan
		(a)	(b)	(c)
	Operating Regions[2]			
1	Operations & Maintenance	184.4	5.5	189.8
2	- Operations	30.3	1.6	31.8
3	- Maintenance	154.1	3.9	158.0
4	Site and Support Services	21.7	1.7	23.3
5	**Total Operating Regions**	206.0	7.1	213.2
	Operations and Project Support			
7	Enterprise Engineering	31.9	1.8	33.7
8	Integrated Fleet Management	8.7	***1.2***	9.9
9	Environment, Health & Safety	5.4	0.9	6.3
10	Enterprise Projects	3.5	(0.6)	2.9
11	Other Support	18.7	1.7	20.4
12	**Total Operations and Project Support**	68.1	5.0	73.1
13	**Total Base OM&A**	274.2	12.1	286.2

Notes:

1 Bold italic font indicates variance of 10% or greater and subject to miniumum materiality threshold of $1M.

2 Operating Region descriptions effective 2021 (see Ex. A1-4-2).

PROJECT OM&A COSTS – REGULATED HYDROELECTRIC

1.0 PURPOSE

This evidence provides a summary of the Operations, Maintenance and Administration ("OM&A") project expenses ("Project OM&A") within the regulated hydroelectric portfolio for the historical period (2016-2024), bridge period (2025-2026), and test year (2027).

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 OM&A projects within the regulated hydroelectric portfolio are largely sustaining expenditures for repairs and maintenance, including turbine-generator overhaul projects and projects related to aging civil infrastructure. OPG defines a project (whether capital or OM&A) as a temporary, unique endeavour undertaken outside the routine base activities of the normal work program. The final decision on whether work will be classified as a capital project or an OM&A project is based on OPG governance. OPG's capitalization policy is set out in Ex. D4-1-1.

OPG is requesting the approval of forecasted regulated hydroelectric Project OM&A expenditures of $127.0M for the 2027 test year. This represents an increase of $46.8M from the annual average of the 2022-2026 term of $80.2M, and reflects the increased Project OM&A portfolio necessary to maintain aging assets, as described in Ex. F1-1-1. Summaries of the regulated hydroelectric Project OM&A expenditures for the historical period, bridge period, and test year can be found in Ex. F1-3-1, Table 1.

As detailed in Ex. F1-1-1, Section 3.2.3.4, Renewable Generation has aligned the management of its OM&A project portfolios with the rest of the company, which includes establishing an unallocated OM&A project portfolio to provide funding in the business plan for potential projects expected to start in the future but that are not yet fully scoped or approved. Allocated Tier 1 OM&A projects are listed in Ex. F1-3-3.

Unallocated regulated hydroelectric OM&A projects amount to $68.8M in expenditures in the test year, and are primarily composed of planned major maintenance investments to sustain existing site assets and equipment. Unallocated OM&A projects with a potential cost over $5M are presented in Ex. F1-3-3, Tables 4a and 4b. OPG expects that throughout the forecast period, some of these projects (or other projects yet to be identified) will move from the project identification and initiation phases into the project planning and execution phase as part of the ongoing portfolio management process (refer to Ex. D2-1-1, Section 3.1), thus transitioning from unallocated projects to allocated projects. All projects, both allocated and unallocated, have been reviewed and approved to be entered into OPG's business plan in alignment with its asset management and investment planning processes (Ex. D2-1-1, Section 3.2).

The management of regulated hydroelectric OM&A projects uses the same process as for the capital projects as described in Ex. D1-1-1 and Ex. D2-1-1.

3.0 MAJOR CATEGORIES OF OM&A PROJECTS

Regulated hydroelectric Project OM&A expenditures are organized into three categories: portfolio projects, conceptual work for regulated hydroelectric development initiatives, and infrastructure expenditures.

3.1 Portfolio Projects

Project portfolios are developed and tailored to ensure the safety and reliability of OPG's assets, address issues of obsolescence, optimize unit/station generation, or meet regulatory requirements. The regulated hydroelectric Project OM&A portfolio primarily consists of routine sustaining investments to ensure ongoing equipment reliability, with major categories including turbine-generator unit overhaul projects and concrete restoration.

3.1.1 Turbine-Generator Overhaul Projects

Turbine-generator overhaul projects ("overhaul projects") consist of OM&A maintenance activities to sustain reliable operations of the turbine-generator equipment and related systems. Overhaul projects involve work on components that do not yet require replacement but require maintenance to ensure continued operability. Overhaul projects are generally performed every 25-30 years. Over the business plan period, many units will undergo equipment overhauls executed in parallel with capital refurbishments to minimize the number of required outage days.

OPG plans to progress approximately 20 overhaul projects in support of the turbine-generator refurbishment program in the test year, with significant projects at Otter Rapids GS, R.H. Saunders GS, and Stewartville GS. For more information on turbine-generator overhaul projects, refer to Ex. F1-1-1, Section 3.2.1.

3.1.2 Concrete Restoration

OPG plans to progress approximately 30 concrete restoration initiatives in the 2027 test year, with significant work taking place at Stewartville GS and R.H. Saunders GS.

The OM&A work performed as part of concrete restoration programs involves repairs of aging concrete, such as crack repairs and parging,[1] which do not extend the overall life of an asset but allow it to perform its intended function. Conversely, capital work performed to rehabilitate concrete structures involves extensive work including major demolition, concrete replacement, and the integration of new structural supports. Details on capital concrete projects are provided in Ex. D1-1-2.

As discussed in Ex. F1-1-1, Section 3.2.3, concrete restoration work is a critical aspect of OPG's regulated hydroelectric portfolio, particularly in addressing the phenomenon of Alkali-Aggregate Reaction at stations including the R.H. Saunders GS, Otto Holden GS, and Chats

[1] Concrete parging is the application of mortar over walls to provide durability and protection against environmental factors.

Falls GS. OPG is required to spend significant amounts of effort and funding to mitigate the impacts of Alkali-Aggregate Reaction, which has led to increased Project OM&A expenditures.

3.2 Conceptual Work for Hydroelectric Development Investments

In alignment with the Province's expectations detailed in the 2023 Powering Ontario's Growth report[2] and the 2025 Integrated Energy Plan,[3] OPG is continuing to assess the viability of potential development investments in regulated hydroelectric assets. This includes evaluating the options to redevelop stations at or nearing end of life, as well as opportunities to add substantial generation capacity to an existing regulated asset (e.g., via adding new units at existing generating stations).

This conceptual work includes site selection, feasibility analysis, interfacing with key government stakeholders, and engaging with Indigenous communities. Once an investment is deemed viable for progression, it proceeds from the identification and initiation phases into the project planning and ultimately execution phase as part of the ongoing portfolio management process. OPG forecasts to spend $3.7M in Project OM&A on regulated hydroelectric development initiatives in the test year. A summary of historical and forecasted expenditures is provided in Ex. F1-3-1, Table 1.

3.3 Infrastructure

Regulated hydroelectric infrastructure expenditures consist of removal costs associated with capital projects. Removal costs include costs associated with dismantling, crating, tearing down, or disassembling equipment formerly in service. These costs are expensed to Project OM&A in accordance with OPG's capitalization policy (Ex. D4-1-1, Section 2.0). A summary of historical and forecasted removal costs can be found in Ex. F1-3-1, Table 1.

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[2] Government of Ontario, *Powering Ontario's Growth: Ontario's Plan for a Clean Energy Future*, July 10, 2023 <https://www.ontario.ca/page/powering-ontarios-growth>.

[3] Government of Ontario, *Energy for Generations: Ontario's Integrated Plan to Power the Strongest Economy in the G7*, June 12, 2025, p. 56 <https://www.ontario.ca/page/energy-generations>.

Table 1
Project OM&A Summary - Regulated Hydroelectric ($M)

Line No.	Business Unit[1]	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Portoflio Projects (Allocated)												
1	**Niagara Region**	11.9	6.5	6.1	7.4	7.7	5.0	3.9	11.7	6.5	3.0	3.6	3.3
2	**Eastern Region**	16.5	24.3	34.6	34.7	26.7	47.9	58.1	51.4	43.8	47.4	35.2	18.0
3	**Western Region[2]**	9.3	7.3	2.9	1.7	2.9	14.8	4.1	2.0	2.7	3.6	2.9	0.7
4	**Subtotal Portfolio Projects (Allocated)**	37.7	38.1	43.6	43.8	37.3	67.7	66.1	65.1	53.0	53.9	41.7	21.9
5	**Infrastructure[3 4]**	0.7	4.1	10.1	10.5	15.5	13.4	7.9	10.0	14.9	29.1	22.1	32.7
	Portfolio Projects (Unallocated)												
6	**Niagara Region**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.6	2.4	13.5
7	**Eastern Region**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.7	19.3	47.9
8	**Western Region**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.6	1.3	7.4
9	**Subtotal Portfolio Projects (Unallocated)**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.9	22.9	68.8
10	**Small Hydro Redevelopment[5]**	0.7	0.1	0.0	0.1	0.8	0.0	0.1	0.2	0.4	1.7	3.8	3.7
11	**Total**	39.0	42.3	53.8	54.3	53.6	81.1	74.1	75.3	68.3	92.6	90.5	127.0

Notes:
1. Operating Region descriptions effective 2021 (see Ex. A1-4-2).
2. Western Region 2021 total includes recognition of a provision of $9.5M in connection with a Final Settlement Agreement with a First Nation to perform remediation work to address shoreline erosion impacts related to work performed by the Hydro-Electric Power Commission of Ontario (Ontario Hydro) at Lake Nipigon in 1925.
3. Reflects all removal costs regardless of related capital project CRVA eligibility.
4. 2027 amounts include $18.2M of removal costs related to CRVA-eligible projects.
5. Conceptual work to assess the viability of proposed regulated hydroelectric development projects. See F1-3-1, Section 3.2.

Numbers may not add due to rounding.

Table 2
Project OM&A Summary - Regulated Hydroelectric ($M) (Allocated)

Line No.	OM&A Project Category	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget	2027 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	**Regulatory**	3.8	3.3	5.9	3.9	1.9	5.3	3.8	2.5	4.2	4.6	2.6	0.6
2	**Sustaining**	33.9	34.8	37.8	39.8	35.4	62.4	62.3	62.6	48.7	49.4	39.1	21.3
3	**Value Enhancing/Strategic**	0.7	0.1	0.0	0.1	0.8	0.0	0.1	0.2	0.4	0.0	0.0	0.0
4	**Total**	38.3	38.2	43.7	43.8	38.1	67.7	66.2	65.2	53.3	53.9	41.7	21.9

COMPARISON OF PROJECT OM&A COSTS – REGULATED HYDROELECTRIC

1.0 PURPOSE

This evidence presents term-over-term comparisons of Project OM&A expenditures within the regulated hydroelectric portfolio.

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 hydroelectric business below, for the period 2016-2024. As there is no OEB-approved Project OM&A information for 2015 onwards, OPG has only provided term-over-term variance analyses for the following periods: 2017-2021 actuals versus 2022-2026,[1] and the annual average of 2022-2026[2] versus the 2027 test year forecast.

As discussed in Ex. F1-3-1, the increase in Project OM&A expenditures over the historical period reflects the increased Project OM&A portfolio necessary to maintain aging assets, as described in Ex. F1-1-1.

2.0 TERM-OVER-TERM CHANGES – 2022-2026 ANNUAL AVERAGE VERSUS 2027

OPG is requesting the approval of forecasted regulated hydroelectric Project OM&A expenditures of $127.0M for the 2027 test year. This represents an increase of $46.8M from the previous period's average annual expenditure of $80.2M between 2022-2026. The increase in Project OM&A expenditures is primarily due to an increase of $28.6M for Portfolio Projects, and an increase of $15.9M for infrastructure costs. A summary of the regulated hydroelectric Project OM&A expenditures for the historical period (2017-2021), bridge period (2022-2026), and test year (2027) can be found in Ex. F1-3-1, Table 1 and Ex. F1-3-2, Table 1.

[1] 2022-2024 actuals, 2025-2026 forecast.
[2] *Ibid*.

2.1 Portfolio Projects

In the 2027 test year, Portfolio Project OM&A expenditures are forecasted to total $90.7M, an increase of $28.6M from the previous period's average annual expenditure of $62.1M. This term-over-term change consists of increases in expenditures for Niagara Region (+$10.1M), Eastern Region (+$14.3M), and Western Region (+$4.2M).

<u>Niagara Region</u>

In the 2027 test year, OM&A Project expenditures for Niagara Region are forecasted to total $16.8M. This is an increase of $10.1M from the previous period's average annual expenditure of $6.7M. This change is driven primarily by increased Project OM&A spending for Niagara station overhauls, such as DeCew Falls 1 GS. Additional contributors to this increase include Niagara Region building rehabilitation programs as well as the rehabilitation of the Sir Adam Beck 1 GS powerhouse, screenhouse interior, and building envelope, which is necessary to accommodate the increased staffing levels required for the Sir Adam Beck 1 and Sir Adam Beck 2 GS refurbishment projects described in Ex. D1-1-2, Section 3.2.1.

<u>Eastern Region</u>

In the 2027 test year, OM&A Project expenditures for Eastern Region are forecasted to total $65.9M. This is an increase of $14.3M from the previous period's average annual expenditure of $51.6M. This change is driven by increased expenditures related to concrete repair and restoration projects, primarily those pertaining to concrete structures at the Des Joachims GS and R.H. Saunders GS.

<u>Western Region</u>

In the 2027 test year, OM&A project expenditures for Western Region are forecasted to total $8.1M. This is an increase of $4.2M from the previous period's average annual expenditure of $3.8M. This change is driven by increased expenditure related to concrete repair and restoration projects, notably those pertaining to the Auburn GS forebay and Tretheway Falls GS gravity walls.

2.2 Infrastructure Expenditures

In the 2027 test year, infrastructure Project OM&A expenditures are forecasted to total $32.7M, an increase of $15.9M from the previous period's average annual expenditure of $16.8M. This is driven by an increase in removal costs corresponding with increased refurbishment activity in the forecast period (refer to Ex. D1-1-1, Section 4.2).

3.0 TERM-OVER-TERM CHANGES: EXTENDED HISTORICAL YEARS – 2017-2021 VERSUS 2022-2026

Pursuant to the OEB's letter dated September 17, 2024, issued in EB-2024-0136, OPG has included an additional analysis of term-over-term historical data (2017-2021 versus 2022-2026) for its regulated hydroelectric business below. OPG expects to spend a total of $400.8M in Project OM&A expenditure during the 2022-2026 term, an increase of $115.7M from the 2017-2021 period's expenditures of $285.1M. The increase in Project OM&A expenditure is primarily due to an increase in expenditures for Portfolio Projects of $80.2M and an increase in infrastructure costs of $30.4M. A summary of the regulated hydroelectric Project OM&A expenditures for the 2017-2021 and 2022-2026 terms can be found in Ex. F1-3-2, Table 1.

3.1 Portfolio Projects

During the 2022-2026 term, Portfolio Project OM&A expenditures are forecasted to total $310.6M, an increase of $80.2M from the 2017-2021 term's expenditure of $230.5M. This term-over-term change mainly consists of an increase for Eastern Region (+$89.7M), and a $10.5M decrease for Western Region.

<u>Eastern Region</u>

Project OM&A expenditures for Eastern Region are forecasted to total $257.8M in the 2022-2026 term. This is an increase of $89.6M from the 2017-2021 term's expenditure of $168.2M. This is driven by an increase in turbine-generator overhaul projects within the Eastern Region, including the following Tier 2 projects:

- Otter Rapids GS Unit G1 (project #82515 Otter Rapids GS G1 Overhaul)
- Otter Rapids GS Unit G2 (project #82521 Otter Rapids GS G2 Overhaul)
- Otto Holden GS Unit G8 (project #86476 Otto Rapids GS G8 Overhaul)

- R.H. Saunders GS Unit G9 (project #83371 R.H. Saunders GS G9 Overhaul)
- R.H. Saunders GS Units G12 (project #86593 R.H. Saunders GS G12 Overhaul)

Further details on these projects are provided in Ex. F1-3-3, Table 2.

Western Region

Project OM&A expenditures for Western Region are forecasted to total $19.1M in the 2022-2026 term. This is a decrease of $10.5M from the 2017-2021 term's expenditure of $29.6M. The 2017-2021 term saw higher Project OM&A expenditures due to a provision of $9.5M in connection with a Final Settlement Agreement with a First Nation to perform remediation work to address shoreline erosion impacts related to work performed by the Hydro-Electric Power Commission of Ontario (Ontario Hydro) at Lake Nipigon in 1925.

3.2 Infrastructure Expenditures

Infrastructure Project OM&A expenditures are forecasted to total $84.0M in the 2022-2026 term, an increase of $30.4M from the 2017-2021 term's expenditure of $53.6M. The term-over-term increase was driven by an increase in removal costs corresponding with a greater number of capital refurbishment projects (refer to Ex. D1-1-1, Section 5.2).

Numbers may not add due to rounding.

Table 1
Comparison of Project OM&A - Regulated Hydroelectric ($M)

Line No.	Business Unit[1]	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Budget	2026 Budget
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Portoflio Projects (Allocated)											
1	**Niagara Region**	11.9	6.5	6.1	7.4	7.7	5.0	3.9	11.7	6.5	3.0	3.6
2	**Eastern Region**	16.5	24.3	34.6	34.7	26.7	47.9	58.1	51.4	43.8	47.4	35.2
3	**Western Region[2]**	9.3	7.3	2.9	1.7	2.9	14.8	4.1	2.0	2.7	3.6	2.9
4	**Subtotal Portfolio Projects (Allocated)**	37.7	38.1	43.6	43.8	37.3	67.7	66.1	65.1	53.0	53.9	41.7
5	**Infrastructure[3,4]**	0.7	4.1	10.1	10.5	15.5	13.4	7.9	10.0	14.9	29.1	22.1
	Portfolio Projects (Unallocated)											
6	**Niagara Region**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.6	2.4
7	**Eastern Region**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.7	19.3
8	**Western Region**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.6	1.3
9	**Subtotal Portfolio Projects (Unallocated)**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.9	22.9
10	**Small Hydro Redevelopment[5]**	0.7	0.1	0.0	0.1	0.8	0.0	0.1	0.2	0.4	1.7	3.8
11	**Total**	39.0	42.3	53.8	54.3	53.6	81.1	74.1	75.3	68.3	92.6	90.5

Line No.	Business Unit[1]	2017-2021 Actuals Total	(c)-(a) Change	2022-2026 Actuals & Budget Total	2022-2026 Actuals & Budget Average	(f)-(d) Change	2027 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	Portoflio Projects (Allocated)						
12	**Niagara Region**	32.7	(4.0)	28.7	5.7	(2.4)	3.3
13	**Eastern Region**	168.2	67.7	235.8	47.2	(29.2)	18.0
14	**Western Region[2]**	29.6	(14.4)	15.2	3.0	(2.4)	0.7
15	**Subtotal Portfolio Projects (Allocated)**	230.5	49.3	279.7	55.9	(34.0)	21.9
16	**Infrastructure[3,4]**	53.6	30.4	84.0	16.8	15.9	32.7
	Portfolio Projects (Unallocated)						
17	**Niagara Region**	0.0	5.0	5.0	1.0	12.5	13.5
18	**Eastern Region**	0.0	22.0	22.0	4.4	43.5	47.9
19	**Western Region**	0.0	3.9	3.9	0.8	6.6	7.4
20	**Subtotal Portfolio Projects (Unallocated)**	0.0	30.9	30.9	6.2	62.6	68.8
21	**Small Hydro Redevelopment[5]**	1.0	5.2	6.2	1.2	2.4	3.7
22	**Total**	285.1	115.7	400.8	80.2	46.8	127.0

Notes:

1 Operating Region descriptions effective 2021 (see Ex. A1-4-2).
2 Western Region 2021 total includes recognition of a provision of $9.5M in connection with a Final Settlement Agreement with a First Nation to perform remediation work to address shoreline erosion impacts related to work performed by the Hydro-Electric Power Commission of Ontario (Ontario Hydro) at Lake Nipigon in 1925.
3 Reflects all removal costs regardless of related capital project CRVA eligibility.
4 2027 amounts include $18.2M of removal costs related to CRVA-eligible projects.
5 Conceptual work to assess the viability of proposed regulated hydroelectric development projects. See F1-3-1, Section 3.2.

DETAILS OF OM&A PROJECTS – REGULATED HYDROELECTRIC

1.0 PURPOSE

The purpose of this evidence is to provide project listings and supporting information, including business case summaries ("BCS"), for allocated Project OM&A expenditures within the regulated hydroelectric business portfolio.

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

Consistent with OEB filing requirements, OPG has used a tiered reporting structure to present the evidence for all allocated projects with forecast expenditures in the bridge period (2025-2026) and/or test year (2027), as well as completed projects since 2016. The BCSs are provided for Tier 1 projects with expenses in the 2027 test year.

Tier 1:
This tier comprises individual projects with a total cost of $20M or more. For these projects, summary level information is provided in Ex. F1-3-3, Table 1. There is one regulated hydroelectric Tier 1 project. Further information on Tier 1 projects is provided in Section 3.0 below.

Tier 2:
This tier comprises individual projects with a total cost of $5M or more, but less than $20M, for which summary level information is provided in Ex. F1-3-3, Table 2. There are 43 regulated hydroelectric Tier 2 projects listed in Ex. F1-3-3, Table 2. This includes 34 projects in Eastern Region, seven projects in Niagara Region, and two projects in Western Region.

Tier 3:

This tier comprises individual projects with a total cost of less than $5M, for which aggregated information is provided in Ex. F1-3-3, Table 3. There are 13 regulated hydroelectric Tier 3 projects listed in Ex. F1-3-3, Table 3. This includes four projects in Niagara Region, seven projects in Eastern Region, and two projects in Western Region. The average cost of these projects is $2.6M.

Unallocated Projects

There are 17 unallocated Portfolio Projects which are currently in the project identification or project initiation phases, with one project with a total preliminary cost forecast of over $20M presented in Ex. F1-3-3, Table 4a, and the remaining 16 with a total preliminary cost forecast of more than $5M presented in Ex. F1-3-3, Table 4b. OPG expects that over the forecast period, some of these projects (or other projects yet to be identified) will move from the project identification and initiation phases into the project planning or execution phase as part of the ongoing portfolio management process (Ex. D2-1-1, Section 3.1).

3.0 PROJECT-SPECIFIC INFORMATION – TIER 1 REGULATED HYDROELECTRIC PROJECTS

The following information relates to projects identified in Ex. F1-3-3, Table 1.

Project #82328 Otto Holden GS Concrete Mitigation Phase 2. This project rehabilitated major concrete structures at the Otto Holden GS, including the east gravity section, tailrace training wall, downstream powerhouse wall, tailrace deck grating, headworks deck, headworks pier noses, west gravity section, powerhouse beams, and headworks beams. This project was completed in May 2025 at a total cost of $31.0M, which is an increase of $7.4M from the Class 3 Estimate of $23.6M detailed in the first Execution Phase business case. The cost variance of $7.4M was driven by the discovery of extensive concrete deterioration caused by Alkali-Aggregate Reaction. Further details on Alkali-Aggregate Reaction can be found in Ex. F1-1-1, Section 3.2.3.1.

Table 1
OM&A Project Listing - Regulated Hydroelectric
Projects ≥ $20M Total Project Cost (Allocated)[1]

Line No.	Region[2]	Project Name	Project No.	Category	Start Date	Final Completion Date	Total Project Cost ($M)[3]	Partial/Devmt Release ($M)	Initial Full Release ($M)	Superseding Full Release ($M)	2016 Actual ($M)	2017 Actual ($M)	2018 Actual ($M)	2019 Actual ($M)	2020 Actual ($M)	2021 Actual ($M)	2022 Actual ($M)	2023 Actual ($M)	2024 Actual ($M)	2025 Budget ($M)	2026 Budget ($M)	2027 Plan ($M)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)
1	Eastern	OTO - Concrete Mitigation Phase 2	82328	Sustaining	Mar-16	May-25	31.0			31.8	0.2	3.7	8.0	7.7	4.2	3.7	3.4	0.0	0.1	0.0	0.0	0.0
		Total					31.0	0.0	0.0	31.8	0.2	3.7	8.0	7.7	4.2	3.7	3.4	0.0	0.1	0.0	0.0	0.0

Notes:

1 Projects with expenditure in the 2016-2024 historical period, 2025-2026 bridge period, or 2027 test year.

2 Operating Region descriptions effective 2021 (see Ex. A1-4-2).

3 Total Project Cost reflects BCS amounts at the time of preparing the 2025-2031 Business Plan, with the exception of Completed/Deferred/Cancelled Projects (for which actual costs are shown). BCS amounts reflect point estimates or, if range estimate or no estimate is provided in lieu of a point estimate, the current estimate of total project cost. Total Project Cost may include expenditures beyond the 2027 test year.

Numbers may not add due to rounding.

Table 2
OM&A Project Listing - Regulated Hydroelectric
Projects $5M - $20M Total Project Cost (Allocated)[1]

Line No.	Region[2]	Project Name	Project No.	Category	Project Description	Start Date	Final Completion Date	Total Project Cost ($M)[3]
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Eastern	Chats Falls - Main Dam Concrete Repairs	80591	Sustaining	Restoration of stop log sluices, head works, main dam gravity sections and associated equipment to address existing deterioration and operational issues.	Aug-10	Feb-18	19.5
2	Eastern	OTO - G7 Overhaul - Mechanical/Electrical Unit Overhauls	82326	Sustaining	Overhaul of turbine generator unit components.	Mar-16	Jan-25	14.5
3	Eastern	R.H. Saunders GS - Repaint Barnhardt Island Bridge (JW NYPA)	80639	Regulatory	Sandblasting of old lead paint and repainting of bridge.	Mar-10	Aug-16	6.9
4	Eastern	R.H. Saunders GS - Concrete Growth Mitigation	80788	Sustaining	Slot cutting around generating units.	Sep-16	Feb-26	17.7
5	Eastern	R.H. Saunders GS - Replace Administration Building window & brick	80641	Sustaining	Replacing original windows and decaying brick on the administration building.	Mar-12	Sep-18	5.6
6	Eastern	Barrett Chute GS - G1-G4 Mechanical/Electrical Unit Overhauls	82319	Sustaining	Overhaul of turbine generator unit components.	Dec-15	Sep-24	12.8
7	Eastern	Des Joachims GS - Headworks Piers Concrete Repairs	82588	Sustaining	Repair Headworks Piers, Gains, Upstream face of North & South Bulkheads	Sep-16	Sep-25	19.5
8	Eastern	Des Joachims - Re-insulate Rotor Field Poles	80605	Sustaining	Re-insulate Rotor Field Poles - All units	Jan-12	Aug-23	9.7
9	Eastern	Stewartville GS - G5 Mechanical/Electrical Overhauls	82340	Sustaining	Overhaul of turbine generator unit components.	Mar-23	Dec-27	10.0
10	Eastern	Lower Notch GS - G1 Overhaul	80693	Sustaining	Overhaul of turbine generator unit components.	Nov-11	Sep-16	5.4
11	Eastern	Lower Notch GS - G2 Overhaul	80695	Sustaining	Overhaul of turbine generator unit components.	Nov-11	Mar-21	5.1
12	Eastern	SAU - Unit Generator Concrete Slot Cutting	83086	Sustaining	Implementing concrete contraction joints to relieve concrete stress and deformation driven by Alkali-Aggregate Reaction.	Apr-16	Mar-20	10.1
13	Eastern	Abitibi - G2 Overal	83156	Sustaining	Overhaul of turbine generator unit components.	Feb-19	Nov-23	8.2
14	Eastern	BAR - NS G4 Mech/Elec Overhaul	84588	Sustaining	Overhaul of turbine generator unit components.	Jul-19	Feb-25	9.1
15	Eastern	SAU - Rep. Tailrace Deck Cncrt & Gantry	83370	Sustaining	Repair of spalling, scaling and ravelling on the tailrace concrete deck to prevent tripping hazards and maintain deck integrity.	May-17	Mar-23	6.6
16	Eastern	BAR - G1 Mech/Elec Overhaul	86078	Sustaining	Overhaul of turbine generator unit components.	Jul-20	Feb-26	14.3
17	Eastern	BAR G2 Mech/Electrical Overhaul	86079	Sustaining	Overhaul of turbine generator unit components.	Jul-20	Dec-25	10.6
18	Eastern	OTO - G8 Overhaul (NS)	86476	Sustaining	Overhaul of turbine generator unit components.	Feb-23	Jan-26	10.0
19	Eastern	OTO - G6 Overhaul; NS	86479	Sustaining	Overhaul of turbine generator unit components.	Feb-24	Dec-26	9.0
20	Eastern	OTO - G5 Overhaul; NS	86481	Sustaining	Overhaul of turbine generator unit components.	Feb-22	Sep-25	9.6
21	Eastern	OTO - Regasket Transformers	84407	Sustaining	Restoration of main transformers that have experienced recent oil leaks, and rehabilitation of concrete transformer bay.	Mar-19	Dec-24	5.9
22	Western	SLV G1 Overhaul	82381	Sustaining	Overhaul of turbine generator unit components.	Jan-18	Jul-24	6.1
23	Eastern	SAU - Concrete Growth Mitigation	80788	Sustaining	Concrete remediation throughout powerhouses for all 16 units to address effects of Alkali-Aggregate Reaction.	Feb-16	Feb-26	17.5
24	Eastern	SAU - G9 Overhaul	83371	Sustaining	Overhaul of turbine generator unit components.	Jun-17	Jun-26	17.1
25	Eastern	SAU - LSD Barrier JW NYPA	84895	Regulatory	NYPA-executed project to install positive restraint barriers at Long Sault Dam.	Jan-20	Dec-26	10.2
26	Eastern	SAU - Unit Hatchcover Refurb	82334	Sustaining	Replacement of hatch cover seals, drive mechanisms, electrical and control equipment.	Feb-18	Jun-25	7.3
27	Eastern	DEJ - Auxiliary Dam Repair Deck & Handrails	84161	Sustaining	Restoration of concrete deterioration on the auxiliary dam returning it to a state of original function.	Nov-19	Dec-25	10.5
28	Eastern	UMD - MAD River IDF Deficiency Objective	84897	Sustaining	Completion of precipitation and dam safety review studies for Upper Madawaska system.	May-20	Dec-26	5.6
29	Eastern	Otter G2 Non-Standard Overhaul	82521	Sustaining	Overhaul of turbine generator unit components.	Aug-20	Mar-26	16.1
30	Niagara	PG6 Overhaul	82421	Sustaining	Overhaul of turbine generator unit components.	Feb-17	Dec-21	10.0
31	Niagara	PG1 Overhaul	80917	Sustaining	Overhaul of turbine generator unit components.	Feb-15	Dec-19	8.8
32	Niagara	PG5 Overhaul	80657	Sustaining	Overhaul of turbine generator unit components.	Apr-14	Jan-17	8.5
33	Niagara	Dredge Tunnel 1 and 2 Intakes	82413	Sustaining	Dredge tunnel 1 and 2 intakes to restore them to as-built condition and prevent debris from entering tunnels and restricting flow to SAB complex.	Aug-19	Mar-25	7.9
34	Niagara	ICD Bridge Repair	80764	Sustaining	Rehabilitation of the International Control Dam bridge to resolve deficiencies in its original design and construction.	Oct-13	Dec-20	5.9
35	Niagara	SAB2 Rock Cliff Concrete Rehab	82426	Sustaining	Rehabilitation of concrete rock cliff to prevent rock and concrete debris from falling to lower levels.	Jul-21	Oct-26	5.2
36	Niagara	H1 BK1 Switchyard Reconfig.	84562	Sustaining	HONI-executed project to upgrade HONI E-bus to accommodate increased generation capacity from SAB1.	Dec-19	Jun-26	5.7
37	Eastern	Otter G1 Non-Standard Overhaul	82515	Sustaining	Overhaul of turbine generator unit components.	Nov-24	Jun-27	10.0
38	Eastern	SAU - G12 Overhaul	86593	Sustaining	Overhaul of turbine generator unit components.	Jun-22	Aug-26	10.9
39	Eastern	SAU - G16 Overhaul	86945	Sustaining	Overhaul of turbine generator unit components.	Nov-24	Jul-28	12.1
40	Eastern	OTO - G1 Overhaul, NS	87558	Sustaining	Overhaul of turbine generator unit components.	Jan-25	Apr-27	6.4
41	Eastern	Otter Penstock Transition-Grout Leakage	82547	Sustaining	Repair of penstock leaks, including penstock transitions and concrete joints.	Dec-18	Sep-31	5.9
42	Eastern	ABI Rep. Tunnels and Headwork East Stair	83154	Sustaining	Rehabilitation of concrete structures in relay tunnel, east stairwell and lower inspection tunnel.	Jan-20	May-26	7.8
43	Western	Whitesand Erosion Repairs	80749	Regulatory	Repair of erosion damage to Whitesand First Nation shoreline.	Aug-09	Dec-25	17.4
44		**Total**						432.7

Notes:
1 Projects with expenditure in the 2016-2024 historical period, 2025-2026 bridge period, or 2027 test year.
2 Operating Region descriptions effective 2021 (see Ex. A1-4-2).
3 Total Project Cost reflects BCS amounts at the time of preparing the 2025-2031 Business Plan, with the exception of Completed/Deferred/Cancelled Projects (for which actual costs are shown). BCS amounts reflect point estimates or, if range estimate or no estimate is provided in lieu of a point estimate, the current estimate of total project cost. Total Project Cost may include expenditures beyond the 2027 test year.

Numbers may not add due to rounding.

Table 3
OM&A Project Listing - Regulated Hydroelectric
Projects < $5M Total Project Cost[1]

Line No.	Operating Region[2]	Number of Projects	Total Project Cost ($M)	Average Cost Of All Projects ($M)
	(a)	(b)	(c)	(d)
1	**Niagara Region**	4	11.0	2.8
2	**Eastern Region**	7	20.8	3.0
3	**Western Region**	2	2.6	1.3
4	**Total**	13	34.4	2.6

Notes:
1 Projects with expenditures in 2027 test year.
2 Operating Region descriptions effective 2021 (see Ex. A1-4-2).

Table 4a
OM&A Project Listing - Regulated Hydroelectric
Portfolio Projects (Unallocated)[1]

Line No.	Facility	Project Name	Category	Potential Start Date
	(a)	(b)	(c)	(d)
		Regulated Hydroelectric - Projects With Potential Cost ≥ $20M		
		Niagara Region		
1		No projects in this category		
		Eastern Region		
2	R.H. Saunders	89174 - SAU - Headworks Deck Concrete Repairs	Sustaining	2027
		Western Region		
3		No projects in this category		

Notes:

1 Projects with forecast expenditure in the 2027 test year. Each project is forecast to have a project expenditure of greater than $20M.

Table 4b
OM&A Project Listing - Regulated Hydroelectric
Portfolio Projects (Unallocated)[1]

Line No.	Facility	Project Name	Category	Potential Start Date
	(a)	(b)	(c)	(d)
		Regulated Hydroelectric - Projects With Potential Cost $5M - $20M		
		Niagara Region		
1	Sir Adam Beck Pump Generating Station	PGS Building Rehab	Sustaining	2027
		Eastern Region		
2	R.H. Saunders	SAU - Concrete Growth Mitigation-Phase 2	Sustaining	2025
3	R.H. Saunders	SAU - G1 Overhaul	Sustaining	2026
4	R.H. Saunders	SAU G11 Overhaul	Sustaining	2027
5	Des Joachims	DEJ - Rep Sluicegate Deck & Upstrm Pier	Sustaining	2027
6	Chenaux	CHE - O/H Program 1st Unit Overhaul	Sustaining	2025
7	Stewartville	STW - 3rd Overhaul-Mech Elec Unit	Sustaining	2027
8	Stewartville	STW - 2nd Unit Overhaul	Sustaining	2026
9	Chats Falls	CHF - Main Earth Dyke Riprap, Repair-Net	Sustaining	2026
10	Otter Rapids	Otter - G4 Non Standard Overhaul	Sustaining	2026
11	Stewartville	STW - Repair Concrete-Sluice Discharge Channel	Sustaining	2026
12	Crystal Falls	CRY – Sluice Gate Refurb	Sustaining	2027
13	Otto Holden	OTO - G2 Overhaul	Sustaining	2027
14	Chenaux	CHE - Machine Shop Repairs - Footings	Sustaining	2026
15	Barrett Chute	BAR - Rehab Penstock Envelopes	Sustaining	2026
16	Lower Notch	LWN - Sandblast/Repaint Sluice Structure	Sustaining	2026
		Western Region		
17		No projects in this category		

Notes:
1 Projects with forecast expenditure in the 2027 test year. Each project is forecast to have a project expenditure of between $5M - $20M.

Table 5
OM&A Project Listing - Regulated Hydroelectric
Listing of Business Case Summaries Filed[1]

Line No.	Facility	Business Case Summary (BCS) Title	Project Number	BCS Approval Date	Project Stage	BCS Status
	(a)	(b)	(c)	(d)	(e)	(f)
		There are no Tier 1 projects with expenditures in the 2027 test year.				

Notes:
1 Projects with expenditures in the 2027 test year.

GROSS REVENUE CHARGE AND OTHER WATER AGREEMENT COSTS – REGULATED HYDROELECTRIC

1.0 PURPOSE

This evidence describes the gross revenue charges ("GRC") that OPG is required to pay the Province of Ontario pursuant to legislative and regulatory requirements. It also describes water rental charges and other water agreement costs payable to other governments, agencies, or companies (St. Lawrence Seaway Management Corporation, Parks Canada, Government of Québec, Hydro-Québec) and funding contributions to the Lake of the Woods Control Board and the Ottawa River Regulation Planning Board (Government of Canada).

2.0 OVERVIEW

Gross revenue charges refer to the taxes and charges that are required to be paid by owners of hydroelectric generating stations under Section 92.1 of the *Electricity Act, 1998*. Details pertaining to GRC are available in the legislation and *Ontario Regulation 124/02* ("O. Reg. 124/02"), and the calculation methodology is unchanged from EB-2013-0321. A description of GRC applicable to the regulated hydroelectric stations is provided in Section 3.0 below.

Water rental charges and other costs associated with leases, licenses, funding of Control Boards, or agreements with other governments, agencies, or companies are described in Section 4.0.

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 hydroelectric business below, for the period 2016-2024. Exhibit F1-4-1, Table 1, presents the total of GRC and other water agreement costs for the years 2016-2027. Actual amounts are shown for the years 2016-2024 and forecasted amounts are shown for the bridge period (2025-2026), and test year (2027).[1] Year-over-year changes in GRC are discussed in Ex. F1-4-2.

[1] GRC figures reflect the final billed amounts for each respective year 2016-2024.

3.0 GROSS REVENUE CHARGE ON REGULATED HYDROELECTRIC GENERATING STATIONS

The GRC consists of a property tax component and a water rental component. All 54 of the regulated hydroelectric facilities are subject to the property component, payable to the Ontario Electricity Financial Corporation ("OEFC"). Only 35 of those facilities where water power leases are held with the Ontario Ministry of Natural Resources are subject to the water rental component, which is payable to the Ministry of Finance, with the exception of a portion[2] for the Sir Adam Beck Complex which is paid directly to the Niagara Parks Commission as required by Ontario Regulation 135/02 under the *Electricity Act, 1998*. The remaining 19 regulated hydroelectric facilities that are not subject to GRC water rentals are shown in Chart 1; payments related to any other applicable water rental agreements are detailed in Section 4.0 below.

Chart 1 – Regulated Hydroelectric Facilities Not Subject to GRC Water Rental Component

Region	Hydroelectric Facilities
Niagara Region	DeCew Falls 1 GS, DeCew Falls 2 GS
Eastern Region	Bingham Chute GS, Elliott Chute GS, Nipissing GS, Calabogie GS
Western Region	Eugenia Falls GS, Auburn GS, Frankford GS, Hagues Reach GS, High Falls GS, Lakefield GS, Merrickville GS, Meyersburg GS, Ranney Falls GS, Seymour GS, Sidney GS, Sills Island GS, Kakabeka Falls GS

The GRC is determined by multiplying the station's annual energy production by a fixed rate of $40,000 per GWh (as prescribed by O. Reg. 124/02 and extended by Ontario Regulation 09/10) and then applying the appropriate GRC property and water rental tax rates. Any applicable water transactions with another utility are also included in the determination of the station's annual energy production that is subject to the GRC according to the formulas prescribed in O. Reg. 124/02, Part II, s. 3(2-5) (see Ex. G1-1-1 for a discussion of Water Transactions). The GRC property tax rates are graduated through four tiers of production,

[2] In accordance with subsection 92.1 (5.1) of the *Electricity Act, 1998.*

increasing from 2.5% to 4.5%, 6.0%, and 26.5%, as shown in Chart 2. The GRC water rental rate is fixed at 9.5%.

Chart 2 – Gross Revenue Charge Components

Station Production (GWh/yr)	Water Rental Rate (%)	Property Graduated Rate (%)	Total GRC Rate (%)
0 – 50	9.5	2.5	12.0
50 – 400	9.5	4.5	14.0
400 – 700	9.5	6.0	15.5
> 700	9.5	26.5	36.0

Per O. Reg. 124/02, s. 3(2), a station's annual generation for the year includes the net energy associated with water transfers to and from another station. The GRC associated with forecast water transfers to and from New York Power Authority stations on the Niagara and St. Lawrence Rivers is included as a separate row in Ex. F1-4-1, Table 1.

Ontario Regulation 124/02, s. 7, allows deductions to GRC for eligible capacity of new, redeveloped, or upgraded stations.[3] These deductions reduce the GRC payments of a station by a factor proportional to the upgraded capacity. Calabogie GS, which was redeveloped following a tornado in 2017, is currently operating with an approved GRC deduction. No other O. Reg. 124/02 GRC deductions are currently in effect or included in the GRC forecast. OPG expects to apply for GRC deductions for capacity expansions when eligible. As the eligibility for and magnitude of potential GRC deductions cannot be determined until projects are completed, OPG proposes to capture any future GRC deductions in the Gross Revenue Charge Variance Account. In order to do so, OPG is proposing to expand the existing Gross Revenue Charge Variance Account to apply to all of OPG's regulated hydroelectric facilities. OPG also proposes that the account capture the revenue requirement impact of any differences in GRC expenses that result from a legislative or regulatory charge to the GRC rates or rules. These proposals are as described in Ex. H1-1-1, Section 5.9.

[3] In accordance with O. Reg. 124/02, s. 7(2), in the case of a new or redeveloped station the deductions include all of the station's annual generation.

4.0 OTHER WATER AGREEMENT, WATER RENTAL, AND CONTROL BOARD COSTS

In addition to the GRC payable to the OEFC, Ontario Minister of Finance, and the Niagara Parks Commission, land rentals are paid to the Ontario Ministry of Natural Resources for Crown Leases or Licenses of Occupation associated with the regulated hydroelectric facilities. These nominal rentals are included in the GRC totals presented for each Operating Region in Ex. F1-4-1, Table 1.

Other water rental charges and costs are incurred pursuant to a number of agreements with other government agencies and companies, as well as legislative requirements related to control board funding. The main agreements are described below.

4.1 St. Lawrence Seaway Management Corporation Lease Agreement

OPG holds a lease agreement with the St. Lawrence Seaway Management Corporation ("SLSMC") pertaining to the conveyance of water from Lake Erie through the SLSMC's Welland Canal to intakes at Allanburg, where water is withdrawn and diverted to the DeCew Falls generating stations (Niagara Region) for power generation; water conveyance charges payable to SLSMC are determined based on the monthly average diversion flow. The current 30-year lease is in place until 2038, with rates subject to review every five years. The water conveyance payment terms are currently in legal arbitration. Pending the outcome of the arbitration, OPG has based the 2025-2027 amounts included in the Niagara Region GRC totals presented in Ex. F1-4-1, Table 1 on the existing rates.

4.2 Government of Québec Water Rentals

The Governments of Ontario and Québec ratified an Agreement dated January 2, 1943, pertaining to the development of water power on the Ottawa River.[4] Under the terms of this agreement, water rentals are paid to the Government of Québec based on one-half of station production from the upper three Ottawa River plants (Otto Holden GS, Des Joachims GS, and Chenaux GS). Rental rates prescribed by the 1943 Agreement were revised by subsequent agreement between the parties for the 25-year period from 1993-2017. The rental rate

[4] The Ottawa River Water Powers Act, 1943.

applicable for the years 2015-2017, inclusive, was $30 per average annual horsepower of energy. A rate agreement for the next 25-year period beginning in 2018 was finalized in 2019. The agreement sets a rental rate applicable for January 2018-March 2020, inclusive, at $30 per average annual horsepower of energy and a rental rate for April 2020-March 2023, inclusive, at $4.59 per each thousand kilowatt hours of energy (note that this change represents a unit conversion from yearly horsepower to kilowatt hours; the rental rate is effectively the same).[5] Beginning in April 2023 and continuing to January 1, 2043 the rental rate is indexed to the Consumer Price Index.[6] Water rental costs for the three Ottawa River plants are projected to be $10.7M in 2025 and increase to $12.6M by 2031. The Québec water rental costs have been included with the Eastern Region GRC totals presented in Ex. F1-4-1, Table 1.

OPG does not pay water rentals to the Government of Québec for the fourth Ottawa River plant, Chats Falls GS, as ownership of Chats Falls GS is shared with Hydro-Québec. Water rentals payable to the Government of Québec are paid by Hydro-Québec, based on one-half of station production. OPG pays GRC (property and water rental components) to the OEFC and the Ontario Ministry of Finance based on one-half of Chats Falls GS annual production.

4.3 Hydro-Québec – Dozois Agreement and Cabonga Diversion Agreement

The *Ottawa River Water Powers Act, 1943*, prescribed that expenses for works that increase or regulate the flow of the Ottawa River are to be shared by the benefitting parties. Under an agreement with Hydro-Québec (the "Dozois Agreement"), OPG shares in operation, maintenance, and project refurbishment costs associated with Hydro-Québec's Bourque Dam and the Dozois Reservoir. These facilities enable diversion of water from Québec to the Ottawa River basin (referred to as the "Cabonga diversion") where benefits from this additional water are realized at OPG's four generating stations on the Ottawa River. Annual costs pertaining to the Dozois Agreement are projected to be approximately $1.3M between 2025-2027. These

[5] The Ottawa River Water Powers Act, 1943.
[6] Statistics Canada. Table 18-10-0005-01. Consumer Price Index, annual average, not seasonally adjusted. <https://www150.statcan.gc.ca>.

costs have been included with the Eastern Region GRC totals presented in Ex. F1-4-1, Table 1.

One-half of the energy produced that is attributable to the Cabonga diversion water is returned to Hydro-Québec as per terms of the Cabonga Diversion Agreement. This "Cabonga diversion payback" is forecast to be approximately 42 GWh in 2027 and is settled by scheduled transfers of energy via the R.H. Saunders interconnection. This payback is considered to be energy that belongs to Hydro-Québec and is not subject to GRC.

4.4 Other Agreements and Control Boards

Water rental charges and costs are also incurred pursuant to the following agreements and requirements, totaling less than $1M annually:

- Parks Canada: Annual water rentals prescribed by Parks Canada licenses for hydroelectric facilities located on the Trent River or Rideau Canal. All Parks Canada licenses were renewed in 2020 for a period of 40 years;
- Ottawa River Water Powers Act: An annual rental payable to the Department of Natural Resources in Québec;
- Hydro-Québec: Annual payments to Hydro-Québec for production losses for a facility located upstream of OPG's Chenaux GS;
- H2O Power LP Settlement Agreement: Amortized cost of previous lump-sum payment to private dam owners for production losses caused by OPG's Whitedog Falls GS;
- Ottawa River Regulation Planning Board: Annual cost share funding requirements; and
- Lake of the Woods Control Board: Annual cost share funding requirements.

Numbers may not add due to rounding.

Table 1
Gross Revenue Charge - Regulated Hydroelectric ($M)

Line No.	Operating Region[1,2]	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Niagara Region**	n/a	n/a	n/a	n/a	156.4	162.7	163.1	172.0	180.4
2	**Eastern Region**	n/a	n/a	n/a	n/a	151.4	140.1	148.9	148.9	150.6
3	**Western Region**	n/a	n/a	n/a	n/a	15.7	12.9	18.3	15.9	17.7
4	**Total**	312.7	319.7	319.2	324.5	323.4	315.7	330.3	336.7	348.6
5	**NYPA Water Transactions[2]**	0.6	0.3	(0.6)	(0.5)	0.1	0.0	0.2	0.8	1.9

Line No.	Operating Region[1,2]	2025 Budget	2026 Budget	2027 Plan
		(a)	(b)	(c)
6	**Niagara Region**	189.0	184.8	182.8
7	**Eastern Region**	145.9	147.2	148.1
8	**Western Region**	22.3	22.3	21.3
9	**Total**	357.2	354.3	352.2
10	**NYPA Water Transactions[2]**	1.4	1.1	2.2

1 Operating Region descriptions effective 2021 (see Ex. A1-4-2).
2 Consistent with OPG's letter dated June 11, 2024, issued in EB-2024-0136, data is provided at the regulated hydroelectric level for 2016-2019.
3 GRC amounts associated with NYPA Water Transactions are not included in the totals presented above.

COMPARISON OF GROSS REVENUE CHARGE AND OTHER WATER AGREEMENT COSTS – REGULATED HYDROELECTRIC

1.0 PURPOSE

This evidence presents period-over-period comparisons of the gross revenue charge ("GRC"), including other water rental and water agreement costs, for the regulated hydroelectric facilities as described in Ex. F1-4-1.

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 hydroelectric business below, for the period 2016-2024. As there is no OEB-approved GRC and other water agreement cost information for 2015 onwards, OPG has only provided year-over-year variance analysis for the historical period (2016-2024), bridge period (2025-2026), and test year (2027).

2.0 OVERVIEW

A year-over-year comparison of GRC costs and costs pertaining to other water rentals and water agreements is provided in Ex. F1-4-2, Table 1. Actual costs are shown for the years 2016-2024 and forecast costs are shown for the bridge period (2025-2026) and test year (2027). The GRC costs comprise approximately 95% of the total GRC and other water agreement costs shown in this table.

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

3.0 PERIOD-OVER-PERIOD CHANGES – TEST YEAR

2027 Plan versus 2026 Forecast

The GRC and other water agreement costs are expected to remain stable between 2026 and 2027, decreasing by $2.1M from $354.3M to $352.2M.

4.0 PERIOD-OVER-PERIOD CHANGES – BRIDGE YEARS

2026 Forecast versus 2025 Forecast

The GRC and other water agreement costs are expected to remain stable between 2025 and 2026, decreasing by $2.9M from $357.2M to $354.3M.

2025 Forecast versus 2024 Actual

The GRC and other agreement costs are expected to increase by $8.6M between the actual values for 2024 and the 2025 budget, from $348.6M to $357.2M, corresponding to forecasted production increase. This increase is primarily driven by the completion of an outage at one of the DeCew Falls 2 GS units in 2024.

5.0 PERIOD-OVER-PERIOD CHANGES – HISTORICAL YEARS

2024 Actual versus 2023 Actual

The increase of $11.9M GRC and water rentals costs from $333.6M in 2023 to $348.6M in 2024 is primarily attributed to a 1.1 TWh increase in total fleet production year-over-year driven by higher electricity demand in the province.

2023 Actual versus 2022 Actual

The increase of $6.4M in total GRC and water rental costs from $330.3M in 2022 to $336.7M in 2023 was primarily caused by a year-over-year increase in production of 0.3 TWh, including a 0.7 TWh increase at the Sir Adam Beck complex.

2022 Actual versus 2021 Actual

The increase of $14.6M in GRC and water rental costs from $315.7M in 2021 to $330.3M in 2022 was primarily caused by a year-over-year production increase. This was predominantly due to a combination of high-water conditions and fewer outages in 2022. This production increase led to a GRC payment increase of $13.7M and an increase of $2.6M in Government of Québec water rental payments from 2021-2022.

2021 Actual versus 2020 Actual

The decrease of $7.7M in GRC and water rental costs from $323.4M in 2020 to $315.7M in 2021 was primarily due to year-over-year changes in production as a result of deferred maintenance from 2020 (resulting from the COVID-19 pandemic) and low water conditions in Eastern Region. A reduction in production decreased GRC payments by $7.1M and Government of Québec water rental payments by $1.2M.

6.0 PERIOD-OVER-PERIOD CHANGES – EXTENDED HISTORICAL YEARS

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

2020 Actual versus 2019 Actual

The GRC and other water agreement costs were stable between 2019 and 2020, decreasing by $1.1M from $324.5M to $323.4M. Niagara Region production decreased due to higher SBG spill as a result of the impact of the COVID-19 pandemic on electricity demand, leading to a GRC payment reduction of $5.6M. Eastern Region production increased resulting in a GRC payment increase of $6.1M, and Western Region production decreased resulting in a GRC payment reduction of $3.2M.

2019 Actual versus 2018 Actual

The increase of $5.3M in GRC and water rental costs from $319.2M in 2018 to $324.5M in 2019 was primarily driven by additional energy produced between Niagara Region and Western Region.

2018 Actual versus 2017 Actual

GRC and water rentals costs were essentially the same between 2017 and 2018, decreasing slightly from $319.7M in 2017 to $319.2M in 2018. This was driven by additional energy produced from the Sir Adam Beck complex, leading to a GRC increase of $9.6M, offset by a return in 2018 to normal water conditions on the Ottawa and Madawaska Rivers in Eastern Region in 2018 (from high levels experienced in 2017), leading to a decrease production and a corresponding reduction of $8.3M in GRC costs and $1.6M reduction in Government of Québec water rental payments.

2017 Actual versus 2016 Actual

The increase of $7.0M in GRC and water rental costs from $312.7M in 2016 to $319.7M in 2017 was primarily driven by very high water conditions in Eastern Region in 2017, leading to higher production and a corresponding increase of $15.0M of GRC payments, and $1.4M of Government of Quebec water rental payments. This was partially offset by lower production in Niagara Region, leading to a reduction of $8.3M in GRC costs and $1.6M in St. Lawrence Seaway Management Corporation fees.

Numbers may not add due to rounding.

Table 1
Comparison of Gross Revenue Charge - Regulated Hydroelectric ($M)

Line No.	Operating Region[1,2]	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
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**Niagara Region**	n/a	-	n/a	-	n/a	-	n/a	-	156.4	6.3	162.7
2	**Eastern Region**	n/a	-	n/a	-	n/a	-	n/a	-	151.4	(11.3)	140.1
3	**Western Region**	n/a	-	n/a	-	n/a	-	n/a	-	15.7	(2.8)	12.9
4	**Total**	312.7	7.0	319.7	(0.5)	319.2	5.3	324.5	(1.1)	323.4	(7.7)	315.7
5	**NYPA Water Transactions[3]**	0.6	(0.3)	0.3	(0.9)	(0.6)	0.1	(0.5)	0.6	0.1	(0.1)	0.0

Line No.	Operating Region[1,2]	2021 Actual	(c)-(a) Change	2022 Actual	(e)-(c) Change	2023 Actual	(g)-(e) Change	2024 Actual	(i)-(g) Change	2025 Budget	(k)-(i) Change	2026 Budget
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
6	**Niagara Region**	162.7	0.4	163.1	8.9	172.0	8.4	180.4	8.6	189.0	(4.2)	184.8
7	**Eastern Region**	140.1	8.8	148.9	0.0	148.9	1.7	150.6	(4.7)	145.9	1.3	147.2
8	**Western Region**	12.9	5.4	18.3	(2.4)	15.9	1.8	17.7	4.6	22.3	0.0	22.3
9	**Total**	315.7	14.6	330.3	6.4	336.7	11.9	348.6	8.6	357.2	(2.9)	354.3
10	**NYPA Water Transactions[3]**	0.0	0.2	0.2	0.6	0.8	1.1	1.9	(0.5)	1.4	(0.3)	1.1

Line No.	Operating Region[1,2]	2026 Budget	(c)-(a) Change	2027 Plan
		(a)	(b)	(c)
11	**Niagara Region**	184.8	(2.0)	182.8
12	**Eastern Region**	147.2	0.9	148.1
13	**Western Region**	22.3	(1.0)	21.3
14	**Total**	354.3	(2.1)	352.2
15	**NYPA Water Transactions[3]**	1.1	1.1	2.2

Notes:
1 Operating Region descriptions effective 2021 (see Ex. A1-4-2).
2 Consistent with OPG's letter dated June 11, 2024, filed in EB-2024-0136, data is provided at the regulated hydroelectric level for 2016-2019.
3 GRC amounts associated with NYPA Water Transactions are not included in the totals presented above.

OM&A PURCHASED SERVICES – REGULATED HYDROELECTRIC

1.0 PURPOSE

This evidence presents the purchases of OM&A expense services and products for the regulated hydroelectric facilities that meet the threshold of $20M in total OM&A expense, consistent with the OEB's filing requirements.

2.0 OVERVIEW

As detailed in Ex. F1-2-1, Section 3.1, OM&A purchased services represent the costs of specialized external services, primarily for construction and maintenance services supporting work programs. An overview of OPG's procurement processes is presented in Ex. F3-3-1. 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, for the period 2016-2024.

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

Information on contractor contracts for OM&A purchased services within the regulated hydroelectric business that are equal to or in excess of the $20M threshold, per supplier, for the years 2016 through to 2024 is presented in Chart 1.

Chart 1 – Purchase of Services – Regulated Hydroelectric OM&A Contracts

Contractor Name	Description/Nature of Activities	Tendering Process Competitive	Tendering Process Single Source	Rationale if Single Source
Andritz Hydro Canada Inc.	Original Equipment Manufacturer and provider of general construction and Engineering-Procurement-Construction ("EPC") services in 2016-2024, primarily related to design, supply, and construction for unit overhauls.	X	X	1. Contracts were under the $500k single-source threshold, or 2. Andritz was the owner of the Intellectual Property (OPG was obligated to purchase directly from the contractor).
Barclay Constructors Limited	Provider of shoreline erosion services in 2016-2024.	X	X	Contracts were under the $500k single-source threshold.
GDB Constructeurs	Provider of general construction and EPC services in 2016-2024, primarily related to concrete repair work at regulated hydroelectric generating stations and dams, and site construction work related to unit overhauls.	X	X	1. Contracts were under the $500k single-source threshold, or 2. GDB was already on-site performing similar work; the contract was extended to ensure consistency.
Stuart Olsen Industrial Constructors Inc	Provider of general construction and EPC services in 2016-2024, primarily related to site construction work for unit overhauls.	X		No single-source contracts.
M. Sullivan & Son Limited	Provider of general construction and EPC services in 2016-2024, primarily related to concrete repair work at regulated hydroelectric generating stations and dams, safety booms and site construction work related to unit overhauls.	X	X	Contracts were under the $500k single-source threshold.