CCC Interrogatory #018

Interrogatory

Reference:
Exhibit B1, Tab 1, Schedule 1, pp. 6, 8-9

Question(s):

a) With respect to the D2O Storage Project, please further explain the statement that "the rate base values in the Application reflect the results of [OEB] review." As part of the response, please provide the rate base value that has been removed for each year of the historical and forecast period.

b) Please provide a list of all permanent rate base disallowances (both hydroelectric and nuclear) ordered by the OEB and show how those disallowances are reflected in the regulated PP&E continuity schedules.

c) Please confirm, or correct, CCC's understanding regarding the conversion of in-service additions (for both hydroelectric and nuclear assets) to rate base for forecasting purposes as follows:

   i. For in-service additions with a value below $50M, the half-year rule is applied.
   ii. For in-service additions with a value above $50M, a forecast of the day/month that the asset will enter service is applied (i.e., the ISA is weighted to the day/month that it is expected to enter service).

d) With respect to in-service additions with a value below $50M, please explain whether OPG has the ability to forecast the month that the asset is expected to enter service.

e) With respect to the determination of depreciation expense associated with in-service additions for forecasting purposes, please confirm, or correct CCC's understanding as follows:

   i. For in-service additions with a value below $50M, depreciation is calculated based on the assumption that the asset enters service mid-year (i.e., half-year rule).
   ii. For in-service additions with a value above $50M, depreciation expense reflects the forecast month that the asset enters service (i.e., if an asset enters service on November 1, two months of depreciation expense are reflected in the revenue requirement).

Response

a) In the Decision and Order, EB-2020-0290, November 15, 2021, the OEB applied a permanent rate base disallowance of $94.0M to the D2O Storage Project, along with carrying costs incurred on the project during the period from May 2017 to March 2020, which collectively resulted in a combined reduction of $113.7M.[1] The OEB also found that the appropriate in-service date for the proposed 2016 and 2019 D2O Storage Project in-service additions was March 2020. Corresponding adjustments were implemented, as of the year 2020, in calculating the approved rate base values for the D2O Storage Project in the Payment Amounts Order, EB-2020-0290, January 27, 2022, Appendix A (Table 9a, lines 3b, 3c and 3d) such that the go-forward rate base values reflected the OEB's findings. As noted in Ex. B3-3-1, Table 1a, Note 5 and Ex. B3-4-1, Table 1, Note 4, the rate base values for the D2O Storage Project in this Application reflect these adjustments. For example, the 2020 gross plant opening value for the D2O Storage Project of $395.6M at Ex. B3-3-1, Table 1, line 3, col. (a) is equal to the Payment Amounts Order, EB-2020-0290, January 27, 2022, Appendix A, Table 9a, line 3e. Thus, the statement that "the rate base values in the Application reflect the results of [OEB] review" is in reference to the proposed 2027-2031 rate base values for OPG's nuclear facilities reflecting the effects of the above adjustments.

b) In addition to the D2O Storage Project, the OEB applied the following permanent rate base disallowances in prior OPG proceedings:
   - 50% of the variance between the in-service identified in the first execution business case of and the actual or then-forecast in-service additions for the Auxiliary Heating System ("AHS") and Operations Support Building ("OSB") as part of the nuclear rate base in EB-2016-0152.[2] The resulting disallowance of $35.3M was reflected in the 2017 continuity of property, plant and equipment for OPG's nuclear facilities, as noted in EB-2020-0290, Ex. B3-3-1, Table 1a, Note 4.[3] Since the disallowance was reflected in rate base but did not result in a downward adjustment of the assets as reported in OPG's consolidated financial statements in accordance with US GAAP, it is an ongoing reconciling item between the net plant amount for OPG's nuclear facilities for regulatory purposes, and the corresponding net property, plant and equipment values reported in OPG's financial statements. This is shown in Ex. B3-3-1, Table 1a, Note 7, line 7e, demonstrating that the proposed rate base values reflect the effects of this disallowance.

[1] EB-2020-0290 Decision and Order, November 15, 2021, p. 4.
[2] EB-2016-0152 Decision and Order, December 28, 2017, pp. 21-22 and calculation in EB-2016-0152 Payments Amounts Order, App. A, Table 9a, Note 2.
[3] Reduction of the remaining $5.5M (from EB-2016-0152 Payment Amounts Order, App. A, Table 9, col. (b), lines 5 and 6) was reflected within EB-2020-0290, Ex. B3-3-1, Table 1, line 9, col. (b).

- $88.0M for the Niagara Tunnel project in EB-2013-0321, of which $28.0M was subsequently varied to $6.4M in EB-2014-0369.[4,5] These adjustments resulted in a corresponding net downward adjustment of the assets in accordance with US GAAP as reported in OPG's consolidated financial statements.[6] Accordingly, there is no corresponding reconciling item between the net plant amount for OPG's regulated hydroelectric facilities for regulatory purposes, and the corresponding net property, plant and equipment values reported in OPG's financial statements. This can be seen in Ex. B3-2-1, Table 2a, Note 2, demonstrating that the proposed rate base values reflect the effects of this net disallowance.

c) i. and ii. Confirmed.

d) OPG could estimate the month that an asset is expected to enter service for forecast in-service additions below $50M to the extent they relate to allocated projects (refer to Ex. D2-1-1, Section 3.2) within a portfolio.

As explained in EB-2020-0290, Ex. L-B1-01-Staff-030, the $50M threshold – used since OPG's first cost-based application in EB-2007-0905 – allows for higher precision in rate base calculations for more material impacts, while keeping the instances of such calculations to a manageable level by using the mid-year average for in-service additions below this level even if the month the asset is expected to enter service can be estimated. OPG further notes that, by not increasing with inflation, the $50M threshold has in fact declined significantly in real dollar terms, meaning that it is now equivalent to somewhere between $25M and $35M in the original 2007 dollars, depending on the measure of inflation used. Applying greater timing precision for in-service additions by further depressing this threshold would add complexity to the rate base calculations and would not be expected to have a material revenue requirement impact.

e) i. and ii. Confirmed.

[4] EB-2013-0321 Decision and Order, November 20, 2014, pp. 32-33.
[5] EB-2014-0369 Decision and Order, January 28, 2016, p. 2.
[6] EB-2016-0152, Ex. A2-1-1, Attachment 2 and EB-2020-0290, Ex. A2-1-1, Attachment 3.

CCC Interrogatory #019

Interrogatory

Reference:
Exhibit B1, Tab 1, Schedule 1, p. 14
Exhibit A1, Tab 4, Schedule 1, Attachment 4, p. 49

Question(s):

a) Please further discuss the statement that the market value of materials and supplies takes into account technological obsolescence and remaining useful life. To the extent that certain materials that were purchased and not used, please explain how those costs are treated from a ratemaking perspective.

b) Please explain whether the MRNI reduction initiative (discussed as part of the 23-08 Nuclear Work Orders Materials Management audit) is related to minimizing unutilized materials and supplies. If not, please explain the noted MRNI initiative.

c) For the historical period, please provide the dollar value of materials/supplies that were purchased and evaluated as not consumed by year.

Response

a) The statement in Ex. B1-1-1, p.14, lines 19-23 is related to the measurement of the value of Materials & Supplies subsequent to initial recognition in accordance with US GAAP and OPG accounting governance. As OPG is required to hold both lifetime and critical spares at all times in support of nuclear operations safety and continuous operations, some spares may become obsolete due to externalities such as changes in the operating systems or reaching shelf-life expiration.

Where materials have been purchased but not immediately used, these materials are not expensed and are instead placed into inventory for future use. Materials & Supplies, net of provision for accumulated obsolescence, is identified in OPG's rate base (refer to Exhibit B1-1-1, Table 2). As discussed in Ex. B1-1-1, section 3.2.4, such a provision is built up over the life of the respective nuclear station, and the cost of inventory identified as obsolete is offset against this provision. The build up of the provision is recognized as a nuclear Base OM&A expense that is included in the revenue requirement (Ex. F2-2-1, p. 6, lines 6-7).

In the course of preparing this response, OPG identified a data input error resulting in incorrect 2025-2031 values being reflected in the pre-filed evidence for materials

and supplies for OPG nuclear facilities, at Ex. B3-5-1, Tables 1 and 2. The corrected year-end values for 2025-2031 are $511.5M, $531.0M, $535.4M, $534.7M, $537.9M, $551.5M and $547.7M, respectively, and the resulting corrected materials and supplies rate base values for 2025-2031 at Ex. B1-1-1, Table 2 are $503.4M, $521.2M, $533.2M, $535.0M, $536.3M, $544.7M and $549.6M, respectively. The Applicants propose to reflect this correction in the revenue requirements during the drafting of the payments amounts order in this proceeding. The correction will reduce the revenue requirements.

b) The MRNI reduction initiative focuses on minimizing materials and supplies requested but not immediately used as part of OPG's broader effort to continuously optimize materials management while maintaining nuclear station reliability. This initiative enhances visibility into material demand, usage, and inventory levels, with the objective of reducing excess or long-dormant inventory where practicable.
In support of nuclear operations safety and continuous operations, OPG is required to hold both lifetime and critical spares at all times. These critical spares allow OPG to:

- Respond to unexpected equipment issues during online and outage work
- Manage the uncertainty inherent in nuclear maintenance and equipment refurbishment and overhaul activities
- Address vendor lead times and specialized nuclear-grade material availability
- Maintain plant reliability, safety, and continuity of operations.

As a result, inventory levels reflect a risk-informed approach to managing the availability of supply.

In addition to the actions undertaken following the referenced audit, the MRNI reduction initiative focuses on distinguishing between materials that are appropriately held or ordered to manage operational risk and ensure availability or where inspections during maintenance confirmed that the existing parts remained serviceable. In 2025, OPG started to utilize an AI tool that examines historical data on part usage to inform work management assessors when ordering parts. This initiative is expected to improve overall MRNI metrics over time.

c) Chart 1 shows an overall estimate of the dollar value of materials/supplies that were purchased and evaluated as not consumed, by year, over the historical period of 2020- 2024 for OPG's nuclear stations.

The amounts presented include procurement for operations, outages, and projects.

Chart 1 – OPG Nuclear Stations Materials Purchased but Not Consumed ($M)

$M	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual
Materials Purchased[1,2]	212.2	274.9	203.7	271.2	323.8
Materials Purchased for Demand (a)[1,2,3]	154.3	224.7	170.3	218.8	273.5
Materials Consumed/Issued (b)[1]	182.4	212.0	230.5	220.9	275.6
Materials Purchased for Demand but Not Consumed (c = a – b)	(28.1)	12.7	(60.2)	(2.0)	(2.1)

1. Materials Purchased is valued based on the actual purchase price of the materials received in the stated year. The stated values are inherently larger than the values of the same materials when consumed (b) due to the weighted-average inventory cost of accounting treatment.
2. Materials Purchased can be for consumption, replenishment of spare parts or for future planned consumption.
3. Materials Purchased for Demand (a) reflects purchases linked to specific demand and excludes purchases associated with replenishment of spare parts

SEC Interrogatory #028

Interrogatory

Reference:

Question(s):

Please complete the attached Excel spreadsheet.

Response

Refer to Attachment 1 for the completed Excel spreadsheet requested in this interrogatory.

In preparing the response to this interrogatory, OPG has identified several reconciling differences, as follows:

- $126.3M in regulated hydroelectric capital expenditures in Ex. D1-1-1, Table 2 that are not associated with forecast capital in-service additions over the 2025-2031 period;
- an omitted $19.1M in nuclear operations capital expenditures in Ex. D2-1-2, Table 2 relative to the forecast capital in-service additions over the 2025-2031 period; and
- a net difference of $21.8M between Corporate Support Services capital expenditures in Ex. D3-1-1, Table 1 and in-service additions in Ex. D3-1-2, Table 4, comprised of expenditures that are not associated with forecast in-service additions and omitted forecast in-service additions over the 2025-2031 period.

Correcting for the above differences is estimated to increase the proposed 2027-2031 nuclear revenue requirements by approximately $1M per year and the 2027 regulated hydroelectric revenue requirement by less than $0.5M, and increase the 2028-2031 regulated hydroelectric capital related revenue requirements by less than $5M in aggregate (through impacts on capital cost allowance deductions).[1] OPG does not propose to update the Application for these changes.

[1] OPG also assessed the impact of the regulated hydroelectric change to the information incorporating the preliminary forecast impacts of Clean Electricity Investments Tax Credits ("CEITCs") and the reinstatement of the accelerated investment incentive property ("RIIP") program in Ex. L-F4-CCC-084. There is a less than $0.5M estimated impact to such 2027 regulated hydroelectric revenue requirement and a less than $5M increase to such 2028-2031 capital related revenue requirements. OPG does not propose to update that interrogatory response for this change.

Witness Panel: Finance, D&V, Cost of Capital, Regulatory Constructs, Customer Impacts

For clarity, the above identified reconciling differences have no impact on project prioritization, performance or execution, and do not form part of the capital in-service additions reflected in the pre-filed evidence and interrogatory responses.

Board Staff Interrogatory #017

Interrogatory

Reference:
Ref 1: Exhibit B1 / Tab 1 / Schedule 1 / Table 1
Ref 2: Collectively, OPG's Annual Reporting of Estimated Earnings Before Taxes, where the 2024 Report is available at "2024 EBT Estimate Prescribed RRR Final. Non-Confidential.pdf"

Preamble:

At Reference 1, OPG reports the Prescribed Facility Rate Base for Regulated Hydroelectric. OPG also reports this rate base to the OEB through annual filing commitments.

OEB staff notes an apparent discrepancy for recent years between what has been filed in this proceeding compared to what has been reported annually. Specifically, Reference 1 line 6 appears to correspond exactly to Table 2a line 5a of the annual reporting for the years 2017 to 2021 (Reference 2), but not so in the years 2022 to 2024.

Question(s):

a) Please confirm the data in the following table. If not confirmed, please correct the table:

Table 1 – Comparison of Rate Base between Reference 1 and Reference 2 ($ millions)

	2017	2018	2019	2020	2021	2022	2023	2024
B1-1-1 Table 1, line 6	7,383.3	7,391.2	7,438.0	7,476.1	7,517.5	7,734.7	7,990.0	8,124.4
Rate Base from annual reporting	7,383.3	7,391.2	7,437.9	7,476.1	7,517.5	7,727.8	7,982.4	8,117.4

b) Please reconcile Reference 1, line 6 to the annual reporting, explaining any differences in reported prescribed hydroelectric rate base between the filed evidence and the annual reporting.

Response

a) Not confirmed, as OPG filed revised annual reporting for 2022-2024 on March 10, 2026. Please see corrected amounts below.

Chart 1 – Comparison of Rate Base between Reference 1 and Reference 2 ($millions)

	2017	2018	2019	2020	2021	2022	2023	2024
Ex. B1-1-1 Table 1, line 6	7,383.3	7,391.2	7,438.0	7,476.1	7,517.5	7,734.7	7,990.0	8,124.4
Rate Base from annual reporting	7,383.3	7,391.2	7,437.9	7,476.1	7,517.5	7,734.7	7,990.0	8,124.4

b) Reference 1, line 6 agrees to the revised annual reporting for 2022-2024 filed on March 10, 2026, subject to minimal differences.

Board Staff Interrogatory #019

Interrogatory

Reference:
Ref 1: Exhibit B1 / Tab 1 / Schedule 1 / p. 8-9
Ref 2: Exhibit B2 / Tab 3 / Schedule 1 / Table 3a
Ref 3: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 41

Preamble:

In Reference 1, OPG states that, for regulated hydroelectric net fixed and intangible assets, rate base is generally determined using a mid-year average, but for in-service additions or adjustments greater than $50 million, the actual in-service month is used.

In Reference 2, OEB staff notes that Project 87768, Sir Adam Beck 2 G20/G19 Refurbishment, is reflected in rate base using in-service dates of October 1, 2028 and February 1, 2029. In Reference 3, OPG indicates that turbine contractor selection was not yet complete, that Gate 3 funding release was anticipated in Q4 2025, that a fully integrated resource-loaded schedule was expected be developed, and that key project risks include engineering delays, procurement of long-lead materials, system integration complexity, and interconnection assessments.

Question(s):

a) Please confirm whether the Business Case Summary (BCS) provided at Reference 3 is the most recent BCS for Project 87768. If not, please provide the most recent BCS.

b) OPG states that the Gate 3 funding release for Project 87768 was anticipated in Q4 2025. Please confirm whether the Gate 3 funding release has been completed. If not, please explain the reason it has not been completed, provide the current expected approval date, and indicate whether this has affected, or may affect, the in-service dates reflected in hydroelectric rate base.

c) If the BCS provided at Reference 3 is the most recent BCS, please confirm whether the deliverable target dates shown in that BCS are the latest target dates for the project. If they are not, please provide the updated deliverable target dates.

d) Please confirm that the following in-service timing assumptions for Project 87768 are reflected in hydroelectric rate base (or if not confirmed please explain):
   i. October 1, 2028, for an in-service addition of $176.5 million, and
   ii. February 1, 2029, for an in-service addition of $176.5 million.

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

e) For each in-service date identified in part d), please identify the corresponding deliverable or milestone and target date from the most recent BCS, or from the updated deliverable target dates provided in response to part c), that supports the in-service date reflected in rate base.

f) Please identify the key risks currently facing Project 87768 that could affect the in-service dates reflected in rate base. For each such risk, please indicate whether it has materialized to date and, if so, whether it has affected the current project schedule.

Response

a) Not confirmed. See Ex. L-B2-Staff-018, part a.

b) Confirmed.

c) Not confirmed. See Ex. L-B2-Staff-018, part b.

d) Confirmed.

e) See Ex. L-B2-Staff-018, part b.

f) Chart 1 provides the risks that could affect the in-service dates for Project #87768. Some risks have materialized but have not impacted the critical path schedule.

Chart 1 – Key Risks for Project #87768

Risk Category	Risk Title	Materialized	Schedule Impact
Technical	OEM Resource Capacity and Capability Issues	Yes	No
Technical	OEM Engineering - Completeness of Design Packages	Yes	No
Project Management	Equipment and Material Storage/Early Delivery	No	No
Technical	SAB2 Floor Space Concern	No	No
Quality	Stay Vane Extensions, Complexity of Scope of Work	No	No

Board Staff Interrogatory #020

Interrogatory

Reference: Ref 1: Exhibit B1 / Tab 1 / Schedule 1 / pp. 2-3

Preamble:

In Reference 1, OPG states that the early in-service additions of the Darlington Refurbishment Units is one of the key drivers of increased OPG Nuclear rate base in the 2022-2026 term from what was presented in EB-2020-0290.

Question(s):

a) Please confirm how OPG defines the in-service date for the Darlington Refurbishment Units. Please confirm that OPG proposes the same definition for the Pickering Refurbishment Units. If not confirmed, please explain.

b) In accordance with part a), please identify the in-service date of each of Darlington Refurbishment Units 1, 3, and 4. For each unit, please also confirm the in-service date approved in EB-2020-0290.

c) For each of Darlington Refurbishment Units 1, 3, and 4, please identify the Revenue Requirement increase in each of 2027 to 2031 due to the early in-service date. Please provide the supporting tables in excel format.

d) Please confirm that OPG is stating in Reference 1 that there are anticipated Capacity Refurbishment Variance Account (CRVA) balances for future recovery due to the early return to service of Unit 4, regardless of whether the Darlington Refurbishment Program cost was over the approved budget.

e) OEB staff notes that, as of 11:00AM EST on March 8, 2026, Darlington Nuclear Generating Station Unit 4 is generating approximately 666 MW. Please provide the CRVA details showing CRVA additions that are anticipated based on the early return to service of Unit 4.

Response

a) OPG defines the in-service date for a Darlington Refurbishment unit as the date it is substantially complete and ready for its intended use with the unit being commercially available. Specifically, in-service follows the successful release of all CNSC regulatory hold points, with all high-power testing and commissioning

complete. OPG proposes to use the same definition for the Pickering Refurbishment Units.

b) The requested information is provided in Chart 1 below.

Chart 1 – Darlington Refurbishment Unit In-Service Dates

Unit	Actual / Forecast[1]	EB-2020-0290[2]	Difference
Unit 3 (A)	July 18, 2023	January 2, 2024	-169 days
Unit 1 (A)	November 27, 2024	April 18, 2025	-142 days
Unit 4 (F)	April 15, 2026	October 16, 2026	-185 days

[1] Per Ex. D2-2-1, p. 10, Chart 1. The Unit 4 actual in-service date is March 12, 2026. Refer to part e) in response for further information.
[2] EB-2020-0290, Ex. D2-2-1, p. 7, Chart 1.

c) OPG interprets the question to be requesting OPG to quantify how much lower its proposed 2027-2031 nuclear revenue requirements would be had Darlington Refurbishment Units 1, 3 and 4 returned (or be forecasted to return) to service on the dates identified in EB-2020-0290 (i.e., as set out in part b) above). While OPG has not performed such a hypothetical business planning exercise for this alternate scenario that would be entirely dependent on assumptions that have no basis in fact, OPG can confirm that, mathematically, the capital-related revenue requirement for the Darlington Refurbishment Program ("DRP") over the 2027-2031 period would not be lower in the alternate scenario because, all else equal, a later in-service date would result in lower accumulated depreciation and therefore a higher rate base value and higher cost of capital amounts in respect of these assets going into the 2027-2031 IR term. Thus, from a DRP capital-related revenue requirement standpoint, the 2027-2031 proposed revenue requirements are lower than they would have been in the postulated scenario.

d) OPG confirms that there will be incremental amounts recoverable recorded in the Capacity Refurbishment Variance Account ("CRVA") in 2026 because of the earlier Darlington Unit 4 return to service date, compared to the forecast date reflected in the EB-2020-0290 revenue requirements. OPG notes that this was similarly the case for the earlier than forecast return to service dates for Darlington Unit 3 in 2023 and Unit 1 in 2024, while the converse applied to Unit 2 in 2020 as it returned to service several months later than forecast in the EB-2016-0152 approved revenue requirements, resulting in a refund to ratepayers being recorded in the CRVA. The recording of these impacts in the account is in accordance with the OEB's EB-2020-0290 and EB-2016-0152 payment amounts orders, respectively, and the requirements in O. Reg. 53/05, section 6(2)4 that the OEB must ensure recovery of DRP costs if it is satisfied that they were prudently incurred. For clarity, the above impacts arise as a result of differences in the timing of when the units

are returned to service, whether or not there any differences in costs. The impacts are further discussed in Ex. H1-1-1, pp. 23-24.

e) Darlington Unit 4 was in the dynamic testing phase of the DRP on March 8, 2026 and had not yet been commercially declared in-service. The revenue generated during this commissioning period is credited against the cost of the project, reducing the amount placed in-service. This treatment is consistent with all prior Darlington units.

The estimated capital-related additions to the CRVA for future recovery in respect of Darlington Unit 4, based on the forecast in-service date of April 15, 2026, and associated in-service amount, per the pre-filed evidence, are $144.9M in 2026.[1] Based on the actual in-service date of March 12, 2026, and associated in-service amount, such estimated CRVA additions are $131.1M in 2026.[2] Refer to Attachment 1, Table 1 and 2 for these calculations.

OPG does not propose to update the Application to reflect the actual Unit 4 in-service date of March 12, 2026. This view is informed by the fact that this could constitute a significant update to the Application that could introduce potential delays, while the revenue requirement impact of the earlier return to service date would be fully captured by the CRVA. Under OPG's approvals sought as set out in in Ex. D2-2-1, Section 3.0 and further outlined at Ex. H1-1-1, p. 24, lines 20-25, while OPG seeks a final determination of all DRP costs in this Application, OPG would record any variances in the amount and/or timing of the final capital in-service additions in the CRVA, subject to OPG's commitment not to seek recovery of any costs that exceed the $12.8B budget, until the effective date of a subsequent payment amounts order that reflects the impacts of such final actual in-service additions in the payment amounts. OPG has proposed that such CRVA additions be recoverable in a future application on a mechanical basis, subject to the amounts being accurately recorded.

[1] As discussed further in Attachment 1, Table 1, Note 3, the estimated account additions do not reflect the tax impact of capital cost allowance deductions since those are determined at the overall program level, rather than unit-by-unit, for the DRP.
[2] *Ibid*.

Numbers may not add due to rounding.

Table 1
Capacity Refurbishment Variance Account - Nuclear - Capital Portion - DRP - Unit 4 (Budgeted In-Service Date)
Summary of Account Transactions - 2026 ($M)

Line No.	Particulars	Note	Budget 2026
			(a)
	Capital Addition to Variance Account - Unit 4:		
1	**Forecast Cost of Capital Amount**	1	24.5
2	**Budgeted Net Plant Rate Base Amount**	2	1,593.6
3	**Weighted Average Cost of Capital**	1	5.92%
4	**Budgeted Cost of Capital Amount** (line 2 x line 3)		94.3
5	**Cost of Capital Variance** (line 4 - line 1)		69.8
6	**Forecast Depreciation**	1	15.9
7	**Budgeted Depreciation**	2	60.8
8	**Depreciation Variance** (line 7 - line 6)		44.9
	Income Tax Impact:		
9	**Forecast Capital Cost Allowance Deduction**	3	0.0
10	**Budgeted Capital Cost Allowance Deduction**	3	0.0
11	**SR&ED Qualifying Capital Expenditures**		0.0
12	**Difference** (line 9 - line 10 - line 11)		0.0
13	**Net Increase in Regulatory Taxable Income**	4	90.8
14	**Income Tax Rate**		25.0%
15	**Income Tax Impact** (line 13 x line 14 / (1 - line 14))		30.3
16	**Capital Addition to Variance Account - Unit 4** (line 5 + line 8 + line 15)	5	144.9

For notes see Table 1a

Numbers may not add due to rounding.

Filed: 2026-04-24
EB-2025-0297
Exhibit L
B1-Staff-020
Attachment 1
Table 1a

Table 1a
Notes to Table 1
Capacity Refurbishment Variance Account - Nuclear - Capital Portion - DRP - Unit 4 (Budgeted In-Service Date)

Notes:

1 The amounts in line 1 are determinded as follows:

Table to Note 1 - Capacity Refurbishment Variance Account - EB-2020-0290 Forecast Capital Amounts for DRP - Unit 4 ($M)		
Line No.		2026
		(a)
1a	Forecast Net Plant Rate Base Amount*	414.6
2a	Weighted Average Cost of Capital**	5.92%
3a	Forecast Cost of Capital Amount (line 1a x line 2a)	24.5
4a	ROE Component of Forecast Cost of Capital Amount***	16.2
5a	Forecast Depreciation (EB-2020-0290, Ex. B3-4-1, Table 3, line 10, col. (c))	15.9

* Forecast Net Plant Rate Base Amount - Unit 4 ($M)

Line No.		2026
		(a)
1b	Gross Plant Opening Balance	0.0
2b	Forecast In-service Addition (EB-2020-0290 Payment Amounts Order, App. A, Table 9, line 38, col. (b))+	2,028.3
3b	Gross Plant Closing Balance (line 1b + line 2b)	2,028.3
4b	Gross Plant Rate Base Amount (line 1b + line 3b)/2 +	422.6
5b	Accumulated Depreciation Opening Balance	0.0
6b	Forecast Depreciation (EB-2020-0290, Ex.B3-4-1, Table 3, line 10, col. (c))	15.9
7b	Accumulated Depreciation Closing Balance (line 5b + line 6b)	15.9
8b	Accumulated Depreciation Rate Base Amount (line 5b + line 7b)/2	8.0
9b	Forecast Net Plant Rate Base Amount (line 4b - line 8b)	414.6

\+ For this in-service addition, the full amount was approved as per EB-2020-0290 OEB-approved Settlement Proposal, Ex. O-1-1,Table 15, p. 22 and the month in which the addition is reflected is used to determine the gross plant rate base amount, instead of a mid-year average as per EB-2020-0290 Ex. B3-3-1, Table 2a.

** Col. (a) from EB-2020-0290 Payment Amounts Order, App. A, Table 15: line 4, col. (b) x col. (c), plus line 5a, col. (c) x line 5b, col. (b).

*** The ROE component of the cost of capital forecast is equal to line 1a mulitiplied by the OEB-approved equity portion (45%) of the capital structure and the OEB-approved ROE rate of 8.66% for 2026.

2 The amounts in line 2 are determined as follows:

Table to Note 2 - Capacity Refurbishment Variance Account - Budgeted 2026 Net Plant Rate Base Amounts for DRP - Unit 4 ($M)		
Line No.		Budget 2026
		(a)
1c	Gross Plant Opening Balance	0.0
2c	In-service Addition - Darlington Refurbishment - Unit 4 (Ex. D2-2-3, Table 5a, line 24, col. (i))	2,291.5
2cc	In-service Addition - Darlington Refurbishment - Early In-Service - Unit 4 (Ex. D2-2-3, Table 5a, line 25, col. (i))	1.7
3c	Gross Plant Closing Balance (line 1c + line 2c + 2cc)	2,293.2
4c	Gross Plant Rate Base Amount (line 1c + line 3c)/2+	1,624.0
5c	Accumulated Depreciation Opening Balance	0.0
6c	Depreciation (Ex. B3-4-1, Table 2, line 14, col. (c))	60.8
7c	Accumulated Depreciation Closing Balance (line 5c + line 6c)	60.8
8c	Accumulated Depreciation Rate Base Amount (line 5c + line 7c)/2	30.4
9c	Net Plant Rate Base Amount (line 4c - line 8c)	1,593.6

\+ For the Unit 4 in-service addition of $2,291.5M, the mid-month of April, in which the addition is reflected is used to determine the gross plant rate base amount, instead of a mid-year average.

3 CCA is determined at the program level, rather than on a unit-by-unit basis, for the Darlington Refurbishment Program. Therefore, neither EB-2020-0290 OEB-approved nor 2026 budgeted CCA is reflected herein for additions to the account specific to Unit 4 return to service. Overall CCA for the program in the year would be reflected as part of the overall additions to the account in 2026, as shown in Ex. H1-1-1, Table 16, col. (k), lines 9 and 10.

4 The change in regulatory taxable income is calculated as the sum of lines 8 and 12, plus the ROE component of the cost of capital variance at line 5 . The ROE component of the variance is equal to the difference between: (i) line 2 multiplied by the OEB-approved equity portion (45%) of the capital structure and the OEB-approved ROE rate of 8.66% for 2026; and (ii) line 4a, col. (a).

5 The budgeted account addition for Unit 4, is embedded in the overall account addition in Ex. H1-1-1, Table 16, col. (k), line 20.

Numbers may not add due to rounding.

Table 2
Capacity Refurbishment Variance Account - Nuclear - Capital Portion - DRP - Unit 4 (Actual In-Service Date)
Summary of Account Transactions - 2026 ($M)

Line No.	Particulars	Note	Projected Actual 2026
			(a)
	Capital Addition to Variance Account - Unit 4:		
1	**Forecast Cost of Capital Amount**	1	24.5
2	**Projected Actual Net Plant Rate Base Amount**	2	1,484.2
3	**Weighted Average Cost of Capital**	1	5.92%
4	**Projected Actual Cost of Capital Amount** (line 2 x line 3)		87.9
5	**Cost of Capital Variance** (line 4 - line 1)		63.3
6	**Forecast Depreciation**	1	15.9
7	**Projected Actual Depreciation**	2	56.4
8	**Depreciation Variance** (line 7 - line 6)		40.4
	Income Tax Impact:		
9	**Forecast Capital Cost Allowance Deduction**	3	0.0
10	**Projected Actual Capital Cost Allowance Deduction**	3	0.0
11	**SR&ED Qualifying Capital Expenditures**		0.0
12	**Difference** (line 9 - line 10 - line 11)		0.0
13	**Net Increase in Regulatory Taxable Income**	4	82.1
14	**Income Tax Rate**		25.0%
15	**Income Tax Impact** (line 13 x line 14 / (1 - line 14))		27.4
16	**Capital Addition to Variance Account - Unit 4** (line 5 + line 8 + line 15)		131.1

For notes see Table 2a

Numbers may not add due to rounding.

Filed: 2026-04-24
EB-2025-0297
Exhibit L
B1-Staff-020
Attachment 1
Table 2a

Table 2a
Notes to Table 2
Capacity Refurbishment Variance Account - Nuclear - Capital Portion - DRP - Unit 4 (Actual In-Service Date)

Notes:

1 The amounts in line 1 are determinded as follows:

Table to Note 1 - Capacity Refurbishment Variance Account - EB-2020-0290 Forecast Capital Amounts for DRP - Unit 4 ($M)		
Line No.		2026
		(a)
1a	Forecast Net Plant Rate Base Amount*	414.6
2a	Weighted Average Cost of Capital**	5.92%
3a	Forecast Cost of Capital Amount (line 1a x line 2a)	24.5
4a	ROE Component of Forecast Cost of Capital Amount***	16.2
5a	Forecast Depreciation (EB-2020-0290, Ex. B3-4-1, Table 3, line 10, col. (c))	15.9

* Forecast Net Plant Rate Base Amount - Unit 4 ($M)

Line No.		2026
		(a)
1b	Gross Plant Opening Balance	0.0
2b	Forecast In-service Addition (EB-2020-0290 Payment Amounts Order, App. A, Table 9, line 38, col. (b))+	2,028.3
3b	Gross Plant Closing Balance (line 1b + line 2b)	2,028.3
4b	Gross Plant Rate Base Amount (line 1b + line 3b)/2 +	422.6
5b	Accumulated Depreciation Opening Balance	0.0
6b	Forecast Depreciation (EB-2020-0290, Ex.B3-4-1, Table 3, line 10, col. (c))	15.9
7b	Accumulated Depreciation Closing Balance (line 5b + line 6b)	15.9
8b	Accumulated Depreciation Rate Base Amount (line 5b + line 7b)/2	8.0
9b	Forecast Net Plant Rate Base Amount (line 4b - line 8b)	414.6

\+ For this in-service addition, the full amount was approved as per EB-2020-0290 OEB-approved Settlement Proposal, Ex. O-1-1,Table 15, p. 22 and the month in which the addition is reflected is used to determine the gross plant rate base amount, instead of a mid-year average as per EB-2020-0290 Ex.B3-3-1, Table 2a.

** Col. (a) from EB-2020-0290 Payment Amounts Order, App. A, Table 15: line 4, col. (b) x col. (c), plus line 5a, col. (c) x line 5b, col. (b).

*** The ROE component of the cost of capital forecast is equal to line 1a mulitiplied by the OEB-approved equity portion (45%) of the capital structure and the OEB-approved ROE rate of 8.66% for 2026.

2 The amounts in line 2 are determined as follows:

Table to Note 2 - Capacity Refurbishment Variance Account - Projected Actual 2026 Net Plant Rate Base Amounts for DRP - Unit 4 ($M)		
Line No.		Budget 2026
		(a)
1c	Gross Plant Opening Balance	0.0
2c	In-Service Addition - Darlington Refurbishment - Unit 4	1,814.9
3c	Gross Plant Closing Balance (line 1c + line 2c)	1,814.9
4c	Gross Plant Rate Base Amount (line 1c + line 3c)/2+	1,512.4
5c	Accumulated Depreciation Opening Balance	0.0
6c	Depreciation	56.4
7c	Accumulated Depreciation Closing Balance (line 5c + line 6c)	56.4
8c	Accumulated Depreciation Rate Base Amount (line 5c + line 7c)/2	28.2
9c	Net Plant Rate Base Amount (line 4c - line 8c)	1,484.2

\+ For the Unit 4 in-service addition of $1,814.9M, the beginning of the month of March, in which the addition is reflected, is used to determine the gross plant rate base amount, instead of a mid-year average.

3 CCA is determined at the program level, rather than on a unit-by-unit basis, for the Darlington Refurbishment Program. Therefore, neither EB-2020-0290 OEB-approved nor 2026 projected actual CCA is reflected herein for additions to the account specific to Unit 4 return to service.

4 The change in regulatory taxable income is calculated as the sum of lines 8 and 12, plus the ROE component of the cost of capital variance at line 5 . The ROE component of the variance is equal to the difference between: (i) line 2 multiplied by the OEB-approved equity portion (45%) of the capital structure and the OEB-approved ROE rate of 8.66% for 2026; and (ii) line 4a, col. (a).

Board Staff Interrogatory #018

Interrogatory

Reference:
Ref 1: Exhibit B2 / Tab 3 / Schedule 1 / Table 3a
Ref 2: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / pp. 1-3

Preamble:

At Reference 1, OPG provides the in-service dates, in-service amounts, and first-year weighting for certain hydroelectric projects reflected in rate base. OPG identifies 13 regulated hydroelectric in-service addition amounts greater than $50 million in the bridge years and IR term. At Reference 2, OPG provides the latest business case status for those projects.

Question(s):

a) For the projects listed below, please confirm that the latest Business Case Summaries (BCS) have been filed in the evidence. If not confirmed, update as required. Where required, please provide the updated BCS status and a copy of the latest BCS.

Table 1 – Selected Hydroelectric Projects

Source: Reference 1							Source: Reference 2
Line	**Project name**	**Project #**	**Facility / Region**	**In-service date**	**In-service amount ($M)**	**First-year weighting (months)**	**Latest BCS Status**
1	Otter G2 Capital Upgrade	82543	Otter Rapids / Eastern Region	15-Nov-25	61.9	1.5	Superseding Execution
2	Kakabeka Falls GS Redevelopment	86386	Kakabeka / Western Region	01-Apr-27	134.9	9	Full Release Execution
3	Kakabeka Falls GS Redevelopment	86386	Kakabeka / Western Region	01-Jul-27	165.7	6	Full Release Execution
4	BK1 G4 Refurbishment	86570	Sir Adam Beck 1 / Niagara Region	08-Jun-27	96.5	7	Full Release Execution

5	BK2 G20/G19 Refurbishment	87768	Sir Adam Beck 2 / Niagara Region	01-Oct-28	176.5	3	G2 – Definition (Full)
6	BK1 G6 G8 Refurbishment	86372	Sir Adam Beck 1 / Niagara Region	01-Oct-28	113.1	3	Full Release Definition
7	Matabitchuan GS Redevelopment	86387	Matabitchuan / Eastern Region	07-Aug-28	180.0	5	Full Release Execution
8	Kakabeka Falls GS Redevelopment	86386	Kakabeka Falls / Western Region	01-Dec-28	171.9	1	Full Release Execution
9	SAB1 Canal Isolation Preparedness Phase 1	89252	Sir Adam Beck 1 / Niagara Region	01-Mar-29	65.0	10	G2 – Definition (Full)
10	BK2 G20/G19 Refurbishment	87768	Sir Adam Beck 2 / Niagara Region	01-Feb-29	176.5	11	G2 – Definition (Full)
11	BK1 G6 G8 Refurbishment	86372	Sir Adam Beck 1 / Niagara Region	01-Mar-30	113.1	10	Full Release Definition
12	BK2 G18 G17 Refurbishment	87356	Sir Adam Beck 2 / Niagara Region	01-Jul-30	172.1	6	Full Release Development
13	BK2 G18 G17 Refurbishment	87356	Sir Adam Beck 2 / Niagara Region	01-Nov-30	172.1	2	Full Release Development

b) For each project listed in part a), please indicate whether the in-service date reflected in Reference 1 was established based on the most recent BCS approval or update identified in part a). Where it was not, please provide:
   i. the schedule update or other project controls document on which the in-service date was based.
   ii. a brief explanation of why the most recent BCS approval or update was not the basis for the in-service date reflected in Reference 1.

Response

a) OPG confirms that the latest Business Case Summaries ("BCS") have been filed in evidence for all the referenced projects, with the exception of two projects that have updated BCSs, as shown in Chart 1 below. The updated BCSs have been filed as Attachments 1 (confidential) and 2 (confidential) to this response.

Chart 1 – Updated Business Case Summaries

Project Name	Project #	New BCS Status	Reference
BK2 G20/G19 Refurbishment	87768	Full Release Execution	Attachment 1 (confidential)
BK1 G6 G8 Refurbishment	86372	Full Release Execution	Attachment 2 (confidential)

b) OPG confirms that, for the three projects listed in Chart 2 below, the in-service dates detailed in Reference 1 were established based on the most recent BCS approvals provided as part of the Application.

Chart 2 – Prefiled Business Case Summaries

Project Name	Project #	Latest BCS Status	Reference
Otter Rapids GS G2 Refurbishment	82543	Superseding Execution	Ex. D1-1-2, Attachment 1, Tab 9
Sir Adam Beck 1 GS G4 Refurbishment	86570	Full Release Execution	Ex. D1-1-2, Attachment 1, Tab 26
Matabitchuan GS Redevelopment	86387	Full Release Execution	Ex. D1-1-2, Attachment 1, Tab 25

For the two projects listed in Chart 3 below, the in-service dates detailed in Reference 1 were established based on forecast dates. The more recent BCSs filed in this response include minor updates to in-service dates, as detailed in Chart 3. OPG will not be updating the pre-filed evidence or approvals sought in this Application, as these projects would be subject to true up via the Capacity Refurbishment Variance Account.

Chart 3 – Updated BCS In-Service Dates

Project Name	Project #	New BCS Status	New BCS I/S Date	Reference
Sir Adam Beck 2 GS G20/G19 Refurbishment	87768	Full Release Execution	13-Oct-28 (unit G20)	Attachment 1
Sir Adam Beck 2 GS G20/G19 Refurbishment	87768	Full Release Execution	4-Feb-29 (unit G19)	Attachment 1
Sir Adam Beck 1 GS G6/G8 Refurbishment	86372	Full Release Execution	9-Oct-28 (unit G6)	Attachment 2
Sir Adam Beck 1 GS G6/G8 Refurbishment	86372	Full Release Execution	9-Apr-30 (unit G8)	Attachment 2

In the course of preparing this response, OPG discovered errors in in-service dates detailed in Reference 1. OPG has provided the correct information in Chart 4 below. OPG will not be updating the pre-filed evidence or approvals sought in this Application, as these projects would be subject to true up via the Capacity Refurbishment Variance Account.

Chart 4 – Corrected In-Service Dates

Project Name	Project #	Reference 1 I/S Date	Correct I/S Date(s)	Correct I/S Reference
Kakabeka Falls GS Redevelopment	86386	1-Apr-27	13-May-27 (powerhouse)	Ex. D1-1-2, Attachment 1, Tab 24
Kakabeka Falls GS Redevelopment	86386	1-Jul-27	24-Jul-27 (surge building) 26-Jul-27 (penstocks)	Ex. D1-1-2, Attachment 1, Tab 24
Kakabeka Falls GS Redevelopment	86386	1-Dec-28	21-Apr-28 (unit G1) 5-May-28 (unit G2)	Ex. D1-1-2, Attachment 1, Tab 24
SAB1 Canal Isolation Preparedness Phase 1	89252	1-Mar-29	30-Mar-29	Ex. D1-1-2, Attachment 1, Tab 42

Project Name	Project #	Reference 1 I/S Date	Correct I/S Date(s)	Correct I/S Reference
Sir Adam Beck 2 GS G18/G17 Refurbishment	87356	1-Jul-30	8-Sep-29 (unit G17)	Ex. D1-1-2, Attachment 1, Tab 37
Sir Adam Beck 2 GS G18/G17 Refurbishment	87356	1-Nov-30	31-Jan-30 (unit G18)	Ex. D1-1-2, Attachment 1, Tab 37

1

Business Case Summary

Project #	87768, 84293	**BCS Document Number**	NF28-BCS-08707.021-0092
Project Title	87768 - BK2 G20 G19 REFURBISHMENT 84293 - BK2 G20 G19 OVERHAUL OMA		
Facility	BK2 - SIR ADAM BECK 2	**Investment Classification**	Sustaining
Project Level (Scalability)	A	**Financial Classification**	17553 - CAPITAL - GENERATING FACILITIES 62030 - OM&A - PROJECT
Release: Gate and Project Phase	G3 - Execution - (Full)	**Target Project Completion Date**	2030-Feb-04
Estimate Class (Current Request)	Class 3	**Estimate Class (Overall Project)**	Class 3

Recommendation

We recommend a release of $152,663K, including [redacted] of contingency. This will bring the total released-to-date to $373,742K including [redacted] of contingency.

Breakdown of each project specific release (including contingency) is as follows:
87768 (Capital): $147,924K including [redacted] of contingency bringing the total release to-date to $369,003K.
84293 (OMA): Current and total release to-date $4,739K.

This project will refurbish the Sir Adam Beck 2 (SAB2) G20 and G19 units to sustain their long-term reliable operation. The previous Definition Phase release provided funding for the Original Equipment Manufacturer (OEM) Target Price, covering project management, detailed engineering design of the turbine, generator, governor, electrical balance of plant, mechanical balance of plant, civil works, headworks, scale model testing, auxiliary systems, and procurement. Procurement efforts are focused on securing key vendors and contracts, as well as long-lead materials, tooling, and equipment, to meet critical path milestones and support the construction schedule. This Execution Phase release will provide funding for the balance of the project scope, which includes mobilization, construction, commissioning, demobilization, and project closeout.

Investment Cash Flows

Project Number	84293 - BK2 G20 G19 OVERHAUL OMA					**FAC**	62030 - OM&A - PROJECT		
$K	**LT YE last year**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**Future**	**Total**
Previous releases	0								0
Currently Requested	0		523	3,895	321				4,739
Total released to date	0		523	3,895	321				4,739
Future required	0								0
Total Project Cost	0		523	3,895	321				4,739
Ongoing Costs	0								0

Project Number	87768 - BK2 G20 G19 REFURBISHMENT	**FAC**	17553 - CAPITAL - GENERATING FACILITIES

ONTARIO POWER GENERATION

Records File Information:
Retention Permanent

OPG Confidential
OPG-FORM-0076-R006*

Business Case Summary

$K	LT YE last year	2025	2026	2027	2028	2029	2030	Future	Total
Previous releases	15,998	32,262	86,100	66,797	19,922				221,079
Currently Requested		255	18,324	52,528	49,070	27,747			147,924
Total released to date	15,998	32,517	104,424	119,325	68,992	27,747			369,003
Future required									
Total Project Cost	15,998	32,517	104,424	119,325	68,992	27,747			369,003
Ongoing Costs									

Total OAR Approval	373,742.0

Approvals	Signatures	Date
The recommendation, including the identified ongoing costs, if any, represents the best option to meet the validated business need.		
Recommended by: Direct Report of Line Approver : Shelley Babin Chief Operations Officer Chief Operations Officer	Shelley Babin	2025-11-27
I concur with the business decision as documented in this BCS.		
Finance Approval : Aida Cipolla CFO & CAO	Aida Cipolla	2025-11-27
I confirm that this investment/project, including the identified ongoing costs, if any, will address the business need, is of sufficient priority to proceed, and provides value for money.		
Line Approval per OAR : OAR Element : 1.1 Nicolle Butcher President & Chief Executive Officer	Nicolle Butcher	2025-11-27

EXECUTIVE SUMMARY – Project Overview

The SAB2 Hydroelectric Generation Station, consisting of 16 units, has been operational since the 1950s. As one of the largest capacity assets in OPG's fleet, it has the capacity to provide Ontario with a Maximum Continuous Rating of 1,499 MW of emissions-free energy. The overall SAB2 Refurbishment Program (the "Program") aims to sustain clean, reliable, and cost-effective generation at SAB2 by reducing the risk of forced outages, enhancing unit efficiency and targeting a capacity increase of approximately 1.5 MW per unit. Project BK287768, which consolidates five projects (G20 CAP/OM&A, G19 CAP/OM&A, and Upgraded Main Output Transformers (MOT) T19), will execute the refurbishment of the first pair of units, G19 and G20, and their associated MOT T19. Given the complexity of the refurbishment and the fact that SAB2 is a high-capacity factor station with several shared systems, joint unit outages must be scheduled concurrently to optimize the execution timelines.

The G20 and G19 turbines and generators were last refurbished in 1999 and 2000, respectively. G20, the first unit scheduled for refurbishment, will begin in December 2026, followed by G19, the second unit, in April 2027, creating a 27-year gap between refurbishments. Major hydroelectric unit refurbishments are periodically required to maintain reliability. It is becoming increasingly challenging to maintain the reliability of the SAB2 fleet; additionally, the station is experiencing issues with obtaining obsolete parts and is subject to operating restrictions that increase outage risk and costs. The sequence of refurbishments for the SAB2 units is based on a Decision Analysis (DA) with input from Production, Engineering, Operations, and Project representatives. This order may be adjusted as necessary, based on the condition of each unit and any forced outages.

This project aligns with then Energy Minister Todd Smith's announcement on April 15, 2024, supporting OPG's refurbishment of Niagara Hydro Stations in collaboration with GE Vernova (GEV), stating that the "program would secure up to 1,700 megawatts (MW) of clean electricity, equivalent to powering 1.7 million homes, helping to meet increasing demand from electrification and fueling the province's growth." It also supports the Provincial Government's "Powering Ontario's Growth Plan", released on July 10, 2024, in response to public consultation on the Independent Electricity System Operator's Pathway to Decarbonization, which aims to achieve a net-zero economy by 2050. It also supports OPG's Climate Change Plan, which commits to refurbishing hydroelectric units across

the fleet.

OPG plans to work with a selected OEM, GE Vernova, through the RG Programmatic Collaborative Agreement (PCA), employing a Design Build Contracting Strategy and Target Pricing structure to provide engineering, procurement, and construction services for the project.

Before the consolidation of the five predecessor projects into this project, BK287768 G20 G19 Refurbishment, the previously approved scope primarily covered the Development Phase (Gate 1) activities, which included developing a detailed project scope, completing engineering specifications, conducting site inspections, determining the contracting/procurement strategy, and selecting a contractor for turbine-associated work. These activities have been completed. Since units G19 and G20 are the first to be refurbished, the upfront costs associated with selecting suppliers and contractors required for the entire Program are included in the project costs for G19 and G20. They will not be incurred for the subsequent units. This scope comprises selecting a partner OEM for the design, supply, and installation of the generator, turbine, and headgate gains, selecting contractors for quality assurance and control, engineering, project support, and protection and control (P&C) design & supply.

A Definition Phase (Gate 2) release was approved in August 2024, spanning from Q3 2024 to Q1 2025, to finalize the initial design and develop the detailed design. This phase included reviewing actions following the conceptual design reviews, creating preliminary designs of (major) components, and preparing calculation reports, including finite element analysis (FEA) calculations. Additionally, the funding covered costs for pass-through expenses, project management, project engineering, runner model testing, supply chain management, legal services, and procurement of long lead materials, and related project activities for the detailed mechanical design of the new runner and progressing through 30% and 60% design stages for various turbine and generator components, along with their associated systems. These activities are complete.

A Definition Phase (Gate 2B) release was approved in March 2025, spanning from Q1 2025 to Q3 2029, to address critical path design and supply activities, including procurement, completion of the design work, and enabling the project to secure contracts for the construction and installation phase, which includes down payments to key contractors. This phase includes reviewing actions following the conceptual design reviews, creating preliminary designs of (major) components, and preparing calculation reports, including FEA calculations. Additionally, the funding covers costs for pass-through expenses, project management, project engineering, runner model testing, supply chain management, legal services, and procurement of long lead materials as well as related project activities for the detailed mechanical design of the new runner and progressing through detailed design stages for various turbine and generator components, along with their associated systems. These activities are underway.

The requested funding release will be utilized during the Execution Phase (Gate 3), spanning from Q1 2026 to Q3 2029, for project management and engineering scope not included in Gate 2B, escalation, interest, field inspections of existing structures and components, execution of construction activities defined in the project specifications for Power Worker's Union (PWU) assigned work (by OPG) and Building Trades Union (BTU) assigned work (by GEV), OPG construction supervision, designated substance testing and abatement, construction tooling, commissioning, and project close out.

The key risks for this project are schedule delays and the complexity of the refurbishment. These include potential engineering delays caused by the availability of engineering design drawings and calculations, which may require additional condition assessments. These assessments, in turn, could delay engineering activities and the procurement of long-lead materials, impacting equipment delivery timelines and critical path milestones. Furthermore, there is a risk of delays due to the complexity of integrating major equipment, including protection and control systems, main output transformers, excitation systems, governor systems, and related equipment. These issues could delay the interconnection assessments with Hydro One and the Independent Electricity System Operator (IESO), potentially negatively impacting the in-service date. To mitigate these potential risks, a resource-loaded critical path schedule has been developed that includes a contingency based on a quantitative risk analysis and outlines the required resources based on estimated hours. Additionally, the roles and responsibilities for GEV and OPG personnel will be clearly defined to ensure transparency and accountability, supporting the development of a detailed strategy, tools, platform, and other pre-outage activities essential to the project's success.

Business Need For Project Level A or B

The business objective is to sustain the long-term reliability and safe operation of the G20 and G19 units. These units were last refurbished in 1999 and 2000, respectively. It is becoming increasingly challenging to maintain the reliability of the SAB2 fleet; additionally, the station is experiencing issues with obtaining obsolete parts and is subject to operating restrictions that increase outage risk and costs. Therefore, adhering to the scheduled refurbishment is crucial to achieving the project's objectives.

This project will achieve the business need in the following ways:

1) Minimize the risk of forced outages due to unexpected equipment failure and the replacement of obsolete parts.
2) Eliminate known safety hazards identified by plant staff.
3) Sustain long-term reliable and safe operation.
4) Enhance unit efficiency and target a capacity increase of 1.5 MW per unit (approximately)
5) Upgrade equipment to meet current regulatory requirements.

Given that 27 years have passed since the last refurbishment, if the current situation persists, unit reliability is expected to decline because maintenance will be reactive, rather than proactive, which might result in longer outages and a reduction in the amount of electricity that can be generated for the grid.

Preferred Alternative:	For Project Level A, B or C

Description of Preferred Alternative

In January 2024, OPG executed a strategic 15-year PCA with a vendor partner (GEV) to secure engineering, procurement, and construction (EPC) services utilizing the Target Pricing structure for the Program. Under this agreement, G20 and G19 will be the first pair of units to be refurbished for SAB2.

The preferred alternative consists of refurbishing units and replacing components where economical or required by Regulation. Capital spares will be purchased before the refurbishment to reduce downtime, be used for future maintenance, or be utilized throughout the Program. Implementation of this alternative would involve the following scope:

1) Replace the turbine and auxiliaries.
2) Refurbish and replace the generator and auxiliaries.
3) Replace the governor system.
4) Replace the electrical common balance of plant.
5) Replace the mechanical balance of the plant.
6) Replace protection and controls.
7) Refurbish civil works.
8) Refurbish the hydro mechanical headworks and headgate intake.

The preferred alternative will provide the following benefits:

1) Minimize the risk of forced outages due to unexpected equipment failure and the replacement of obsolete parts.
2) Eliminate known safety hazards identified by plant staff.
3) Sustain long-term reliable and safe operation.
4) Enhance unit efficiency and target a capacity increase of 1.5 MW per unit (approximately)
5) Upgrade equipment to meet current regulatory requirements.

The disadvantages of this method are:

1) OEM warranty has an upset limit of 2.4% of the Contract Price.
2) The project involves more replacement work than repair work, primarily due to the decision analysis and key critical path activities, which impacts the overall project cost.
3) The project scope is extensive, requiring a significant amount of qualified resources and hours.

Deliverables:

Previous Release:			
Deliverable Type	*Milestones*	*Associated Milestones (if any):*	*Target Date*
BCS for Gate 1A Approved	Gate G1 Approval		2019-10-31
Labour Determination	Labour Determination Completed		2020-02-25
Scope of Work Document	Scope of Work Document Complete		2021-06-30
Gate 2 Approval	Gate G2 Approval		2024-08-20
OEM Ph. 2 Worksheet Ext.	Contracts Awarded		2024-09-25
P&C Fac (Sub-Ph 1B)- Long Lead Procurement	Procurement Contracts Awarded/PO Issued		2024-11-06
Concept Design By OEM Specified In Worksheet Ext.	Conceptual Design Complete		2024-11-24
BCS for Gate 2B Approved	Gate G2B Approval		2024-12-10
OEM for Gate 2B Worksheet Approved	Contracts Awarded		2025-03-12
OEM Detailed Engineering Complete	Detailed Design Complete		2026-05-13
P&C Sub-Ph 1C Approved	Award Contracts / PO Issued		2026-07-07
P&C Detailed Engineering	Detailed Design Complete		2026-11-04
Current Release:			
Deliverable Type	*Milestones*	*Associated Milestones (if any):*	*Target Date*
Gate 3 Approval	Gate G3 Approval		2025-12-23
G20 Start of Outage	Start of Outage		2026-12-13
G19 Start of Outage	Start of Outage		2027-04-04
G20 End of Outage	End of Outage		2028-10-13
G20 Available for Service	Available for Service and/or Ready For Service Completed		2028-10-13
G19 End of Outage	End of Outage		2029-02-04
G19 Available for Service	Available for Service and/or Ready For Service Completed		2029-02-04
Project Closeout	Project Close Out Completed		2030-02-04
Post Implementation Review	Post Implementation Review		2031-02-04
Future Release: N/A			

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

Alternative 2 is not recommended because it does not address the business need for sustained long-term reliable operation. This approach would mean that no major proactive maintenance would be undertaken. Instead, repairs would be performed reactively, which would likely lead to a decline in unit reliability. Consequently, reactive maintenance costs are expected to rise, along with potential loss of generation.

Advantages:

1) No up-front project costs.

Disadvantages:

1) Maintenance costs are expected to increase each year as the unit condition continues to degrade.
2) Sustained long-term reliable operation is not expected. Forced outages are expected to increase.
3) Spare parts availability is expected to decrease over time due to obsolescence.

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

Alternative 3 is not recommended because multiple SAB2 units, including G20, have experienced failures and is in need of a (major) refurbishment. Delaying the Program will increase the frequency and duration of forced outages, raise operating and repair costs, and heighten the risk of significant, long-term damage to the asset. This would further compromise reliability and could result in higher costs and lost generation for Ontario.

Alternative 4:	**Full Unit Replacement**	For Project Level A, B

Alternative 4 is not recommended due to its significantly higher costs compared to the preferred alternative with minimal expected incremental benefits. It involves the complete replacement of units G20 and G19.

Advantages:

1) Meets the business needs of long-term reliable unit operation.
2) Unit forced outages will be reduced.
3) Lower production loss due to shorter outage window.

Disadvantages:

1) Significantly higher project costs.
2) An extended period is required for design, manufacturing, model testing, and installation

Business Case Summary

Key Risk Assessment			For Project Level A, B or C
Risk Class	**Description of Risk**	**Response Type / Actions / Final TCD**	**Residual Ranking**
Technical	OEM Resource Capacity and Capability Issues	Mitigate 57899 - Identify a dedicated commissioning coordinator to support OEM 74357 - OEM to be fully integrated with OPG schedule development (OPG P6) 12/31/2025	Medium
Technical	OEM Engineering - completeness of design packages	Mitigate 71597 - Follow up and keep oversight during OEM Engineering work 10/30/2026	Medium
Project Management	Equipment and Material Storage/early delivery	Mitigate 75728 - Equipment Storage Determination 76134 - establish inventory management system for critical components that have to be stored 6/30/2027	Medium
Technical	SAB2 floor space concern	Mitigate 57080 - Model needed floor space. Rent external storage space if required 4/30/2026	Medium
Quality	Stay Vane extensions, complexity of scope of work	Mitigate 77081 - Pre-plan / Mapping of work (Lesson Learned from Otter Rapids) 2/27/2026	Medium

Additional Risk Analysis	For Project Level A or B
Additional risks will be assessed throughout the project life cycle. Execution phase risks will be identified in the risk assessment workshops during the Definition phase.	

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

Analysis of Financial Evaluation – Key Assumptions and Key Results:

A financial analysis is not required for Sustaining projects.

Qualitative Factors	For Project Level A or B

Qualitative factors provided by the Preferred Alternative are listed below:

1) Ensure OPG continues to provide a reliable renewable source of energy while reducing the environmental impact of meeting Ontario's electricity demand.
2) Provide unrestricted operation, such as removing limitations on Automatic Generation Control.
3) Address identified safety hazards by implementing enhancements like ergonomic improvements to generator excitation and enhanced grounding.
4) Decrease the frequency and intensity of maintenance requirements.
5) Drive project excellence by leveraging the insights gained from the first refurbishment of the G20 unit to enhance the performance of the remaining SAB2 units.

Post Implementation Review (PIR) Plan (refer to OPG-GUID-00120-0007)			
Is PIR Required?	Yes	**PIR Completion Date**	2031-02-04

PIR KPI's	Current Baseline	Target Result	How to Measure?	Who will measure?
G19 Runner Weighted Mean Efficiency	[redacted]	[redacted]	Field performance test. If guaranteed performance is within the measured test uncertainty band, the turbine meets the requirement.	OPG Performance and Testing (P&T) to measure and report field performance with applicable uncertainty band.
G20 Runner Weighted Mean Efficiency	[redacted]	[redacted]	Field performance test. If guaranteed performance is within the measured test uncertainty band, the turbine meets the requirement.	OPG P&T to measure and report field performance with applicable uncertainty band.
G19 Turbine Rated Power	101MW at rated net head (90.5 m)	101MW at rated net head (90.5 m)	Turbine power is derived from the unit output at the generator terminal, factored by the generator efficiency.	OPG/GEV commissioning team, to be later confirmed by P&T in field test.
G20 Turbine Rated Power	101MW at rated net head (90.5 m)	101MW at rated net head (90.5 m)	Turbine power is derived from the unit output at the generator terminal, factored by the generator efficiency.	OPG/GE commissioning team, to be later confirmed by P&T in field test.
Canadian General Electric (CGE) Generator Efficiency	[redacted]	[redacted] as per GEV Submittal of Supplemental Specification OPG-M-769S, Section B, Rev E, 2025-10-17	Field Final Acceptance Testing; if guaranteed performance is at or better than guaranteed values, the generator design is acceptable	GEV will arrange for OPG approved testing vendor to conduct generator testing as per IEEE 115
Canadian Westinghouse Company (CWC) Generator Efficiency	[redacted]	[redacted] as per GEV Submittal of Supplemental Specification OPG-M-769S, Section B, Rev A, 2025-10-21	Field Final Acceptance Testing; if guaranteed performance is at or better than guaranteed values, the generator design is acceptable	GEV will arrange for OPG approved testing vendor to conduct generator testing as per IEEE 115
CGE Generator Rated Power	110 MVA, 13.8 kV at 0.95PF	110 MVA, 13.8 kV at 0.95PF	Field Final Acceptance Testing; if guaranteed performance is at or better than guaranteed values, the generator design is acceptable	GEV will arrange for OPG approved testing vendor to conduct generator testing as per IEEE 115
CWC Generator Rated Power	110 MVA, 13.8kV at 0.95PF	110 MVA, 13.8kV at 0.95PF	Field Final Acceptance Testing; if guaranteed performance s at or better than guaranteed values, the generator design is acceptable.	GEV will arrange for OPG approved testing vendor to conduct generator testing as per IEEE 115

Definitions and Acronyms	
BTU	Building Trades Union
DA	Decision Analysis

EPC	Engineering, Procurement and Construction
FEA	Finite Element Analysis
IESO	Independent Electricity System Operator
MOT	Main Output Transformer
MV	Medium Voltage
OEM	Original Equipment Manufacturers
P&C	Protection and Control
PIR	Post-Implementation Review
PWU	Power Workers' Union
SAB	Sir Adam Beck

APPENDICES

Appendix A1: Summary of Estimate

Project Number	84293 - BK2 G20 G19 OVERHAUL OMA						FAC	62030 - OM&A - PROJECT		
$K	LT YE last year	2025	2026	2027	2028	2029	2030	Future	Total	%
0 - Cost Management										0
1 - Project Management										0
2 - Inspection										0
3 - Engineering										0
4 - Procurement										0
5 - Construction			523	3,895	321				4,739	100
6 - Commissioning										0
Closeout										0
Subtotal			523	3,895	321				4,739	100
Outside WBS										0
Contingency										0
Subtotal w/ Contingency			523	3,895	321				4,739	100
Interest										0
Other										0
Total			523	3,895	321				4,739	100
Removal Costs (incl. above)										0

Project Number	87768 - BK2 G20 G19 REFURBISHMENT						FAC	17553 - CAPITAL - GENERATING FACILITIES		
$K	LT YE last year	2025	2026	2027	2028	2029	2030	Future	Total	%
0 - Cost Management	313	3,200	5,137	529	110				9,289	3
1 - Project Management	5,872	2,660	5,098	4,113	4,743	340			22,826	6
2 - Inspection	351				100				451	0
3 - Engineering	[redacted]									
4 - Procurement										
5 - Construction										
6 - Commissioning										
Closeout										
Subtotal										
Outside WBS										
Contingency										
Subtotal w/ Contingency										

Business Case Summary

Interest	[redacted]									
Other										
Total	15,998	32,517	104,424	119,325	68,992	27,747			369,003	100
Removal Costs (incl. above)			420	2,098					2,518	1

Appendix A2: Summary of Estimate – Notes

Escalation Rate	**3.00**	**Interest Rate (going-forward)**	**4.62**

Appendix A3: Summary of Estimate - In-Service Estimates

$K — Only applicable to capital projects. In-Service amount shall include interest but exclude removal costs.

Project#	Date	Description	Amount	%
87768	2028-10-13	G20 Return to Service	154,226	48.7
87768	2029-02-04	G19 Return to Service	162,459	51.3
		Total:	**316,685**	**100**

Prepared by		Reviewed and Endorsed by (Execution Authority)	
Bill Van Luven Project Leader SAB2 Refurbishment Program	2025-11-19	Shelley Babin Chief Operations Officer Enterprise Operations	2025-11-26

Business Case Summary

Project #	86372, 86373	**BCS Document Number**	NF20-BCS-08707.021-0062
Project Title	86372 - BK1 G6 G8 REFURBISHMENT 86373 - BK1 G6 G8 OVERHAUL OMA		
Facility	BK1 - SIR ADAM BECK 1	**Investment Classification**	Sustaining
Project Level (Scalability)	A	**Financial Classification**	17553 - CAPITAL - GENERATING FACILITIES 62030 - OM&A - PROJECT
Release: Gate and Project Phase	G3 - Execution - (Full)	**Target Project Completion Date**	2030-Dec-12
Estimate Class (Current Request)	Class 3	**Estimate Class (Overall Project)**	Class 3

Recommendation

We recommend a release of $223,530K, including [redacted] of contingency.

This will bring the total released-to-date to $267,611K, including [redacted] of contingency.

This project is to refurbish Sir Adam Beck 1 (SAB1) G6 & G8 units in order to sustain their long-term reliable operation, including:
- Replace the turbine;
- Replace the governor;
- Refurbish and repair the generator, and replace auxiliary equipment;
- Replace the excitation system;
- Replace the protection and control equipment;
- Replace the unit breaker;
- Replace the transformer; and
- Inspect and repair the penstock

This Execution Phase release will provide funding for the refurbishment of the unit including material purchasing, equipment procurement, completion of engineering, construction, commissioning and project management for the generator, governor, electrical balance of plant, mechanical balance of plant, civil works, auxiliary systems, and inspect and repair the penstock.

Investment Cash Flows

Project Number	86372 - BK1 G6 G8 REFURBISHMENT					**FAC**	17553 - CAPITAL - GENERATING FACILITIES		
$K	**LT YE last year**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**Future**	**Total**
Previous releases	1,566	7,594	34,921						44,081
Currently Requested	0		2,212	71,636	68,528	62,630	13,526		218,532
Total released to date	1,566	7,594	37,133	71,636	68,528	62,630	13,526		262,613
Future required	0								0
Total Project Cost	1,566	7,594	37,133	71,636	68,528	62,630	13,526		262,613
Ongoing Costs	0								0

Project Number	86373 - BK1 G6 G8 OVERHAUL OMA	**FAC**	62030 - OM&A - PROJECT

ONTARIO POWER GENERATION

Records File Information:
Retention Permanent

OPG Confidential
OPG-FORM-0076-R006*

Business Case Summary

$K	LT YE last year	2025	2026	2027	2028	2029	2030	Future	Total
Previous releases									
Currently Requested				1,998	2,000	1,000			4,998
Total released to date				1,998	2,000	1,000			4,998
Future required									
Total Project Cost				1,998	2,000	1,000			4,998
Ongoing Costs									

Total OAR Approval	267,611.0

Approvals	Signatures	Date
The recommendation, including the identified ongoing costs, if any, represents the best option to meet the validated business need.		
Recommended by: Direct Report of Line Approver : Shelley Babin Chief Operations Officer Chief Operations Officer	Shelley Babin	2025-12-04
I concur with the business decision as documented in this BCS.		
Finance Approval : Aida Cipolla CFO & CAO	Aida Cipolla	2025-12-04
I confirm that this investment/project, including the identified ongoing costs, if any, will address the business need, is of sufficient priority to proceed, and provides value for money.		
Line Approval per OAR : OAR Element : 1.1 Nicolle Butcher President & Chief Executive Officer	Nicolle Butcher	2025-12-05

EXECUTIVE SUMMARY – Project Overview

The SAB1 Hydroelectric Generating Station, consisting of 10 units, has been operational since the 1920s.

The last major refurbishment on these units was in 1990 for G8 and 1995 for G6. These are the last two SAB1 units requiring refurbishment. Major hydroelectric unit refurbishments are required to maintain reliability. Recent condition assessments have confirmed that sustaining unit reliability will be challenged due to normal wear and aging and there is a lack of readily available spare parts as the OEM no longer makes or supports the existing parts; this has led to prolonged outages required for repairs. This project aims to sustain the long-term reliable operations of SAB1 G6 and G8 by modernizing the generating units, including a new runner design, and increasing its capacity by approximately 4.9MW per unit.

The preferred alternative is to complete a unit refurbishment on G6 & G8. The project consists of performing a mechanical and electrical refurbishment of the generating unit. Obsolete and end of life equipment (protection and controls equipment, Main Output Transformer, etc.) will be replaced to ensure cost effective, clean and renewable electricity production.

This project aligns with the Energy Minister's announcement on April 15, 2024, stating that "Niagara Hydro Stations are set to be refurbished, securing about 1,700 MW of clean power for another 30-plus years". It also supports the Provincial Government's "Powering Ontario's Growth Plan", released on July 10, 2024, in response to public consultation on the Independent Electricity System Operator's Pathway to Decarbonization, which aims to achieve a net-zero economy by 2050.

OPG plans to work with GE Vernova as the OEM vendor partner under the RG Programmatic Collaborative Agreement (PCA), employing a Design Build Contracting Strategy and Target Pricing structure to provide engineering, procurement, and construction services for the project. Vendor partners from the G4 Major Refurbishment and the SAB2 Refurbishment Program will be engaged to incorporate lessons learned, ensure equipment consistency and designs, and to drive programmatic efficiency.

The contracting and procurement strategy on the SAB Refurbishment Program includes:
1) A primary OEM vendor partner (GE Vernova) that is engaged to engineer, procure components, and construct in alignment with the planned schedule, and
2) Specialized suppliers for P&C equipment and main output transformers (T6 & T8).

The previously approved scope was for the Development Phase (Gate 1) and Definition Phase (Gate 2) activities. Developing a detailed project scope, completing engineering specifications, conducting site inspections and contracting/procurement strategies are now complete. Detailed design, procurement of long lead equipment and final selection of the construction contractors for associated work are in progress. The previous funding covers costs for pass-through expenses, project management, project engineering, runner design, supply chain management, legal services, procurement, and related project activities for the detailed design progressing through 30% and 60% design stages for various turbine and generator components along with their associated systems.

Under the RG PCA, the upfront costs to complete the selection of majority suppliers and contractors required for all SAB1 Refurbishment Projects are completed during the execution phase of the G4 project and this cost is not expected to be incurred for G6 & G8 Execution Phase.

The project primarily involves capital refurbishment and replacement, with less than 2% of the total budget allocated to OM&A costs.

The Execution Phase funding in this release will encompass the full execution costs for the construction phase, including commissioning and project closeout. A comprehensive, resource-loaded schedule has been developed, drawing on lessons learned from G4. For G6/8, GE Vernova will be responsible for the full project scope, including both disassembly/reassembly and balance of plant activities. This approach differs from G4, where OPG managed disassembly and reassembly, and GE Vernova was responsible only for balance of plant work. GE Vernova's participation in G4 will help build confidence in their ability to deliver G6/8 successfully.

The released funds will be used to complete the following:
1) Engineering (100% detailed design completion)
2) Finalize contract with GE Vernova for the project lifecycle
3) Procurement of all materials
4) Release contracts for P&C supply and installation
5) Release Worksheet to GE Vernova under the RG (PCA) for the construction execution and close out phases
6) QA/QC for all materials, equipment and construction
7) Commissioning of unit and in-service

The key risks for this project include contractor integration, equipment costs, procurement and resourcing.

For G6/8, GE Vernova will be accountable for unit disassembly, reassembly and balance of plant works, which increases execution risk given this is their first time acting as the primary contractor responsible for the full execution of a refurbishment at Niagara. To mitigate this, GE Vernova is being onboarded during G4 to transfer knowledge, document processes, and embed lessons learned. OPG will provide continuous safety and quality oversight during execution of G6/8 and will lead the commissioning efforts.

The equipment costs are a key factor in the overall project costs, and any substantial changes would have a direct impact. The mitigation efforts include leveraging the PCA with GE Vernova to secure capacity and early cost estimates for key long lead items such as runners, circuit breakers, and lightning arrestors.

The risk of procurement challenges, leading to delays or cost increases, is common to OPG and GE Vernova. The partners are mitigating this risk by bundling scope to achieve cost reductions and collaborating with vendors to develop and optimize integrated schedules. Parallel plans for local sourcing of components and advanced procurement of long lead items is also being performed.

Both OPG and GE Vernova share the risk of limited access to qualified vendors and technical trades, particularly as the G6/8 schedule overlaps with other major units during a period of peak program demand. This shared constraint is heightened by the transition from G4 to G6/8 work, which may affect the timely mobilization of key personnel and completion of final design deliverables. These risks are being mitigated through proactive, coordinated resource planning, early engagement of critical external resources by both organizations, and enhanced collaboration to streamline integration and minimize schedule impacts. This shared accountability underscores the importance of unified planning and transparent communication between OPG and GE Vernova.

Business Need For Project Level A or B

Business Case Summary

The business objective is to sustain the long-term reliable and safe operation of the SAB1 Unit G6 & G8. The last major refurbishment on these units occurred in 1990 for G8 and 1995 for G6. Engineering condition assessments show risk of declining reliability, obsolete parts, and operating restrictions that increase outage risk and cost. G6 and G8 have a similar design and age to G4 and G5 and are expected to face the same operating restrictions. Applying the lessons learned from successful repairs on G5, which are now being implemented on G4, will allow OPG to proactively address issues on G6 and G8 and ensure long-term reliable operation. Adhering to the scheduled refurbishment is crucial to achieving the project's objectives.

This project will achieve the business need in the following ways:
1) Reduce the risk of forced outages due to unexpected equipment failure and replacement of obsolete parts.
2) Eliminate known safety hazards to ensure safe operation of the unit.
3) Sustain long-term reliable and safe operation.
4) Increase installed capacity by an estimated 4.9MW and improve runner efficiency.
5) Upgrade equipment to meet current regulatory requirements.

It has been over 30 years since the last refurbishment of G6 and G8. Engineering assessments show that without intervention, equipment reliability will decline, and the risk of unexpected failures and operating restrictions will increase. This could lead to frequent, longer outages and a reduction in electricity generating capacity in the SAB 1 Station.

Preferred Alternative:	Refurbishment and upgrade to a higher capacity	For Project Level A, B or C

Description of Preferred Alternative

In January 2024, OPG executed a strategic 15-year PCA with GE Vernova to secure engineering, procurement, and construction services utilizing a Target Pricing structure for the SAB Refurbishment Program. These units will be executed under this partnership agreement.

The preferred alternative consists of refurbishing the units and replacing components where economical or required by regulation.

The units are planned to have an increase in capacity from the new runners and other major work scope which includes:
1) Convert the generator floating rim to a shrunk design, blast and re-wedge stator, replace surface air coolers, replace bearing cooling coils, refurbish brake assembly with new seals and pads;
2) Replace generator main output bus, insulators, and switches;
3) Replace MOT and exciter;
4) Replace 115 kV disconnects, voltage transformers and lightning arrestors;
5) Upgrade governor and protections and control systems;
6) Manufacture and install new major turbine components: rotating components (runner, turbine shaft) and tower assembly (head cover, bottom ring, operating ring, and wicket gates);
7) Replace valves and piping.

Advantages:
1) Generator issues (vibration and operational constraints) are addressed proactively.
2) Installed capacity increase by an estimated 4.9MW per unit.
3) Sustains the long-term operation of SAB1.
4) Long term PCA with GE Vernova which secures capacity and provides transparent pricing structure, resource stability, cost minimization, optimal project solutions, and equipment consistency.

Disadvantages:
1) Warranty on replaced components only.
2) More complex outage coordination to complete refurbishment activities.

Deliverables:

Previous Release:			
Deliverable Type	*Milestones*	*Associated Milestones (if any):*	*Target Date*
Gate 1 approval and BCS signed by OAR	Gate G1 Approval		2024-05-30
Contract award for OEM Engineering 30%	Design Contract Awarded/PO Issued		2024-06-28
Contract award for MOT Engineering T6	Award Contracts / PO Issued		2025-01-08
Gate 2 BCS Approval	Gate G2 Approval		2025-05-21
Contract Award for OEM Phase 2 Worksheet	Award Contracts / PO Issued		2025-05-30
Contract Award for P&C Upgrade	Award Contracts / PO Issued		2025-05-30
OEM PO for Long Lead items Issued (Ph. 2)	Procurement Contracts Awarded/PO Issued		2026-02-02
Contract Award for OEM Engineering (60%)- Ph. 2	Detailed Design Complete		2026-02-28
Contract award for T8 MOT	Award Contracts / PO Issued		2026-03-31
Current Release:			
Deliverable Type	*Milestones*	*Associated Milestones (if any):*	*Target Date*
Gate G3 Approval	Gate G3 Approval		2026-02-27
Start of Outage (SOO)/Installation - Unit G6	Start of Installation		2027-03-08
Finish of Installation (FOI) - Unit G6	Finish of Installation		2028-05-08
Design Engineering by OEM 90% completed	Detailed Design Complete		2028-10-02
Available for Service (AFS)- Unit G6	Available for Service and/or Ready For Service Completed		2028-10-09
Start of Outage (SOO)/Installation - Unit G8	Start of Outage		2028-10-09
Finish of Installation (FOI) - Unit G8	Finish of Installation		2029-10-18
Available for Service (AFS)- Unit G8	Available for Service and/or Ready For Service Completed		2030-04-09
Close Out	Project Close Out Completed		2031-04-09
Post Implementation Review (PIR)	Post Implementation Review		2032-04-08
Future Release: N/A			

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

Alternative 2 is not recommended. The base case involves the status quo, continue to maintain and repair on an as-needed basis. Equipment and structures would only be replaced or rehabilitated if they fail, and unit safety concerns are not sufficiently addressed. This alternative is impractical as an operational strategy as it would likely result in unscheduled significant forced outages for major maintenance and repairs in a reactive, uncoordinated, and inefficient manner.

Advantages:
1) No commitment of funds.

Disadvantages:
1) No capacity increase.
2) Reactive approach to known issues already observed on similar units (G4, G5), as confirmed by engineering assessments and past repair experience. A reactive approach would lead to lower reliability.
3) Mid and long-term reliability of G6 & G8 at risk.
4) Obsolete spare part availability will impact unit availability negatively.
5) Higher incidental costs to address failures as they occur in comparison to a planned refurbishment program.

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

Alternative 3 is not recommended because delaying the refurbishment does not address any issues identified with G6 & G8. Delaying the work is likely to increase equipment risks and safety concerns. Delaying work, maintaining and repairing as needed would only address equipment after failure, causing unplanned forced outages. This project is part of a major refurbishment program with sequential execution of unit refurbishments. Following a sequential execution minimizes demobilization costs, retains experienced staff, and ensures predictability for long lead time suppliers. Thus, this alternative is not practical as an operational strategy, will result in unscheduled costly forced outages, and disrupt the program and supply chain.

Advantages:
1) Deferring large capital commitments.

Disadvantages:
1) Maintenance and repair costs due to aging components will continue and increase as equipment wears faster.
2) Reactive approach to known issues already observed on similar units (G4, G5), as confirmed by engineering assessments and past repair experience. A reactive approach would lead to lower reliability.
3) Disruption to refurbishment program and supply chain partnerships.

Alternative 4:	**Full unit replacement**	For Project Level A, B

Alternative 4, full unit replacement, is not recommended. Full replacement would address the risks identified in engineering condition assessments, specifically declining reliability, obsolete parts, and operating restrictions that increase outage risk and cost. However, the preferred alternative would do so at a higher cost with minimal incremental benefit over the preferred alternative. Niagara Operations would undertake a project similar to the G1/G2 Replacement project and install completely new units to replace G6 & G8. Unlike G1/G2, which required new generators for frequency conversion, G6 & G8 do not as they are already designed for 60 Hz.

Major work would consist of:
1) Complete removal of all existing G6 & G8 units and all associated equipment.
2) Installation of all new equipment including new designs for the generator, turbine, and embedded components (scroll case, draft tube).
3) Inspection and repairs of the penstocks and headgates.

Advantages:
1) Generator issues are addressed proactively.
2) Capacity increase.
3) Re-using design elements from prior unit replacement.
4) Long-term reliable operation. All new components including generator (unlike preferred Alternative).
5) Warranty on the full unit.
6) Potential for shorter outage duration for installation.

Disadvantages:
1) Higher costs than the Preferred Alternative.
2) Longer planning window compared to a unit refurbishment (frequency of unit replacement projects is much lower than refurbishment projects); increased reliability and safety risks in the interim.

Business Case Summary

Key Risk Assessment			For Project Level A, B or C
Risk Class	**Description of Risk**	**Response Type / Actions / Final TCD**	**Residual Ranking**
Commercial (Contract/Legal)	Cost increase of equipment due to external factors	Mitigate 76010 - Establish early procurement: set deadlines for placing Purchase Orders to lock in initial costs. 3/1/2027	Medium
Procurement - Materials	Supplier capacity constraints and shortages of raw materials	Mitigate 64195 - Plan local supply of equipment when possible. 3/1/2027	Medium
Resources	External resource constraints of qualified vendors and technical trades available	Mitigate 64197 - Initiate early planning and engagement of potential vendors and contractors. 3/1/2027	Medium
Integration	Prime contractor integration and schedule execution delays due to GE Vernova's first full-scope execution at an OPG hydro facility.	Mitigate 77004 - Onboard GE Vernova during G4 to transfer knowledge, document processes, and embed lessons learned; maintain enhanced OPG oversight and structured performance reviews throughout execution. 3/9/2027	Medium
Quality	Existing site condition worse than expected: civil, rotor, stator, intake and embedded components	Mitigate 76000 - Conduct targeted inspections using advanced diagnostic tools where feasible 8/15/2027	Medium

Additional Risk Analysis	For Project Level A or B
Additional risks will be assessed throughout the project life cycle. Execution phase risks will be identified in the risk assessment workshops during the Definition phase.	

Financial Evaluation		For Project Level A, B (with multiple feasible alternatives) or Value-Enhancing			
$K	**Alternative**	**Base Case (No Project)**	**Delay Work**	**Alternative 4**	**Alternative 5**
N/A					
Analysis of Financial Evaluation – Key Assumptions and Key Results:					
A financial analysis is not required for Sustaining Projects.					

Qualitative Factors	For Project Level A or B
Qualitative factors provided by the Preferred Alternative are listed below: 1) Ensure OPG continues to provide a reliable renewable source of emissions-free energy while reducing the environmental impact of meeting Ontario's electricity demand. 2) Sustain reliable G6 and G8 operation, without operating restrictions. 3) Address identified safety hazards by implementing enhancements like ergonomic improvements to generator excitation and enhanced grounding. 4) Drive project excellence by leveraging the insights gained from the SAB1 G4 and G5 refurbishments, as well as other refurbishments throughout the province (SAB2, Otto Holden GS and Saunders GS), to enhance the performance of this refurbishment. 5) Refurbished generator components (stator and rotor) are expected to be in good condition. It is expected that there is no added value in replacing them with new, if the condition is as assumed upon discovery. The G4 refurbishment stator testing is to be used to support G6 G8 expectations.	

Post Implementation Review (PIR) Plan (refer to OPG-GUID-00120-0007)			
Is PIR Required?	Yes	**PIR Completion Date**	2032-04-08

PIR KPI's	Current Baseline	Target Result	How to Measure?	Who will measure?
MCR (MW)	53.0 MW (MCR).	57.9 MW (MCR) or higher.	OPG Performance and Testing	SAB1 Production
Operating Range Flexibility	G6 and G8 are currently recommended to not operate between 0 MW to 45 MW due to rough zones.	Greater MW range than existing G6 and G8 units which currently have an operating range of 8 MW.	Vibration Readings During Commissioning	Project Commissioning Team
Conversion to Shrunk Rotor Rim Design	Existing design is the unreliable floating rim style.	Rotor with shrunk rim design.	Quality Documentation	GE Vernova and OPG Refurb Crew

Definitions and Acronyms	
SAB	Sir Adam Beck
P&C	Protection and Control
OEM	Original Equipment Manufacturers
PWU	Power Workers' Union
MV	Medium Voltage
MOT	Main Output Transformer
QA	Quality Assurance
QC	Quality Control

Business Case Summary

APPENDICES

Appendix A1: Summary of Estimate

Project Number	86372 - BK1 G6 G8 REFURBISHMENT						FAC	17553 - CAPITAL - GENERATING FACILITIES		
$K	LT YE last year	2025	2026	2027	2028	2029	2030	Future	Total	%
0 - Cost Management										0
1 - Project Management	404	2,226	4,238	9,968	10,397	10,103	1,576		38,912	15
2 - Inspection										0
3 - Engineering	[redacted]									
4 - Procurement										
5 - Construction										
6 - Commissioning										
Closeout										
Subtotal										
Outside WBS										
Contingency										
Subtotal w/ Contingency										
Interest										
Other										
Total	1,566	7,594	37,133	71,636	68,528	62,630	13,526		262,613	100
Removal Costs (incl. above)				2,349	1,409	939			4,697	2

Project Number	86373 - BK1 G6 G8 OVERHAUL OMA						FAC	62030 - OM&A - PROJECT		
$K	LT YE last year	2025	2026	2027	2028	2029	2030	Future	Total	%
0 - Cost Management										0
1 - Project Management										0
2 - Inspection										0
3 - Engineering										0
4 - Procurement										0
5 - Construction				1,998	2,000	1,000			4,998	100
6 - Commissioning										0
Closeout										0
Subtotal				1,998	2,000	1,000			4,998	100
Outside WBS										0
Contingency										0
Subtotal w/ Contingency				1,998	2,000	1,000			4,998	100

Business Case Summary

Interest										0
Other										0
Total				1,998	2,000	1,000			4,998	100
Removal Costs (incl. above)										0

Appendix A2: Summary of Estimate – Notes

Escalation Rate	**3.30**	**Interest Rate (going-forward)**	**4.71**

Appendix A3: Summary of Estimate - In-Service Estimates

$K	Only applicable to capital projects. In-Service amount shall include interest but exclude removal costs.			
Project#	**Date**	**Description**	**Amount**	**%**
86372	2028-10-06	Unit G6 In-Service	107,867	50.0
86372	2030-04-09	Unit G8 In-Service	107,867	50.0
86372	2031-04-09	Project Close Out	425	0.0
		Total:	**216,159**	**100**

Prepared by		**Reviewed and Endorsed by (Execution Authority)**	
Jeff Dancy Senior Project Leader SAB1 Refurbishment Program	2025-11-25	Shelley Babin Chief Operations Officer Enterprise Operations	2025-12-03