Ontario Energy Board | Commission de l'énergie de l'Ontario

**BY EMAIL**

March 5, 2024

Nancy Marconi
Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Marconi:

**Re: Ontario Power Generation Inc. (OPG)**
**Market Renewal Program and Disposition of Deferral & Variance Accounts Application**
**OEB Staff Interrogatories**
**Ontario Energy Board File Number: EB-2023-0336**

In accordance with Procedural Order #1, please find attached the Ontario Energy Board (OEB) staff interrogatories in the above proceeding. The applicant has been copied on this filing.

Ontario Power Generation Inc.'s responses to interrogatories are due by March 22, 2024.

Any questions relating to this letter should be directed to Andrew Pietrewicz at Andrew.Pietrewicz@oeb.ca or at 416-440-7642. The Board's toll-free number is 1-888-632-6273.

Yours truly,

Andrew Pietrewicz
Senior Advisor, Energy Transition – Strategic Policy

cc.

Encl.

**Ontario Power Generation Inc. (OPG)**
**Market Renewal Program and Disposition of**
**Deferral & Variance Accounts Application**
**EB-2023-0336**
**OEB Staff Interrogatories**
**March 5, 2024**

Please note, OPG is responsible for ensuring that all documents it files with the OEB, including responses to OEB staff questions and any other supporting documentation, do not include personal information (as that phrase is defined in the *Freedom of Information and Protection of Privacy Act*), unless filed in accordance with rule 9A of the OEB's *Rules of Practice and Procedure*.

**Staff-1**

**Ref:** (1) Exhibit H1 / Tab 1 / Schedule 1 / pages 11-12
(2) Exhibit H1 / Tab 1 / Schedule 1 / Table 6

**Preamble:**

OPG recorded four entries to the Income and other Taxes Variance account in 2020, 2021 and 2022. Two of the four entries are as follows:

- Credit entries in 2020, 2021 and 2022 related to a CCA rule change pursuant to the passing of Bill C-97, the Budget Implementation Act, 2019, No. 1 in 2019, which provides for a first-year increase in CCA deductions on eligible capital assets acquired after November 20, 2018, referred to as accelerated investment incentive property ("AIIP").

- A credit entry related to an increase in the recognition of SR&ED ITCs for the 2016 taxation year from 75% to 100%, based on the resolution of the 2016 income tax audit in 2021.

**Question(s):**

a) Please explain why the SR&ED ITCs recognition percentages have increased from 75% to 100% for the 2016 taxation year, following their respective audits.

i. Please provide the relevant page(s) of the 2016 income tax audit report to substantiate the percentage change.

b) Please provide the supporting 2020, 2021 and 2022 CCA difference calculations for:

i. Nuclear (2020: $10.1M) line 3 Table 6
ii. Nuclear (2021: $8.0M) & Hydroelectric (2021: $8.1M) line 4 Table 6
iii. Hydroelectric (2022: $10.8M) line 5 Table 6

**Staff-2**

**Ref:** (1) Exhibit H1 / Tab 1 / Schedule 1 / pages 45-46
(2) Exhibit H1 / Tab 1 / Schedule 1 / Table 14

**Preamble:**

OPG stated that:

- Actual SR&ED ITCs net of tax attributed to the nuclear facilities recorded in 2020 and 2021, inclusive of immediately preceding year's true-up adjustments based on income tax return completion, were lower than the forecast amounts reflected in the corresponding revenue requirements approved in EB-2016-0152.

- Actual SR&ED ITCs net of tax recorded in 2022, inclusive of immediately preceding year's true-up adjustment based on income tax return completion, were higher than the forecast amount reflected in the corresponding revenue requirement approved in EB-2020-0290.

**Question(s):**

a) Please explain if OPG had undergone any audits for 2020, 2021 and 2022 SR&ED ITCs. If so, please provide any findings from those audits and if these findings have been incorporated into the DVAs.

**Staff-3**

**Ref:** (1) Exhibit H1 / Tab 1 / Schedule 1 / p. 51
(2) Ontario Power Generation Inc. | OSC

**Preamble:**

OPG stated that:

> The Impact for IFRS Deferral Account was approved in EB-2020-0290, effective January 1, 2022, to record financial impacts of transition to and implementation of International Financial Reporting Standard ("IFRS") from US GAAP in the event that OPG adopts IFRS for financial reporting purposes to meet the requirements of the Securities Act (Ontario). No entries were recorded in this account in 2022 as OPG has continued to apply US GAAP to report its consolidated financial statements.

OEB staff notes that the exemption granted by OSC for OPG adopting IFRS is subject to certain conditions, potentially resulting in the expiration of the exemption before January 1, 2027.

**Question(s):**

a) Please provide comments on OPG's plan to transition from US GAAP to IFRS, considering the expiration of the exemptive relief granted by OSC before January 1, 2027.

   i. If so, please provide a schedule and timeline for the transition.
   ii. If not, please explain OPG's plan of requesting an extension of the exemptive relief.

**Staff-4**

**Ref:** (1) Exhibit H1 / Tab 1 / Schedule 1 / p. 29
(2) Exhibit H1 / Tab 1 / Schedule 1 / Attachment 5 / p. 5 / Actuarial Report
(3) Government of Ontario Will Not Appeal Bill 124 Decision | Ontario Newsroom

**Preamble:**

OPG noted that "OPEB payments attributed to the nuclear facilities for 2020 and 2021 were lower than the reference amounts, primarily due to changes in claim patterns resulting from the COVID-19 pandemic. OPEB payments attributed to the regulated hydroelectric facilities for 2020 to 2022 were higher than the reference amounts, primarily due to a growing retiree population."

On Page 5 of Attachment 5, OPG noted that the actuarial report confirms OPG's total actual pension and OPEB costs for the period from January 1, 2020 to December 31, 2022, as determined in accordance with US GAAP, are as follows:

| (in Canadian $ 000's) | January 1, 2020 to December 31, 2020 | January 1, 2021 to December 31, 2021 | January 1, 2022 to December 31, 2022 |
|---|---|---|---|
| RPP | $ 158,857 | $ 199,089 | $ 85,612 |
| SPP | 26,408 | 26,902 | 24,859 |
| OPRB | 156,539 | 150,020 | 154,882 |
| LTD | 42,515 | 35,765 | 17,403 |
| **Total** | **$ 384,319** | **$ 411,776** | **$ 282,756** |

**Question(s):**

a) Please confirm whether the impact of the COVID-19 pandemic and the growing retiree population have been fully accounted for in OPG's pension and OPEB costs as noted in the above table. If not, please explain.

b) Please quantify the impact on pension and OPEB accrual costs if the impact(s) from Bill 124 were taken into account.

**Staff-5**

**Ref:** (1) Exhibit H1 / Tab 1 / Schedule 1 / pages 37-40

**Preamble:**

OPG noted that over the 2020-2022 period, it recorded debit additions of $105.2M to the Nuclear Development Variance Account in relation to non-capital preliminary planning and preparation costs for a "Darlington SMR".

On page 39, OPG included a table (Chart 4) with a breakdown of costs over 2020 to 2022. The costs are broken down by four main categories; i) Developer Technology Design and Planning, ii) OPG Project Management and Engineering Oversight, iii) Licencing and iv) OPG Site Specific and Other Activities.

**Question(s):**

a) Please provide a detailed breakdown of costs identified in Chart 4. As part of the breakdown, please classify whether the line-item costs are external contractor related or internal OPG costs, and whether the costs are capital or non-capital related.

b) Please provide all Business Cases conducted by OPG for projects related to the Nuclear Development Variance Account.

c) If applicable, provide an explanation for any cost overruns in the individual projects outlined in a) and b). For the purpose of this analysis, OPG may assume cost overruns to be cases where actual costs were more than 5 percent the estimated costs (e.g., Business Case costs).

**Staff-6**

**Ref:** (1) Exhibit H1 / Tab 1 / Schedule 1 / pages 49-50

**Preamble:**

OPG noted that the sale of the “Kipling Site” resulted in net proceeds of $196.1M and that 23% of the net proceeds are tracked in the “Kipling Site Deferral Account”.

OPG further stated:

> OPG does not propose to clear this tracking account, as OPG’s position is that the net proceeds and net gain on the sale of this unregulated property should accrue entirely to OPG. The Kipling Site was not a prescribed facility under O. Reg. 53/05 and, accordingly, has never been included in OPG’s rate base. Prior to the sale, the Kipling Site primarily supported OPG’s unregulated business and was reported as an unregulated asset in OPG’s financial statements. To the extent that OPG has historically used a portion of the Kipling Site to support the company’s regulated operations, the revenue requirements have included asset service fees, as an ongoing OM&A expense akin to lease payments, charging the regulated operations for such use

**Question(s):**

a) What is the total amount tracked in the Kipling Site Deferral Account as of December 31, 2023?

b) What is the total amount that ratepayers have contributed in payments towards the

"Kipling Site"? Please also provide an annual breakdown of the payments.

c) Please provide any governance documents and presentations to the Board of Directors related to the "Kipling Site". Please also provide documents that outline the arrangement between the regulated and unregulated uses of the property.

d) What was the leasing arrangement between OPG's unregulated business and "Kipling Site"? Please outline how this arrangement was similar or different to the arrangement with OPG's regulated business.

**Staff-7**

**Ref:** (1) Exhibit H1 / Tab 1 / Schedule 1 / Attachment 4 / pages 3-4

**Preamble:**

OPG noted that the "Sir Adam Beck I Generating Station – Unit G5 Major Overhaul" project was placed in service in 2021 with a total cost of $44.7M.

OPG further stated:

> This represented an increase of $9.9M from the Class 2 estimate of $34.8M in the First Execution Business Case. While characterized as a Class 2 estimate at the time, the level of project definition was reflective of a Class 3 estimate, which would have been typical for the phase of the project at that time.
>
> The cost variance was mainly due to greater execution complexity compared to the station's Unit G10 Major Overhaul (discussed above), which was used as a basis for the cost estimate, resulting in greater than expected OEM cost to perform the work. Additionally, actual cost was impacted by the COVID-19 pandemic, including from suspension of on-site work at the pandemic's onset and additional safety protocols upon resumption, and extended dry commissioning phase and equipment failure during wet commissioning.

**Question(s):**

a) Please elaborate on why the project costs were characterized as a "Class 2 estimate" when the level of project definition was reflective of a "Class 3 estimate".

b) What was the in-service date for the project?

c) Please provide a breakdown of the $44.7M in project costs. As part of the breakdown, please also classify whether the line-item costs are external contractor related or internal OPG costs.

d) Please provide a similar breakdown of costs (as outlined in b)) for the "Sir Adam Beck I Generating Station – Unit G10 Major Overhaul and Upgrade" project.

e) Please elaborate on why the "Unit G5 Major Overhaul" project was more complex than the "Unit G10 Major Overhaul and Upgrade" project.

**Staff-8**

**Ref.:** (1) Exhibit M1 / Tab 1 / Schedule 1 / pages 13-15
(2) Exhibit M1 / Tab 1 / Schedule 1 / page 11

**Preamble:**

The revised HIM formula proposed by OPG incorporates a separate day-ahead and real-time incentive. OPG states in the second reference that the proposed updated HIM calculation "will create the same incentives for efficient use of the company's regulated hydroelectric facilities in the new market."

**Question(s):**

a) What would be the effect on OPG's incentive to shift production if the revised HIM incorporated a day-ahead incentive only? For example, in OPG's view, would a HIM formula that only incorporated a day-ahead incentive provide a worse, similar or improved incentive for OPG to shift production compared to today?

b) What would be the effect on OPG's incentive to shift production if the revised HIM incorporated a real-time incentive only? For example, in OPG's view, would a HIM formula that only incorporated a real-time incentive provide a worse, similar or improved incentive for OPG to shift production compared to today?

c) If not already addressed in OPG's responses to the questions above, please comment on why it is appropriate for the revised HIM formula to incorporate a separate day-ahead and real-time incentive.

**Staff-9**

**Ref.:** Exhibit M1 / Tab 1 / Schedule 1 / pages 14-15

**Preamble:**

OPG characterizes the proposed revised HIM formula as "Incentive Payment = DA Incentive + RT Incentive". OPG states that its proposed real-time incentive "would create an economic driver for OPG to respond to market changes between [day-ahead] and [real-time], while ensuring that OPG only receives an incentive for incremental changes in the [real-time]".

**Question(s):**

a) Please briefly explain whether the real-time incentive means that OPG gets paid twice for a quantity scheduled in the day-ahead, or rather, whether the real-time incentive addresses incremental production relative to the day-ahead schedule?

**Staff-10**

**Ref.:** Exhibit M1 / Tab 1 / Schedule 1 / page 14

**Preamble:**

OPG states that "the IESO expects the new market's DAM to schedule most of the supply, with the intention to provide greater operational certainty to the IESO and greater financial and scheduling certainty to participants".

**Question(s):**

a) Does incorporating a separate day-ahead and real-time HIM incentive encourage OPG to offer more in one of those two markets compared to if there was no HIM? For example, does the proposed revised HIM formula encourage OPG to offer less of its regulated waterpower into the day-ahead market to potentially benefit from higher market prices in the real-time market? If so, is this appropriate? Why or why not?

b) Has OPG received an opinion from the IESO on the proposed revised HIM in relation to market efficiency, operational needs, consumer interests, any actual or likely perverse incentives brought about by the revision, and any other relevant considerations? If so, please summarize the IESO's opinion. If not, please request an opinion from the IESO and provide it.

**Staff-11**

**Ref.:** Exhibit M1 / Tab 1 / Schedule 1 / pages 14-15

**Preamble:**

OPG proposes the day-ahead incentive to settle based on the day-ahead LMP and the real-time incentive to settle based on the real-time LMP. OPG proposes “that the incentive mechanism settle on a locational/resource basis”.

**Question(s):**

a) Please confirm that by proposing to settle on a “locational/resource basis”, OPG means that the LMPs used in the revised HIM calculation would be the LMPs that correspond to each of the individual OPG hydroelectric stations that are subject to the Hydroelectric Incentive Mechanism. Otherwise, please clarify.

b) What would be the effect on OPG’s incentive to shift production if the revised HIM was settled on the zonal LMP in the day-ahead and real-time instead of on a locational/resource basis? If there are other relevant considerations, please feel free to comment.

c) Would the amount of incentive payment change depending on whether the calculation of the Hydroelectric Incentive Mechanism was based on the zonal LMP in the day-ahead and real-time instead of on a locational/resource? If so, how? If not, why not?

d) In OPG’s view, does a HIM formula that settles on a locational/resource basis provide a worse, similar or improved incentive for OPG to shift production compared to the current practice of settling on the Ontario-wide price?

e) How many “locational/resource basis” LMPs would be involved in the revised LMP calculation for a given hour? Is this the same as the number of OPG hydroelectric stations that are subject to the Hydroelectric Incentive Mechanism? If not, please clarify.

**Staff-12**

**Ref.:** (1) Exhibit M1 / Tab 1 / Schedule 1 / page 14
(2) Exhibit M1 / Tab 1 / Schedule 1 / page 12

**Preamble:**

At the first reference, OPG's description of the proposed revised HIM formula includes the following expressions:

- LMPDA(*t*): the day-ahead LMP for the resource for each hour, *t*, of the day,
- LMPRT(*t*): the real-time LMP for the resource for each hour, *t*, of the day
- MWRT(*t*): net energy production supplied to the IESO real-time market for each hour, *t*, of the day

At the second reference, the current HIM formula includes the following expression:

- MCP(t): market clearing prices for each hour of the month

**Question(s):**

a) Please clarify whether the day-ahead and real-time LMPs in the first reference are the simple or weighted averages of the twelve five-minute LMPs in each day-ahead and real-time hour, respectively. If the LMPs are the weighted averages, please clarify what they are weighted by.

b) Please clarify what "net energy production" means in the first reference. For example: net of what?

c) Please clarify whether the "MCP(t)" in the second reference is the simple or weighted average of the twelve five-minute market clearing prices in each hour. If it is the weighted average, please clarify what it is weighted by and whether it is the same as the "Hourly Ontario Energy Price" or "HOEP"?

**Staff-13**

**Ref.:** Exhibit M1 / Tab 1 / Schedule 1 / page 15

**Preamble:**

OPG proposes that the calculation of the Hydroelectric Incentive Mechanism be changed from monthly production averaging to daily averaging. OPG states that "the current monthly averaging implies a monthly storage capability, which overestimates the storage capability at the majority of OPG's regulated hydroelectric resources."

**Question(s):**

a) Please clarify how the current monthly averaging approach overestimates or does not ideally align with the storage capability at the majority of OPG's regulated hydroelectric resources.

b) Please comment on the implications for the effectiveness of the Hydroelectric Incentive Mechanism of having a daily averaging that would be more in line with the storage capability at the majority of OPG's regulated hydroelectric resources.

c) Would the amount of incentive payment change depending on whether the calculation of the Hydroelectric Incentive Mechanism was based on monthly production averaging or daily averaging? If so, how? If not, why not?

**Staff-14**

**Ref.:** Exhibit M1 / Tab 1 / Schedule 1 / page 15

**Preamble:**

OPG proposes that the calculation of the Hydroelectric Incentive Mechanism be changed from monthly production averaging to daily averaging. OPG states that "daily averaging better aligns with the IESO's daily scheduling timeframe of resources in the new market" and that "the IESO's scheduling optimization and settlement of the market will be on a daily resolution."

**Question(s):**

a) Compared to monthly averaging, would daily production averaging provide any practical advantage by better aligning with the resolution of market scheduling optimization and settlement, or would the advantage of moving to daily averaging be more conceptual? If the advantage is practical, please explain.

b) Is the IESO's scheduling optimization and settlement of the market currently done on a daily resolution, or would that be a new feature brought about by the MRP?

**Staff-15**

**Ref.:** (1) Exhibit M1 / Tab 1 / Schedule 1 / pages 16-17

**Preamble:**

At reference 1, OPG states that “SBG spill is compensated through an entry to the SBGVA”. OPG also states that “while spill may be forecasted in the DA timeframe, the actual spill that occurs in RT may vary for reasons such as changing market conditions between DA and RT impacting production and changes to inflows and forebay storage levels. Accordingly, OPG’s proposed revised unintended benefit calculation is based on the RT LMP.”

At reference (2), OPG proposes that “SBGVA entries would be calculated using the volume of spill remaining after excluding spill amounts incurred by OPG not attributable to the impact of the presence of SBG conditions.”

**Question(s):**

a) Please confirm that “while spill may be forecasted in the [day-ahead] timeframe”, it will not be scheduled/committed (or offered) in the day-ahead market, unlike energy production, which will scheduled/committed (and offered) in the day-ahead market. Otherwise, please clarify.

b) Is OPG proposing that SBGVA entries would be calculated on the basis of the volume of spill in the real-time market only? If not, please clarify and reconcile with OPG’s proposal to calculate the revised unintended benefit on basis of the real-time LMP only.

c) Please clarify on why it makes sense to have separate HIM incentives in both the day-ahead and real-time markets, but to have a revised unintended benefit calculation based on the real-time market only.

**Staff-16**

**Ref.:** Exhibit M1 / Tab 1 / Schedule 1 / page 12

**Preamble:**

OPG states that “In EB-2010-0008, the OEB required that 50% of the forecast amount of HIM proceeds be returned to customers and incorporated this as a reduction of the revenue requirement. OPG was allowed to retain 50% of the HIM revenue with any excess above the retained amount tracked in the Hydroelectric Incentive Mechanism Variance Account and shared equally between OPG and ratepayers”. OPG also states that “in EB-2013-0321, the HIM was expanded to include the newly prescribed facilities, using the same formula. The OEB also increased the variance account threshold to reflect the inclusion of the newly regulated facilities, maintaining a 50% revenue requirement offset and a 50% sharing of additional revenues above the threshold.”

**Question(s):**

a) Please confirm that OPG is not proposing any change in this application to the approved 50% revenue requirement reduction/offset and 50% sharing of additional revenues above the approved threshold. Otherwise, please explain.

b) Please confirm the currently approved forecast of HIM revenues for each remaining year of OPG’s current rate framework, the applicable revenue requirement reduction/offset, and the applicable sharing threshold.

c) What is OPG’s forecast of HIM revenues for each remaining year of OPG’s current rate framework assuming that OPG’s revised HIM proposals are implemented?

**Staff-17**

**Ref.:** (1) Exhibit M1 / Tab 1 / Schedule 1 / page 9
(2) Exhibit M1 / Tab 1 / Schedule 1 / page 21

**Preamble:**

At the first reference, OPG states that “forgone generation due to market constraints, which are presently compensated via CMSCs, are not also booked in the SBGVA”.

At the second reference, OPG states that “there may continue to be conditions in the new market where resources are needed to be scheduled or dispatched out-of-merit that would result in lost cost or lost opportunity requiring MWPs.”

**Question(s):**

a) Does OPG propose to book forgone generation that receives MWPs in the SBGVA? If not, what is OPG’s proposal to ensure that OPG does not get compensated twice for the same quantity of forgone production due to SBG: once through the SBGDVA and once through MWPs?

**Staff-18**

**Ref.:** (1) Exhibit M1 / Tab 1 / Schedule 1 / page 9
(2) Exhibit M1 / Tab 1 / Schedule 1 / page 21

**Preamble:**

In the existing rate framework and market design, OPG is compensated for forgone revenues that result from forgone production due to SBG. Some of the compensation comes from CMSCs, some of it comes from the SBGVA. In the new market design, the CMSC will be eliminated and therefore won’t be available as a mechanism to compensate OPG for forgone revenue due to SBG. OPG therefore proposes to use the SBGVA as the mechanism to recover all of its forgone revenue due to SBG in the new market design.

**Question(s):**

a) Please confirm that the CMSCs that OPG receives in the current market design for forgone production reflect the difference between the market clearing price and OPG’s offer in a given interval. Otherwise please clarify.

b) Please confirm that SBGVA entries reflect the difference between OPG's hydroelectric payment amount and the applicable GRC in a given interval. Otherwise, please clarify.

c) Please estimate and compare the dollar amounts that OPG has received through CMSCs versus the SBGVA per unit of forgone production due to SBG over a recent indicative period. Has OPG typically received more or less compensation per unit of forgone production due to SBG from CMSCs compared to the SBGVA?

d) Does OPG expect that recovery of all of its forgone production due to SBG through the SBGVA will increase or lower the compensation that OPG receives per-unit of SBG spill compared to today?

**Staff-19**

**Ref.:** Exhibit M1 / Tab 1 / Schedule 1 / pages 20-21

**Preamble:**

OPG states that "there may continue to be conditions in the new market where resources are needed to be scheduled or dispatched out-of-merit that would result in lost cost or lost opportunity requiring MWPs".

OPG states that "in the DA timeframe, conditions that could trigger out-of-merit scheduling include "constraint violations, co-optimization of energy with operating reserve or the commitment of an NQS [Non-quick start] resource in the reliability pass of the DAM engine." In the real-time timeframe, OPG starts that "MWP can result from special instructions for "constraint violations, multi-interval optimization, co-optimization with operating reserve or emergency control actions."

**Question(s):**

a) Do the conditions described above sometimes drive out-of-merit order dispatch instructions in today's market design?

b) How are resources compensated in today's market for following out-of-merit order dispatch instructions driven by the conditions described above? Is it through CMSCs?

c) What is the total dollar amount of CSMC payments that OPG's regulated hydroelectric facilities have received over the past three years? Does OPG have an estimate of how much of that total CMSC dollar amount has related to the conditions described above versus congestion and losses?

d) What is OPG’s estimate of the dollar amount that it will receive from MWPs for each remaining year of its current rate term?

**Staff-20**

**Ref.:** Exhibit M1 / Tab 1 / Schedule 1 / page 21

**Preamble:**

OPG states that CSMC payments/make whole payments are not reflected in the existing payment amounts and would serve to compensate OPG for an identified loss resulting from IESO dispatches.

**Question(s):**

a) Please clarify how CSMC payments/make whole payments are not reflected in the existing payment amounts. For example, is OPG saying that it does not lower the production forecasts that are used to set its rates to account for future foregone production that would result from following constrained-off instructions? For constrained-on situations, is OPG saying that the incremental cost of producing out-of-merit order is not reflected in the costs which underpin its rates?

**Staff-21**

**Ref.:** Exhibit M1 / Tab 1 / Schedule 1 / page 21

**Preamble:**

OPG states that it “is not seeking approval with respect to the treatment of DA MWPs as they will form part of the day-ahead market settlement and have no impact on OPG's actual output.”

**Question(s):**

a) OEB staff seeks clarification on the relationship among DA and RT MWPs and the approvals sought by OPG in this application. Please clarify why OPG is not seeking approval with respect to the treatment of DA MWPs. Will OPG receive MWPs in the day ahead market? Does it propose to retain them? If so, why is OPG not seeking approval with respect to them?

**Staff-22**

**Ref.:** Exhibit H1 / Tab 1 / Schedule 1 / pages 3-73

**Preamble:**

The reference above details why OPG would have experienced an economic loss for hours when OPG recorded additions to the Hydroelectric Surplus Baseload Generation Variance Account, but did not pump water at the PGS.

**Question(s):**

a) Please summarize the information provided at the reference above using the table below. Please feel adapt the table as necessary.

**Table: summary of information provided at H1-1-1, pages 3-73**

| | | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|---|
| a | # of spill hours | | | | | |
| b | # of non-spill hours | | | | | |
| c | # of hours not pumping when spill | | | | | |
| d | # of hours pumping when spill | | | | | |
| e | # of hours not pumping when spill because of economic loss due to inability to recover pumping costs | | | | | |
| f | # of hours not pumping when spill because of economic loss due to inability to economically generate | | | | | |

**Staff-23**

**Ref.:** Exhibit H1 / Tab 1 / Schedule 1 / pages 8-11

**Preamble:**

The Hydroelectric Surplus Baseload Generation Variance Account (SBGVA) records the financial impact of foregone production at regulated hydroelectric facilities due to surplus baseload generation (SBG) conditions.

**Question(s):**

a) How will the quantity and dollar value of SBG that OPG records in the SBGVA change with the advent of LMP in the new market design?

**Staff-24**

**Ref.:** Exhibit A1 / Tab 2 / Schedule 1 / pages 1-2

**Preamble:**

OPG requests approval for "the disposition of audited December 31, 2022 deferral and variance account balances less amortization amounts previously approved by the OEB in EB-2020-0290 for the 2023-2026 period, together with the income tax impacts associated with the recovery of the Pension & OPEB Cash Versus Accrual Differential Deferral Account as set out in Ex. H1-1-1 and Ex. H1-2-1." OPG states that it seeks to recover the amounts "over a 30-month period from July 1, 2024 through December 31, 2026".

OPG seeks "payment riders for the output of the regulated hydroelectric facilities of $2.75/MWh for the period from July 1, 2024 to December 31, 2026; and for the output of the nuclear facilities of $3.25/MWh for the period from January 1, 2024 to December 31, 2024, $3.55/MWh for the period from January 1, 2025 to December 31, 2025, and $5.04/MWh for the period from January 1, 2026 to December 31, 2026."

**Question(s):**

a) For clarify, does OPG seek to begin recovering the deferral and variance account balances described above through payment riders starting on July 1, 2024 until December 31, 2006?

b) When OPG says that it is seeking payment riders for the output of the nuclear facilities of $3.25/MWh for the period from January 1, 2024 to December 31, 2024, does it mean that the applicable nuclear balances will begin to be collected through payment riders starting on July 1, 2024 until December 31, 2024 but on the basis of nuclear production from January 1, 2024 until December 31, 2024? In other words, is the $3.35/MWh beginning on July 1, 2024 an annualized figure?

**Staff-25**

**Ref.:** (1) Exhibit A1 / Tab 2 / Schedule 1 / page 1
(2) Exhibit M1 / Tab 1 / Schedule 1 / page 1

**Preamble:**

OPG requests approval of methodologies related to the Hydroelectric Surplus Baseload Generation Variance Account spill calculation, Hydroelectric Incentive Mechanism (HIM), and HIM adjustment for spill, as well as approval to continue to retain real-time make whole payments. OPG makes these requests based on expected changes to Ontario's electricity market that will be made under the IESO's Market Renewal Program.

**Question(s):**

a) Please clarify whether OPG is proposing a specific implementation date for the changes that it is proposing to the Hydroelectric Surplus Baseload Generation Variance Account spill calculation, Hydroelectric Incentive Mechanism (HIM), and HIM adjustment for spill, as well as approval to continue to retain real-time make whole payments?