CCC Interrogatory #1

Interrogatory

Reference: Ex. H1/T1/S1

Question:

Are any of the accounts OPG is proposing to clear subject to a materiality threshold? If so, what is the materiality threshold for each account? If not, why not?

Response

OPG interprets the question to be whether any deferral or variance accounts proposed for disposition in this application are required to have a balance greater than a minimum threshold in order to be cleared.

There is no minimum balance threshold for any of the accounts proposed for disposition in this application, as no such thresholds have been established by the OEB's decisions and orders or *Ontario Regulation 53/05* authorizing these accounts.

CCC Interrogatory #2

Interrogatory

Reference: Ex. H1/T1/S1/p. 17 and Attachment 4

Question:

Nineteen regulated hydroelectric projects placed in service between June 1, 2017 and December 31, 2021, give rise to capital-related additions recorded to the CRVA during the period. Is OPG seeking final approval of the costs of these projects through this Application? If not, when will the prudence of these projects be reviewed?

Response

OPG is seeking final approval of all regulated hydroelectric projects in-service amounts between January 1, 2016 and December 31, 2021 that give rise to capital-related additions recorded to the Capacity Refurbishment Variance Account between January 1, 2016 and December 31, 2021. These in-service amounts are set out at Ex. H1-1-1, Table 7a, lines 2b and 3b and at Ex. H1-1-1, Table 7b, Note 4, lines 1b through 19b. The prudence of any in-service amounts for these projects after December 31, 2021, would be subject to review in a subsequent proceeding.

CCC Interrogatory #3

Interrogatory

Reference: Ex. H1/T1/S1/Attachment 4

Question:

The Sir Adam Beck- Unit G5 Major overhaul cost was $9.9 million over the Class 2 estimate of $34.8 million. Please provide a detailed explanation of the cost overruns.

Response

As noted in Ex. L-H-SEC-01, OPG incorrectly used a Full Execution Business Case Summary (BCS) instead of an earlier Partial Execution BCS to identify the "First Execution Business Case" value for the Sir Adam Beck Unit G5 Major Overhaul project in the pre-filed evidence. Based on the Partial Execution BCS, the First Execution Business Case estimate should have been reported as $20.0M (see Ex. L-H-SEC-01, Attachment 7). However, as the primary purpose of the Partial Execution BCS was to release funds for the procurement of long lead materials, the estimate for which was identified as Class 3, the overall estimate for the project at the time was identified as only Class 4 and was, in fact, premature for an execution BCS. As OPG stated in EB-2020-0290, generally, movement to the execution phase requires that a project have progressed to at least a Class 3 estimate (as defined in the Association for the Advancement of Cost Engineering ("AACE") International estimate class).[1]

Chart 1 below sets out the breakdown of the additional $9.9M costs incurred relative to the Unit G5 Major Overhaul Full Execution BCS, and associated explanations. As noted at Ex. H1-1-1, Attachment 4, p. 4, lines 6-8, and further explained at Ex. L-H-Staff-07, part a), while characterized as a Class 2 estimate at the time, the level of project definition for this Full Execution BCS would be considered a Class 3 estimate under OPG's current project management standards.

[1] EB-2020-0290, Ex. D2-1-1, p. 9.

Chart 1

Item	**Detail**	**Cost ($M)**
Civil discovery work	Additional scope required to address as-found conditions of scroll case, generator shaft, draft tube, and penstock areas.	0.3
Execution schedule – OPG	Additional OPG costs due to schedule extension as a result of greater execution complexity relative to the Unit G10 Major Overhaul used as the cost estimate basis (see Ex. L-H-Staff-07) and COVID-19 protocols.	3.4
Execution schedule – Contractor	Additional contractor costs due to schedule extension as a result of greater execution complexity relative to Unit G10 Major Overhaul used as the cost estimate basis (see Ex. L-H-Staff-07) and COVID-19 protocols.	1.3
COVID-19 impact	Additional direct costs resulting from the COVID-19 pandemic (e.g., cleaning, quarantine, supplies).	0.6
Commissioning schedule – OPG labour	Additional OPG labour costs because of extended commissioning schedule (due to rubber air shroud failure).	1.9
Commissioning schedule - Contractor	Additional contractor costs due to additional reassembly, replacement materials, and labour because of extended commissioning schedule (due to rubber air shroud failure).	2.3
Total		**9.9**

CCC Interrogatory #4

Interrogatory

Reference: Ex. H1/T1/S1/Attachment 4

Question:

The Pine Portage Generating Station – Auto Sluice System Replacement project was $3.4 million higher than the Class 3 estimate of $9.7 million. Please provide a detailed explanation of the cost overruns.

Response

A breakdown of the additional costs incurred for the Pine Portage Generating Station – Auto Sluice System Replacement project over the First Execution Business Case estimate of $9.7M is provided in Chart 1 below.

Chart 1

Item	Detail	Cost ($M)
Electrical discovery work	A new 600V panel was required to supply the new sluicegates and existing loads in the headworks.	0.4
Stair tower cladding	The stair tower to the hoist house required cladding to mitigate a safety risk due to ice accumulation.	0.3
Dam deck surface replacement	Concrete replacement required to address damage to the dam deck as a result of salt used to mitigate ice hazards in connection with the project.	2.7
Total		**3.4**

Note: numbers may not add due to rounding.

CCC Interrogatory #5

Interrogatory

Reference: Ex. H1/T1/S1/p. 19

Question:

OPG proposes to clear a debit of $33.4 million in 2020 and $43.9 million in 2021 for the D2O Storage project. Are these amounts the result of cost overruns? Please explain and provide a detailed explanation as to what these amounts relate to. Please provide all of the OEB-approved forecast costs and actual costs related to the D2O Project.

Response

No, the amounts OPG proposes to clear for the D2O Storage project are not the result of cost overruns.

The debit entries in 2020 and 2021 reflect the difference between the revenue requirement impact of the final cost and in-service timing for the project approved by the OEB through a prudence review in the EB-2020-0290 proceeding[1] following the project's completion, and any such forecast impacts reflected in the EB-2016-0152 nuclear payment amounts in effect during those years. In particular, the OEB approved a capital in-service amount of $381.0M with a March 27, 2020 in-service date in EB-2020-0290;[2] OPG has reflected these approvals in the derivation of the 2020 and 2021 debit entries at Ex. H1-1-1, Table 17 (e.g., Note 2, line 2b). Due to project uncertainty at the time, as proposed by OPG, the EB-2016-0152 nuclear payment amounts did not include a forecast of future in-service amounts for the project during the 2017-2021 period, with the actual revenue requirement impact for those years anticipated to be recorded in the Capacity Refurbishment Variance Account.[3]

For clarity, the revenue requirement impact of the final cost and in-service timing for the project approved in EB-2020-0290 was reflected in the nuclear payment amounts effective January 1, 2022, requiring no further entries into the Capacity Refurbishment Variance Account in relation to the project as of 2022.

[1] EB-2020-0290 Decision and Order, November 15, 2021, pp. 35-46, 50-52.
[2] EB-2020-0290 Payment Amounts Order, App. A, Table 9a, cols. (e) and (f): line 3b + line 3c + line 3d; and Note 3, Note #.
[3] EB-2016-0152 Decision and Order, December 28, 2017, p. 16, footnote 16.

CCC Interrogatory #6

Interrogatory

Reference: Ex. H1/T1/S1/p. 21

Question:

Please provide a detailed schedule setting out the OEB-approved forecasts for the Pickering Extended Operations and the actual costs for each year. Please explain all variances.

Response

The Pickering Extended Operations initiative was originally presented in EB-2016-0152, with an expected completion timeline within the 2017-2021 term covered by that Application. The total OEB-approved forecast cost for Pickering Extended Operations was $307.2M in EB-2016-0152.[1] As shown in Ex. H1-1-1, p. 21, Chart 2, the actual expenditures on Pickering Extended Operations totaled $306.3M, with the work substantially completed in 2021. The requested information is detailed below relative to the EB-2016-0152 OEB-approved forecasts. Note that amounts may not add due to rounding. There were no such OEB-approved forecasts for Pickering Extended Operations in EB-2020-0290.

Chart 1

	2016 OEB Approved	2016 Actual	2016 Variance	2017 OEB Approved	2017 Actual	2017 Variance
Base OM&A	11.0	9.6	(1.4)	1.0	14.9	13.9
Project OM&A	4.0	1.2	(2.8)	2.5	0.2	(2.3)
Outage OM&A	0.0	0.0	0.0	22.1	3.2	(18.9)
Capital Expenditures	0.0	0.0	0.0	0.0	0.0	0.0
Minor Fixed Assets	0.0	0.0	0.0	0.0	0.0	0.0
Total	**15.0**	**10.8**	**(4.2)**	**25.6**	**18.4**	**(7.2)**

[1] EB-2016-0152, Ex. F2-2-3, Chart 2.

Chart 2

	2018 OEB Approved	2018 Actual	2018 Variance	2019 OEB Approved	2019 Actual	2019 Variance
Base OM&A	0.0	10.0	10.0	0.0	12.1	12.1
Project OM&A	18.0	6.3	(11.7)	18.4	25.4	7.0
Outage OM&A	37.3	9.3	(28.0)	88.7	24.7	(64.0)
Capital Expenditures	0.0	2.8	2.8	0.0	9.0	9.0
Minor Fixed Assets	0.0	1.4	1.4	0.0	0.6	0.6
Total	**55.3**	**29.9**	**(25.4)**	**107.1**	**71.9**	**(35.2)**

Chart 3

	2020 OEB Approved	2020 Actual	2020 Variance	2021 OEB Approved	2021 Actual	2021 Variance
Base OM&A	0.0	7.2	7.2	0.0	5.5	5.5
Project OM&A	18.7	30.0	11.3	0.0	19.6	19.6
Outage OM&A	85.6	47.3	(38.3)	0.0	26.1	26.1
Capital Expenditures	0.0	19.7	19.7	0.0	16.9	16.9
Minor Fixed Assets	0.0	0.0	0.0	0.0	0.7	0.7
Total	**104.3**	**104.1**	**(0.2)**	**0.0**	**68.7**	**68.7**

Chart 4

	2022 Actual	2023 Actual
Base OM&A	0.0	0.0
Project OM&A	0.9	0.4
Outage OM&A	0.0	0.0
Capital Expenditures	0.5	0.3
Minor Fixed Assets	0.4	0.0
Total	**1.9**	**0.7**

The above annual information is summarized in Chart 5 for the full duration of the Pickering Extended Operations initiative:

Chart 5

	OEB Approved Total	Actual Total	Variance Total
Base OM&A	12.0	59.3	47.3
Project OM&A	61.6	84.1	22.5
Outage OM&A	233.7	110.7	(123.0)
Capital Expenditures	0.0	49.2	49.2
Minor Fixed Assets	0.0	3.1	3.1
Total	**307.2**	**306.3**	**(0.9)**

The overall expenditure on Pickering Extended Operations were $0.9M below the OEB-approved forecast. This was mainly due to lower Outage OM&A, offset by higher Base OM&A, Project OM&A, and Capital Expenditures.

There were minimal Base OM&A expenses forecast in EB-2016-0152 beyond 2016. As specific work in connection with Pickering Extended Operations was identified, funding was re-allocated from Outage OM&A to Base OM&A. These Base OM&A variances totaling $47.3M over the life of the initiative included funding for such activities as life cycle management plan assessment, Periodic Safety Review ("PSR") analysis in support of an amended CNSC operating license, development of associated Global Assessment Report ("GAR") and Integrated Implementation Plan ("IIP"), and incremental equipment reliability initiatives.

As the scope of work for Pickering Extended Operations was further defined, the timing and details of Project OM&A changed relative to forecasts in EB-2016-0152. Additional Project OM&A of $22.5M over the life of the initiative, for which funding was re-allocated from Outage OM&A, was driven primarily by the following projects: Feeder Replacements, U1 FC Positioning Assembly Hardware Modification, Minor Modification Projects, Condenser Debris Filter and Expansion Joint Upgrades, and U56 Calandria Tube to LISS Nozzle Contact Mitigation.

Outage OM&A was overall $123.0M lower relative to the EB-2016-0152 forecasts, primarily as a result of the scope of the initiative being further defined, and changes in the timing of planned outages at Pickering Nuclear GS, including due to the transition from a 24 month to a 30 month outage cycle during the period. As noted, a portion of the funding was re-allocated to Base OM&A, Project OM&A and Capital Expenditures as part of the improved definition of the work.

Subsequent to the OEB's approval of forecast Pickering Extended Operations costs in EB-2016-0152, OPG determined certain projects met capitalization eligibility criteria.[2] The resulting Capital Expenditures of $49.2M over the life of the initiative, for which funding was re-allocated from Outage OM&A, were driven primarily by the following projects: Fire Water Supply Project, Algae Mitigation Projects, Emergency Power Generator 3 Permanent Installation, and Universal Delivery Machine East Annex Operations and Maintenance Area.

[2] In EB-2016-0152, Ex. L.-6.5-1 Staff-119, OPG noted that as the work program associated with Pickering Extended Operations progressed and the scope of specific modifications was defined, it would be determined if a project met the capitalization criteria.

CCC Interrogatory #7

Interrogatory

Reference: Ex. H1/T1/S1/p. 23-24

Question:

Please provide a schedule setting out the OEB-approved forecasts for the Fuel Channel Life Extension Ongoing Costs and the actual costs for each year. Please explain all variances.

Response

An annual comparison of the OEB-approved forecasts and actual costs for the Fuel Channel Life Extension Ongoing Costs is set out below for 2020, 2021 and 2022. The forecasts were approved in EB-2016-0152 for 2020 and 2021 and in EB-2020-0290 for 2022.

	2020 OEB Approved	2020 Actual	2020 Variance	2021 OEB Approved	2021 Actual	2021 Variance
Base OM&A	6.0	7.8	1.8	6.0	8.7	2.7
Outage OM&A	8.4	20.3	11.9	1.5	25.5	24.0
Total	**14.4**	**28.1**	**13.7**	**7.5**	**34.1**	**26.6**

	2022 OEB Approved	2022 Actual	2022 Variance
Base OM&A	5.9	9.7	3.8
Outage OM&A	29.8	25.3	(4.5)
Total	**35.7**	**35.0**	**(0.7)**

Notes:
1. Numbers may not add due to rounding.
2. The 2020-2021 OEB Approved amounts are from EB-2016-0152, Ex. L-4.1-1 Staff-024; the 2022 OEB Approved amounts are from EB-2020-0290, Ex. L-H1-01-Staff-328, Chart 1.

Higher Base OM&A in 2020 relative to the OEB-approved forecast was driven mainly by the single fuel channel replacement ("SFCR") at Darlington GS Unit 3 completed outside of a regular planned maintenance window, rather than as part of the initially planned Darlington GS Unit 1 regular outage that was deferred from 2020 to 2021, as well as additional fuel channel inspections and fitness for service assessments performed to support station Pickering GS end-of-life and Darlington GS refurbishment dates.

Higher Base OM&A in 2021 relative to the OEB-approved forecast was primarily due to incremental costs incurred as a result of the spacer retrieval and analysis work related to Darlington GS Unit 3, along with additional fuel channel inspections and fitness for service assessments performed to support station Pickering GS end-of-life and Darlington GS refurbishment dates.

Higher Base OM&A in 2022 relative to the OEB-approved forecast stemmed primarily from the analysis and material examination scope completed during 2022 for the spacers retrieved during 2021 from Darlington GS Unit 3.

Higher Outage OM&A in 2020 relative to the OEB-approved forecast was mainly due to higher SFCR costs for Darlington GS Unit 3 that was originally planned for Darlington GS Unit 1; additional inspections and maintenance readiness (pre-requisite) activities to support fuel channel scrape sampling and analysis for Darlington GS Unit 1, and Pickering GS Unit 5.

Higher Outage OM&A in 2021 relative to the OEB-approved forecast reflected impacts related to the Darlington GS Unit 1 outage deferred from 2020 to 2021, expanded scope of planned fuel channel inspections required by the CNSC to demonstrate pressure tube fitness-for-service, and additional steam generator water lancing scope during outages at Pickering GS.

Lower Outage OM&A in 2022 relative to the OEB-approved forecast stemmed primarily from lower than anticipated resourcing requirements to complete the planned SFCR at Pickering GS Unit 5, along with lower water lancing scope in the Pickering GS planned outages.

CCC Interrogatory #8

Interrogatory

Reference: Ex. H1/T1/S1 pp. 38-39

Question:

Over the 2020-2022 period OPG recorded debit additions of $105.2 million to the Nuclear Development Business Account in relation to non-capital preliminary planning and preparation costs for a Darlington SMR (small modular reactor):

a) Is OPG seeking recovery of this amount through the Application?
b) Please provide detailed budgets for each of the 4 activities identified in Chart 4 for 2020, 2021 and 2022;
c) Please provide detailed budgets for the years 2023-2026 regarding SMRs;
d) Please provide the due diligence assessment referred to in the evidence;
e) Please provide all materials provide to OPG's Board of Directors regarding the selection of the SMR technology;
f) Please provide all materials provided to the Province regarding the selection of the SMR technology;
g) Please provide a list of all technologies considered.
h) Please provide all reports produced internally regarding the selection of the SMR supplier and technology.

Response

a) Yes.

b) OPG managed the costs of preliminary planning and preparation activities for a small modular reactor ("SMR") at the Darlington New Nuclear site as identified in Ex. H1-1-1, Chart 4, within the budget envelope of $270M. As discussed in part e) below, this budget envelope was approved by OPG's Board of Directors (See Attachment 2).[1] A breakdown of the projected amounts for the anticipated activities can be found in Appendix 4 of Attachment 2, DNNP Project & Scope Breakdown. The OPG Board of Directors' approval required that actual expenditures be substantially consistent with Appendix 4, which they were.

c) OPG declines to provide the requested information on the basis of relevance. OPG's Application addresses only the amounts OPG proposes to clear from the previously authorized deferral and variance accounts and certain specific

[1] OPG's plans for these activities were also discussed in EB-2020-0290, Ex. F2-8-1.

approvals sought in connection with the implementation of the IESO's Market Renewal Program. As such, the information sought is not relevant to any issue before the OEB in this Application.

d) See Attachment 1 (confidential) for OPG's assessment process in respect of the three identified developers and their respective SMR technologies. This assessment was undertaken with the goal of selecting a single technology developer to deploy an SMR at the Darlington New Nuclear site.

e) See Attachment 2 (confidential) for the OPG Board of Directors' approval of OPG's preliminary planning and preparation budget for a SMR at the Darlington New Nuclear site, including the selection of a SMR technology. OPG is providing this document as this approval underpins OPG's request for recovery of amounts recorded in the Nuclear Development Variance Account in this Application. OPG declines to provide any additional "materials provided to the Board of Directors" that mention the selection of SMR technology on the basis of relevance.

f) OPG declines to provide the requested information on the basis of relevance. This interrogatory seeks information on communications with the Province of Ontario that is not relevant to deciding any issue on the approved Issues List in this application. The activities and resulting costs related to SMR technology selection were undertaken by OPG and are fully explained in evidence with additional detail provided in the document produced in response to part d) of this interrogatory.

g) OPG considered a total of 11 different SMR technologies (in no particular order):
- Terrestrial IMSR-400
- GE-Hitachi BWRX-300
- X-Energy XE-100
- [redacted]

h) OPG declines to answer on the basis that this is not an appropriate question. The question ignores the principle of proportionality, which underlies the interrogatory process, in that it is overly broad and all encompassing. Contrary to the OEB Rules of Practice and Procedure (Section 26.02 (d)), the question does not "contain specific requests for clarification of a party's evidence, documents or other information in the possession of the party and relevant to the proceeding. The question seeks without limit all reports produced internally regarding the selection of the SMR supplier and technology.

Furthermore, OPG notes that much of the documentation captured by this request would not be relevant to any issue before the OEB in this proceeding. OPG is seeking approval of the costs associated with the technology selection process, and not approval of the technology that was selected, and has provided, in response to part d) of this interrogatory, a detailed internal document outlining the process. OPG's assessment and evaluation of particular technologies and their characteristics and potential vulnerabilities are, as such, irrelevant, and moreover, contain highly confidential information proprietary to third parties and OPG, disclosure of which could lead to significant commercial harm.

Ex. L-H-CCC-08 ATTACHMENT 1
IS CONFIDENTIAL IN ITS ENTIRETY

OPG's due diligence process in respect of the three identified developers and their respective SMR technologies.

OPG Confidential Exclusive

FOR APPROVAL by the Board of Directors

August 13, 2020

SMALL MODULAR REACTORS – APPROVAL OF FUNDS AND UPDATE OF SMR PROJECTS

DECISION REQUIRED

The purpose of this memo is to request Board approval to release $270 Million (consistent with the business plan) for the planning and design of a Small Modular Reactor (SMR) at Darlington, and to renew and maintain the Power Reactor Site Preparation Licence (PRSL).

ISSUE

The Darlington New Nuclear Project (DNNP) is part of OPG's Strategic Objectives including Energy Industry Leader (which our climate strategy contributes to). OPG has selected four developers to proceed to the next phase of our process, which includes planning and design work, plus activities to maintain the PRSL. Funding for this work, equivalent to the release requested, is included in the 2020 to 2026 business plan. OPG is seeking approval to release funds for 2020 and 2021 in order to further develop the technologies and select one by November 2021. Once selected, a detailed business case and release quality estimate will be prepared by 2023. OPG has provided a release strategy for future years below.

ANALYSIS

To briefly recap, OPG has been evaluating the opportunity to deploy a First-Of-A-Kind SMR at our Darlington New Nuclear Project site which is the only site in Canada with an approved Environmental Assessment and a PRSL.

- OPG is proposing a 300-400 MW SMR plant which is the right size for coal plant replacement elsewhere in Canada, and fits into the Ontario electricity grid.
- [redacted]
- The 2028 deployment period goal for DNNP is important to
  - obtain First-mover benefits in North America (maximum supply chain in Canada, jobs and GDP) and,
  - [redacted]

(Note that this DNNP work is quite separate from OPG's support to the Global First Power micro-modular reactor project).

In 2019, OPG began a process to systematically review potential SMR Technology Developers to identify which would be the best fit for a potential new nuclear power plant at the DNNP site.

At the October 2019 Board Retreat, OPG reported on the first phase of that review, and outlined how we would undertake a more in-depth Due Diligence process to identify potential SMR technology developers that could meet the required timeline, with sufficient engineering complete, the right design features, at a competitive cost, and bringing supply chain opportunities to Ontario and Canada.

In March 2020, we reported that OPG was beginning the Due Diligence assessment of certain SMR developers, and in May we reported that commercial options were being evaluated with respect to potential funding and partnership arrangements with SMR technology developers (not yet selected as of May) and for potential future strategic alliances.

The March 2020 GOC update included an economic case and detailed the due diligence process to select two (or more) developers that had the most suitable technologies, and could meet our schedule to deploy an SMR at DNNP by 2028. OPG also highlighted the intent to fund some detailed engineering work, as well as the preparation of a CNSC Licence to Construct (LTC) application, in order to ensure that necessary timelines are met with quality.

OPG regularly updates the Province of Ontario, as our shareholder, on our new nuclear work. Such updates have included our overall SMR strategy; potential impact on electricity rates from an SMR; benefits in terms of combating climate change; the pan-Canadian approach; potential for federal funding to support SMRs; and our SMR work with utilities in Saskatchewan, New Brunswick, as well as Bruce Power in Ontario. In particular, we have worked closely with these peer utilities to support the three provinces on the Premiers' Memorandum of Understanding on SMRs signed Dec 2019, which calls for the provinces to work collaboratively on an SMR feasibility study and a strategic plan for deployment. Additional details on collaborative work are provided in **Appendix 5.**

OPG has now completed its DNNP due diligence work, [redacted]. [redacted], OPG has selected four developers to work with more closely over the next 15 months with the goal of selecting a single technology partner and progressing the project. A detailed explanation of the DNNP due diligence outcomes is included in **Appendix 1.**

OPG has decided to progress further discussions with SMR companies GE-Hitachi, X-Energy, [redacted] and Terrestrial as those which bring the best combination of opportunities for a pan-Canadian fleet.

The work to be completed over the next 15-month period through November 2021 is to ensure project development and engineering design sufficiently complete for a Class 5 estimate and an application to the CNSC for a Licence to Construct. This will include preparing a full project scope, schedule, and cost estimate to support a Business Case, and determining which technology partner and project will deliver the best investment for OPG and Ontario. Choice of an SMR partner could happen in phases, reducing from four to one potential partner as certain hurdles are overcome as described in **Appendix 1.** This work will require certain funding, which is why we are seeking Board approval for release of the budgeted funding envelope at this time.

See **Appendix 3** for a more detailed description of the deliverables, and **Appendix 4** for a preliminary estimate of major project costs over this period.

For clarity, the request for approval is a preliminary step and does not include full project costs, such as construction. No decision to proceed with project construction has been made, and is subject to ongoing development of the project and a gated release strategy which is described below under DNNP Release Strategy.

Delegation of approval authority to the CEO for execution of the contracts is requested at this time as the detailed scope and cost estimates will be completed in Q4-2020 through discussions with developers.

DNNP Release Strategy

Funding for the DNNP will be released in phases as certain deliverables are completed and as an updated business case analysis is refined, including the total cost of the project.

Current Phase

Project OM&A for preliminary planning costs, including SMR technology development and Site Preparation relicensing were approved as part of the 2020-2026 Business Plan. Delegation of authority from the OPG Board of Directors to the CEO is being requested in August 2020, prior to issuing contracts to the SMR technology developers to continue with project development for DNNP, detailed engineering design, and preparation for DNNP licensing. Ongoing updates to the Board will be provided in November 2020 and early 2021 on the progress with commercial negotiations and the SMR companies' progress at meeting our expectations for the project.

Future Phases

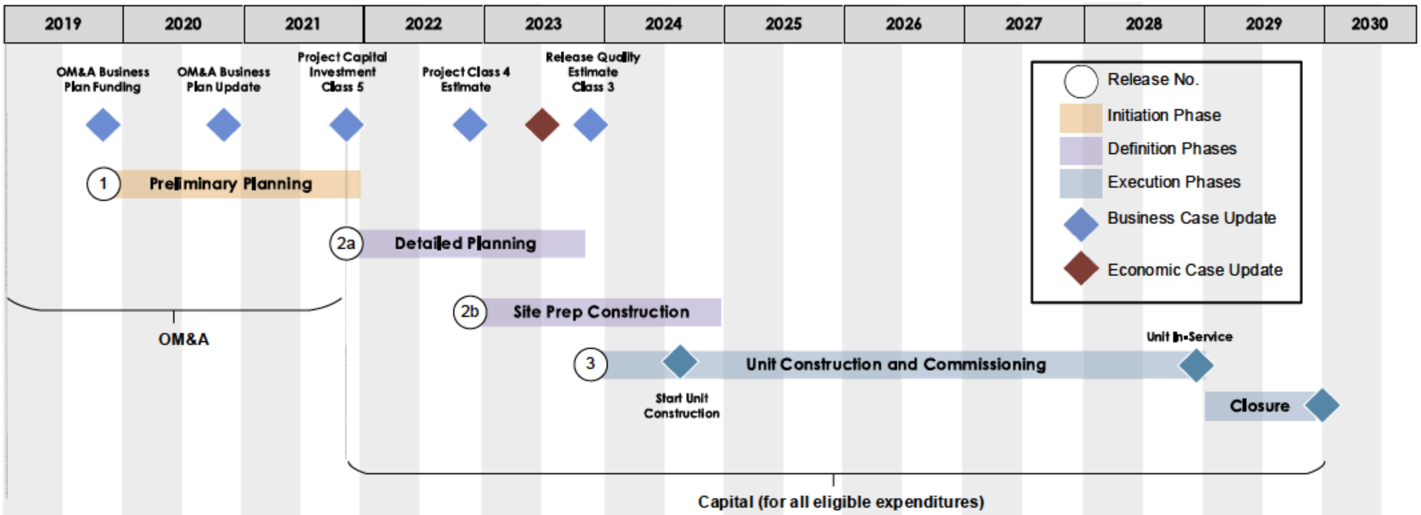
A DNNP Business Case will be developed in 2021 to incorporate project costs for site preparation and construction, for gated release decisions in the fall of 2021 and the fall of 2022, summarized as follows and as shown in the diagram below:

- Nov 2021 - Nov 2022: Class 4 estimate enabling a decision to proceed on site preparation and long lead material manufacturing with a preferred SMR technology developer [Capital Funding].

- Nov 2022 – Nov 2023: Class 3 Release Quality Estimate (RQE) to be prepared, with High Confidence schedule and cost, enabling a decision to construct and final project estimate to be approved in November 2023 [Capital Funding].

Refined classes of estimates will progressively be achieved, similar to how the Darlington Refurbishment Release Quality Estimates were prepared over time, to provide cost certainty prior to moving forward with construction and for procurement of long lead time materials.

The final project approval which includes the remaining project funding for construction, commissioning, and closeout is expected to be requested in late 2023, at the point where a Release Quality Estimate and High Confidence Schedule are available, approximately 6 months prior to the planned start of construction in Q2 2024.



RECOMMENDATION / RESOLUTION

That the Board of Directors:

(i) Approves release of a $270 M funding envelope to commence project development work on the Darlington New Nuclear Project for the approximate 2020 – 2021 period substantially consistent with the DNNP Project & Scope Breakdown set out at **Appendix 4**;

(ii) Delegates approval authority to the OPG President and CEO for the release of funds within the funding envelope referenced in (i) above;

(iii) Requires that further Board approvals be sought if the cost of the work as set out in (i) above is expected to increase.

Recommended by:	**Approved for submission to the Board of Directors by:**
"Original signed by:"	*"Original signed by:"*
Dominique Minière President, Nuclear	Ken Hartwick President and CEO

<u>This Board memo was reviewed and approved for submission to the Board of Directors by the Generation Oversight Committee at their meeting of August 12, 2020.</u>

APPENDICES

1. Update on Darlington New Nuclear Project (DNNP) small modular reactor (SMR) Due Diligence work including recommendations on SMR Developers with whom commercial negotiations are commencing
2. DNNP Illustrative Roadmap
3. Developer Deliverables
4. Projected Major DNNP spending areas
5. Update on New Nuclear growth strategy collaborative work

APPENDIX 1: UPDATE ON DARLINGTON NEW NUCLEAR PROJECT (DNNP) SMALL MODULAR REACTORS (SMR) DUE DILIGENCE WORK INCLUDING RECOMMENDATIONS ON SMR DEVELOPERS WITH WHOM COMMERCIAL NEGOTIATIONS ARE COMMENCING

Darlington New Nuclear Project
In 2019, OPG began a process to systematically review potential SMR Technology Developers to identify which would be the best fit for a potential new nuclear power plant at the Darlington New Nuclear (DNNP) site. As of July 2020, OPG has completed phase 3 of the review and assessment process (the "due diligence" phase), in collaboration with other utilities, and wishes to report the outcome to the Board.

In summary, OPG has decided to progress its options development discussions with GE-Hitachi, X-Energy, [redacted] and Terrestrial, for reasons outlined below.

<u>Due Diligence process</u>
Since the May update, OPG has completed the due diligence process on six potential SMR Technology Developers – [redacted]. [redacted]

The process entailed:
- development of questions to the developers in the subject areas of Engineering, Fuel & Physics, Reactor Safety, Licensing, Quality Assurance and Supplier Relationships, Finance, and Legal.
- provision by each developer of written materials covering the subject areas
- a deep dive review by teams of subject matter experts and representatives of each utility
- developer response to a fundamental question identified during the previous stage of the process as being key to the potential success of that developer for the DNNP process (eg: commitment to the project; timeline; fuel qualification and availability)
- review of strategy options and opportunities for OPG, taking account of potential pan-Canadian deployment [redacted] and Canadian content
- creation of recommendations and alternatives, with pros and cons

The output of the due diligence process has been reviewed by ELT members.

<u>Due Diligence results</u>
The result of the due diligence process is that OPG intends to continue working with four developers in order to determine which of these four developers is best fit for the project. These developers are GE-Hitachi, X-Energy, [redacted] and Terrestrial. It was not possible at this stage to confidently limit further work to fewer developers, due to pro's and con's, and the risks and opportunities associated with each of these developers. [redacted]

[redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

[redacted]
- [redacted]
- [redacted]

- [redacted]
- [redacted]
- [redacted]

[redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

[redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

Although OPG has decided to continue working with the above four SMR technology developers, please note that as reported in previous GOC updates, OPG may allow the other developers that can demonstrate sufficient progress on their own, to re-engage in further discussions with OPG prior to November 2021.

[redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

<u>Next steps</u>
By about the end of 2020, our goals are to:
- have clearly identified key requirements for each potential SMR technology developer partner;
- have a path established for their work over the next year; and
- ideally to have narrowed the field to fewer than four developers to continue working with in 2021.

By Nov 2021, the goal is to finalize a decision on the single SMR technology developer, and develop a business case for Board approval to advance to a construction licence application. In order to do this, the following steps need to be completed.

Hurdles
By September 2020:
- [redacted]
- [redacted]
- [redacted]
  - [redacted]
  - [redacted]
  - [redacted]
  - [redacted]
  - [redacted]

By November 2020:

- [redacted]

By November 2021:

- To have from all the remaining SMR technology developers,
  - completed basic design and a certain level of detailed design of the nuclear island completed, enabling a class 5 estimate; and
  - a sufficiently advanced licensing framework to enable submission of License to Construct Application in early 2022.
- [redacted]
- [redacted]
  - [redacted]
  - [redacted]
  - [redacted]

Depending on the results of this hurdle/gating process, we could stop progressing with some developers at the different gates.

Commercial discussions
OPG will undertake further discussions with the developers GE-Hitachi, X-Energy, [redacted] and Terrestrial. [redacted]

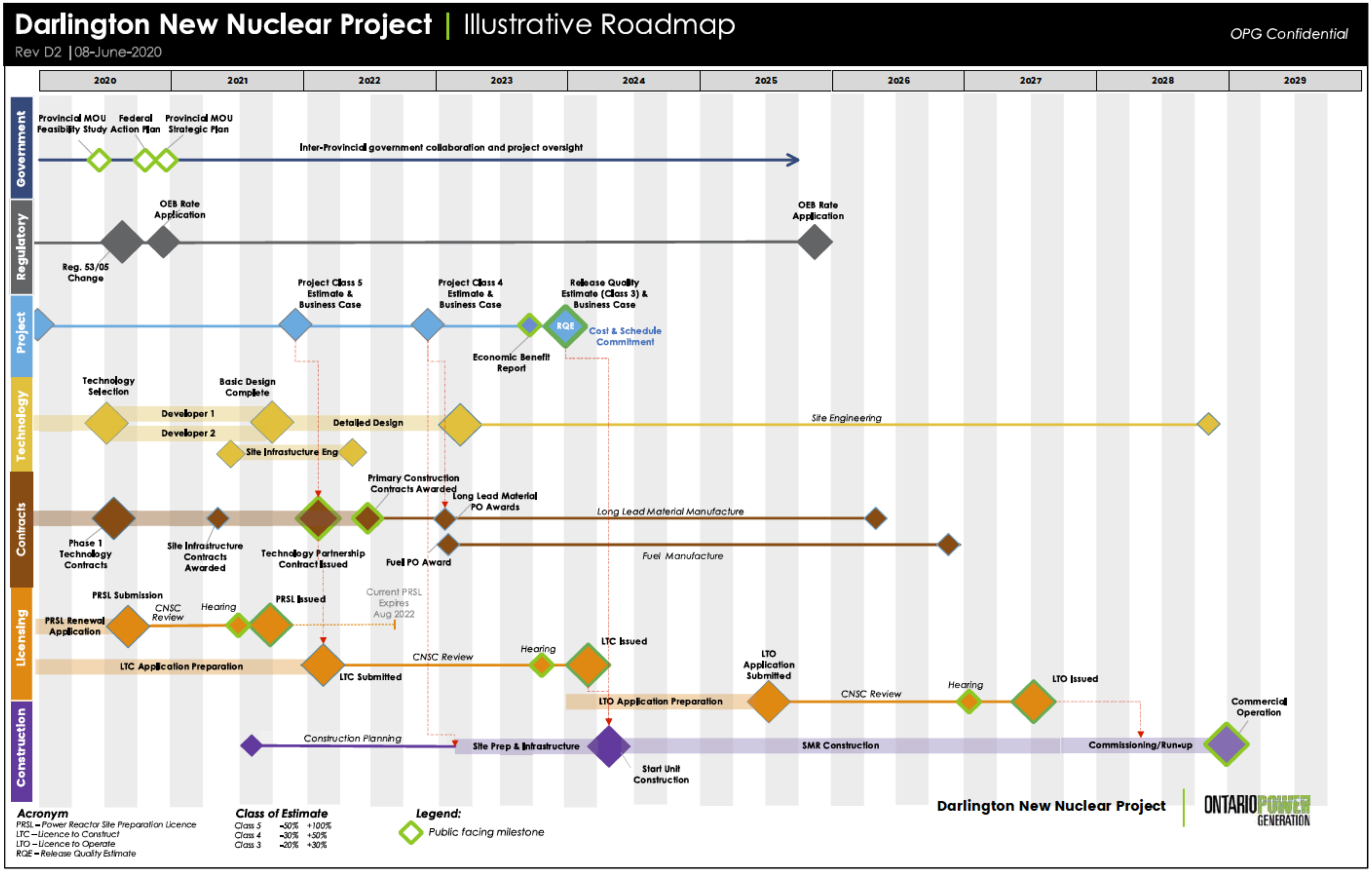
If successful in establishing satisfactory arrangements, it is anticipated that OPG will work with these developers on the design, and preparation of construction and manufacturing strategies from mid-2020 to late-2021. This will include discussions around financing of their detailed manufacturing design, and commercial aspects such as intellectual property rights, and sharing in future contracts, etc. This is expected to include OPG funding some detailed engineering work, and preparation of a CNSC construction licence application, in order to ensure our schedule is met with quality. More details on this topic are provided in Appendix 3.

<u>Additional Details</u>
The main body of this report shows a simplified chart of the proposed funding release timelines, project development and plant construction. A more detailed illustrative roadmap is provided (see Appendix 2) outlining additional milestones of the project.

Funding related to this stage of the process is discussed in a separate section of this Board memo (for Approval).

Further updates on the commercial discussions described above will be brought to future Board meetings. In addition, progress on overall development of a potential DNNP new nuclear project will continue to be provided at upcoming Board meetings.

APPENDIX 2: DNNP ILLUSTRATIVE ROADMAP



APPENDIX 3: DEVELOPER DELIVERABLES

The current developmental scope of work spans about 15 months, to November 2021. During 2021, the strategy is to work with the leading Developers to progress their SMR design and the associated business case in order to make a final technology selection in Q4 2021.

For each SMR design, the following project goals are to be accomplished in this period:

1. Advancing the SMR design specific to a reactor facility for Darlington
2. Preparing the required deliverables for a Licence to Construct application
3. Preparing a full project scope, schedule and cost estimate to support a Business Case
4. Defining requirements for site preparation work, and supporting PRSL renewal as required.

Based on the outcomes of the work listed above, a business case supporting the best technology option will be developed for Board approval in November 2021.

Deliverables Summary:
Each Developer is at a different stage of design completion, and therefore the effort required, and the scope of the contracts to meet the project goals, will be specific to each. As a result, the contracts will be broken up into two phases:

1. Phase A (nominally 3 months) is focused on developing design and site requirements, gap identification, and establishing the scope and schedule for the remainder of the contract
2. Phase B (to the end of 2021) will be executing the scope agreed in Phase A to meet the project goals

Advancing the facility design is the most significant component of the work to be done. The Developers will have to review their current design and reconcile the requirements to Canadian regulations, codes, and standards. In addition, site-specific requirements, facility layout, and geotechnical testing is required. Balance of Plant design, an area that typically has not been a priority for a number of the Developers, will also need to be progressed.

The current project plan requires submission of the Licence to Construct in early 2022 to meet a 2024 start of construction. This licence application is a significant undertaking, with design and safety analyses expected to be at an advanced state. The application also calls for deliverables related to construction and commissioning programs.

In June 2020, OPG submitted an application for renewal of the current PRSL for Darlington, with a hearing projected in mid-2021. Any required support for this hearing, as well as site preparation requirements are also included in the scope of work for the Developers.

In addition to the technical deliverables, each Developer will work with OPG project staff to put together full project scope, schedule, and cost estimates, as well as OM&A and lifecycle capital cost estimates. These products will support the final technology selection and associated business case.

Other specific deliverables that the Developers will be required to produce in this period include the following:

1. Lifecycle fuel management strategy and interface with NWMO
2. Operating radiation dose estimates and minimization strategy
3. Operating radiation emission estimates and minimization strategy
4. Operating conventional emission estimates and minimization strategy
5. Low and intermediate level radiation waste estimates and minimization strategy
6. Modular construction strategy
7. Supplier strategy
8. Full Scope Simulator preliminary design

Appendix 4: Projected Major DNNP spending areas

DNNP Project & Scope Breakdown	2020 $M	2021 $M
83274 – DNNP Program Management & Oversight • Overall Program Management • Oversee and manage the Development Partner Agreements • Stakeholder and indigenous community outreach and engagement • OPG matrixed support (SLAs) • External legal contracts • Program Contingency of $5M	6.0	18
27601 – DNNP EA & Licensing • PRSL renewal submission and support through Licence issuance (TCD Q3 2021) • LTC protocol development • Support of preparation of LTC submission for multiple Developers • Environment support of DNNP licence Commitments • CNSC Licensing fees $5M	7	13
86022 – DNNP Engineering & Oversight • Development of Engineering programs required to manage Advance reactor • Embedded engineers to directly collaborate on basic design with the development partners • Perform owners engineer activities to review and accept designs • Engineering matrixed support (SLAs) • Managed Task Contracts & Project Contingency $10.5M	5	25
86066 – DNNP Site Preparation Engineering & Planning • Engineering required to support site preparation activities (Bridges, services, roads, buildings, etc) • Geotechnical studies required for site layout	0	7
86064 & 86065 – SMR Development • SMR & BOP design • LTC Technical deliverable preparation • Site layout options and requirements • SMR OM&A and lifecycle capital cost assessment • SMR Project scope, schedule, and cost estimates	86.0	103
Total	**104**	**166**

APPENDIX 5: UPDATE ON NEW NUCLEAR GROWTH STRATEGY COLLABORATIVE WORK

As described in Appendix 1, OPG has completed a detailed due diligence review of potential SMR technology partners. [redacted]

[redacted]

[redacted] Likewise, OPG is participating in the work of the Canadian Nuclear Association-Candu Owners Group SMR Secretariat which is helping develop actions for the national SMR Action Plan to respond to the recommendations of the 2019 SMR Roadmap.

CCMBC Interrogatory #2

Interrogatory

Reference: Exhibit H1, Tab 1, Schedule 1, Page 49

Preamble: "The Clarington Corporate Campus Deferral Account was approved in EB-2020-0290, effective January 1, 2022, to record, for the nuclear facilities, the revenue requirement impacts of OPG's capital expenditures and operating costs for its previously planned Clarington Corporate Campus. No entries were recorded in this account for 2022."

Question:

The quoted paragraph refers to "previously planned Clarington Corporate Campus". Have the plans changed? If the answer is yes, please summarize the current plans. If the answer is no, please explain why the have been no entries in the deferral account.

Response

Yes, the plans have changed. OPG is no longer planning to construct a new corporate headquarters in Clarington. In 2023, OPG purchased the building located at 1908 Colonel Sam Drive in Durham to serve as the company's new corporate headquarters. OPG is currently in the process of retrofitting the space prior to occupancy. OPG expects to provide further information in its next payment amounts application.

CCMBC Interrogatory #3

Interrogatory

Reference: Exhibit H1, Tab 1, Schedule 1, Page 50

Preamble: "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."

Questions:

a) Please provide the date of the last day of use of any portion of the Kipling Site by OPG's regulated operations?

b) Were there any leasehold improvements of the portion of the Kipling Site occupied by regulated operations since OPG leased space for its regulated operations at the site? If the answer is yes, were these costs included in OPG revenue requirements during those years?

Response

a) The sale of the property located at 800 Kipling Avenue in Toronto ("Kipling Site") closed on October 31, 2022. Immediately following, OPG leased back a portion of the space pending the company's new corporate campus being ready for occupancy. The lease presently remains in place. Both prior to the sale and during the lease, the space has partially supported OPG's regulated operations.

b) As discussed in Ex. L-H-Staff-06, parts c) and d), during the time that OPG owned the Kipling Site, there were no formal leasing arrangements in place for the use of the site by either regulated operations or unregulated operations. The Kipling Site was a corporate-level asset that was not a prescribed facility and was not included in rate base. Both the regulated generation operations and the unregulated generation operations were charged an internal, cost-based asset service fee for their use of the site. Modifications to the premises that were eligible for capitalization were capitalized as part of the asset's cost and were accordingly reflected in the depreciation and return components of the asset service fees charged to the regulated and unregulated operations. Asset service fees charged to the regulated operations are included in their revenue requirements. Further details on the asset service fee methodology can be found in EB-2020-0290, Ex. F3-2-1, pp. 2-3. The asset service fees for the Kipling Site recovered through OPG's payment amounts are detailed in Ex. L-H-SEC-02, Attachment 2.

No leasehold improvements have been made to the premises after OPG leased back a portion of the Kipling Site following its sale.

ED Interrogatory #1

Interrogatory

Reference: Exhibit H1, Tab 1, Schedule 1

Question(s):

(a) Please reproduce the Chart 2 on page 21 with additional columns indicating the forecast amounts in each year and in total. Where there have been multiple forecasts over time, please include those as well.
(b) Please provide, for each of the past five years and a forecast for the next five years, the cost of producing power at Pickering ($/MWh), including both operating costs and annualized capital costs.
(c) Please provide a table showing, for all of the nuclear costs that OPG proposes to clear, the variance from the forecast amount and the actual amount.
(d) Please provide the actual versus forecast costs for each of the Darlington rebuild project components and for each reactor.
(e) Please provide how much OPG as spent and is forecast to spend on the new nuclear reactors at Darlington.

Response

(a) Please see Ex. L-H-CCC-06 that provides an annual comparison of the actual Pickering Extended Operations costs to the OEB-approved forecasts. There were no such OEB-approved forecasts for Pickering Extended Operations in EB-2020-0290.

(b) OPG declines to provide the requested information on the basis of relevance. OPG's Application addresses the amounts OPG proposes to clear from the previously authorized deferral and variance accounts and certain specific approvals sought in connection with the implementation of the IESO's Market Renewal Program. This question does not seek information that is relevant to any issue before the OEB in the current application.

(c) Please see Attachment 1, which summarizes information provided in the corresponding tables of Ex. H1-1-1.

(d) OPG declines to provide the requested information on the basis of relevance. OPG's Application addresses the amounts OPG proposes to clear from the previously authorized deferral and variance accounts and certain specific approvals sought in connection with the implementation of the IESO's Market

Renewal Program. Consistent with EB-2018-0243 and EB-2020-0290, with the exception of the D2O Storage Project the prudence review of which was completed in EB-2020-0290, OPG is not seeking recovery of deferral and variance account amounts related to the actual versus forecast cost performance of the Darlington Refurbishment Program ("DRP") in this Application. OPG expects to provide information regarding the DRP in its next payment amounts application.

(e) OPG's Application addresses the amounts OPG proposes to clear from the previously authorized deferral and variance accounts and certain specific approvals sought in connection with the implementation of the IESO's Market Renewal Program. Among the accounts requested for disposition is the Nuclear Development Variance Account ("NDVA"), which reflects actual non-capital costs incurred by OPG in connection with preliminary planning and preparation costs for a small modular reactor ("SMR") at the Darlington New Nuclear site, chiefly over 2020 and 2021. Information on those costs is provided at Ex. H1-1-1, Section 5.15 and associated Table 20, as well as Ex. L-H-CCC-08 and Ex. L-H-Staff-05. OPG declines to provide information related to actual and forecasted project (capital) costs on the basis of relevance. These costs, which commenced following the technology selection decision made at the end of 2021, do not form part of deferral and variance account balances requested for disposition in this Application (and none were recorded in the NDVA). OPG expects to provide information regarding SMRs at the Darlington New Nuclear site in its next payment amounts application.

Numbers may not add due to rounding

Table 1: Summary of Nuclear Deferral and Variance Account Amounts Proposed for Clearance in EB-2023-0336

Line	Account	Reference (Ex. H1-1-1)	Note	2020 Forecast	2020 Actual	2020 Variance	2021 Forecast	2021 Actual	2021 Variance	2022 Forecast	2022 Actual	2022 Variance
				(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Ancillary Services Net Revenue Variance Account	Table 3, Lines 4-6		1.9	6.7	(4.8)	2.0	6.6	(4.6)	5.8	7.2	(1.5)
2	Income and Other Taxes Variance Account	Table 6	1	0.0	(3.4)	(3.4)	(7.1)	(12.1)	(5.0)	0.0	0.0	0.0
3	Pension & OPEB Cash Payment Variance Account	Table 8, Lines 3,6,7	2	352.3	231.3	(121.0)	359.2	226.9	(132.3)	N/A	N/A	N/A
4	Pension & OPEB Cash Versus Accrual Differential Deferral Account	Table 8, Lines 6,10,13	2	231.3	303.0	71.8	226.9	320.0	93.1	N/A	N/A	N/A
5	Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Variance Account - Carrying Charges	Table 8a, Line 11		0.0	(1.6)	(1.6)	0.0	(2.4)	(2.4)	0.0	(8.0)	(8.0)
6	Pension and OPEB Cost Variance Account	Table 8b	3	N/A	N/A	N/A	N/A	N/A	N/A	333.4	210.9	(122.6)
7	Bruce Lease Net Revenues Variance Account	Table 11, Lines 1,6,7		(23.5)	(11.9)	(11.6)	(45.1)	(68.7)	23.6	(47.9)	(33.0)	(14.9)
8	Nuclear Deferral and Variance Over/Under Recovery Variance Account	Table 12, Lines 1-7,14	4	161.4	189.3	(27.9)	216.9	242.7	(25.8)	39.0	40.9	(1.9)
9	Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account	Table 13, Line 21	5	0.0	(157.1)	(157.1)	0.0	263.5	263.5	N/A	N/A	N/A
10	Scientific Research and Experimental Development ("SR&ED") Investment Tax Credits ("ITCs") Variance Account	Table 14	6	18.4	13.8	4.6	18.4	15.5	2.9	16.0	23.7	(7.7)
11	Capacity Refurbishment Variance Account - Non-Capital - Non DRP	Table 15	7	118.7	117.0	(1.7)	7.5	91.3	83.8	36.1	50.1	14.0
12	Capacity Refurbishment Variance Account - Capital - Non DRP	Table 16	8,9	0.5	4.6	4.1	0.5	11.3	10.9	12.7	18.6	5.9
13	Capacity Refurbishment Variance Account - Accelerated Investment Incentive CCA - DRP	Table 1a, Line 24; Table 1b, Line 24	10	0.0	(19.9)	(19.9)	0.0	3.1	3.1	N/A	N/A	N/A
14	Capacity Refurbishment Variance Account - D2O Project	Table 17	11,12	1.5	34.9	33.4	1.5	45.3	43.9	N/A	N/A	N/A
15	Nuclear Liability Deferral Account	Table 18, Line 16	13	N/A	N/A	N/A	N/A	N/A	N/A	0.0	188.3	188.3
16	Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account	Table 19, Line 21	14	N/A	N/A	N/A	0.0	1.0	1.0	0.0	(45.9)	(45.9)
17	Nuclear Development Variance Account	Table 20, Lines 1-3		1.8	13.1	11.3	1.8	95.4	93.6	2.2	2.4	0.2

Notes:

1 Forecast is Ex. H1-1-1, Table 6, line 15. Actual is the sum of (i) Ex. H1-1-1, Table 6, line 11 (Nuclear), and (ii) Ex. H1-1-1, Table 6, line 16 (Nuclear).

2 No additions recorded beginning January 1, 2022 as the nuclear revenue requirements approved in EB-2020-0290 reflect pension and OPEB costs calculated on an accrual basis.

3 No additions recorded in 2020 or 2021 as the nuclear revenue requirements approved in EB-2016-0152 reflected pension and OPEB amounts calculated on a cash basis. Forecast is the sum of Ex. H1-1-1, Table 8b, lines 3 and 1a. Actual is the sum of Ex. H1-1-1, Table 8b, lines 6 and 7a.

4 Forecast is the product of the corresponding Nuclear Riders (Ex. H1-1-1, Table 12, Lines 1-3) and Nuclear Production Forecast Used to Set Nuclear Rider (Ex. H1-1-1, Table 12, Lines 4-6). Actual is the product of the corresonding Nuclear Riders (Ex. H1-1-1, Table 12, Lines 1-3) and Actual Nuclear Production (Ex. H1-1-1, Table 12, Line 7).

5 No additions recorded beginning January 1, 2022 as the impacts arising from nuclear station end-of-life changes implemented on December 31, 2017 were reflected in the nuclear revenue requirements approved in EB-2020-0290.

6 Forecast amounts are Ex. H1-1-1, Table 14, line 4 divided by (1-25%). Actual amounts are the difference of (i) and (ii), where: (i) Ex. H1-1-1, Table 14, line 8 divided by (1-25%), and (ii) Ex. H1-1-1, Table 14, line 16.

7 Excludes the impacts of balances for which OPG is not seeking clearance as part of this proceeding.

8 Forecast is the sum of (i), (ii) and (iii), where: (i) Ex. H1-1-1, Table 16, line 1, (ii) Ex. H1-1-1, Table 16, line 6, and (iii) Ex. H1-1-1, Table 16, line 6 less line 9 plus the ROE component of line 4a, multiplied by 25%/(1-25%).

9 Actual is the sum of (i), (ii) and (iii), where: (i) Ex. H1-1-1, Table 16, line 4, (ii) Ex. H1-1-1, Table 16, line 7, and (iii) Ex. H1-1-1, Table 16, line 7 less line 10 less line 11 plus 45% x 8.78% (for 2020 and 2021) and 8.66% (for 2022) x line 2, multiplied by 25%/(1-25%).

10 No additions recorded beginning January 1, 2022 since the impact of the CCA rule changes was reflected in the nuclear revenue requirements approved in EB-2020-0290.

11 Forecast is the sum of (i), (ii), and (iii), where: (i) Ex. H1-1-1, Table 17, line 1, (ii) Ex. H1-1-1, Table 17, line 6, and (iii) the sum of Ex. H1-1-1, Table 17, line 6 and the ROE component of line 4a, multiplied by 25%/(1-25%). No additions recorded beginning January 1, 2022 as the nuclear revenue requirements approved in EB-2020-0290 reflect the full impact of the prudence review of the D2O Project.

12 Actual is the sum of (i), (ii), and (iii), where: (i) Ex. H1-1-1, Table 17, line 4, (ii) Ex. H1-1-1, Table 17, line 7, and (iii) the sum of Ex. H1-1-1, Table 17, line 7 and 45% x 8.78% x line 2, multiplied by 25%/(1-25%).

13 No additions recorded in 2020 or 2021 as the nuclear revenue requirements approved in EB-2016-0152 reflected the impact arising from the current ONFA Reference Plan approved by the Province of Ontario.

14 No additions recorded in 2020 as the account is effective January 1, 2021.

ED Interrogatory #2

Interrogatory

Reference: Exhibit H1-1-1, Attachment 3

Question(s):

(a) Please provide a copy of the table in Attachment 3 in excel format. Please also add to the table: (i) the foregone electricity generation in each row, and (ii) whether gas generation is on the margin at that time, and (iii) whether gas plants that the pump station could offset are generating at that time.

(b) Please express the economic decision-making rules described at pages 1-2 as formulas.

(c) When assessing the opportunity to recover pumping costs, the revenues are considered net of applicable gross revenue charge. Please consider a scenario where that was not the case (i.e. GRC was not netted out):

- (i) How much more would have been generated from the pump station in each year from 2018 to 2022 (an approximate answer on a best-efforts basis is sufficient)?
- (ii) What amount of GRC would have been collected in those periods where this change would result in incremental generation from the pump station?
- (iii) How much would the SBGVA and HIMVA be?

(d) Please describe the GRC and confirm that it is a cost that benefits taxpayers by generating government revenue.

Response

(a) Refer to Ex. L-H-SEC-04 part a) which provides the requested information with respect to the foregone electricity generation. OPG is unable to provide the information requested in parts (ii) and (iii). OPG does not have visibility into whether gas plants are operating on the margin or whether gas plants that the SAB Pump Generating Station ("PGS") could offset were generating. This type of analysis would not be in OPG's purview as it can only be performed with the dispatch algorithm and market inputs held by the IESO. Refer to Ex. L-H-SEC-05 for additional information regarding entries to the SBGVA during hours when HOEP exceeds GRC.

(b) The economic decision-making described at pages 1-2 of Ex. H1-1-1, Attachment 3 can be expressed with the following two formulas:

1. The formula for the breakeven PGS generation price:

$$\frac{\begin{array}{c} PGS\ Pump\ Efficiency\ \times (Forecast\ Pump\ Price + PGS\ Load\ Charges) + \\ Beck\ Gen\ Efficiency * (Forecast\ Pump\ Price - Beck\ GRC) + \\ (PGS\ Gen\ Efficiency * PGS\ GRC) + (Beck\ Gen\ Efficiency * Beck\ GRC) \end{array}}{PGS\ Gen\ Efficiency\ MW + Beck\ Gen\ Efficiency\ MW}$$

To determine the economics of generating with the PGS, OPG calculates the breakeven generation price according to the formula above and compares that to the latest pre-dispatch market clearing price. If that market clearing price is greater than the breakeven generation price, OPG concludes it is economic to generate.

2. The formula for the breakeven PGS pump price:

$$\frac{\begin{array}{c} PGS\ Gen\ Efficiency\ x\ (Forecast\ Gen\ Price - PGS\ GRC) + \\ Beck\ Gen\ Efficiency\ x\ (Forecast\ Gen\ Price - Beck\ GRC) + \\ (Beck\ Gen\ Efficiency\ x\ Beck\ GRC) - (PGS\ Pump\ Efficiency\ x\ PGS\ Load\ Charges) \end{array}}{PGS\ Pump\ Efficiency\ MW + Beck\ Gen\ Efficiency\ MW}$$

To determine the economics of pumping with the PGS, OPG calculates the breakeven pump price according to the formula above and compares that to the latest pre-dispatch market clearing price. If that market clearing price is less than the breakeven pump price, OPG concludes it is economic to pump.

Further discussion on the economic decision-making rules that govern the operation of the PGS can be found in EB-2020-0290, Ex. JT2.26.

(c) OPG cannot analyze the scenarios listed in (i), (ii) or (iii). This type of analysis is not in OPG's purview as it can only be performed with the dispatch algorithm and market inputs held by the IESO.

Furthermore, OPG notes that it would not be appropriate to ignore the cost of gross revenue charges ("GRC") in the economic assessment of cycling the PGS, as this would result in under-recovery of incurred GRC costs and cause an economic loss to OPG. OPG is a commercial generator and it is not its function to operate the PGS at an economic loss.

(d) The GRC refers to the taxes and charges payable by owners of hydroelectric generating stations under Section 92.1 of the *Electricity Act, 1998* based on energy produced, as prescribed under O. Reg. 124/02. The GRC is payable to the Ontario government and its agencies. OPG is unable to confirm the treatment or use of these funds by the Ontario government and its agencies.

ED Interrogatory #3

Interrogatory

Reference: Exhibit H1-1-1, Attachment 3

Question(s):

(a) The evidence in Attachment 3 shows numerous occasions where OPG did not operate its regulated fleet to minimize total electricity supply costs during hours when OPG is booking additions to this variance account because doing so would cause OPG to experience an economic loss. Please propose a number of options to change the way that OPG is compensated to reduce or eliminate instances in which OPG is not operating its fleet to minimize total electricity supply costs.

Response

(a) In Ex. H1-1-1, Section 5.4, OPG identified the SAB Pump Generating Station ("PGS") as the only OPG resource subject to an economic loss assessment as part of the market-based decisions underpinning its utilization. Therefore, contrary to the question's reference to the "regulated fleet", Ex. H1-1-1, Attachment 3 only includes instances of economic loss related to the assessment of the PGS. As fully explained in Ex. M1-1-1, the compensation OPG receives through the existing market structure and regulatory framework, and would receive through the new market structure and proposed regulatory framework, are appropriate drivers for participation in the market and promote following market signals at all its regulated resources. As demonstrated in Ex. M1-1-1, Section 3.5, Chart 1, these drivers lead to lower customer costs. As such, OPG has not developed other alternatives as the question requests and is therefore unable to provide them.

ED Interrogatory #4

Interrogatory

Reference: Exhibit H1-1-1, Attachment 3

Question(s):

(a) Attachment three only provides evidence on the pump generations station. For OPG's whole fleet, please "identify each time that OPG did not operate its regulated fleet to minimize total electricity supply costs during hours when OPG is booking additions to this variance account because doing so would cause OPG to experience an economic loss, and explain why operating to minimize total electricity supply costs would have caused economic loss in each case" – as required by the settlement agreement.

Response

a) The information OPG provided in Ex. H1-1-1, Attachment 3, for the SAB Pump Generating Station ("PGS"), fully satisfies the provisions of the OEB-approved EB-2020-0290 Settlement Proposal referenced in the question because, other than for the PGS where OPG incurs the cost of pumping, OPG does not make decisions regarding the operation of its regulated hydroelectric facilities due to economic loss. Therefore, other than for the PGS, the circumstances described in the question are not relevant to the operation of OPG's regulated hydroelectric fleet. As part of the SBG Study, OPG explored alternative offer strategies for the regulated hydroelectric facilities that could reduce the foregone production captured in the Hydroelectric Surplus Baseload Generation Variance Account. However, these strategies would be contrary to the IESO's existing dispatch order and, in consultation with the IESO, were therefore determined to be undesirable from an overall system cost perspective. Refer to Ex. M1-1-1, Attachment 1, Section 4 for further details.

ED Interrogatory #5

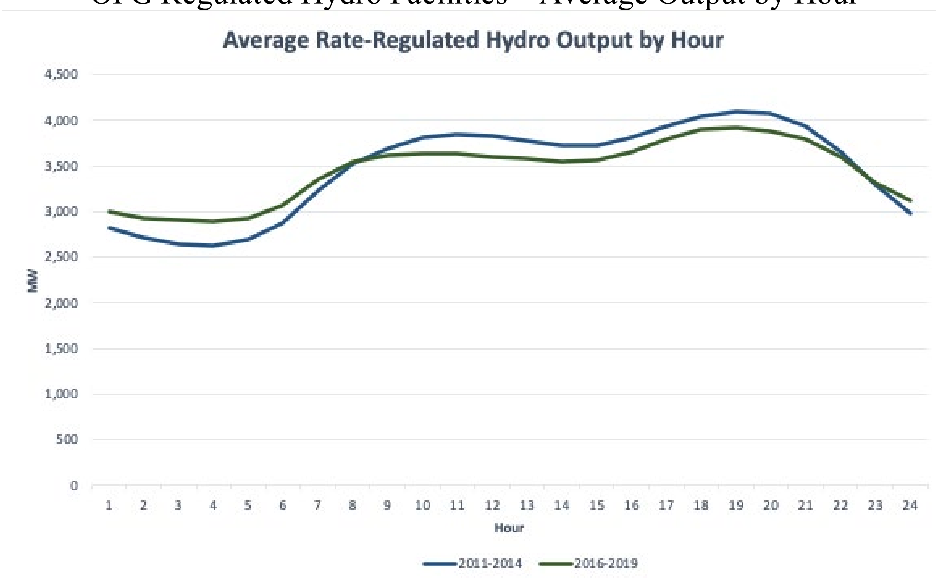
Interrogatory

Reference: Exhibit H1-1-1, p. 8

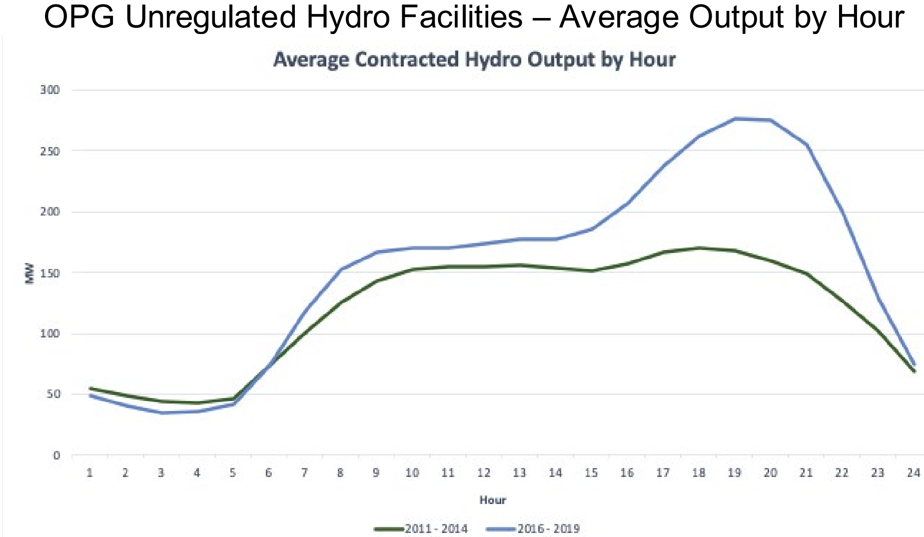
Preamble:

The below figures show the average output of OPG's rate regulated vs. unregulated hydro assets.

OPG Regulated Hydro Facilities – Average Output by Hour



OPG Unregulated Hydro Facilities – Average Output by Hour



Question(s):

(a) Please reproduce the above figures adding a line for 2020-2023

(b) Please explain why OPG time-shifted its output for its regulated hydro assets less in 2016-2019 versus 2011-2014 (as shown by the flatter curve in the top figure). Please enumerate all causes. Please also describe any differences arising in 2020-2023 versus previous periods, enumerating all the differences.

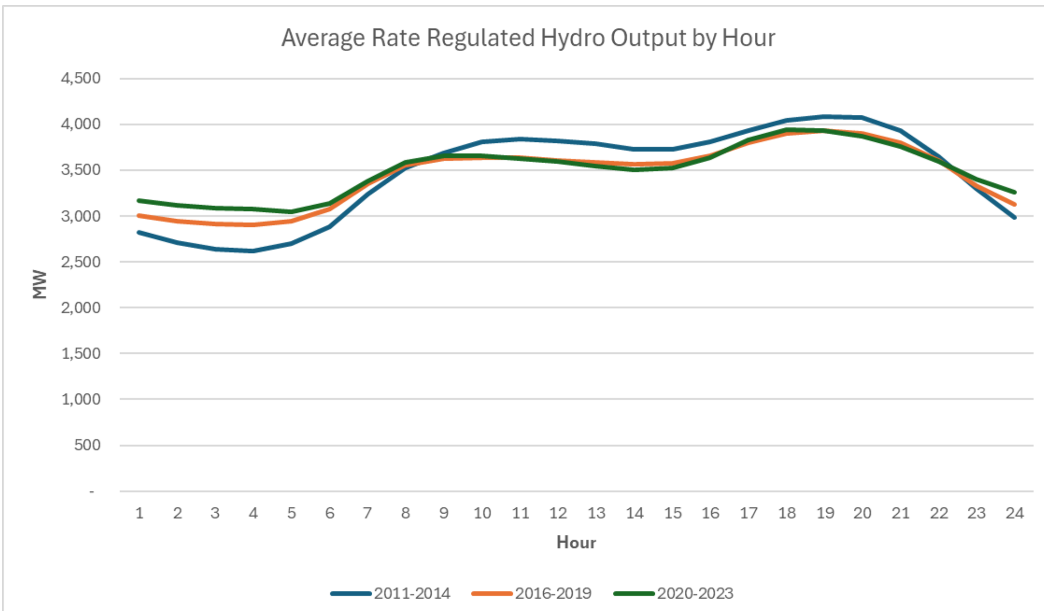
(c) Please explain why OPG time-shifted its output for its regulated hydro facilities far less than the output of its unregulated hydro facilities (as shown by comparing the figures). Please enumerate all causes.

(d) If OPG had time-shifted its regulated hydro facilities like it did its unregulated hydro facilities, how much less SBG costs would it be seeking in this application? Please provide an annual breakdown

Response

a) OPG has provided the requested charts, reproduced using IESO data as Figures 1 and 2 below.[1] A line for 2020-2023 has been added. In addition, OPG has provided the Regulated Hydroelectric output shown in Figure 1, further split into the categories of “Baseload and Run-of-River”, “Intermediate” and “Peaking” facilities. This breakdown is necessary to accurately analyze the changes in time shifting for the regulated facilities between time periods and between the regulated and the unregulated hydroelectric facilities. The “peaking” category includes the PGS.

Figure 1: Average Rate Regulated Hydro Output by Hour



[1] See: https://ieso.ca/Power-Data/Data-Directory#Generator-Output-and-Capability.

Figure 2: Average Contracted Hydro Output by Hour

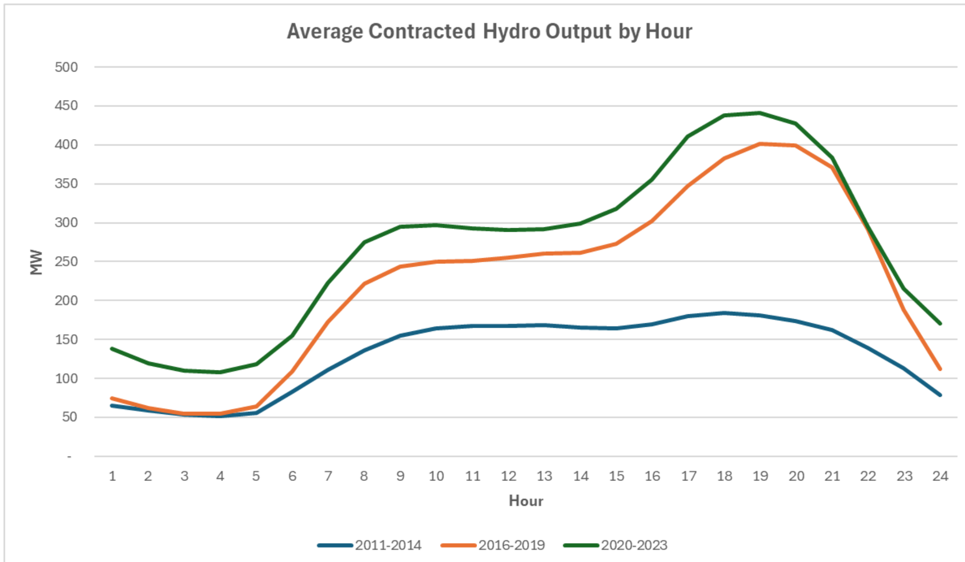


Figure 3: Regulated Baseload and Run-of-River

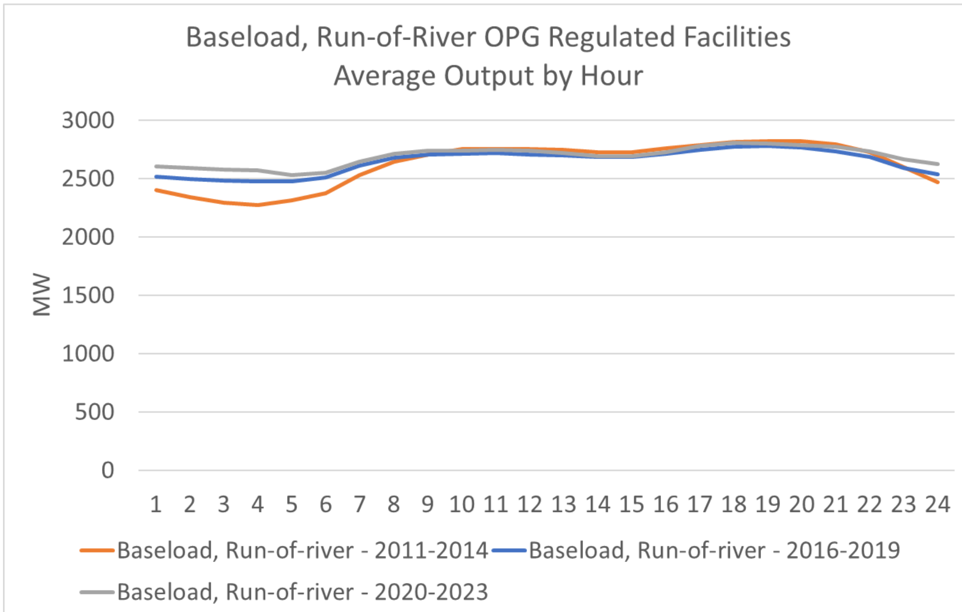


Figure 4: Regulated Intermediate

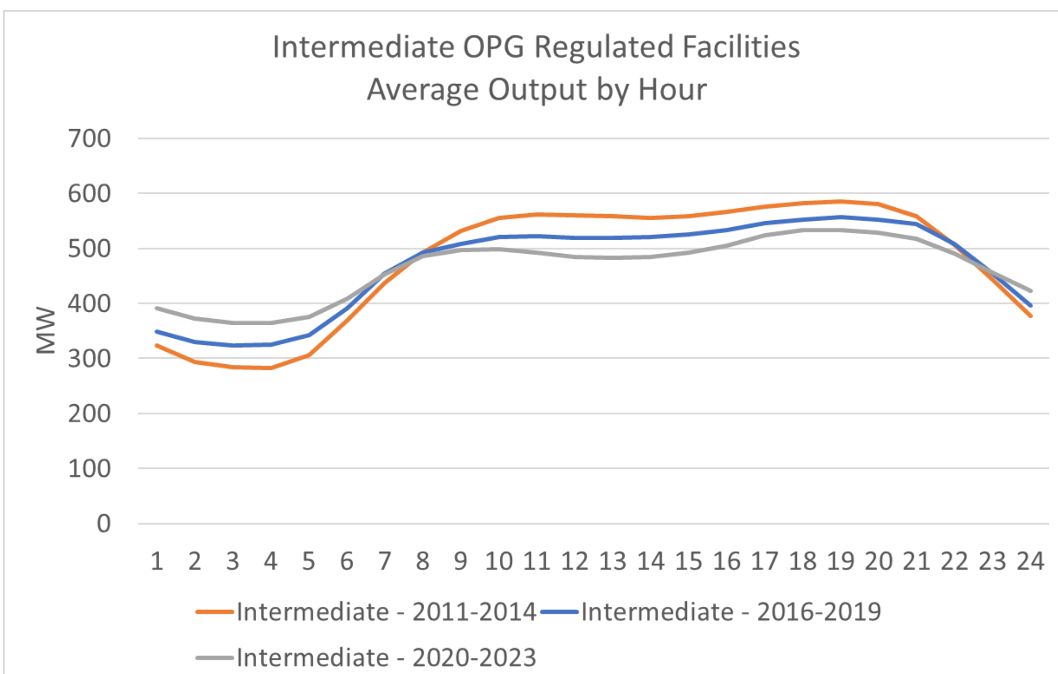
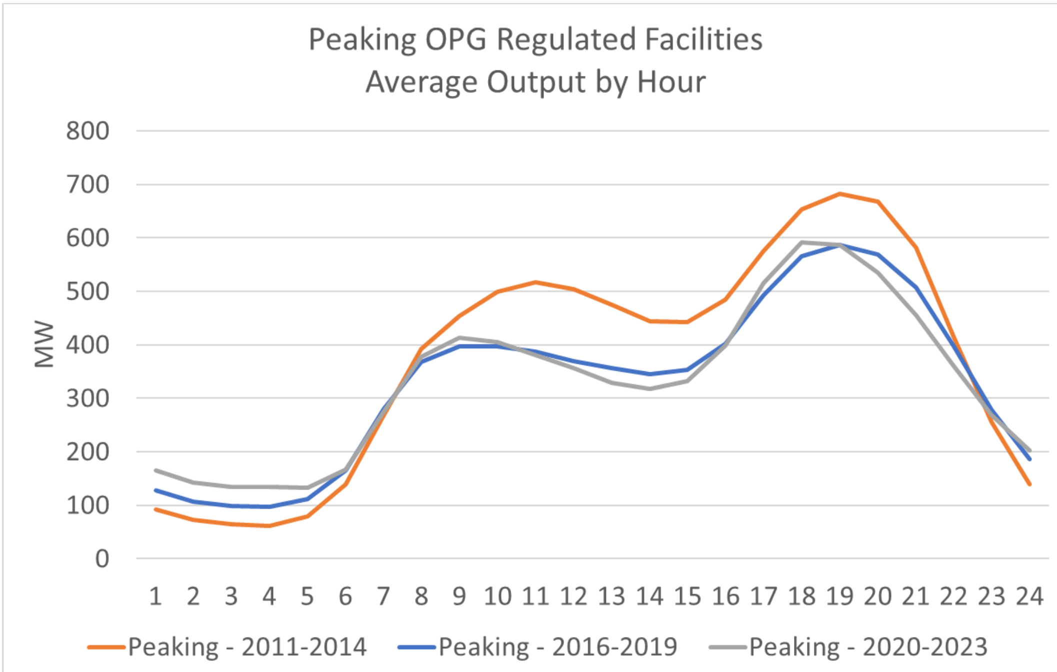


Figure 5: Regulated Peaking



b) As shown in the Figures provided in part (a), the difference in time shifting of energy for the regulated hydroelectric facilities between the periods is primarily driven by the baseload facilities, in particular the Sir Adam Beck Generating Stations ("SAB 1" and "SAB 2"). Period over period differences in OPG's time shifting observed for the baseload facilities between the 2011-2014 period and 2016-2019 period are primarily attributed to water flow conditions, with higher water flow limiting OPG's ability to time shift generation. The 2020-2023 period is similar to 2016-2019.

The main difference in on-peak generation for OPG's intermediate and peaking regulated hydroelectric facilities related to the impact of lower flows on the Abitibi watershed for the 2016-2019 and 2020-2023 period as compared to the 2011-2014 period. The impact of these lower flows is observed as a decrease in the on-peak generation profile for the entire category. Additionally, off-peak SBG spill at OPG's intermediate and peaking regulated hydroelectric facilities was 90% higher in 2016-2019 period than during 2020-2023, with both being higher than in the 2011-2014 period, and is a major reason for the difference observed in off-peak generation.

c) Each river system is subject to unique operating restrictions as discussed in Ex. L-M-Staff-13 a). The total installed capacity for the regulated hydroelectric resources is 6420 MW, of which 3149 MW, or 49%, is classified as baseload generation. As presented in Figures 2 and 5, OPG's regulated peaking hydroelectric facilities have a similar peaking profile when compared to OPG’s contracted hydroelectric facilities, which are primarily peaking. Thus, OPG does not believe that there is a marked difference between the peaking profiles of its regulated peaking hydroelectric facilities and its contracted hydroelectric facilities.

d) This type of analysis is not in OPG's purview as it can only be performed with the dispatch algorithm and market inputs held by the IESO.

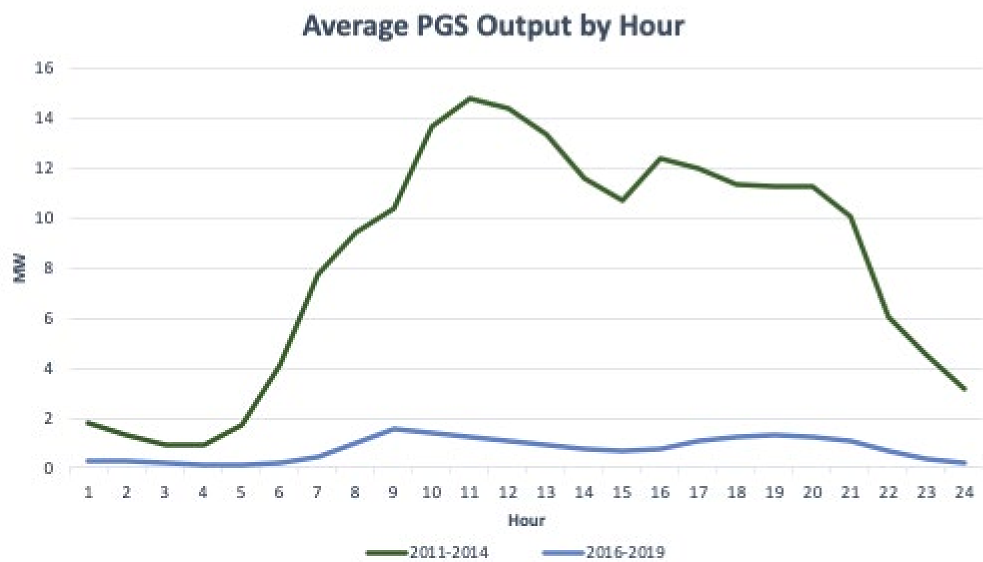
ED Interrogatory #6

Interrogatory

Reference: Exhibit H1-1-1, p. 8

Preamble:

The below figure shows the decline in the PGS's operations in recent years.



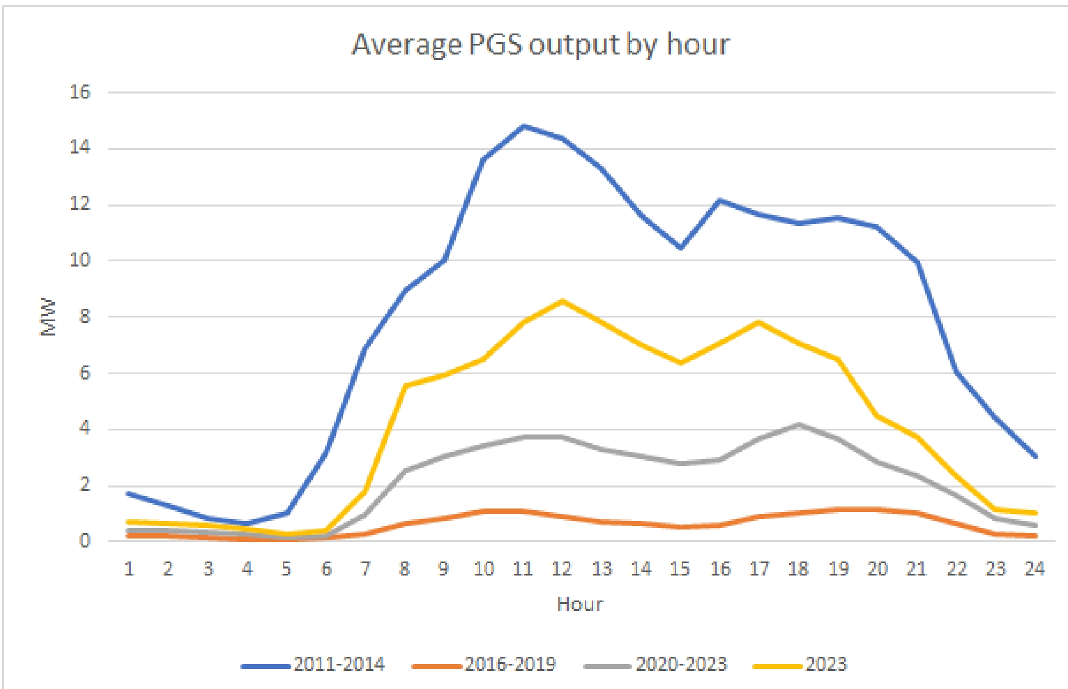
Question(s):

(a) Please reproduce the above figure adding a line for 2020-2023.
(b) What percent of the decline in PGS output from 2011-2014 to 2020-2023 (if any) was due to water levels?
(c) What is the demand (MW) of the PGS pump running at full capacity?
(d) What is the generating capacity (MW) of the PGS generator running at full capacity?
(e) What is the GRC for power generated from the PGS?
(f) What production did OPG forecast for the PGS for 2020 to 2023 in its last payment amounts application?
(g) What production is OPG forecasting for the PGS for 2025-2026?

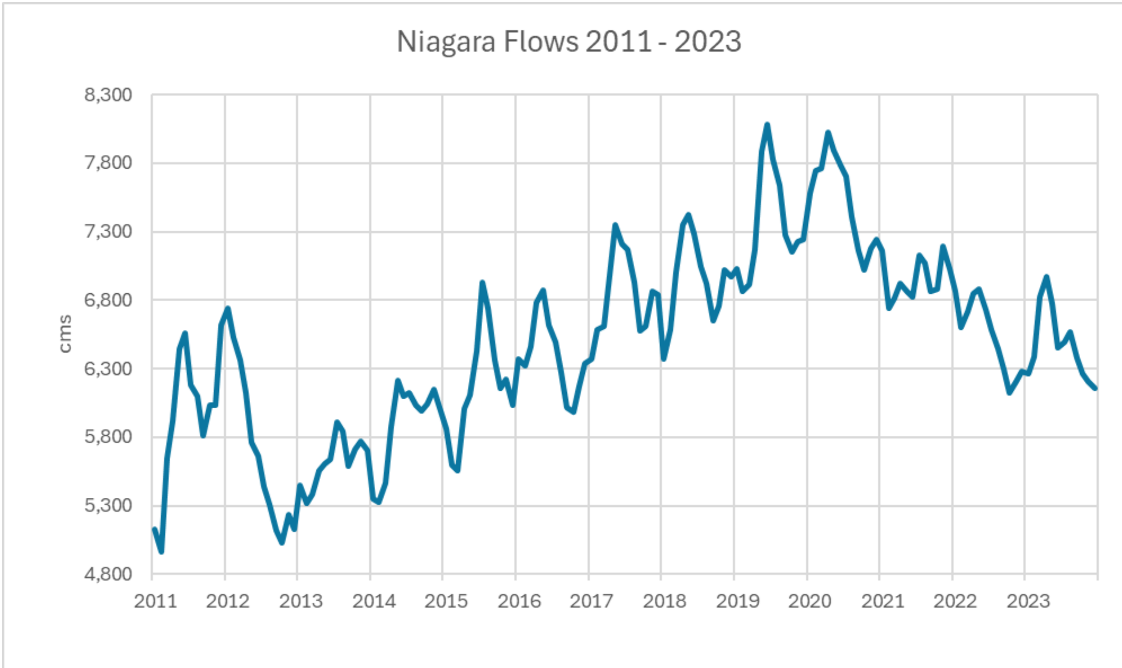
Response

a) Figure 1 has been reproduced using IESO data and a line for 2020-2023 has been added. OPG has also added a line for 2023 to illustrate PGS generation with the lower flows on the Niagara River observed in 2023 as discussed below.

Figure 1: Average Hourly PGS Generation



b) As presented in Chart 4, the Niagara River has experienced very high flows since 2017, with the increase trend reversing since 2020 while still higher than long term average. As a result, though higher than PGS usage in the 2016-2019 period, usage in the 2020-2023 period remained below that of the 2011-2014 period, with high water levels being a significant factor in the reduction. For the 2020-2023 period, in 64% of typical PGS generation hours, SAB 1 and SAB 2 did not have available capacity to generate incremental water from the PGS, leading to reduced PGS cycling efficiency, which factors into the assessment of uneconomic operations.



c) Each PGS unit requires approximately 37MW in pump mode.

d) Each PGS unit produces approximately 29MW is generation mode.

e) The GRC for the PGS ranges from $4.8/MWh to $5.6/MWh, depending on annual generation.

f) OPG's last payment amounts proceeding was EB-2020-0290. OPG did not forecast PGS production for the years 2020-2023 as (i) its hydroelectric base payment amounts for 2022 to 2026 have been legislatively set at those previously established effective January 1, 2021 in EB-2020-0210,[1] and (ii) its hydroelectric base payment amounts for 2020 and 2021 were established by the OEB pursuant to the price-cap index approved in EB-2016-0152, as applied to the EB-2013-0321 regulated hydroelectric base payment amount.[2]

g) OPG declines to provide the requested information on the basis of relevance. OPG's Application addresses only the amounts OPG proposes to clear from the previously authorized deferral and variance accounts and certain specific approvals sought in connection with the implementation of the IESO's Market Renewal Program. As such, the future production forecast information sought is not relevant to any issue before the OEB in this Application.

[1] EB-2020-0290 Payment Amounts Order, p. 4
[2] EB-2016-0152 Payment Amounts Order, p. 9.

ED Interrogatory #7

Interrogatory

Reference: Exhibit H1-1-1, p. 8

Questions:

(a) Comment on a change whereby, going forward, SBG payments for spilt water would be reduced by the capacity of the PGS pump if for the time in question the PGS pump was not running;
(b) Comment on a change whereby the PGS decision-making tool would be adjusted to focus on minimizing total system costs to customers instead of focusing on maximizing revenue;
(c) Comment on a change to ensure that water is not spilt at a hydro facility if that can be avoided in whole or in part by ceasing generation and utilizing storage at another hydro facility (e.g. where the HOEP is $10 and the facility A has a GRC of $14.4 and no storage capacity whereas facility B has a GRC of $5); and
(d) Comment on the possibility of allocating a greater portion of existing capital budgets to cost-effectively expanding storage and/or time-shifting capabilities at OPG's hydro facilities.

Response

(a) It would not be appropriate to reduce SBG payments by the capacity of the SAB Pump Generating Station ("PGS") when the PGS was not running as this would not reflect the financial impact of forgone production due to SBG conditions on OPG's regulated hydroelectric facilities, resulting in an under-recovery of the OEB-approved revenue requirement and negatively impacting OPG's ability to earn the authorized rate of return. As a general matter, OPG notes that system wide costs and the management of SBG conditions are within the purview of the IESO. The PGS is offered based on economic market signals in accordance with the Hydroelectric Incentive Mechanism, as outlined in Ex. H1-1-1, Attachment 3, and subject to physical, operational and safety of any person, equipment damage, or the violation of any applicable law ("SEAL") constraints.

Furthermore, OPG notes that the postulated approach would be contrary to the OEB's EB-2010-0008 findings regarding the interaction of PGS usage and OPG's compensation for forgone production through the Hydroelectric Surplus Baseload Generation Variance Account ("SBGVA") that contemplated an opportunity for OPG to justify instances of SBGVA entries when the PGS is not utilized, as OPG has done in this Application.[1]

(b) OPG is a commercial generator and it is not its function to operate the PGS at an economic loss so as to minimize total system cost, which, in any case, would depend on the operation of all generators in the market.

(c) The postulated scenario would not constitute a change as this principle is currently embedded in OPG's operations. OPG offers each hydroelectric facility's energy with limited remaining storage at the facility's marginal costs, the Gross Revenue Charge ("GRC"). Opportunity cost offers associated with storage are priced above OPG's highest tier of GRC offers.

In order to illustrate this principle, the provided example needs to be expanded to include three facilities, A, B and C. Facility A has no available storage and a GRC of $14.4, facility B has no available storage and a GRC of $5 and facility C has available storage and an expectation of a $40 daily highest price. In an hour when HOEP is $10/MWh, facility C's offer of $40 will be uneconomic and the facility will not be dispatched to generate and will utilize its storage. Facility A will also be uneconomic and will spill water as it does not have available storage. Facility B's $5/MWh GRC offer will be economic and the facility will generate thereby not incurring any spill. This example illustrates that all of OPG's storage is utilized (facility C) before spill takes place (facility A) while any further spill if price becomes lower will take place where all storage has been utilized already (facility B).

(d) OPG does not currently have plans to increase storage capacity at existing regulated facilities as it would require significant capital investment to rebuild existing dams and inundation of additional lands beyond current legal limits.

[1] EB-2010-0008, Decision with Reasons, March 10, 2011, p. 147.

ED Interrogatory #8

Interrogatory

Reference: Exhibit H1-1-1, p. 8

Questions:

(a) Please provide a table showing how much energy generation was spilt (MWh) for each year from 2018 to 2023 during hours in which gas generation was on the margin?
(b) Please provide a table showing how much energy generation was spilt (MWh) for each year from 2018 to 2023 during hours in which gas generation was on the margin AND that gas generation could have been replaced by the foregone electricity from spilt water from one of OPG's hydroelectric stations?
(c) Please describe all the situations in which OPG's decision-making rules for operating its hydroelectric stations might result in a hydroelectric station spilling water even though its output could be replacing some gas-fired generation. Please list and describe each potential situation and what element of the decision-making rules or market conditions cause that to take place.
(d) Please provide all internal documents guiding its staff on when to generate at its hydroelectric facilities.
(e) Please provide all internal documents guiding its staff on when to pump and generate at its PGS.

Response

(a) OPG is unable to provide the requested table as OPG does not have visibility into whether gas plants are operating on the margin in a particular hour.

(b) OPG is unable to provide the requested table as OPG does not have visibility into whether gas plants are operating on the margin in a particular hour. This type of analysis is beyond OPG's purview as it can only be performed with the dispatch algorithm and market inputs held by the IESO.

(c) OPG interprets "spilling water" to refer to forgone production at OPG's regulated hydroelectric facilities that result in entries into the SBGVA. Generally, such hydroelectric spill occurs off-peak when gas-fired generation is not running. Refer to Ex. L-H-SEC-05 for additional information regarding entries to the SBGVA during hours when HOEP exceeds GRC. In general, the specific assessment and analysis requested is beyond OPG's purview as it can only be performed with the dispatch algorithm and market inputs held by the IESO.

(d) and (e)

OPG generates at its hydroelectric facilities (including the PGS) in accordance with IESO market dispatches. OPG makes offers into the IESO administered market in accordance with market rules and in compliance with OPG's generator license.[1] The IESO has the responsibility to assess all market offers and optimize the economic dispatch. Absent SEAL, OPG follows dispatches received from the IESO. Thus, there are no documents that tell OPG staff when to generate as these actions are undertaken only as directed by IESO dispatches. OPG's methodology of assessing when it is economic to pump is described in Ex. H1-1-1, Attachment 3.

[1] See: https://www.rds.oeb.ca/CMWebDrawer/Record/816291/File/document.

ED Interrogatory #9

Interrogatory

Reference: Exhibit H1

Questions:

(a) Please provide a table for each year from 2018 to 2023 showing the quantity of clean energy credits OPG has sold (MWh and TWh). Please also provide a breakdown between the types of generation the credits are attributable, where possible.

(b) Please describe why the incremental revenue sought in this application should or should not be offset by the credits that OPG has sold for electricity that ratepayers already paid for.

(c) Please describe and quantitatively itemize how OPG has spent the funds it has earned from selling clean energy credits over 2018 to 2023.

Response

OPG declines to provide the requested information on the basis of relevance. OPG's Application addresses the amounts OPG proposes to clear from the previously authorized deferral and variance accounts and certain specific approvals sought in connection with the implementation of the IESO's Market Renewal Program. Clean Energy Credits are not within the topics the Application addresses. As determined by the OEB Chief Commissioner in the letter dated August 25, 2022 (Attachment 1), the OEB has determined that the forecasted revenue amounts associated with the sale of Clean Energy Credits ("CECs") are well below OPG's materiality threshold on an annual basis. The OEB Chief Commissioner denied establishing a new deferral or variance account to track OPG's revenues from the sale of CECs, and also determined that there was no need to re-open EB-2020-0290 establishing final payment amounts for OPG during 2022-2026. OPG further notes that, pursuant to Section 4.2 of *Ontario Regulation 39/23*, proceeds from the sale of CECs will be directed to the Province of Ontario's Future Clean Electricity Fund.

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

BY EMAIL

August 25, 2022

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Dear Mr. Elson and Ms. Zadeh:

Re: Ontario Power Generation Inc. (OPG) Clean Energy Credits

The Ontario Energy Board (OEB) has considered the request made by Environmental Defence (ED) on May 2, 2022 to re-open or institute a new proceeding to consider issues relating to OPG's sales of clean energy credits (CECs) arising from its regulated generation facilities. For the reasons below, the OEB has concluded that it will not do so.

Background

On May 2, 2022, the OEB received a letter sent by Mr. Elson on behalf of ED, which was copied to OPG and all parties to the most recent OPG payment amounts proceeding (EB-2020-0290), in which ED was an approved intervenor.

The letter asserted that OPG appears to have "been selling clean energy credits to buyers outside of Ontario for some time now" through registries such as the Midwest Renewable Energy Tracking System (M-RETS) or via Attestation Letters.

The letter asked the OEB to institute a new proceeding on its own motion under s. 78.1(5)(b) of the *Ontario Energy Board Act, 1998* or, alternatively, re-open the EB-2020-0290 proceeding on the basis that "details with respect to clean energy credit revenue, both past and forecast, were not included in the application." In either case, the purpose of the proceeding would be to explore the following two issues:

1. Is it appropriate for OPG to sell environmental attributes, credits, and/or rights with respect to the regulated assets funded by ratepayers?
2. If yes, how should the proceeds be accounted for and allocated?

By way of a letter dated May 4, 2022, the OEB provided OPG with an opportunity to respond to ED's request. OPG did so on May 6, 2022, asking the OEB to deny the request. OPG noted that the revenues from the sale of CECs have been immaterial and that, since its hydroelectric payment amounts were frozen pursuant to O. Reg. 53/05 (Payments under Section 78.1 of the Act), it did not lead any evidence about CEC sales related to its hydroelectric facilities in the last payment amounts case. OPG added that:

> The determination of how revenues from Clean Energy Credits sales will either flow back to ratepayers or be used to support future clean energy projects will be based on developing government policy direction, which is expected to issue following the conclusion of the Independent Electricity System Operator's ('IESO') ongoing stakeholder engagement to develop a Clean Energy Credit registry.

ED replied the same day, taking issue with a number of OPG's responses.

Shortly thereafter, the OEB received letters from the following entities supporting ED's request: the Atmospheric Fund, Clean Air Council, Ontario Sustainable Energy Association (OSEA), and the City of Ottawa (among them, only OSEA had intervened in the EB-2020-0290 proceeding).

OEB staff also required additional information from OPG about its past and forecast sales of CECs, which was provided on June 10, 2022.

Correspondence related to ED's request, including a version of OPG's response to OEB staff's information request that has been partially redacted on confidentiality grounds, has been posted on the OPG page on the OEB's website.

Analysis

The final Payment Amount Order for the EB-2020-0290 proceeding was issued on January 27, 2022. The OEB will not re-open this closed proceeding.

As mentioned above, the IESO has been consulting with stakeholders on the development of a CEC registry. That consultation was initiated after the Minister of Energy directed the IESO on January 26, 2022 to assess options for a provincial CEC registry, including examining the availability of CECs from contracted and regulated resources to enable the registry to be launched in January 2023.

On August 2, 2022, the Government posted a regulatory proposal for the development of a CEC registry. As described in the regulatory registry posting, two aspects of the proposal are legislative or regulatory amendments that would:

- Allow the minister to direct how the revenues from CECs created by regulated assets owned by Ontario Power Generation Inc. or CECs arising from IESO's procurement contracts should be used, including directly benefiting ratepayers and supporting the future development of new clean energy in the province.

- Add reporting requirements for the sale and retirement of CECs to ensure transparency and accountability.

Comments from stakeholders on the Government’s proposal are due September 16, 2022.

The OEB will monitor this initiative on developing a provincial CEC registry. Until those consultations have concluded and the results are known, it would be premature for the OEB to consider the matters raised by ED. The OEB is therefore not initiating a proceeding on this matter.

After receiving ED’s letters, the OEB considered establishing a new deferral or variance account to track any OPG revenue from the sale of CECs, but has determined that doing so at this time is not warranted. Based on the forecast provided by OPG, the revenue amounts are well below OPG’s materiality threshold on an annual basis. Furthermore, the use of such revenues is within the scope of the Government consultation.

There may be other matters for the OEB to consider once the results of the Government’s consultation on the development of a CEC registry are known. For example, there may be value in a CEC reporting requirement for OPG but the OEB notes that this is a matter being considered within the current consultation. It is therefore premature for the OEB to impose any reporting requirements. Furthermore, any direction from the Minister on how revenues from CECs should be used may impact how the earnings sharing mechanism for OPG is determined. There may be value in ensuring there is clarity on this prior to the end of the 2022 to 2026 term for OPG’s payment amounts. Again, these are matters best considered after completion of the Government’s consultation.

To be clear, nothing in this letter should be taken as expressing a view on the OEB’s jurisdiction to impose conditions on CEC sales by OPG, a question on which ED and OPG evidently disagree.

Yours truly,

Original Signed By

Lynne Anderson
Chief Commissioner

c: The Atmospheric Fund, Clean Air Council, OSEA, City of Ottawa
All parties to EB-2020-0290