JUPITER
ENERGY ADVISORS INC.

21 Four Seasons Place, Suite 101
Toronto, Ontario M9B 6J8
Phone: 416.622.9449
Fax: 416.622.9797

March 22, 2021 **Via RESS**

Ms. Christine Long
Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, Ontario
M4P 1E4

Dear Ms. Long:

RE: Ontario Power Generation Inc. (OPG)
2022-2026 Payment Amounts Application
Ontario Energy Board File Number: EB-2020-0290

Interrogatories from Ontario Association of Physical Plant Administrators to OPG

Attached please find the interrogatories from the Ontario Association of Physical Plant Administrators (OAPPA) to OPG. Jupiter Energy Advisors is submitting these IRs on behalf of OAPPA.

Yours truly,

Valerie Young

Valerie Young
Director, Regulatory Affairs and Government Relations

cc. E. Wong, OPG
A. Collier, OPG
C. Keizer, Torys LLP
C. Smith, Lax O'Sullivan Lisus Gottlieb
L. Gluck, OEB
M. Millar, OEB
I. Richler, OEB
N. Splinter, OAPPA / Queen's University
G. DeJulio, Jupiter Energy Advisors
EB-2020-0290 Intervenors

EB-2020-0290

Ontario Energy Board

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B), as amended;

AND IN THE MATTER OF an application by Ontario Power Generation Inc. (OPG) under Section 78 of the OEB Act to the Ontario Energy Board for an Order or Orders approving payment amounts and payment riders for its prescribed generating facilities between 2022 and 2026.

INTERROGATORIES OF

ONTARIO ASSOCIATION OF PHYSICAL PLANT ADMINISTRATORS

(“OAPPA”)

March 22, 2021

OAPPA INTERROGATORIES

ONTARIO POWER GENERATION INC.

2022 TO 2026 PAYMENT AMOUNTS

EB-2020-0290

D2-OAPPA-01

1. Exhibit D2-2-3, Page 1, lines 6-10 and also Page 3, starting at line 22 describes the first-time installation of turbine generator controls (TG Controls) during the DRP, and discusses the anticipated learning that is expected from the initial installation on Unit 3. While the TG Controls installation is to occur during each unit's refurbishment outage, previously refurbished Unit 2 has a scheduled 190.1 day outage in 2025 to install the TG Controls (Exhibit E2-1-1, Page 10, lines 16-21).

a) What learning is expected from the installation of the first TG Controls installation and what is the expected improvement in scheduled outage time for the 4th unit, in 2025?
b) Has the anticipated learning and outage acceleration been incorporated in the Unit 2, 2025 outage forecast, and if so, what was the reduced outage time?

E2-OAPPA-02

2. Exhibit E2-1-1 Pages 7 and 8, Section 3 confirms the basis and methodology used in the Nuclear Production Forecast, including in lines 5 to 13 on Page 8 "*The objective is to establish a realistic and accurate annual nuclear production forecast based on the generation and outage plan, with the following deliverables: A planned outage schedule for all stations that includes unit outage start dates, end dates, and durations based on the major elements comprising the scope of work that will be executed during each outage*". The net result is provided in a monthly format as Exhibit E2-1-1, Table 2. However, OAPPA is unable to confirm the accuracy and appropriateness of this forecast based on the currently filed information, finding instead that either the UCF's have been understated or its interpretation of the known outages are inconsistent with OPG's filed or public intentions.

a) Other than the DRP, which is well documented, would OPG please provide a monthly forecast of the anticipated nuclear outages by station and generating unit, during the IR term?
b) Alternatively, or additionally, can OPG identify the Planned Outage start and end dates, by individual unit, during the IR term?

E2-OAPPA-03

3. Reference: Exhibit E2-1-1, Page 6, lines 7-12

   Has any consideration been given to coordinating the Unit 2, turbine generator controls (TG Controls) installation outage concurrently with its second post-refurbishment outage to further reduce the outage impact during the IR?

E2-OAPPA-04

4. Exhibit E2-1-1 Page 12 of 15, lines 5-8, describe the anticipated use of a new technology for use during the scheduled Vacuum Building Outage (VBO) that would notably reduce the outage duration "(currently 30 days duration for each of the 5 reactors not otherwise in a planned outage)".

a) Please confirm the number of days that the revised technology application is expected to reduce the VBO outage.
b) Please confirm the status of CNSC's approval, if known, or the expected confirmation time.

E2-OAPPA-05

5. Reference: Exhibit E2-1-1 Page 12

   Please update the FLR tables Charts 3 and 4 with the 2020 data.

E2-OAPPA-06

6. Exhibit E2-1-1, Page 14, lines 3 to 6 describe OPG's FLR challenges and targets, despite DRP. At line 6 it reads, "*However, OPG has decided to maintain this industry-leading FLR target in the 2020-2026 Business Plan with a view to continuous improvement*".

   Please explain why the production schedule of Exhibit E2-1-2, Table 1a uses much higher FLR rates than the 1% FLR target considered by the Business Plan, necessarily affecting lower production.

F2-OAPPA-07

7. Exhibit E2-1-1 PRODUCTION FORECAST AND METHODOLOGY – NUCLEAR page 2, line 7 says “and the end of commercial operations at Pickering by the end of 2025”. At Page 6, lines 11-13 it reads:
   “Pickering Optimized Shutdown: Under the Pickering optimized shutdown plan discussed in Ex. F2-1-1, Units 1 and 4 are forecast to be shut down in 2024, followed by the staggered shutdown of Units 5-8 at the end of December 2025.”

   From Exhibit F2-1-1, page 1, lines 15-18 it reads:

   “Highlights of OPG’s 2020-2026 Business Plan as it pertains to Nuclear Operations include the following:

   - Ensuring the success of Pickering Optimized Shutdown of all six Pickering units, operating Unit 1 and Unit 4 to 2024 and Units 5-8 to 2025.”

   From Exhibit F2-1-1, page 25, lines 1-4:

   “This application reflects OPG’s plans to safely optimize the shutdown of Pickering by operating all six units until September 2024, five of the six units through 2024 and the remaining four units until December 2025, as per the 2020-2026 Business Plan (“Optimization”). OPG will require CNSC approval to operate the remaining four units past 2024 until December 2025.”

   But from Exhibit H1-1-1, Updated 2021-03-12 DEFERRAL AND VARIANCE ACCOUNTS at page 40, lines 8-14 it reads:

   “OPG proposes the deferral account because it anticipates that there will be future changes to the Pickering station EOL dates, for financial accounting purposes in accordance with US GAAP, once necessary criteria are met. In particular, this includes the accounting EOL date for Pickering Units 5-8, which is expected to be reassessed in the future when further technical work and the status of the CNSC’s approval process are considered to provide sufficient high confidence, for depreciation purposes, with respect to the planned operation of the units beyond the current EOL date of December 31, 2024.”

(a) Is the evidence at Exhibit H1-1-1, page 40, lines 8-11 inconsistent with the references found at E2-1-1 and F2-1-1, as excerpted above? Please explain any inconsistencies in the evidence related to the EOL dates for Pickering units.
(b) What is the risk/chance that the CNSC will not approve the proposed EOL dates for Pickering units 5-8?
(c) What are the consequences and risks if the CNSC does not approve the proposed EOL dates for Pickering units 5-8?

F2-OAPPA-08

8. Exhibit F2-8-1, Page 1, lines 21-22 describe OPG's costs for preliminary planning and preparation of SMR technology approximating $272M in 2020 and 2021. OPG proposes to recapture these OM&A development costs in the NDVA despite their non-consideration in EB-2016-0156.

a) Please provide further context, background, and basis for requiring rate payer funding of this research and development project, including any legislative, regulatory, prior case precedence or Board rulings.
b) Is this initiative the result of an instruction or request from the Province? If so, please provide the specific request.
c) Has OPG considered this project within the context of its non-regulated business plans or strategies? If so, please elaborate.
d) If the SMR were to realize commercial viability, particularly beyond Ontario, please confirm OPG's intentions concerning rate payer compensation for the initial investment(s) and the rate payers' share of future revenues.

G2-OAPPA-09

9. Exhibit G2-2-1, Table 1 provides that net revenues from the Bruce Power Lease are forecast to be negative for the duration of the IR (2022-2026), for a total gross loss of $217 million which is expected to be reclaimed from Ontario's ratepayers. OAPPA understood from EB-2016-0152 that the principal reason for this loss was precipitated by the extension of the December 2015 amendment to the Bruce Power Lease Agreement, extending the term to 2061 and to consequently increasing the Accretion expense. It was also understood that the 2015 Amendment removed OPG's material obligations specific to OPG payment obligations specific to HOEP settlements.

a) Please provide an annual estimate of the avoided HOEP to contract rate settlement payments that would have occurred during the IR had the pre-2015 obligation persisted.
b) Please provide a detailed explanation as to how the annual Accretion expenses are determined during the IR period.

G2-OAPPA-10

10. Exhibit G2-2-1, Table 4 reflects a Net Book Value (NBV) for the Bruce Nuclear Facility at the start of the IR period of $2.7527B and a closing NBV of $2.3351B by the end of the IR period, as affected by an annual depreciation expense of ~$69.6M. However, we know that Bruce G6 has started its refurbishment program and will be returned to service in 2023, and there does not appear to be any apparent change in the asset value in 2023 or in the later years of the IR.

a) How is Bruce Power's investment of an estimated $13B being captured in the NBV calculation, depreciation, and associated expenses?
b) If it is not being captured, how is such fundamental change in the investment value of an OPG-owned asset being accounted for?

I1-OAPPA-11

11. Reference: Exhibit I1-01-02 Updated 2021-03-12

Please add to *Table 1 Annualized Residential Consumer Impact EB-2016-0152 to EB-2020-0290* or create a new table to provide the corresponding amounts for General Service and Large Use rate classes re consumer impacts, for the service areas of Toronto Hydro-Electric System Limited, Hydro One Networks Inc., London Hydro Inc., Alectra Utilities Corporation – Horizon Rate Zone, Hydro Ottawa Limited, Kingston Hydro Corporation, and Synergy North.