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October 3rd, 2016

By EMAIL and RESS

Ontario Energy Board
2300 Yonge Street
27th Floor
Toronto, Ontario
M4P 1E4
Attn: Kirsten Walli, Board Secretary

Re: EB-2016-0152 – Ontario Power Generation Inc. – OAPPA Interrogatories

Dear Ms. Walli,

We are representing the interests of the Ontario Association of Physical Plant Administrators ("OAPPA") in this Board matter. Enclosed, please find interrogatories on behalf of OAPPA.

Yours very truly,

Scott Walker, PEng, MBA
President and CEO

cc Applicant and Intervenors (by Email)

EB-2016-0152

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 for its prescribed generating facilities between 2017 and 2021.

INTERROGATORIES OF

ONTARIO ASSOCIATION OF PHYSICAL PLANT ADMINISTRATORS

("OAPPA")

October 3rd, 2016

OAPPA INTERROGATORIES

ONTARIO POWER GENERATION INC.

2017 TO 2021 PAYMENT AMOUNTS

CASE EB-2016-0152

Item 1: Have ratepayers been sufficiently informed and to what extend does the DRP create financial obligations for future ratepayers beyond the Test Period.

1-OAPPA-1

Re: Exhibit D2-2-1, Darlington Refurbishment Program Overview, page 2, lines 13 – 15, footnote #1
Exhibit A1-2-1, Application, Page 4, line 1
Exhibit A2-2-1, Attachment 1, "OPG's 2016-2018 Business Plan", Unlabeled Chart, page 5 of27)

The DRP Overview Exhibit advises that the Minister of Energy formally endorsed the project in January 2016, and further provided a footnote link to the Provincial Government's Newsroom release from the Ministry of Energy. While the release identified the expected budget of $12.8B, consistent with the Application, it also states "*OPG electricity rates are regulated by the Ontario Energy Board (OEB). All costs for the Darlington refurbishment will be subject to review and approval by the OEB through a public and transparent process to ensure they are prudently incurred. The average cost of power from Darlington nuclear units post-refurbishment is estimated to range between $72/MWh and $81 MWh, or 7 and 8 cents per kilowatt hour*". Familiar with the release prior to its Exhibit reference, we were therefore surprised to find that the requested nuclear rates in the Application for 2020 and 2021 are $90.01/MWh and $99.91/MWh, respectively. We note that these requested rates also include the lower depreciated rates of Pickering NGS and further note that the DRP will have only seen the completion of Darlington Unit 2 refurbishment by the end of the Test Period (but potentially with some progress expenses incurred for Units 3 and 1).

a) Can you please provide the Nuclear Payment amount request table, differentiating the Darlington and Pickering-specific rates, for each of the years of the Test Period? Can you provide similarly for the post-Test Period?
b) Was sufficient information concerning the actual nuclear rate impacts provided to the Ministry before their endorsement was received?
c) Please confirm that if the Board approves OPG's revenue requirements as filed and agrees to the proposed smoothing methodology for OPG's nuclear rates: the nuclear rate will continue to increase at a rate of 11.1% per year, in each of the 5 years following the Test Period (declining thereafter)? Would the expected nuclear rates, before riders, be as follows: $111/MWh, $123.3/MWh, $137/MWh, $152.2/MWh and $169.1/MW, respectively between 2021 and 2026?

1-OAPPA-2

Re: Exhibit D2-2-9, Program Execution, Page 9

Annual public status reports will be published via OPG's website, for the duration of the DRP. With Unit 2 outage imminently, pending:

a) Please confirm what quality compliances metrics are to be used?
b) When will the first annual reports be available and will future reports be available by the same anniversary date?

Issue 2: Seeking clarifying regulated revenue source payments, hydraulic revenue amounts and ability to influence non-regulated revenue via regulated asset control.

2-OAPPA-1

Ref: Exhibit B1-1-1, Section 2.0 Overview and Table 1 (or Exhibit I1-1-2, Table 11)
Exhibit A2-1-1, Attachment 3, "*OPG's 2015 Annual Report*", Pages 11, 12, 13 (Page 5, 7, 8 of Report)

Acknowledging that OPG earns its regulated revenues firstly from the IESO-controlled Hourly Ontario Electricity Price (HOEP), monthly wholesale market payments and then as true-up from the monthly Global Adjustment payments, for each of the years of the Test Period:

a) What will be the approximate percentage split between HOEP-revenue and GA-revenue for each of (1) nuclear and (2) hydraulic?
b) Summary information for nuclear is well presented and readily located, but hydraulic revenue is difficult to discern. Can you please confirm payment amounts for regulated Hydraulic, in addition to those requested for nuclear, are as follows:

	2017	2018	2019	2020	2021
Revenue Request ($M)	$1,304	$1,323	$1,299	$1,318	$1,338

In 2015, OPG's contracted, non-regulated generation revenue was $264 million of its total $689 million, or ~ 38% of its total annual revenue. Conversely, electricity generated from the contacted generation was only 3.1 TWh of its total production of 78 TWh, or ~ 4% of its total production.

a) What is the approximate split of these contracted revenues between Global Adjustment payments and HOEP earnings?
b) When the Thunder Bay G.S. contracted generation agreement expires during the Test Period, is it management's expectation that it will be re-contracted or will it become part of the regulated generation assets?
c) What assurances can management provide that as the dominant electricity producer in the province, that its regulated nuclear and hydraulic generation assets are not being used to influence HOEP in a manner that benefits its non-regulated revenue?

Item 3: Is the cost sharing between ratepayers and shareholders fair and properly allocated and is the overall increase in nuclear payment amounts including rate riders reasonable given the overall bill impact to customers.

3-OAPPA-1

Ref: Exhibit G2-2-1, Bruce Generating Revenues and Cost, Section 2.0, Page 1 Lines 21 and 22 and Table 1
Exhibit C2-1-1, Nuclear Waste Management … Liabilities, Section 5.0

Net earnings from the Bruce Lease are forecasted to be negative for the duration of the Test Period, for a total gross loss of $401 million ($66.1 + 74.3 + 85.9 + 82.1 + 93.1) which is expected to be reclaimed from Ontario's ratepayers. We understand that the majority of this loss is due to Accretion, which added a further C$ 2.7475 Billion in liabilities, as a consequence of the IESO and Bruce Power refurbishment agreement extending the facility's EOL from 2019 to 2061.

a) Will revenue generally persist at the levels suggested by Table 1, adjusted for CPI, beyond the Test Period years? Consequently, will the [revised] Bruce Lease arrangement continue to operate at a loss until 2061?
b) Is the transfer of Accretion and other costs away from the corporations owning Bruce Power to Ontario's rate payers appropriate?
c) Are other cost-sharing options available and is it reasonable, or possible, to expect any favourable changes to the cost-sharing terms of the Lease arrangement in the years after the Test Period?

3-OAPPA-2

Ref: Exhibit I1-1-2, Consumer Impact, Chart 1, Page 2, Table 1 and Attachment 1, Table 11

OPG's annualized residential consumer bill impacts are calculated as if there is only one common consumer rate class, which we believe to be understated. Using this same methodology, the following is the Customer Impact Table for OAPPA for the 5-year period.

OPG Rate Impact on OAPPA	OAPPA				
	2017	2018	2019	2020	2021
	OPG Proposed 5/27/2016	OPG Proposed 5/27/2016	OPG Proposed 5/27/2016	OPG Proposed 5/27/2016	OPG Proposed 5/27/2016
Annual OAPPA Total Cost $ (1) (2)	$ 182,079,599	$ 182,079,599	$ 182,079,599	$ 182,079,599	$ 182,079,599
OPG's Annual Rate Impact on OAPPA $	$ (1,715,672)	$ 2,290,028	$ 1,403,520	$ 2,507,234	$ 2,616,467
Total OAPPA Annual Cost $	$ 180,363,926	$ 184,369,626	$ 183,483,118	$ 184,586,833	$ 184,696,065
Cummulative Increase on OAPPA	$ (1,715,672)	$ 574,355	$ 1,977,875	$ 4,485,109	$ 7,101,576
Cummulative Unit Cost $/MWh Increase on OAPPA	$ (1.63)	$ 0.55	$ 1.88	$ 4.27	$ 6.76

(1) OAPPA Annual Consumption 1,050,338MWh including line losses
(2) Typical monthly bill is based on the OEB "Bill Calculator" for estimating monthly electricity bills (using Time of Use pricing), available at: http://www.ontarioenergyboard.ca/OEB/Consumers/Electricity/Your+Electricity+Utility.
Based on forecast demand for 2017 (137.6 TWh) from Table 3.1 of IESO 18-Month Outlook Update for April 2016 to September 2017, published March 22, 2016.
Calculated based on OPG_Ex I1-1-1_Att 1_OPG_Revenue Requirement Work Form_20160527 -OPG Bill Impacts - Spreadsheet 11

However, since January 1, 2011, there have been two broad rate classes: customers in the Global Adjustment Class A and customers in the Global Adjustment Class B. Residential consumers are in Class

B. By virtue of the different cost allocation methods used for the two classes, Class B pays a higher share of Global Adjustment costs than does Class A and so would experiences a higher rate impact than other Class A customers. OPG rate impacts will affect the Global Adjustment costs and the result is that OPG's single-class method underestimates the magnitude of certain consumer bill impacts.

a) Please provide an accurate portrayal of the bill impacts over the Test Period, accounting for the difference in Global Adjustment treatments, for three typical consumer classes (1) residential, (2) commercial general service, and (3) large consumer. If possible, the last consumer classification should include those estimated amounts, that would now be covered by the province's September 14, 2016 provincial government announcement[1], expanding the Industrial Conservation Incentive (and Class A consumer coverage), expected to take effect July 1, 2017.

Item 4: Is the production forecast sufficient for the Test Period.

4-OAPPA-1

Re: Exhibit E2-1-1, Production Forecast and Methodology Nuclear, Section 2.0, Page 4, lines 3 to 14
Exhibit D2-1-3, Capital Projects Nuclear Operations, Page 6, lines 27-31 and Page 7, lines 1 to 7

The production forecast considers eight (8) mini-outages of 20 days in duration each, to replace 16 PHT pumps during the Test Period. We understand that the June 2015 failure of a PHT pump took 25.75 days to replace, resulting in 0.54 TWh of lost production (or ~ 0.02097 TWh/day).

a) As they have been specifically identified, are we correct in our understanding that these eight outages will occur independently of the Units 2, 3 and 1 DRP outages, scheduled in 2016, 2020 and 2021 respectively or has any consideration been given to replacing these PHT's during the DRP unit over-hauls, concurrently?
b) Are we correct in our understanding that these eight outages will result in 8 outages x 20 days x 0.02097 TWh / outage day = 3.355 TWh of non-production during the Test Period? If not, can you advise as to actual production loss represented in the schedule?
c) Assuming a planned outage would take less time, what is the estimated difference in lost production under a failed-PHT scenario, versus a planned replacement scenario?
d) Is it appropriate for the Ontario ratepayer to bare 100% of the lost production cost and risk?

Item 5: Does the DRP have sufficient contingencies.

5-OAPPA-1

Re: Exhibit D2-2-3, Major Work Bundle Structure and Contracts, Page 16, lines 5 to 12 and 22

One of the major cost 'extras' and unanticipated schedule delays during Darlington's initial construction was caused by a failed turbine shaft, which if contemplated in the DRP would represent a physically monolithic and expensive component of the Generator Turbine Work Bundle. We note that the equipment component cost estimate of $333M is unlikely to include sufficient funds for any replacement of the turbine shaft. We further note that other consistently strained components of the generating process (e.g. PHT) are being replaced during the Test Period.

[1] http://www.energy-manager.ca/news/ontario-expanding-industrial-conservation-initiative-2740

a) Can you confirm that none of the Turbine shafts is being replaced?
b) What is your confidence level that the shafts will not need to be replaced and what is the expected EOL for each of the shafts?
c) If during the outage(s), a turbine shaft is found to be in need of replacement, please advise:
   i. What is the estimated replacement cost of a turbine shaft?
   ii. Is there a Canadian manufacturer (still) that could construct the shaft?
   iii. How quickly would a new shaft be manufactured and/or how much delay would be invoked in the schedule on a best/worst case scenario basis?
d) Please confirm if the $333M cost for equipment supply component and $284M cost for the fieldwork (Turbine Generator Work Bundle) for each unit, or for all 4 units combined?

5-OAPPA-2

RE: Exhibit D2-2-9, Attachment 2, "*Modus Strategic Solutions & Burns McDonnell Report to Darlington Refurbishment Committee Board of Directors Darlington Nuclear Refurbishment Project*", Page 20.

This November 12, 2015 Report to OPG Board Committee, recommended a total contingency amount of $2.506 B as based on a P90 confidence analysis.

a) Please provide the underlying reasons and approximate cost differential (by reason), as to why the Application has a lower contingency amount of $1.7B?

The report suggested that the P50 & P70 values also be considered.

b) Was a P70 (70% confidence) analysis done?
c) What is the P70 contingency amount?

5-OAPPA-3

RE: Exhibit D2-2-11, Independent Studies, Attachment 3, Testimony of Dr. Patricia Galloway, Pegasus Global Holdings Inc., Page 8.

Dr. Galloway suggests that a P90 confidence value on the contingency amount was reasonable for the DRP, however also suggested that there was no industry best practice for mega-projects. Specifically, based upon OPG's recently completed Sir Adam Beck Tunnel project:

a) What was the confidence level used and what was the original contingency amount?
b) What were the underlying reasons for using this original confidence level?
c) What was the final contingency amount spent upon project completion?
d) What were the lessons learned (from Beck) that would allow for the use of a P90 on the DRP?