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.

Argument and Submissions of

ONTARIO ASSOCIATION OF PHYSICAL PLANT ADMINISTRATORS

("OAPPA")

May 29th, 2017

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1.0 INTRODUCTION

These submissions are made on behalf of the Ontario Association of Physical Plant Administrators ("OAPPA"). OAPPA is a non-profit organization representing Ontario's 20 universities, who collectively consume more than 1 TWh of electricity annually while operating efficient campuses as needed to sustain the pursuit of higher learning and post-secondary education in the province.

Approximately ½ of OAPPA's electricity is supplied from Ontario Power Generation's ("OPG's") regulated hydraulic and nuclear facilities and therefore the financial consequences of this Application are significant to OAPPA, inclusive of the early stages of a C$12.8B capital refurbishment project of the Darlington Nuclear Generating Station ("DNGS") and a $16.8B nuclear revenue requirement during the 2017 to 2021 period.

In preparing these submissions, we have notably benefited from both the Staff's comprehensive submissions and from the collaborative efforts of many of our fellow intervenors to this Application. We have subsequently endeavoured to avoid duplication and to more efficiently utilize scarce intervenor resources available for the analysis of this large and complex Application.

We have also elected to defer to the government's authority, specific to Ontario Regulation 53/05 in our further consideration of the Application's issues and our submissions accordingly. These submissions therefore focus on the components not otherwise knowingly duplicated by others, but which OAPPA still deems need be adjusted to ensure that the Applicant's rates for the next 5 years are just and reasonable.

5.0 NUCLEAR PRODUCTION FORECAST

5.1 Background

Issue 5.1 *(Primary) - Is the proposed nuclear production forecast appropriate*?

OPG's proposed test period (2017-2021) production forecast is presented in the table below:

Nuclear Production Forecast						
	2017	**2018**	**2019**	**2020**	**2021**	**Total (2017-2021)**
Pickering (TWh)	19.1	19.2	19.4	19.6	18.8	96.1
Darlington (TWh)	19.0	19.3	19.7	17.7	16.6	92.3
Total Production (TWh)	38.1	38.5	39.1	37.3	35.4	188.4

The total nuclear production forecast for the period 2017 to 2021 is 188.4 TWh.

OPG's proposed outage schedule for Darlington NGS (only) for the test period (2017-2021), as underpins the above production forecast table is summarized in the following table:

Nuclear Outage Schedule and Production Impact						
Year	Outage Reference	Unit Affected	Description	Outage Duration (Days)	Forecast Production (TWh) Impact Due to Outage	Revenue Impact of Outage ($M)
2017	D1711	Unit 1	Planned Outage	108.4	2.3	177.5
	DNRU2	Unit 2	Refurbishment Outage	365	7.8	597.6
	D1731-PD	Unit 3	Planned Derate	2.5	0.1	4.1
	D1732	Unit 3	PHT Pump Motor Outage	20	0.4	32.7
	D1741-PD	Unit 4	Planned Derate	2.5	0.1	4.1
	D1742	Unit 4	PHT Pump Motor Outage	20	0.4	32.7

Nuclear Outage Schedule and Production Impact

Year	Outage Reference	Unit Affected	Description	Outage Duration (Days)	Forecast Production (TWh) Impact Due to Outage	Revenue Impact of Outage ($M)
	Total (2017)			518.4	11.1	848.7
2018	D1811	Unit 1	PHT Pump Motor Outage	20	0.4	33.7
	DNRU2	Unit 2	Refurbishment Outage	365	7.8	614.9
	D1831	Unit 3	Planned Outage	103.3	2.2	174
	D1841	Unit 4	PHT Pump Motor Outage	20	0.4	33.7
			Total (2018)	508.3	10.9	856.3
2019	D1911	Unit 1	PHT Pump Motor Outage	20	0.4	36.4
	D1912 -PD	Unit 1	Planned Derate	2.5	0.1	4.5
	DNRU2	Unit 2	Refurbishment Outage	365	7.8	663.6
	P1931 -PD	Unit 3	Planned Derate	2.5	0.1	4.5
	D1941	Unit 4	Planned Outage	99.1	2.1	180.2
	Total (2019)			489.1	10.5	889.2
2020	D2011	Unit 1	Planned Outage	108.2	2.3	204.6
	DNRU2	Unit 2	Refurbishment Outage	45	1	85.1
	D2022-PD	Unit 2	Planned Derate	2.5	0.1	4.7
	D2021	Unit 2	Post Refurb Mini Outage	55	1.2	104
	DNRU3	Unit 3	Refurbishment Outage	321	6.9	606.9
	D2042-PD	Unit 4	Planned Derate	2.5	0.1	4.7
	D2041	Unit 4	PHT Pump Motor Outage	20	0.4	37.8
	Total (2020)			554.2	11.9	1047.7
2021	DNRU1	Unit 1	Refurbishment Outage	200	4.3	394.4
	D2121	Unit 2	Post Refurb Mini Outage	31.2	0.7	61.5
	D2122-PD	Unit 2	Planned Derate	2.5	0.1	4.9
	DNRU3	Unit 3	Refurbishment Outage	365	7.8	719.8
	D2142-PD	Unit 4	Planned Derate	2.5	0.1	4.9
	D2141	Unit 4	PHT Pump Motor Outage	20	0.4	39.4
	Total (2021)			621.2	13.3	$1,225
Total for the Test Period (2017 to 2021)				2,691.2	57.7	$4,867

OPG's proposed Darlington NGS (only) total reduction to the nuclear production forecast for the test period 2017 to 2021, due to planned outages is 57.7 TWh; this further equates to lost revenue (and therefore additional rate payer cost) of $4.867 Billion.

5.2 OAPPA Submission

It is OAPPA's assessment that OPG's scheduling of certain outages, particularly those for the Darlington NGS Primary Heat Pump (PHT) Motor replacements are not being done in parallel with numerous other planned outages scheduled during (and beyond) the test period, that would reduce production losses. OAPPA submits that the OEB should increase the nuclear production forecast for Darlington NGS (DNGS) production forecast by no less than 2.95 TWh[1] for the test period.

DNGS PHT Pump Replacement Outages – Alternative Planning Options

OAPPA acknowledges OPG's requirement to replace the PHT pumps, but is unsettled that the unexpected 2015 failure of the precipitating unit had not been preceded by routine testing, analysis or maintenance reporting which would arguably have seen replacements initiated, on a planned-basis, prior to the current period(s). While the absence of prior-period assessment and planning might suggest a measure of accountability on OPG's part, the plethora of other planned outages during the test period affords OPG with an opportunity to re-schedule the PHT pumps concurrently such that there are no additional production losses.

OAPPA suggests that there are 2 alternative PHT pump replacement planned outage scheduling options, as follows:

[1] Tr Vol 15 pages 121, line 12.

- Re-schedule the PHT pump replacements to occur concurrently with their specific Unit’s Refurbishment, as proposed under the DRP, or
- Alter the PHT Pump Replacement outages to align concurrently with the individual Units’ 100 day, 3-year mandated CNSC planned Routine Outage schedule(s).

The following table summarizes OPG’s currently proposed DRP, PHT Pump and Planned Unit Outage schedule during the test period:

	2017	**2018**	**2019**	**2020**	**2021**
Routine Outages (Unit, Outage Number and Days)	Unit 1 (D1711, 108 days)	Unit 3 (D1831, 103 days)	Unit 4 (D1941, 99 days)	Unit 1 (D2011, 108 days)	None
DRP (Unit, Outage Number and Days)	Unit 2 (DNRU2, 365 days)	Unit 2 (DNRU2, 365 days)	Unit 2 (DNRU2, 365 days)	Unit 2 (DNRU2, 45 days)	Unit 1 (DNRU1, 200 days)
				Unit 3 (DNRU3, 321 days)	Unit 3 (DNRU3, 364 days)
PHT Outage (Unit, Outage Number and Days)	**Unit 3** (D1732, 20 days)	**Unit 1** (D1811, 20 days)	**Unit 1** (D1911, 20 days)	**Unit 4** (D2041, 20 days)	**Unit 4** (D2141, 20 days)
	Unit 4 (D1742, 20 days)	**Unit 4** (D1841, 20 days)			
PHT Outage (TWh)	0.84275	0.84275	0.421375	0.421375	0.421375

An alternative PHT Pump Outage schedule is depicted in the following table, which includes the anticipated increases in the DNGS production forecast and expected revenue to OPG (and elimination of rate payer costs):

<table>
<tr><th></th><th>2017</th><th>2018</th><th>2019</th><th>2020</th><th>2021</th></tr>
<tr><td>Routine Outages (Unit, Outage Number and Days)</td><td>Unit 1 (D1711, 108 days)</td><td>Unit 3 (D1831, 103 days)</td><td>Unit 4 (D1941, 99 days)</td><td>Unit 1 (D2011, 108 days)</td><td>None</td></tr>
<tr><td rowspan="2">DRP (Unit, Outage Number and Days)</td><td>Unit 2 (DNRU2, 365 days)</td><td>Unit 2 (DNRU2, 365 days)</td><td>Unit 2 (DNRU2, 365 days)</td><td>Unit 2 (DNRU2, 45 days)</td><td>Unit 1 (DNRU1, 200 days)</td></tr>
<tr><td></td><td></td><td></td><td>Unit 3 (DNRU3, 321 days)</td><td>Unit 3 (DNRU3, 364 days)</td></tr>
<tr><td rowspan="4">(OAPPA-Suggested) PHT Outage (Unit, Outage Number and Days)</td><td rowspan="2">Unit 1 (D1811, 20 days)</td><td rowspan="2">Unit 3 (D1732, 20 days)</td><td>Unit 4 (D1742, 20 days)</td><td rowspan="4">Optional Unit1 Outages (either D1911, 20 days or D1811, 20 days is not completed in 2017)</td><td rowspan="4"></td></tr>
<tr><td>Unit 4 (D2041, 20 days)</td></tr>
<tr><td rowspan="2">Unit 1 (D1911, 20 days)</td><td rowspan="2"></td><td>Unit 4 (D1841, 20 days)</td></tr>
<tr><td>Unit 4 (D2141, 20 days)</td></tr>
<tr><td>Increase in Proposed Production Forecast (TWh)</td><td>0.84275</td><td>0.84275</td><td>0.421375</td><td>0.421375</td><td>0.421375</td></tr>
<tr><td>Increase in Production Revenue (Rate Payer Savings)</td><td>$ 65.4M</td><td>$ 67.4M</td><td>$ 36.4M</td><td>$ 37.8M</td><td>$39.4M</td></tr>
</table>

If the 20 day, PHT Pump replacements are started concurrently with their respective Unit's Routine Outages[2], which range in longer durations of between 99 and 108 days, there is no requirement for additional outage time beyond that of the Routine Outage. As demonstrated by the above table, OAPPA believes that OPG's rescheduling of the PHT Outages is achievable and would still provide further optional flexibility, for example by the optional scheduling of the D1911 or D1811 outages in 2019 if, or as,

[2] In the instance of Unit 4 PHT outages, resource constraints might not allow concurrent replacement of all pumps, but could still be completed consecutively, within the 99 day duration of Routine Outage D1941.

required. Additionally, OAPPA remains unconvinced of the prioritization given by OPG in its original (proposed) scheduling of the proposed PHT pump outages.

DNGS PHT Pump Replacement Outages – Financial Impact to Rate Payers

OAPPA is concerned with the current planning of all nuclear outages as it recognizes that the OEB will approve an annual revenue requirement for OPG independently of its actual production commitments. OPG is seeking approval of a nuclear revenue requirement of $16.8 billion over the period 2017-2021; if approved, the cost of these requirements will be spread across the rate base, regardless of OPG's actual production (once approved). Therefore in very fungible terms, OPG's outages represent real and direct costs to rate payers.

The rate payer cost, as must be paid to OPG for its lost production, due to the proposed PHT Pump outage schedule is $246.4M over the test period. OAPPA further asserts that the real rate payer cost is appreciably more – being no less than twice - as this lost DNGS production, purported by OPG to be baseload power and therefore always needed, must otherwise be replaced and subsequently purchased from other IESO market participants. Therefore, the real rate payer cost of these DNGS PHT pump outages is at least $492.8 million during the test period.

DNGS PHT Pump Replacement Outages – Pump Failures do not represent a Safety Risk

OAPPA was originally concerned that suggesting a revision to OPG's outage schedule could in some way jeopardize equipment, personnel or public safety. However, OPG repeatedly[3] confirmed that a PHT Pump failure would not do so and further, such an event would be highly unlikely to cause a poisoning of the reactor fuel bundles.

A failure of any PHT Pump does not represent a safety risk for the following reasons:

- Two (2) PHT pumps are connected in series – meaning that the second unit will continue to function during a Unit trip, as precipitated by a PHT pump failure;
- The CANDU design includes other systems, redundant pumping and shutdown cooling pumps that would add water to the cooling system[4];
- Thermo-syphoning is a fundamental design benefit of the CANDU reactor, such that in the extreme, for example during a Class IV electrical systems failure (wherein all four PHT Pumps cease to operate), the thermo-syphoning phenomena naturally and safely cools the reactor core;

DNGS PHT Pump Replacement Outage – OPG's Obligations to Rate Payers and Requirement to Align with Shareholder Memorandum Agreement

OAPPA contends that diligent scheduling of outages, such as the DNGS PHT pumps is not only consistent, but required by OPG and is supported by its Shareholder Memorandum of Agreement[5].

Section 4 of the Shareholder Agreement addresses OPG's specific mandate and states the following in 4.7 (b):

> "*The Province of Ontario and the Ministry supports the role of public power and mitigating prices in Ontario and in doing so:*

[3] TC Volume 2, Page 152, lines 14 to 18; Tr Volume 15, Page 108, lines 23 to 27 and Page 109 lines 13 to 21.
[4] Tr Vol 15, Page 108
[5] Exhibit A1-4-1, Attachment 2

> *(b) mandates that OPG plan and operate its generation facilities based on good utility practice recognizing safety, legal, regulatory, environmental and market factors*".

Mitigation of prices should necessarily involve operating the DNGS at optimal levels and in the pursuit of minimal production disruption. OAPPA contents that outage management would necessarily form part of this mandate. For further clarity, the Shareholder Agreement states the following in 4.9:

> *"OPG shall serve the public interest and operate in a way that achieves a commercial rate of return, moderates overall electricity prices, and supports the efficient operation of the electricity market".*

OAPPA contends that any planned removal of low-priced baseload power, due to non-concurrent outage scheduling, where otherwise feasible, is not consistent with the mandate of its Shareholder Agreement. OPG's currently proposed outage schedule requires rate payers to replace the electricity that they have already paid for once, with more expensively priced electricity from the market.

OAPPA has provided one possible alternative outage scheduling option that would increase the DNGS production forecast, acknowledging other such planning options are highly probable and should be aggressively sought out. Accordingly, OAPPA believes that OPG should reschedule its outages in order to minimize rate payer impact and requests that the OEB increase the DNGS production forecast by no less than 2.95 TWh in order to incent OPG to do so.

7.0 ASSET SERVICE FEES AND OTHER REVENUES

7.1 Background - Bruce Nuclear Generating Station

Issue 7.2 (*Primary) - Are the test period costs related to the Bruce Nuclear Generating Station, and costs and revenues related to the Bruce lease appropriate*?

OPG's application reflects its December 4, 2015 amended Bruce Lease agreement that extended the lease term in accordance with its Shareholder's negotiation of the Bruce NGS refurbishment and life extension to 2061 with the privately-owned and non-OEB regulated operator, Bruce Power Limited Partnership[6]. In the 10 years preceding the test period and including three separate rate applications by OPG, total net revenues have been material, cumulatively positive and otherwise positive in each year, except 2.

However, net revenue during the test period is consistently negative. Since the date of the original application, OPG has twice amended its loss forecast of the Bruce Lease net revenues. The original May 2016 application evidence proposed a net loss of $401M, its December 2016 amendment proposed a loss of $123M and its latest March 2017 amendments suggested a loss of $174M. A summary of the changes in the proposed Bruce Lease net revenues is included in the following table:

	2017 ($M)	2018 ($M)	2019 ($M)	2020 ($M)	2021 ($M)	Total ($M)
Bruce Lease Revenues (2016-05-27)[7]	251.1	246.5	245	257.4	223.6	1,223.6
Bruce Lease Costs (2016-05-27)	317.3	320.9	330.8	339.5	316.8	1,625.3
Bruce Lease net Revenues (2016-05-27)	(66.2)	(74.4)	(85.8)	(82.1)	(93.2)	(401.7)

[6] Bruce Power Limited Partnership, or Bruce Power is owned by Borealis, TransCanada Corporation, BPC Generation Infrastructure Trust (OMERS), and in minority by the Power Workers Union and the Society of Energy Professionals.
[7] Ex G2-Tab 2-Schedule 1-Table 1

	2017 ($M)	2018 ($M)	2019 ($M)	2020 ($M)	2021 ($M)	Total ($M)
Bruce Lease Revenues[8] (2016-12-20)	216	210.9	208.5	219.8	188.7	1,043.9
Bruce Lease Costs (2016-12-20)	232.9	228	235.9	243.5	226.8	1,167.1
Bruce Lease net Revenues (2016-12-20)	(16.9)	(17.1)	(27.4)	(23.8)	(38.1)	(123.3)
2017 ONFA Change Impact (2017-03-22)[9]	(2.0)	(6.0)	(10.2)	(14.4)	(18.6)	(51.2)
Bruce Lease Net Revenues After 2017 ONFA Impact (2017-03-22)	(18.90)	(23.10)	(37.60)	(38.20)	(56.70)	(174.50)

OPG currently proposes to capture the $51.2M difference over the test period, since its December 2016 proposal, in the Bruce Lease Net Revenues Variance Account for consideration in a future rate application.

7.2 OAPPA Submission

OAPPA seeks a disallowance for 50% of the proposed Bruce Lease Net Revenue loss, or a reduction of $87.25M in nuclear revenue requirements during the test period.

Albeit improved from the originally filed evidence loss of $401M, the $174M proposed to be collected from rate payers for losses due the Bruce Lease is nevertheless material. Through cross-examination it has been determined that the principal reason for the underlying loss is due to the extension of the Lease term to 2061. The extension of the term was prescribed by the Ministry, OPG's Shareholder and as negotiated with a privately-owned and non-OEB regulated corporation. OPG seeks to have $174M in costs borne by the rate payer, rather than by the privately-held corporation, which does

[8] Ex N1-Tab 1-Schedule 1-Table 7
[9] Ex C2-Tab 1 – Schedule 2 – Page 5 – Chart 1A – Line 9

not have Accretion (or other End-Of-Life) Liabilities. We view this as a transfer of wealth from the public, rate payers to private, corporate interests.

Bruce Power has publicly stated[10], concurrent with the December 2015 amended agreement that it expects to start refurbishing its 6 units in 2020, for a DRP-comparable cost of $13B and that it will have average prices of $77/MWh well beyond the test period[11]. Further, as OPG has evidenced, the majority of Bruce Power's employees (i.e. PWU and Society) will earn more than their OPG peers[12] throughout the test period.

In the absence of the shareholder's ability to enact a regulation (O'Reg. 53/05) requiring OPG to collect the imbalance from its rate payers, GAAP would necessarily prescribe such revenue losses to the company's Earnings Before Interest and Taxes, which would consequently and directly impact the dividend payment to the shareholder. Therefore the revenue collected by OPG from its ratepayers, net of interest and taxes will be returned to the shareholder, the cause and architect of the December 2015 Bruce Lease Agreement that has originated the loss.

During cross examination it was revealed that OPG's book value of the Bruce NGS asset would effectively equate to the amount of its liabilities[13] by the end of the test period. In layman's terms this effectively suggests that the Bruce NGS has no financial value beyond the test period. OPG further advised that it would be unlikely to find a

[10] K20.2 pages 5 through 7.
[11] K20.2 page 5 stated that Bruce Power's nuclear rate was $65.7/MWh in 2016.
[12] Exhibit F4, Tab 3, Schedule 1, Page 2, Lines 24 and 25 and Section 6.0, starting at page 23.
[13] Tr Volume 20 page 58, line 25 to page 59 line 6.

buyer for the asset[14], further confirming that the actual market value of the asset could be less than its book value.

OPG has opined that it could not predict if the net Lease Revenues would be positive or negative beyond the test period and until 2061, the end of the amended December 2015 Bruce Lease Agreement term[15].

OAPPA nevertheless acknowledges that (1) Ministerial policy, LTEP and other social-economic benefits may exist beyond the comparative rate payer costs of $174M for the Bruce Lease and (2) that the OEB cannot wholly deny OPG's claim to losses from the Bruce Lease agreement, pursuant to the Ministry's regulatory direction under O'Reg. 53/05.

OAPPA does however assert that the Board can assess the reasonableness of such costs and should acknowledge having the rate payer increase the annual shareholder dividend, by an amount equivalent to Bruce Lease costs, net of tax and interest costs is unjustifiable and seeks to have the Board reduce OPG's request by half.

Notably, while the March 22, 2017 filing update, as based on the 2017 ONFA amendment, imparts a net negative consequence to the Bruce Lease net revenues of $51.2M, OPG's prescribed facilities will benefit by an offsetting credit of $170.8M[16] during the test period. Without prejudice to the OEB's decision on the aforementioned, OAPPA supports the Staff's opinion[17], as detailed in its May 19th, 2017 that the now-known deferral and variance account credits be applied as a net revenue reduction

[14] Tr Volume 20, page 60, lines 7 to 14.
[15] Tr Volume 20, page 60 line 24 to page 61 line 6.
[16] Ex C2-Tab 1 – Schedule 2 – Page 5 – Chart 1A – Line 4
[17] Board Staff Submission, May 19, 2017, Section 8.2, pages 128 and 129.

during the period – however, with the exception of the Bruce Lease Net Revenue Variance Account. OAPPA is concerned by a three-time material change in the proposed Bruce Lease net revenue losses since the date of the original Application date and therefore believes that any negative financial rate payer consequences should be deferred and settled based on actual results in OPG's next Application.