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.

Compendium Materials Panel 3B (Nuclear Operations and Projects)

ONTARIO ASSOCIATION OF PHYSICAL PLANT ADMINISTRATORS

("OAPPA")

March 2017

Scott Walker
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OAPPA Consultant

EB-2016-0152

THE ONTARIO ENERGY BOARD

Ontario Power Generation Inc.

Application for payment amounts for the period from
January 1, 2017 to December 31, 2021

Hearing held at 2300 Yonge Street,
25th Floor, Toronto, Ontario,
on Tuesday, November 15, 2016,
commencing at 9:30 a.m.

TECHNICAL CONFERENCE

PHT motors cool the water, so just -- you know, in non-technical speak, it cools the water and in a nuclear operation that's a very, very important thing. And in addition, the fuel could be damaged as well if the PHT pump motors aren't running.

MR. WALKER: Is that a high probability?

MS. CARMICHAEL: What, the water wouldn't be cooled?

MR. WALKER: No, the fuel bundles would be damaged.

MS. CARMICHAEL: I think there is a probability. I don't know whether it's high or low, but it is one of the risks.

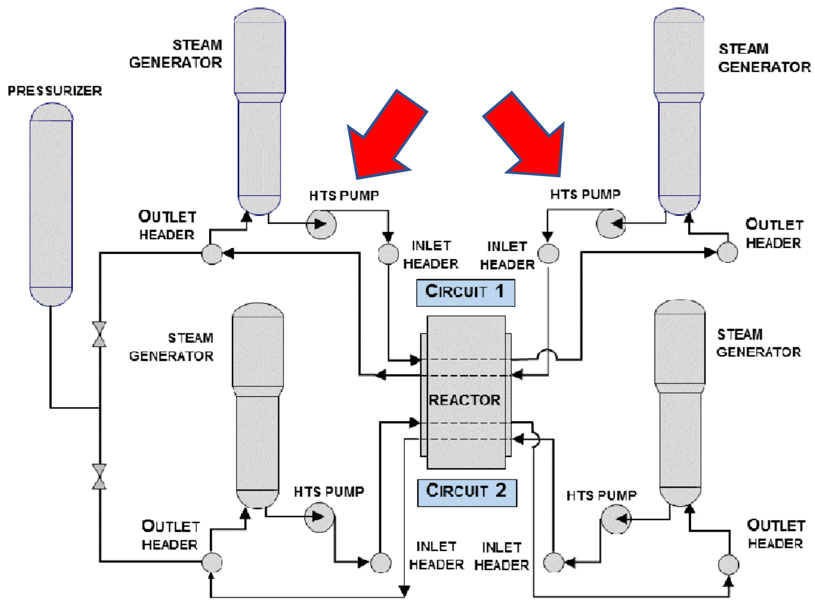
MR. WALKER: I am assuming there is appropriate monitoring systems to --

MR. LAWRIE: It's a low probability. The station is designed -- the design basis of the power plant is that you can have a loss of electrical supply and lose all four motors and still safely cool the unit. So that is a low probability.

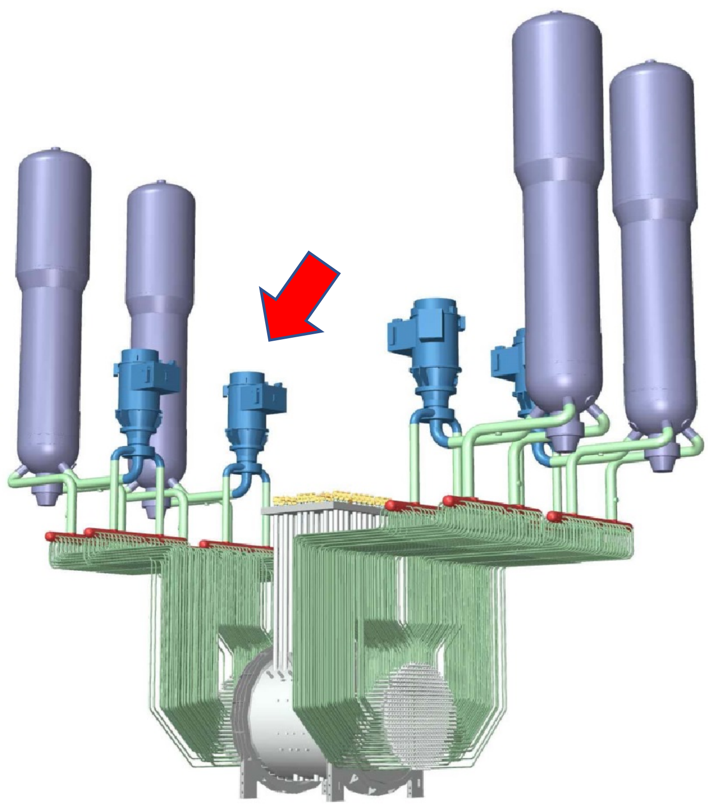
MR. WALKER: That eases my heart a little, thank you.

Your response to (d) says that OPG takes all of the production risk. Just to be clear, the production risks are after the outage production losses have been taken into account; is that correct?

MS. CARMICHAEL: So the plan is based on, like I had mentioned earlier today, a planning methodology that incorporates certain losses into the plan. But above and beyond that, if we do sustain losses, OPG bears complete risk for that 100 percent.



Darlington Primary Heat Transport (PHT) Schematic[1]



Typical CANDU Reactor and Heat Transport System[2]

[1] The Essential CANDU, Editor-in-Chief: Wm. J. Garland, Chapter 6, by Nikola Popov, UNENE, https://unene.ca/education/candu-textbook, 2015

[2] Ibid

Pickering Extended Operations. The outage OM&A costs for Pickering Extended Operations are set out in Chart 2 below.

Chart 1
Outage Frequency and Outage Costs 2013-2021

DESCRIPTION	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Darlington Unit Outages [1]	Unit 2; Unit 4	Unit 1	Unit 3 & Unbudgted Unit 1	Unit 4	Unit 1	Unit 3	Unit 4	Unit 1	None
Darlington Station Outages	VBO Preparation	VBO Preparation	Units 1-4 VBO Execution	None	None	None	None	None	None
Darlington Refurbishment Outages	None	None	None	Unit 2	Unit 2	Unit 2	Unit 2	Unit 2; Unit 3	Unit 3; Unit 1
Darlington PHT Pump Replacement Mini Outages				Unit 3	Unit 3; Unit 4	Unit 1; Unit 4	Unit 1	Unit 4	Unit 4
Darlington Post Refurbishment Outages	None	None	None	None	None	None	None	Unit 2	Unit 2
Pickering Unit Outages	Unit 1 (extended from 2012 [2]) Unit 5, 6	Unit 4,7,8	Unit 1, 5, 6 & Unbudgeted Unit 1, 8	Unit 4,7,8	Unit 1,5,6	Unit 4,7,8	Unit 1,5,6	Unit 4,7,8 [3]	Unit 1,5,6
Pickering Station Outages	None	None	None	None	None	None	None	VBO Preparation	Units 1-6 VBO
Pickering Mid-cycle Outages	Unit 4	None	None	Unit 1	Unit 4	Unit 1	Unit 4	Unit 1	None
Outage Costs ($Millions)	277.5	221.3	313.7	321.2	394.6	393.8	415.3	394.4	308.5

[1] Unit 2 will be subject to inspection and maintenance activities over the period 2017-2019 associated with a planned outage in accordance with OPG's aging and life cycle management programs, in addition to and separate from the refurbishment of the units.
[2] The Unit 1 outage was extended from 2012 into 2013 due to a fire in the Lube Oil Purifier system, resulting in the 2013 scheduled Unit 4 outage being shifted into 2014.
[3] The scope for the Unit 7 outage in 2020 is limited as it is solely for Pickering Extended Operations and therefore excludes "typical" planned outage.

Numbers may not add due to rounding.

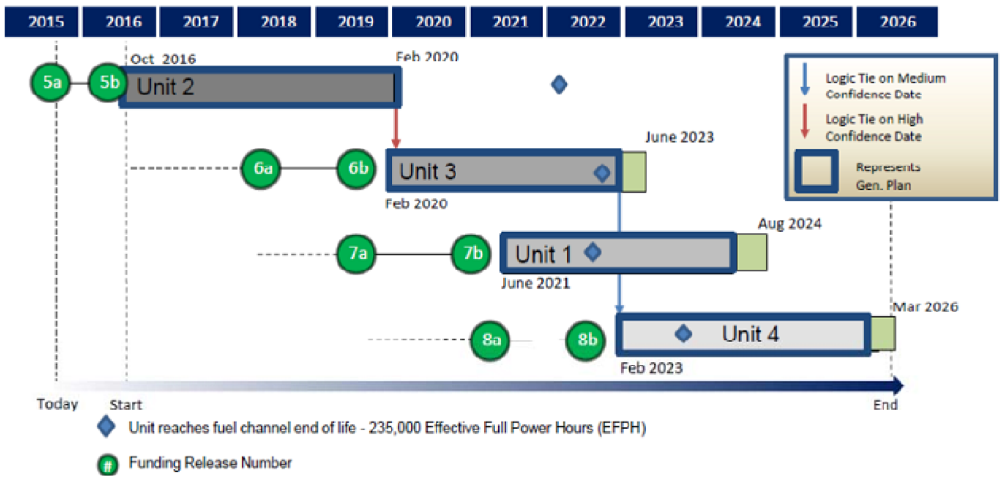
Table 1
Comparison of Production Forecast - Nuclear

Line No.	Business Unit	2013 Budget	(c)-(a) Change	2013 Actual	(g)-(c) Change	2014 OEB Approved[1]	(g)-(e) Change	2014 Actual	(k)-(g) Change	2015 OEB Approved[2]	(k)-(i) Change	2015 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Darlington NGS											
1	**TWh**	26.9	(1.8)	25.1	2.9	27.1	0.9	28.0	(4.7)	25.0	(1.7)	23.3
2	**Unit Capability Factor (%)**	88.8	(5.9)	82.9	9.0	93.5	(1.6)	91.9	(15.0)	86.3	(9.4)	76.9
3	**PO Days**	144.4	0.1	144.5	(52.4)	77.1	15.0	92.1	174.8	188.0	78.9	266.9
4	**FEPO Days**	0.0	39.8	39.8	(39.8)	0.0	0.0	0.0	7.7	0.0	7.7	7.7
5	**FLR (%)**	1.5	3.3	4.8	(3.3)	1.3	0.3	1.5	3.4	1.0	3.9	4.9
6	**FLR Days Equivalent**	19.7	41.8	61.5	(41.0)	14.6	5.9	20.5	36.9	12.7	44.7	57.4
	Pickering NGS											
7	**TWh**	21.1	(1.5)	19.6	0.5	21.9	(1.8)	20.1	1.1	21.6	(0.4)	21.2
8	**Unit Capability Factor (%)**	79.2	(5.5)	73.7	1.6	79.9	(4.6)	75.3	4.1	82.1	(2.8)	79.4
9	**PO Days**	303.5	(82.7)	220.8	64.1	292.9	(8.0)	284.9	65.2	287.9	62.2	350.1
10	**FEPO Days**	0.0	167.6	167.6	(112.2)	0.0	55.4	55.4	(14.8)	0.0	40.6	40.6
11	**FLR (%)**	8.1	1.6	9.7	1.0	7.8	3.0	10.7	(7.8)	5.5	(2.6)	2.9
12	**FLR Days Equivalent**	152.4	21.4	173.8	24.2	147.0	51.0	198.0	(146.3)	104.5	(52.8)	51.7
	Totals											
13	**Unit Capability Factor (%)**	84.3	(5.7)	78.6	5.7	87.6	(3.3)	84.3	(6.3)	84.0	(6.0)	78.0
14	**PO Days**	447.9	(82.6)	365.3	11.7	370.0	7.0	377.0	239.9	475.9	141.0	616.9
15	**FEPO Days**	0.0	207.4	207.4	(152.0)	0.0	55.4	55.4	(7.1)	0.0	48.3	48.3
16	**FLR (%)**	4.5	2.5	7.0	(1.5)	4.1	1.5	5.6	(1.6)	3.1	0.8	3.9
17	**FLR Days Equivalent**	172.1	63.2	235.3	(16.8)	161.6	56.9	218.5	(109.4)	117.2	(8.1)	109.1
18	**Total TWh**	48.0	(3.3)	44.7	3.4	49.0	(0.9)	48.1	(3.5)	46.6	(2.1)	44.5

Line No.	Business Unit	2015 Actual	(c)-(a) Change	2016 Budget	(e)-(c) Change	2017 Plan	(g)-(e) Change	2018 Plan	(i)-(g) Change	2019 Plan	(k)-(i) Change	2020 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Darlington NGS											
19	**TWh**	23.3	2.7	26.0	(7.0)	19.0	0.2	19.3	0.4	19.7	(1.9)	17.7
20	**Unit Capability Factor (%)**	76.9	14.2	91.1	(5.9)	85.1	0.9	86.0	1.7	87.8	(8.4)	79.4
21	**PO Days[3]**	266.9	(155.9)	**111.0**	42.4	**153.4**	(10.1)	**143.3**	(19.2)	**124.1**	64.1	**188.2**
22	**FEPO Days**	7.7	(7.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	**FLR (%)**	4.9	(3.9)	1.0	0.0	1.0	(0.0)	1.0	0.0	1.0	3.2	4.2
24	**FLR Days Equivalent**	57.4	(44.7)	12.7	(3.3)	9.4	0.1	9.5	0.2	9.7	28.4	38.1
	Pickering NGS											
25	**TWh**	21.2	(0.4)	20.8	(1.7)	19.1	0.1	19.2	0.2	19.4	0.3	19.6
26	**Unit Capability Factor (%)**	79.4	(1.7)	77.6	(6.1)	71.5	0.5	72.0	0.6	72.6	0.8	73.4
27	**PO Days**	350.1	51.5	401.6	140.0	541.6	(10.8)	530.8	(13.7)	517.2	(18.3)	498.9
28	**FEPO Days**	40.6	(40.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	**FLR (%)**	2.9	2.1	5.0	0.0	5.0	(0.0)	5.0	0.0	5.0	0.0	5.0
30	**FLR Days Equivalent**	51.7	38.0	89.7	(7.2)	82.4	0.5	83.0	0.7	83.6	1.2	84.9
	Totals											
31	**Unit Capability Factor (%)**	78.0	6.6	84.6	(6.8)	77.8	0.7	78.5	(39.5)	39.0	37.2	76.2
32	**PO Days[3]**	616.9	(104.3)	512.6	182.4	695.0	(20.8)	674.1	(32.9)	641.3	45.8	687.1
33	**FEPO Days**	48.3	(48.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	**FLR (%)**	3.9	(1.1)	2.8	0.2	3.0	(0.0)	3.0	(0.0)	3.0	1.6	4.6
35	**FLR Days Equivalent**	109.1	(6.7)	102.4	(10.6)	91.8	0.6	92.5	0.9	93.4	29.6	122.9
36	**Total TWh**	44.5	2.3	46.8	(8.7)	38.1	0.4	38.5	0.6	39.0	(1.7)	37.4

Line No.	Business Unit	2020 Plan	(c)-(a) Change	2021 Plan
		(a)	(b)	(c)
	Darlington NGS			
37	**TWh**	17.7	(1.1)	16.6
38	**Unit Capability Factor (%)**	79.4	11.5	90.9
39	**PO Days[3]**	**188.2**	(131.9)	**56.2**
40	**FEPO Days**	0.0	0.0	0.0
41	**FLR (%)**	4.2	(1.2)	3.0
42	**FLR Days Equivalent**	38.1	(13.1)	25.0
	Pickering NGS			
43	**TWh**	19.6	(0.8)	18.8
44	**Unit Capability Factor (%)**	73.4	(2.8)	70.6
45	**PO Days**	498.9	63.9	562.8
46	**FEPO Days**	0.0	0.0	0.0
47	**FLR (%)**	5.0	(0.0)	5.0
48	**FLR Days Equivalent**	84.9	(3.5)	81.4
	Totals			
49	**Unit Capability Factor (%)**	76.2	2.8	79.0
50	**PO Days[3]**	687.1	(68.1)	619.0
51	**FEPO Days**	0.0	0.0	0.0
52	**FLR (%)**	4.6	(0.6)	4.0
53	**FLR Days Equivalent**	122.9	(16.6)	106.3
54	**Total TWh**	37.4	(2.0)	35.4

Notes:
1 OEB Approved nuclear production in 2014 is 49.0 TWh per EB-2013-0321 Decision with Reasons p. 39.
2 OEB Approved nuclear production in 2015 is 46.6 TWh per EB-2013-0321 Decision with Reasons p. 39.
3 PO days excludes planned outage days for Darlington units out of service during Darlington refurbishment.



This schedule was accepted by OPG's Board of Director's in November 2015 and the Execution phase of the project was formally launched in January 2016. This high confidence schedule, which includes contingency, assumes the first unit outage will commence in October 2016 with each unit lasting 37 to 40 months. The release strategy is also defined, with a unit specific release for assessing and readiness work followed by a request for full release of funds to execute the outage work. For Generation planning, OPG assumed the high confidence 40 month schedule for the first unit and the medium confidence schedule for the subsequent units.

11.0 DRP ASSUMPTIONS AND RISKS

A formal Risk Management process has been implemented for the DRP. Risks are actively identified and managed, and reported on a routine basis. All key assumptions are also managed in a central database and form the basis of planning as well as risk management.

Key risks within the program include:

Cost and scheduling related Risks - There is a risk to the costs and timelines for refurbishment due to other nuclear projects that may be occurring simultaneously i.e. other major CANDU projects in Canada.

Resource Risk – There is a risk is that labour may not be available at the time of the DRP due to the other potential nuclear programs taking place in the same time frame.

Lessons Learned – Operating Experience from other mega projects and lessons learned from the Pickering Refurbishment planning activities should be factored into the planning of the DRP.

OAPPA Interrogatory #6

Issue Number: 5.1
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

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

$\boxed{\text{4-OAPPA-1}}$

Reference:
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?

Response

a) Yes, the production forecast includes eight mini-outages to mitigate the risk of PHT pump motors failing before they can be replaced in planned outage cycles or in the Unit 2 Refurbishment window.

Evidence shows that the old motors on Units 3, 4, and 1 are at high risk of failure before their refurbishment windows occur, so only the Unit 2 motors can be replaced during the refurbishment window. Mini outages are necessary due to the motors' high risk of failure and there is likelihood that the some of the planned motor replacements will not make their planned outage schedules. Motors have failed before they could be replaced in 2015 and 2016 causing significant losses at Darlington.

b) No, the eight outages represent 3.371 TWh over the test period.

c) It is estimated that the difference in lost production under a PHT pump motor failure scenario versus a planned replacement scenario is approximately three days saved, or 0.063 TWh, providing there is an available spare (new or overhauled motor). If there are no motors available in a multi motor failure scenario, the unit could be offline for up to nine months. Alternatively, if a used motor is installed a subsequent outage would be required to replace it. It is also preferable to replace these motors in a planned manner as opposed to run to failure as this minimizes the nuclear safety risk of having a tripped motor trigger shutdown safety systems and liquid relief valves and lowers the risk of damage to fuel. A planned replacement schedule allows removed motors to be refurbished and reused at a lower cost than new motors.

d) OPG believes it is appropriate to include, as part of its rate filing, outage plans and associated costs that are required to replace end of life components needed for the operation of the nuclear units, particularly ones that pose such a significant risk to production. OPG bears 100% of production forecast risk.

Project #80078 Darlington Digital Control, Common Process and Sequence of Events Monitoring Computer Aging Management: This project is to replace certain components of Darlington digital control, common process and sequence of event computers. Most of the obsolete computer components were custom designed for Darlington, using 1980s technology, which can no longer be supported. The replacement of the majority of these computer components is a regulatory commitment, and is necessary to preserve system configuration and functionality and maintain capability of interfacing with existing computer equipment prior to, during and post refurbishment. The total project cost is $47.3M (plus additional inventory of spares of $9.1M) with an iniital partial release of $1.7M. Planned final in-service is June 2025.

Project #80111 Darlington Generator Stator Core Spare: This project is to purchase a generator stator core as a spare. Darlington's existing generator stator cores are showing signs of degradation and are not expected to reach end of the post-refurbishment period without major failure or a significant maintenance/refurbishment. OPG does not currently have a spare and in the event of a catastrophic failure of the unit, OPG would be at risk of a forced outage of up to two years duration. Purchasing a spare generator stator core will allow OPG to swap it with an existing stator core for replacement/refurbishment. The total project cost is $35.0 with a full release of $35.0M. Planned final in-service is July 2019.

Project # 82816 Darlington Vault Cooling Coil Replacement: This project is to reduce risk to Darlington operations by replacing life expired vault cooling coils. Vault cooling coils provide cooling to the reactor vault under operating conditions and remove heat under a loss of coolant accident condition. The total project cost is $26.3M with an partial release of $11.9M. Planned final in-service is September 2020.

#73566/80144 Darlington Primary Heat Transport Pump Motor Replacement/Overhaul: This project is to replace/refurbish the sixteen primary heat transport ("PHT") pump motors and spare at Darlington, which are approaching the end of their service lives. Primary heat transport pump motors are 100 per cent duty with no installed redundancy. Failure of any one of the operating motors (there are four PHT motors per unit) will result in a forced outage and could result in an extended outage depending on availability of spare motors. In June 2015, OPG experienced an unbudgeted planned outage of 25.75 days (lost production of 0.54 TWh) to replace one PHT pump motor, which was showing high levels of degradation. Additionally, there was a forced outage in December 2015 due to a PHT pump motor mechanical failure. Current condition assessments indicate a medium to very high risk of failure on the remaining PHT pump motors and priority will be given to replacing those motors with the highest risk of failure. The total project cost is $129.5M with a partial release of $53.8M. Planned final in-service is December 2022.

Project #40976 Pickering B Fuel Handling Reliability Modifications: This project is to replace life-expired mechanical and control components and install modifications to improve the reliability of the Pickering B fuel handling systems. Problems with the fuel handling systems have resulted in forced generation losses. This project will help OPG achieve its forced loss rate targets in the test period. The total project cost is $37.3M with an execution phase release of $30.9M. Planned final in-service is July 2017.

Projects #41023 and #49247 Pickering Unit 1 & 4 Fuel Channel East Pressure Tube Shift/Reconfigure: This project is to develop tooling for the repositioning and reconfiguration of the fuel channel assemblies in Pickering Units 1 and 4. The pressure tubes, under the influence of the neutron flux as well as pressure and temperature, elongate over time. The pressure tubes are fixed at one end and are allowed to grow out at the other end. To ensure that the end fittings stay on their bearings, the fuel channels have to be repositioned or reconfigured. The total cost is $38.6M which consists of a full release for execution of $28.8M, with a superceding release for an additional $9.8M to authorize the change in scope, from repositioning the majority of fuel channels to reconfiguring all fuel channels, in Units 1 and 4. The planned final in-service is March 2016.

Project #41027 Pickering Fukushima Phase 2 Beyond Design Basis Event Emergency Mitigation Equipment: This project is to provide portable equipment and install modifications to manage water and protect containment long term following a beyond design basis event. This project is required to meet Canadian Nuclear Safety Commission ("CNSC")

The updated approvals are detailed below. Along with this schedule, OPG has filed an amendment to Ex. A1-2-2 to reflect these changes.

<u>Nuclear Payment Amounts</u>

Effective Date	Payment Amount
January 1, 2017	$76.39/MWh
January 1, 2018	$78.60/MWh
January 1, 2019	$84.83/MWh
January 1, 2020	$88.21/MWh
January 1, 2021	$92.02/MWh

<u>Deferred Revenue Requirement Amounts</u>

OPG proposes that annual OPG weighted average payment amounts (as defined by O. Reg. 53/05, s. 0.1(1)) reflect a constant 2.5% per year rate increase during the 2017 to 2021 period resulting in a deferred nuclear revenue requirement of $251M, $162M, $(38)M, $488M, and $142M in 2017, 2018, 2019, 2020 and 2021, respectively.

	2016	**2017**	**2018**	**2019**	**2020**	**2021**		**2023**
Routine Outages	Unit 4	Unit 1	Unit 3	Unit 4	Unit 1	None		
DRP	Unit 2	Unit 2	Unit 2	Unit 2	Unit 2	Unit 1		Unit 1
					Unit 3	Unit 3		Unit 4
PHT	**Unit 3**	**Unit 3**	**Unit 1**	**Unit 1**	**Unit 4**	**Unit 4**		
		Unit 4	**Unit 4**					
PHT Outage (TWh)	0.421375	0.84275	0.84275	0.421375	0.421375	0.421375		
Requested Rate ($/MWh)		$76.39	$78.60	$84.83	$88.21	$92.02		
Lost Production Revenue (Rate Payer Cost) Due to PHT Outages		$ 64.378 (million)	$ 66.24 (million)	$ 35.745 (million)	$ 37.169 (million)	$38.775 (million)		

- PHT outage revenue losses between 2017 and 2020 are ~ $242.3 million

Filed: 2016-05-27
EB-2016-0152
Exhibit A1-4-1
Attachment 2

MEMORANDUM OF AGREEMENT

BETWEEN
Her Majesty the Queen in right of Ontario, as represented by the
Minister of Energy (the "Shareholder" or "Minister")
And
Ontario Power Generation, Inc. ("OPG")

Agreement and/or Declarations and resolutions, in accordance with section 108 of the OBCA, which shall be made public by OPG within a reasonable timeframe by publishing such agreements, declarations and resolutions on the Corporation's website.

3.7 Unless otherwise directed by the Shareholder or statute, OPG shall operate in Ontario in accordance with the highest corporate standards, including but not limited to the highest corporate standards in the areas of corporate governance and social responsibility. OPG shall continue to benchmark its corporate governance practices against the securities regulators' National Policy on Corporate Governance Guidelines, as well as other leading governance organizations, as appropriate.

4 MANDATE

4.1 The objects of OPG include, in addition to any other objects, owning and operating a diversified portfolio of generation assets and facilities.

4.2 OPG shall leverage its assets and expertise to generate new revenues on a commercially sound basis, including the making of strategic investments and acquisitions in the electricity sector, as well as in related business opportunities inside and outside Ontario, on its own or in partnership as appropriate, for the benefit of the Corporation and the Shareholder.

4.3 OPG shall continue to operate as a respected, publicly-owned electricity generation enterprise and to operate its assets efficiently and cost-effectively, and to deliver value both to Ontario's ratepayers and taxpayers.

4.4 OPG shall ensure that it conducts its operations in full compliance with all laws and regulations and serves as a model in regard to public and employee safety, environmental practices, corporate citizenship, community engagement and First Nations and Métis relations.

4.5 OPG shall undertake generation development projects in support of the Province's electricity planning initiatives, including the Long Term Energy Plan, as may be updated from time to time.

4.6 OPG shall support the Province of Ontario's efforts to fulfill the Crown's constitutional duty to consult and accommodate Aboriginal peoples, where that duty arises in relation to OPG generation projects, by carrying out those procedural aspects of the Crown's consultation obligations that are delegated in writing to OPG by the Province, including the Ministry.

4.7 The Province of Ontario and the Ministry supports the role of public power and mitigating electricity prices in Ontario and in doing so:

a. mandates that OPG maintain itself as a strong, viable public power component of the electricity sector at an appropriate scale and with generation portfolio diversity to ensure long-term operational and financial sustainability and to support OPG long term liabilities; and

b. mandates that OPG plan and operate its generation facilities based upon good utility practice recognizing safety, legal, regulatory, environmental and market factors.

4.8 OPG shall support the Province's economic development objectives where feasible, including generating financial benefits that remain within the Province of Ontario.

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.

4.10 OPG shall earn a commercial rate of return and generate sufficient cash in order to maintain an investment grade credit rating, and service its borrowing needs for operations and projects; as well as supporting the opportunity to access public debt markets in the future. Any significant new generation approved by the Board of Directors and agreed to by the Shareholder may receive financial support from the Province of Ontario, if and as appropriate.

4.11 Subject to any unanimous shareholder declaration or resolution, OPG shall be permitted to participate in all energy-related procurements in Ontario.

4.12 OPG shall inform the Shareholder of any solar and wind developments or projects that the Corporation intends to undertake or assume, including the sources of the Corporation's financing, before undertaking or assuming such developments or projects.

4.13 Where appropriate, OPG shall pursue prospective generation related developments with First Nations and Métis communities that can provide the basis for long term mutually beneficial commercial arrangements.

4.14 Acknowledging sections 3.1 and 3.4 of this MOA, OPG will act in the interests of both OPG and the Shareholder in entering into potential settlements of material Aboriginal claims or grievances or material arrangements with communities potentially affected by OPG generation development. Unless otherwise agreed to with the Shareholder, OPG will pursue such agreements or arrangements so that the Shareholder benefits equally from releases from liability and indemnifications obtained by OPG in relation to damage caused by the construction, operation and development of OPG facilities. Nothing in this MOA will require OPG to pursue releases for matters for which the Shareholder may be solely liable.

5 REPORTING REQUIREMENTS

5.1 OPG and the Shareholder will ensure timely sharing of information sharing on major developments and issues that may impact the business of OPG or the interests of the Shareholder. Major developments and issues include planned acquisition of energy assets and/or assumption of existing power supply contracts, proposed settlements of material Aboriginal peoples' claims or grievances relating to OPG facilities, and proposed arrangements with communities affected by OPG generation development.

5.2 OPG shall report to the Shareholder, on an immediate basis, where a material human safety or system reliability issue arises.