K4.2

Board Staff Interrogatory #045

Ref: Ex. F2-T2-S1, page 1

Issue Number: 6.3
Issue: Is the test period Operations, Maintenance and Administration budget for the nuclear facilities appropriate?

Interrogatory

The application notes on page 1 *"OPG has made significant operational and cost improvements which have been demonstrated since the previous application: Specifically: 2012 base OM&A costs are to be forecast to be below 2008 actual costs, with cumulative work-driven cost savings of $260M for the 2010 - 2012 period; 2012 regular staff levels are forecast below 2008 levels by 689 staff, while non-regular 17 staff FTEs ("full time equivalents") are reduced by 559"*. In A1-T3- S1 (p.4) it notes that these reductions are due to the seven key initiatives as part of the 2010 - 2014 Nuclear Business Plan and other cost control measures explained in Ex. F2-T1-S1. However, based on information provided during the previous OPG payments application process, Board staff expected substantial reductions absent any new cost control measures or initiatives. For example:

- OPG's Reply Argument in the previous case noted *"Staffing levels since 2006 have been under pressure due to changes in work programs for matters such as security, new generation development; Pickering B refurbishment, and the isolation and safe storage of Pickering A units 2 and 3, preparation for vacuum building outages at both Darlington and Pickering and maintenance backlog reductions (Tr. Vol. 5, 3 pages 39-40) ... with completion of planned improvement initiatives and as a result of cost containment initiatives outlined in the evidence, total OM&A for nuclear is forecast to decrease in 2009 compared to 2008"*.

- OPG's Final Argument also noted: *"For nuclear, the trend reflecting increasing FTE numbers into 2008 is necessary for OPG's planned improvement programs. Subsequent reductions in 2009 are consistent with the completion of these programs (Ex. F2-T2-S1, pages 20-21). For example, Mr. Robinson testified: "...that Darlington and the ops and maintenance area was higher than the benchmark. We went back and looked at that, and we said, yes, that is valid because of the increased resources we were applying to backlog reduction, and we see through the evidence that, over time, those numbers will come down (Tr. Vol. 5, page 14)."*

- In addition, OPG's Nuclear Business Plan also discusses a significant reduction in FTEs and Nuclear OM&A costs due to the discontinuation of an agreement with Bruce Power to provide services.

Based on the above and the completion of the two major vacuum building outages (VBOs) in 2009 and 2010:

Z

a) Were many of the reductions in costs and FTEs expected regardless of the seven key initiatives and other cost control measures identified in this application?

b) Please identify the estimated FTE and cost savings associated with each new initiative as well as each additional new cost saving measure OPG refers to in the application.

c) Further to the above, please reproduce Table 1 in F2-T1-S1 (Operating Costs Summary – Nuclear) up to line 9 (Total OM&A) in the following manner. Exclude the costs associated with the following extraordinary and/or non-recurring items:

- Temporary increase in OM&A costs/FTEs approved by the Board to address the backlog issue
- Isolation and safe storage of Pickering A units 2 and 3 (project now completed)
- Major VBO outage completed for Darlington in 2009 (occurs once every decade)
- Major VBO outage completed for Pickering in 2010 (occurs once every decade)
- Discontinuation of Service Agreements with Bruce Power amounting to $145M in savings for the 2010-2012 period (as identified on page 19 of the Nuclear Business Plan in Attachment 1)
- Pickering Continued Operations
- Darlington Refurbishment

Please show the costs associated with the excluded items shown above as separate line items below the revised Total OM&A at Line #9.

Response

a) It is not possible to determine the savings that would have resulted relative to the last application if the initiatives that form the existing 2010 – 2014 business plan are removed. The business plan underpinning the payment amounts in EB-2007-0905 covered 2008 – 2010 and did not include the years 2011 and 2012.

b) Of the 33 initiatives identified in the business plan, the fleet-wide initiatives contributing to the cost savings are presented in Table 1 along with their forecast savings over the test period. FTE savings were not tracked by initiative. For a summary of FTE reductions over the test period, see Ex. F2-T1-S1, Attachment 1, page 19.

Table 1: OM&A Savings Associated with Fleet-Wide Initiatives ($k)

Initiative ID	Initiative Name	OM&A Savings 2011	OM&A Savings 2012	OM&A Savings Total - Test Period
Maintenance				
MA-04	Centralized Measurement and Test Equipment	($350)	($350)	($700)
MA-08	Day Based Maintenance	$0	($5,184)	($5,184)
MA-09	Single Source Laundry	($3,000)	($3,000)	($6,000)
Outage				
OU-02	Outage Improvement Strategy	($5,540)	($7,604)	($13,144)
Engineering				
EN-01	Work Order Readiness	($780)	($1,560)	($2,340)
EN-02	Engineering Value for Money	($3,750)	($7,930)	($11,680)
EN-03	Improve Fuel Reliability Index	$30	$30	$60
Equipment Reliability				
ER-02	Improve Preventive Maintenance Program	($30)	($30)	($60)
Industrial Safety				
IS-01	Musculoskeletal Disorder Prevention	$240	$0	$240
IS-02	Safety Behaviours Assessment	$65	$0	$65
IS-04	Constrain Training Qualification	($1,168)	($1,168)	($2,336)
Radiaton Protection				
RP-05	Optimize Reactor Face Shielding	($315)	($565)	($880)
RP-26	Area Mapping	$75	$0	$75
RP-9	Improve Fuel Machine Filtration	$150	$0	$150
Fire Safety				
FS-03 (Revenue)	Offer Fire Training	($100)	($100)	($200)
Training				
TR-04	Initial Authorization Training Program	$2,605	$2,074	$4,679
TR-02	Computer Based Training Increase	($134)	($129)	($263)
TR-06	Outage Improvement Strategy	($354)	($288)	($642)
Financial Performance				
FP-02	Labour Cost Reduction	($1,068)	($1,068)	($2,136)
TOTALS		**($13,424)**	**($26,872)**	**($40,296)**

In addition to the forecast savings from the fleet-wide initiatives, OPG Nuclear has developed divisional and local cost reduction measures. These measures address areas such as contract services, outsourcing, overtime, organizational consolidations, inspection scopes, etc.

As seen in Notes 1 and 2 to Ex. F2-T1-S1, Attachment 1, page 16, the total divisional cost targets are the net of divisional "targeted reductions" and divisional "additional expenditures" (i.e., $36.3M in 2011 and $41.7M in 2012). The combination of fleet-wide initiatives and the divisional / local measures are the basis for achieving these cost reduction targets.

c) See reproduced and modified Ex. F2-T1-S1, Table 1 below.

Table 1

Operating Costs Summary - Nuclear ($M)

Line No.	Cost Item	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	OM&A:						
1	Base OM&A	1,204.9	1,252.4	1,216.5	1,187.0	1,192.3	1,219.8
2	Project OM&A	111.6	134.7	143.7	143.8	135.9	132.2
3	Outage OM&A	215.6	196.1	254.8	284.6	214.8	201.1
4	Subtotal	1,532.0	1,583.2	1,615.0	1,615.5	1,543.0	1,553.2
5	Generation Development OM&A	11.8	34.1	79.6	60.5	5.9	4.5
6	Allocation of Corporate Costs	240.7	237.6	233.2	244.1	247.3	250.4
7	Allocation of Centrally Held Costs	210.2	132.2	58.8	171.0	199.0	234.3
8	Asset Service Fee	33.2	28.8	27.2	24.6	24.1	23.7
9	**Total OM&A**	**2,027.9**	**2,015.9**	**2,013.7**	**2,115.7**	**2,019.4**	**2,066.0**
	Excluded from Total OM&A (line 9 above)						
Note 1	Temporary Increase for Backlog Issues			(9.3)	(9.8)	(7.4)	
Note 2	P2/P3 Isolation and Safe Storage	(9.5)	(13.5)	(22.5)	(20.6)		
Note 3	Darlington VBO - 2009	(0.8)	(8.1)	(35.4)			
Note 3	Pickering VBO - 2010		(0.9)	(5.8)	(32.2)		
Note 4	Discontinuation of Service Ageement with Bruce Power						
Note 5	Pickering B Continued Operations			(4.9)	(16.9)	(53.3)	(43.6)
Note 5	Darlington Refurbishment	(0.4)	(7.3)	(21.7)	(11.8)	(11.0)	(7.1)
	Sub-total	**(10.8)**	**(29.8)**	**(99.5)**	**(91.4)**	**(71.6)**	**(50.7)**
	Total OM&A (excluding items above)	**2,017.1**	**1,986.0**	**1,914.2**	**2,024.3**	**1,947.7**	**2,015.3**

Note 1 - As per Ex. F2-T2-S1, page 27, incremental funding for backlog reduction was removed in the 2010 – 2014 business planning process, except for the Pickering A Equipment Reliability Restoration program. The costs shown are for this program.

Note 2 - Consistent with Ex. F2-T3-S1, Table 1.

Note 3 - Costs shown are incremental, consistent with the Outage OM&A exhibits (Ex. F2-T4).

Note 4 - The reference cited (page 19 of the Nuclear Business Plan in Ex. F2-T1-S1, Attachment 1) relates to staff, not costs, and we do not recognize the amounts quoted in part c) of the interrogatory. As disclosed in Ex. F2-T2-S1, page 16, cost of Bruce Power Services are forecast to be $1.8M in 2010, $3M in 2011 and $3.9M in 2012, and Total OM&A (Table 1, line 9 above) already excludes these costs.

Note 5 - Pickering B Continued Operations includes 35 per cent of the cost related to the Fuel Channel Life Management project; Darlington Refurbishment includes the remaining 65 per cent of the project costs.

effect for almost three years, the proposed increases are quite small. This is indicative of OPG's efforts since the last payments proceeding to engage in a continuing process to control operating expenses.

Operating Expense

OPG's evidence on operating expenses illustrates its progress in cost control. For example, for regulated hydroelectric, a comparison between the OM&A costs requested in this Application and those approved in the last application shows an increase of approximately 4.5 per cent over a three-year period from the end of 2009 to the end of 2012 (see Ex. I1-T1-S1 Table 2). Considering that labour costs, the major component of OM&A costs, reflect general wage increases of between 2 and 3 per cent per year over this same period, the test period OM&A request embodies substantial cost savings.

In Nuclear, an extensive benchmarking effort led to the development of challenging five-year operational and financial performance targets as explained in Ex. F2-T1-S1. To help meet these targets, nuclear has developed seven key initiatives as part of the 2010 - 2014 Nuclear Business Plan (Ex. F2-T1-S1, Attachment 1). Based on these initiatives and other cost control measures explained in Ex. F2-T1-S1, OPG's 2010 - 2014 Nuclear Business Plan shows more than $200M in OM&A cost savings in the test period.

Corporate groups have also embarked on significant cost savings initiatives. Corporate group costs increase by approximately 5 per cent over the 2007 - 2012 period and incorporate savings in the test period based on the 2010 - 2014 Business Plan. Specific cost savings initiatives by the corporate groups are discussed in Ex. F3-T1-S1.

Of the total corporate group costs, 68 per cent are attributable to the prescribed facilities, which compares favourably to the 72 per cent of OPG's generation that is produced by the prescribed facilities. OPG is using essentially the same cost allocation methodology employed in EB-2007-0905. OPG's corporate cost allocation has been reviewed and endorsed by independent cost allocation experts, Black and Veatch Corporation ("Black and Veatch"). The Black and Veatch study is presented in Ex. F5-T2-S1.

Attachment 1: Board Staff Technical Conference Question #041

Ref: ExhF2/Tab2/Sch1/p.1

Issue Number: 6.3
Issue: Is the test period Operations, Maintenance and Administration budget for the nuclear facilities appropriate?

Question

As referenced in Board staff IR#45, the application notes on page 1 *"OPG has made significant operational and cost improvements which have been demonstrated since the previous application: Specifically: • 2012 base OM&A costs are to be forecast to be below 2008 actual costs, with cumulative work-driven cost savings of $260M for the 2010 - 2012 period; • 2012 regular staff levels are forecast below 2008 levels by 689 staff, while non-regular 17 staff FTEs ("full time equivalents") are reduced by 559".* In A1-T3- S1 (p.4) it notes that these reductions are due to the seven key initiatives as part of the 2010 - 2014 Nuclear Business Plan and other cost control measures explained in Ex. F2-T1-S1.

a) In (a) of OPG's response, OPG notes it is not possible to determine the savings that would have resulted regardless of the seven key initiatives and other cost control measures identified in this application. Based on the figures in the reproduced table in (c) under "Excluded from Total OM&A (line 9 above)", Board staff has calculated, in the absence of key initiatives and other cost control measures identified in the application, savings for 2010 – 2012 would have been $78.7 million (or $70 million excluding Discontinuation of Service Agreement with Bruce Power) as shown in the table below[1]. Please confirm these savings would have been realized in the absence of OPG's key initiatives and other cost control measures.

$ million	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
Temporary Increase for Backlog Issues	$0.0	$0.0	-$9.3	-$9.8	-$7.4	$0.0
P2/P3 Isolation and Safe Storage	-$9.5	-$13.5	-$22.5	-$20.6	$0.0	$0.0
Darlington VBO – 2009	-$0.8	-$8.1	-$35.4	$0.0	$0.0	$0.0
Pickering VBO – 2010	$0.0	-$0.9	-$5.8	-$32.2	$0.0	$0.0
Discontinuation of Service Agreement with Bruce Power	$0.0	$0.0	$0.0	-$1.8	-$3.0	-$3.9
Sub-total (including Bruce Service Agreement)	**-$10.3**	**-$22.5**	**-$73.0**	**-$64.4**	**-$10.4**	**-$3.9**
Sub-total (excluding Bruce Service Agreement)	**-$10.3**	**-$22.5**	**-$73.0**	**-$62.6**	**-$7.4**	**$0.0**
Savings (2008-12: Temp Backlog increase, P2/P3, VBOs, Discontinue Bruce Service Agreement)						**-$174.2**
Savings (2008-12: Temp Backlog increase, P2/P3, VBOs)						**-$165.5**
Savings (2010-12: Temp Backlog increase, P2/P3, VBOs, Discontinue Bruce Service Agreement)						**-$78.7**
Savings (2010-12: Temp Backlog increase, P2/P3, VBOs)						**-$70.0**

b) In (b) of IR#45, it requested the estimated FTE and cost savings associated with each new initiative as well as each additional new cost saving measure OPG refers to in the application. OPG's response provided Table 1 showing OM&A savings associated with

[1] The savings associated with the Discontinuation of the Service Agreements with Bruce Power are from Note 4 of OPG's response.

fleet-wide Initiatives and that amounted to a total of about $40.3M and OPG further noted the total net savings associated with additional new cost saving measures net of divisional "targeted reductions" and divisional "additional expenditures" are $36.3M in 2011 and $41.7M in 2012. Board staff has aggregated these figures as shown below and it amounts to $118.3M.

	$M
OM&A Savings Associated with Fleet-Wide Initiatives	$40.3
Divisional and local cost reduction measures (2011)	$36.3
Divisional and local cost reduction measures (2012)	$41.7
Total – Fleet-Wide Initiatives and Divisional/local cost reduction measures	**$118.3**

Please reconcile the total savings of $118.3M above associated with the new initiatives as well as the new cost saving measures OPG refers to in the application with the following statements in the application:

- In A1-T3- S1 (p.4), *"To help meet these targets, nuclear has developed seven key initiatives as part of the 2010 - 2014 Nuclear Business Plan (Ex. F2-T1-S1, Attachment 1).* ***Based on these initiatives and other cost control measures*** *explained in Ex. F2-T1-S1, OPG's 2010 - 2014 Nuclear Business Plan shows* ***more than $200M in OM&A cost savings in the test period****."* (emphasis added)

- In F2-T2-S1 (p.1), *"OPG has made significant operational and cost improvements which have been demonstrated since the previous application: Specifically: • 2012 base OM&A costs are to be forecast to be below 2008 actual costs, with* ***cumulative work-driven cost savings of $260M for the 2010 - 2012 period****;"* (emphasis added)

c) OPG's response also noted that, for a summary of FTE reductions over the test period, see Ex. F2-T1-S1, Attachment 1, page 19 which refers to OPG's Nuclear Business Plan.

   i) Page 19 of OPG's Nuclear Business Plan cannot be used to confirm OPG's claim in the application that was referenced in IR#45 *"• 2012 regular staff levels are forecast below 2008 levels by 689 staff, while non-regular 17 staff FTEs ("full time equivalents") are reduced by 559"*, as the table does not include 2008. Board staff therefore referred to Table 13 in F2-T2-S1 (Staff Summary - Nuclear Operations) as it does include 2008. This table shows reductions of 689 and 559 as noted in the application. However, Board staff questions whether these figures represent staff or FTE reductions because it subtracts 2008 **Headcount** from 2012 **FTEs**. Subtracting Headcounts from FTEs is inappropriate as Headcount is always much higher than FTEs. Is OPG able to convert the Headcounts for 2008 and 2009 to FTEs to provide an appropriate comparison?

   ii) Putting aside the matter of Headcount vs. FTEs, Exhibit F2-T1-S1 (Attachment 1, page 19) which OPG referred to in the response shows (under "Plan-Over-Plan Major Business Reason for Regular Staff Variance from BP 2009-2013") a cumulative reduction of 265 (2009 to 2012) and that 185 or 70% of that reduction is attributable to "Discontinuing Service Agreements with Bruce Power". Please confirm that Board staff has a correct understanding of the table on page 19 and the figures noted above are correct.

d) In (c) of IR#45, it requested that OPG reproduce Table 1 in F2-T1-S1 (Operating Costs Summary – Nuclear) up to Line #9 (Total OM&A) to exclude the costs associated with the extraordinary and/or non-recurring items identified in IR#45 (e.g., VBOs, P2/P3 Isolation, etc). Based on Board staff's review, it does not appear that this has been done. For example, the amounts associated with Base OM&A, Project OM&A and Outage OM&A all remain the same as Table 1 in F2-T1-S1 in the application. At the same time, a handful of figures have been adjusted associated with "Generation Development OM&A" (2009 and 2010) and "Allocation of Corporate Costs" (2009-2012).

   i) Please reproduce Table 1 in F2-T1-S1 as was requested (e.g., backing out VBO costs from Outage OM&A, P2/P3 Isolation from Project OM&A, etc.).
   ii) Please also explain why "Allocation of Corporate Costs" was adjusted and why "Generation Development OM&A" was *increased* by $20M in 2010 in the table reproduced by OPG.

<u>Response</u>

The preamble in the question incorrectly links two statements regarding cost savings that are made on different bases. The quote from Ex. F2-T2-S1 page 1 is in respect of **base OM&A** costs. The reference to Ex. A1-T3-S1 page 4 is to total Nuclear OM&A, which includes **base, outage and project OM&A**. Therefore it is inappropriate to compare these two statements.

In addition, the statement in Ex. F2-T2-S1 page 1 relates to the trending of costs over the 2008 to 2012 period. That is, it presents **year-over-year reductions in base OM&A** for 2010-2012 relative to 2008 actual costs. The statement in Ex. A1-T3-S1 page 4 relates to **reduction in the test period total nuclear OM&A relative to the previous business plan**. Again, the statements are made on different bases, are illustrating different things, and should not be brought together or reconciled.

a) OPG does not agree with Board staff's calculation of $78.7 million of savings for 2010 – 2012. The calculation has the following errors:
   - Board staff references "savings for 2010 – 2012", without referencing the base against which such savings are measured or the OM&A category to which these savings pertain. As stated above, OPG's statement in Ex. F2-T2-S1 page 4 is for base OM&A relative to expenditures in 2008.
   - Board staff indicates savings for 2010-2012 equal to the planned expenditures for the identified initiatives in those years, which is illogical.
   - The following initiatives in the Board Staff table are not base OM&A expenditures and therefore not related to any statement of base OM&A cost savings:
     - P2/P3 Isolation and Safe Storage
     - Darlington VBO – 2009
     - Pickering VBO - 2010

Excluding these initiatives and correcting the other errors would reduce the $78.7M figure to approximately $33M relative to the 2008 baseline.

- While completion of certain initiatives contributes to cost reductions, new initiatives and evolving issues replace them and place upward pressure on costs, e.g., additional 2011/ 2012 turbine work (Ex. F2-T1-S1 Attachment 1, Page 19), and maintenance of the new fish impingement mitigation system, Through business planning, OPG manages the ongoing requirement to maintain and invest in the nuclear facilities while achieving cost control targets.

As stated in Ex. F2-T2-S1 page 1, OPG has achieved cost savings of $260M for the 2010 - 2012 period in base OM&A compared to 2008.

b) The question refers to 'Divisional and Local Cost Reduction Measures' when, as indicated in Ex. L-1-45 Page 3 Lines 9-13, the amounts of $36.3M and $41.7M are in fact the net divisional and local cost reduction <u>targets</u> for 2011/2012 respectively. The fleet-wide initiatives and divisional/local cost reduction measures are the means for achieving these cost targets. It is therefore not appropriate to add the amounts, as has been done in part b) of the question. Similarly, the requested reconciliation to $118.3M would not be appropriate.

In addition, as stated in the first paragraphs of this response the statements in Ex. A1-T3-S1 page 4 and Ex. F2-T2-S1 page 1 are on different bases and therefore it is not appropriate to reconcile the two statements.

c)

(i) Board Staff are correct that Ex. F2-T2-S1 Table 13 is the appropriate reference.

However, OPG does not accept Board Staff's conclusion that the claimed reduction is inappropriate as "headcount is always much higher than FTEs". In a case such as OPG's, where staff effort (FTEs) are decreasing year-over-year, year-end headcount is expected to be smaller than the budget FTE amounts.

While it would be possible to calculate historic FTEs, it would be a labour-intensive effort requiring a "reverse engineering" of FTEs from headcounts that would involve a number of assumptions (for example, staff working 35 versus 40 hour weeks) that would impact the comparability of historical and future FTE numbers.

For the above-noted reasons, OPG believes that the comparison OPG has provided in its pre-filed evidence is the appropriate comparison.

(ii) Yes, the figures noted in the question are correct. However, it would be overly simplistic to conclude that exiting the Bruce Power agreement was the only significant driver of FTE reductions, and that other Nuclear FTE reduction efforts achieved only 80 FTEs out of the 265 FTEs of cumulative FTE reductions in 2009-2012.

The remaining 80 FTE reduction is a net amount, accommodating forecast FTE increases of 282 FTEs due to Pickering B Continued Operations, Pickering B Turbine Crew (previously purchased services) and Pickering A staff for U2/U3 management.

d) The attached table has been corrected to address errors in the response to L-01-045 (incorrect entries for Generation Development OM&A and Allocation of Corporate Costs, and incomplete information for Temporary Increase for Backlog Issues, Table 1 Line 10). In addition, Table 1 has been reformatted to present the Board Staff-requested adjustments in individual OM&A line items within the table.

Numbers may not add due to rounding.

Table 1
Base OM&A - Nuclear ($M)

Line No.	Division	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	Nuclear Stations						
1	Darlington NGS	294.6	304.7	308.2	291.5	302.1	317.8
2	Pickering A NGS	162.5	187.6	187.3	175.9	172.9	170.6
3	Pickering B NGS	287.4	306.6	292.2	285.3	279.1	288.6
4	Pickering B Continued Operations	0.0	0.0	1.6	9.8	17.7	14.7
5	Pickering B Refurbishment	23.3	9.0	4.3	1.2	0.0	0.0
6	**Total Stations**	767.9	807.9	793.7	763.7	771.8	791.5
	Nuclear Support Divisions						
7	Engineering	60.5	62.4	59.9	56.6	55.8	56.5
8	Projects & Modifications	10.7	12.2	13.9	7.6	5.4	5.1
9	Facilities Management	41.8	38.4	41.8	41.5	42.5	43.4
10	Programs & Training	160.1	169.5	198.4	191.5	193.3	195.1
11	Supply Chain	80.2	77.0	63.6	67.0	67.0	67.7
12	Performance Imprvmnt & Oversight	28.8	29.5	8.5	9.1	9.2	9.4
13	Inspection & Mtce Services	37.7	45.6	38.1	30.8	31.2	31.4
14	Commercial Services[1]	1.3	1.4	1.5	1.7	1.3	1.4
15	Waste & Transportation Services	4.8	5.7	4.2	4.8	5.0	5.1
16	Nuclear Level Common	11.1	2.9	(7.1)	12.6	9.9	13.1
17	**Total Support**	437.0	444.5	422.8	423.4	420.6	428.3
18	**Total**	1,204.9	1,252.4	1,216.5	1,187.0	1,192.3	1,219.8

Notes:
1 Previously Commercial Activities.

BASE OM&A – NUCLEAR

1.0 PURPOSE

This evidence provides a description of the nuclear base OM&A expense for the historical years, bridge year, and test period.

2.0 OVERVIEW

The nuclear base OM&A expense for 2007 - 2012 is provided in Ex. F2-T2-S1 Table 1. The test period base OM&A expense of $1,192.3M and $1,219.8M in 2011 and 2012, respectively forms part of the OM&A expense in the revenue requirement.

OPG has made significant operational and cost improvements which have been demonstrated since the previous application: Specifically:

- 2012 base OM&A costs are to be forecast to be below 2008 actual costs, with cumulative work-driven cost savings of $260M for the 2010 - 2012 period;
- 2012 regular staff levels are forecast below 2008 levels by 689 staff, while non-regular staff FTEs ("full time equivalents") are reduced by 559;
- 2009 elective and corrective maintenance backlogs are below 2008 actuals, with 2012 forecast levels for maintenance backlogs significantly lower again.
- 2009 total Nuclear FLR is below 2008 actual (2008 actual of 12.3 per cent versus 2009 actual of 6.4 per cent); with 2012 forecast levels of 2.8 per cent.

Further details are provided in this exhibit and in Ex. E2-T1-S1. Base OM&A provides the main source of funding for operating and maintaining the nuclear stations in support of:

- The ongoing production of electricity from the operating units
- Ensuring safe operation of the plants
- Maintaining or improving reliability of the nuclear assets
- Ensuring compliance with applicable legislation and nuclear regulatory requirements

In addition to the routine activities listed here, base OM&A is also used to fund the cost of:

- Regular staff labour for planned outages.

Board Staff Interrogatory #38

Ref: Ex. F2-T1-S1, Table 1 and Ex. F2-T2-S1, Table 3

Issue Number: 5.1
Issue: Are the Operation, Maintenance and Administration ("OM&A") budgets for the prescribed hydroelectric and nuclear business appropriate?

Interrogatory

Comparing the Total Regular Staff FTEs in the two tables (Line 14 in Table 1 and Line 41 in Table 3, respectively), it is noted that the staff numbers for the years 2005, 2006 and 2007 are different in the two tables. Please confirm which numbers are correct or, alternatively, provide an explanation for the apparent anomaly.

Response

Both numbers are correct. The values in Ex. F2-T1-S1, Table 1 reflect FTEs (Full Time Equivalents) and reflect the level of full time employee efforts for the year in question. In Ex. F2-T1-S1, Table 3, the historical years in question represent actual headcounts at the end of each year. Full Time Equivalents numbers are generally different than year-end headcount numbers since they reflect the impact of changing staff headcount throughout the year. For example, a staff member hired on July 1 would represent a year-end headcount of 1 but an FTE count of only 0.5.

Note that for the test period, both tables reflect FTEs and are consistent in 2008 and 2009.

14

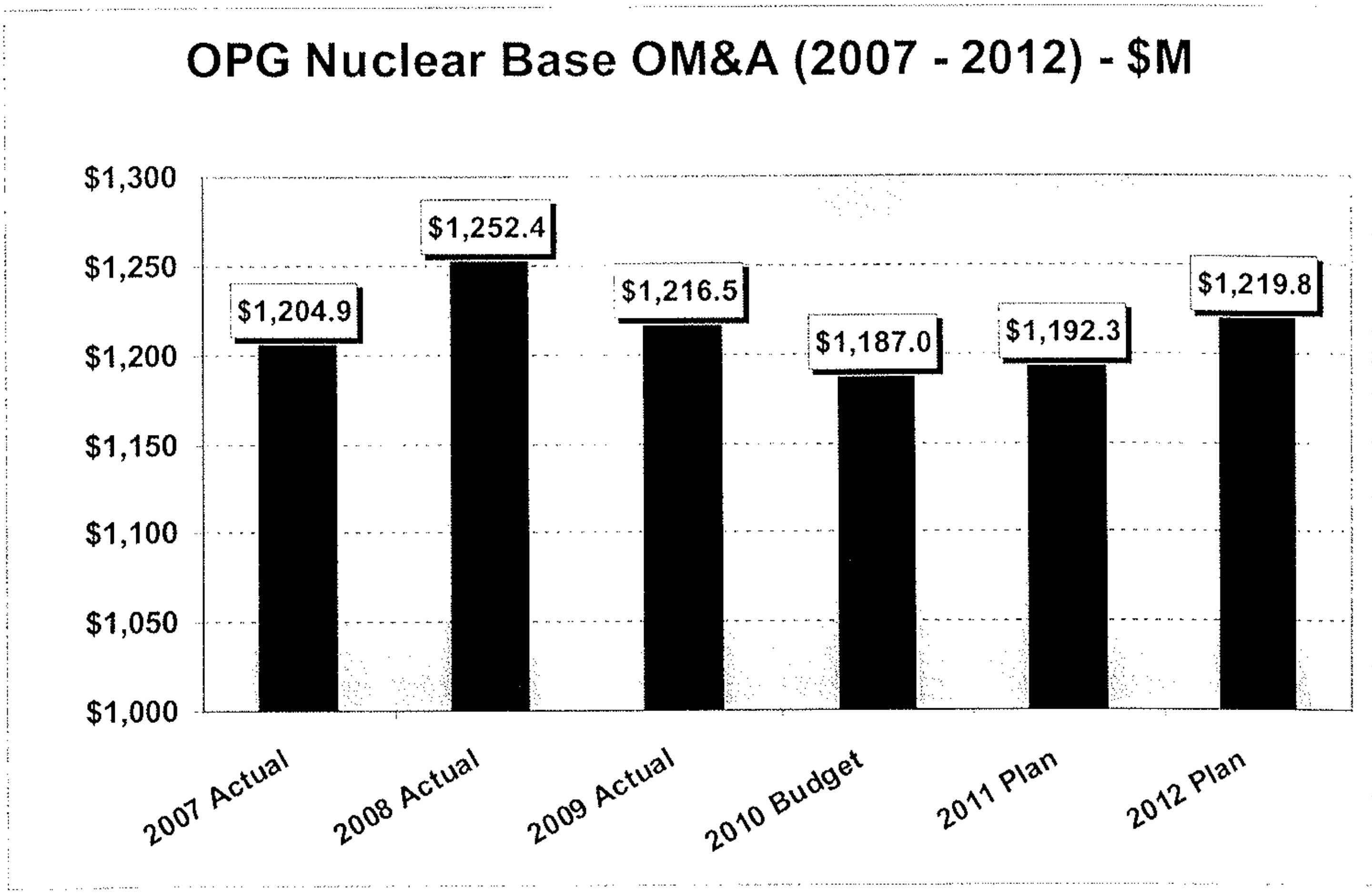
Numbers may not add due to rounding.

Filed: 2010-05-26
EB-2010-0008
Exhibit F2
Tab 2
Schedule 1
Table 13

Table 13

Staff Summary - Nuclear Operations

Line No.	Group	2007 Actual (Headcount)	2008 Actual (Headcount)	2009 Actual (Headcount)	2010 Budget (FTEs)	2011 Plan (FTEs)	2012 Plan (FTEs)
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Regular Staff**	7,281	7,348	7,332	7,155	6,808	6,659
2	**Non-Regular Staff FTEs (all years)**	733	720	732	400	247	161
3	**Total Staff Resources**	8,014	8,068	8,064	7,555	7,056	6,820



Source: F2-T2-S1-Table 1, Base OM&A – Nuclear ($M).

SEC Interrogatory #24

Ref: Ex. F2-T2-S2 Table 7

Issue Number:
Issue:

Interrogatory

The updated evidence shows that actual Base OM&A –Nuclear for 2007 was $39.5 million less than budgeted ($1,256.1 million budgeted vs. $1,216.6 million actual). Please explain the reason for the decrease and whether any of the 2008 or 2009 spending represents spending deferred from 2007.

Response

Spending in 2007 was $39.5M lower than budget as a result of the following;

Operational Functions – Stations ($28M under budget):

- Operations spending was $18.7M under budget across the three sites mainly due to staff vacancies not being filled. Also at Pickering A, spending was lower than budget due to diversion of base staff to support Unit 2/3 safe storage (decommissioning) work and due to savings on some initiative programs.
- Station Engineering spending was $5.8M under budget across the three sites mainly due to staff vacancies not filled at Darlington and the diversion of base staff at Pickering A to support Unit 2/3 safe storage work.
- Support Services spending was $6.5M under budget across the sites mainly due to lower purchase costs for radioactive laundry services and savings achieved through better management of the volume of low and intermediate level waste produced.
- Tritium Removal Facility spending was $3.1M under plan due to delays in both the maintenance improvement initiatives and the life cycle program.
- Maintenance spending was over budget by $8.2M mainly due higher costs to support the forced outages and Inter Station Transfer Bus ("ISTB") issue at Pickering A and higher materials and overtime expended on elective backlog maintenance program and corrective maintenance work at Darlington.

Operational Functions – Support ($12.8M under budget):

- In total the spending for all of the Support groups was $12.8M under budget mainly due to unfilled staff vacancies in Supply Chain, Training and Performance Improvement and Oversight. Also lower than budget external purchase services expenditures were required for Security and for the Nuclear Level Common.

Lower than budget spending in 2007 in the following areas is represented as planned spending in 2008 and 2009:

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Operational Functions – Stations:

- Across the three sites, approximately $14M in lower than budgeted OPG labour cost in 2007 is associated with unfilled staff vacancies in the Operations function. The 2008, 2009 budgets reflect hiring of staff to the budgeted complement. Also, approximately $1M - $2M in initiative work at Pickering A which was not completed in 2007, represents spending in 2008.
- Approximately $2M of Tritium Removal Facility improvement plan initiatives which was not completed in 2007, represents spending in 2008 and 2009.

Operation Functions – Support:

- For Nuclear Programs and Training approximately $7M in lower than budgeted labour costs in 2007 is associated with staff vacancies in the Training organization due to labour relations issues. The 2008, 2009 budgets reflect hiring of staff to the budgeted complement.
- For Security in 2007, approximately $1M lower than budgeted labour costs is associated with staff vacancies. The 2008, 2009 budgets reflect both filling staff vacancies in 2007 plus additional staff to meet the expanded Security Work Program.

Operational Functions – NDGS:

- There was no significant work that was deferred from 2007 to 2008 as overall Base OM&A spending was $1.7M over budget.

While Base OM&A for Nuclear was $39.5M under budget for 2007, all critical and high priority work programs were completed in 2007.

projected.

That's projected between mid 2017 and mid 2018, and this is described in more detail in Exhibit D2, tab 2, schedule 1, attachment 4, pages 28 and 29.

MR. KEIZER: Thank you. Then moving on to Board Staff Question No. 20, issue 6.6, relating to uranium procurement.

MR. PASQUET: OPG's response was not meant to imply that all purchases are made under long-term contracts.

In 2009, OPG purchased uranium on the spot market. In 2007-2008, 100 percent of the uranium purchases were done under long-term contracts.

A little more specifics around 2009, 23 percent of OPG's uranium purchases were done under spot market contracts, and obviously the balance, 77 percent, were done under long-term contracts. The spot market procurement process was put into place to allow OPG to quickly access the spot market.

The B part of this question, by regularly entering the market, OPG means generally entering the market approximately annually, and that is depending on the status of OPG's needs and market conditions.

Since the second half of 2007, OPG has entered the market in the first half of 2009, the spot market, and in the first half of 2010. And in a couple of cases, the long-term contracts are currently being finalized.

MR. KEIZER: Moving on, then, to Board Staff question 21, related to index pricing.

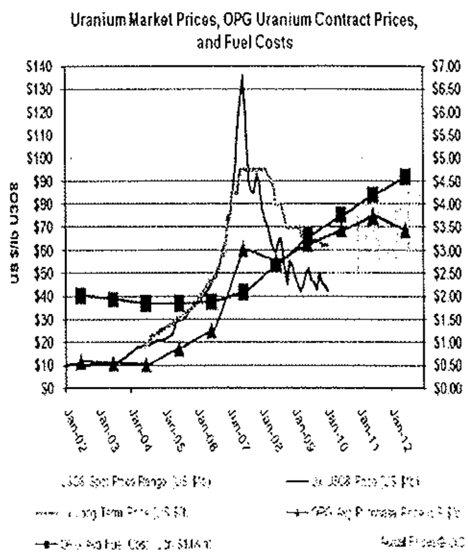
Board Staff Interrogatory #065

Ref: Ex. F2-T5-S1, pages 7-8

Issue Number: 6.6
Issue: Is the forecast of nuclear fuel costs appropriate?

Interrogatory

The chart on page 7 shows that both the spot and long term price for uranium have been steadily declining over the past two years from over US$90 per pound to about $40 and $60, respectively. Over the same period – 2008 to 2010 – OPG's costs associated with uranium have increased by about 35% (or $45.2M) and are forecast to increase a further 32% (or $55.7M) by 2012. It notes on page 8 this "disconnect" between declining market prices and rising OPG costs is primarily due to the timing of OPG's negotiation of uranium concentrate contract prices. This disconnect is reflected in the chart to the right which can be found on page 12 (as Attachment 1).



a) Given this material "disconnect", does OPG believe the current negotiation / purchasing strategy remains appropriate or should it be reviewed?
b) Given the variance account, 100% of the cost increase flowing from OPG's negotiation / purchasing strategy discussed above will be borne by ratepayers. What plans does OPG have to address this "disconnect"?
c) What incentive does OPG have to minimize the fuel costs with the variance account in place?
d) Should consumers pay for contracts that are significantly more expensive than market?

Response

The interrogatory incorrectly characterizes OPG's evidence at lines 24-27 on page 8 of Ex. F2-T5-S1. OPG's evidence is that "this disconnect between the trend in uranium market prices and the trend in nuclear fuel costs is primarily a reflection of the timing of OPG's negotiation of uranium concentrate contract prices, **the expiry of previously negotiated supply contracts, fuel inventory management, and inventory accounting**." [Emphasis added] All of the listed factors are relevant to the observed divergence between market prices for uranium and OPG's nuclear fuel costs.

Witness Panel: Nuclear Base OM&A & Revenues
Deferral and Variance Accounts, Payment Amounts and Regulatory Treatments

a) OPG believes its purchasing strategy of procuring a portfolio of indexed and market priced contracts continues to be appropriate.

The use of a portfolio approach allows OPG, which must regularly enter the uranium market for a portion of its supply needs, to mitigate the variations in extremes in market prices. The resulting average portfolio price will be more stable than relying on market prices alone and this provides a benefit to ratepayers. Any strategy for hedging risk through the use of long-term contracts will show poorly when viewed in hindsight solely through the lens of falling market prices, but market prices rise as well as fall.

Indexed-priced contracts have base prices set at the time of contract negotiation which escalate to the time of delivery by formula or by published, inflation-related indexes. Hence, prices at time of delivery under such contracts do not reflect market prices at time of delivery, but rather market prices at the time the contract was entered into, plus escalation. These indexed prices at the time of delivery may be higher, or lower, than the current market prices. The portfolio also includes market-related contracts, i.e., market contracts or market-related term contracts where price is established by the market price at or near the time of delivery.

OPG's procurement strategy also addresses security of supply. Since the physical markets for uranium are relatively thin, multi-year contracts are a way of ensuring OPG's security of supply. Compared to a strategy that relies more heavily on spot market purchases, OPG's approach helps protect consumers from the cost and risk of needing to procure uranium during periods of supply shortages.

b) The underlying premise of this question is incorrect. The existence of the Nuclear Fuel Variance Account does not mean that 100 per cent of the cost increase will necessarily be borne by ratepayers. If any of the costs in the variance account are found to be imprudent by the OEB, then OPG will not be able to recover these costs from ratepayers. It should also be noted that any cost decreases would be passed on to ratepayers

OPG notes that the current nuclear fuel procurement strategy was in effect long before the variance account. While OPG reviews the portfolio mix from time to time (i.e., indexed vs. market-related price contracts, term vs. spot market) OPG believes its strategy to be appropriate and has no plans to make fundamental changes.

c) Within the context of the Nuclear Fuel Variance Account, OPG continues to have a strong incentive to minimize its fuel costs given that, as indicated in part b), it will be unable to recover any costs determined by the OEB to be imprudent.

d) As indicated in part a), OPG's use of a portfolio approach can result in periods where its average portfolio price is above the prevailing market price and periods where its average portfolio price is below the prevailing market price. To the extent that the contracts in the portfolio were entered into competitively and prudently, then consumers should pay the cost of these contracts during periods when the market price is less than the contract price at the time of delivery since they will reap the benefit from contracts whose price is lower than the market price at the time of delivery. This is in accord with the OEB's consistent approach to reviewing prudence, which explicitly rejects disallowances based on viewing outcomes in hindsight in favour of an assessment based on the information that was known or reasonably should have been known at the time decisions were taken.

Chart 2
Existing Contracts by Pricing Category

	2010	2011	2012	Total
Market Related (000's kgU)	346	354	378	1,078
Indexed (000's kgU)	231	262	141	634
Total	577	616	519	1,712

The 321,000 kgU of new purchases (i.e., either under long-term or short-term spot market contracts) is priced at market prices forecast for 2010, 2011, and 2012.

3.5.2 Market Conditions

Starting in 2003, demand for uranium began to increase in response to a number of factors, including: supply disruption events which highlighted the production risks (e.g., floods in Saskatchewan and Australian mines and a fire at an Australian mill), a renaissance of nuclear programs worldwide, particularly in Asia, and recognition of the limits to inventory reductions. These factors stimulated increases in the price of uranium and, as the price continued to rise, encouraged the entry of non-traditional market participants, such as investment funds. Uranium spot market prices peaked in June 2007 at US$136 per pound. Term prices, which are the starting prices for indexed price contracts, increased in parallel with spot prices through the first quarter of 2007, reaching a plateau of US$95 per pound. The majority of worldwide uranium purchases are provided under term contracts. The remainder is traded on the spot market, defined as having delivery within one year.

Since this peak, spot prices declined through 2008 and 2009, initially, due to a lack of utility demand and the credit crisis which forced the sale of investor-held uranium, and most recently, due to soft utility demand and a higher than planned amount of production available for sale. Term prices declined as well but not as low as spot prices, reflecting the longer-term supply/demand market fundamentals and the expected cost of new production. On the supply side, the price run-up initially stimulated significant exploration, investment in mine expansion and new uranium mining projects around the world. Recently, the drop in uranium

VECC Interrogatory #020
(NON-CONFIDENTIAL VERSION)

Ref: Ex. F2-T5-S1, page 7, Figure 1.0, and page 9, Chart 3

Issue Number: 6.6
Issue: Is the forecast of nuclear fuel costs appropriate?

Interrogatory

a) Are the market-related prices for uranium concentrate simply the spot prices at the time of delivery? If not, please indicate exactly how market-related prices are determined.

b) For contracts B, C, and D, please provide a breakdown of the quantities subject to market related pricing and the quantities subject to indexation.

c) Please provide details as to how the prices are indexed, i.e., by a general index of inflation, by an index of commodity prices, etc.

d) Please provide details as to how OPG has hedged the price risk which is fully borne by ratepayers.

Response

a) The market-related price for uranium concentrate is not simply the spot price at the time of delivery. Market-related price is the price to be paid at the time of delivery, based on the average of published market price indicators for a specified period prior to delivery.

The two most common price indicators used to establish the price paid at the time of delivery for OPG market-related contracts are the following:

- The month-end U3O8 Long-Term Price Indicator (in United States dollars) per pound of uranium as U3O8, listed in The U_X Weekly published by The Ux Consulting Company LLC.

- The month-end U3O8 Long-Term Price Indicator (in United States dollar) per pound of uranium as U3O8 listed in the Nuclear Market Review published by Trade Tech LLC.

A combination of these indicators over different periods may also be utilized.

b) The breakdown of quantities subject to market pricing versus indexation for contracts B, C, and D is provided in the confidential version.

c) Contracts utilizing indexed pricing (base price escalation) will have a fixed price component which is subject to price escalation over the term of the contract based on changes in either (Consumer Price Index ["CPI"} for Canada – all items) or US Gross Domestic Product implicit price deflator for the base period specified in the contract.

d) The underlying premise of this question is incorrect. The existence of the Nuclear Fuel Variance Account does not mean that the price risk is fully borne by ratepayers. If any of the costs in the variance account are found to be imprudent by the OEB, then OPG will not be able to recover these costs from ratepayers. It should also be noted that any cost decreases would be passed on to ratepayers.

OPG's uranium concentrate procurement strategy, as stated in Ex. F2-T5-S1, page 5, is to maintain a combination of uranium concentrate supply contracts and inventory which provide a minimum of 100 per cent of delivery requirements for two years and a declining proportion of delivery requirements for ten years. OPG maintains a portfolio of uranium concentrates supply contract arrangements, diversified by source, contract term, and pricing mechanism. This portfolio diversity aids in the hedging of price risk, reduces cost volatility, and enhances supply security.

4.0 NUCLEAR FUEL COST FORECAST

The nuclear fuel cost forecast for the calendar years 2011 and 2012 is shown in Ex. F2-T5-S1 Table 1 along with comparable figures for 2008, 2009 and 2010. The nuclear fuel costs as shown in Ex. F2-T5-S1 Table 1 represent the total cost of each finished fuel bundle in aggregate as it is loaded into a reactor.

The total cost of a finished fuel bundle as it is loaded into a reactor includes the cost of each of the three components (i.e., uranium concentrate, uranium conversion, and fuel bundle manufacturing). The relative weighting of the cost of the uranium concentrate to the total cost of the finished fuel bundle is expected to vary over time reflecting the underlying price volatility of uranium concentrates as discussed in section 3.5.2 above. This price volatility adds a great deal of uncertainty to forecasting future nuclear fuel costs. Given the expected volatility, OPG is proposing to continue the Nuclear Fuel Cost Variance Account. Over 2008 and 2009, uranium market prices were lower than those forecast by OPG in EB-2007-0905, resulting in a credit in the Nuclear Fuel Cost Variance Account (see Ex. H1 T1 S1 Table 1). OPG is forecasting a debit amount for 2010, such that overall there will be a net debit balance in this account owing to OPG from ratepayers for the period 2008 - 2010.

Exhibit F2-T5-S1 Table 1 also includes costs related to nuclear used fuel management services as discussed at Ex. C2-T1-S2, and fuel oil which is used to run stand-by generators.

As shown in Ex. F2-T5-S1 Table 1, OPG's nuclear fuel costs are trending higher over the period 2007 - 2012, despite uranium market (spot and term) prices having leveled off after spiking in 2007 (Figure 1.0). This disconnect between the trend in uranium market prices and the trend in nuclear fuel costs is primarily a reflection of the timing of OPG's negotiation of uranium concentrate contract prices, the expiry of previously negotiated supply contracts, fuel inventory management, and inventory accounting.

- Timing of OPG contract negotiations: There is a time lag between the time when uranium concentrate indexed contracts are negotiated (which reflect market conditions at the time of negotiation) and the time when the uranium concentrate is delivered into OPG's

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inventory. OPG's indexed priced contracts have base prices, set at the time of contract negotiation, which escalate to the time of delivery by formula or by published, inflation-related, indexes. Hence prices at time of delivery under such indexed price contracts do not reflect market prices at time of delivery, but rather market prices at the time the contract was entered into, plus escalation. For example, prices for indexed contracts negotiated in 2006 that are delivered in 2011 will reflect market prices in 2006, plus escalation, not 2011 spot or term market prices.

Chart 3 shows a summary of existing uranium concentrate supply contracts.

Chart 3

Summary of Existing Fuel Contracts (as of Dec 31, 2009)

Contract	Contract Negotiation	Date of First Delivery	Delivery Period	Total Quantity (000 kgU)	Pricing: MR = Market related COMB = combination of MR and Indexed
A	2006 1st half	2007	7 years	1,462	MR
B	2006 1st half	2010	6 years	1,154	COMB
C	2006 1st half	2011	5 years	385	COMB
D	2007 2nd half	2009	9 years	1,154	COMB

- Expiry of Existing Contracts. Fuel inventory during the period 2010 - 2012 includes uranium delivered prior to 2010 under contracts entered into by OPG during periods of lower uranium prices. While deliveries under these contracts will terminate prior to the test period, these deliveries being in inventory will beneficially impact nuclear fuel costs during the test period.

- Fuel Inventory Management: OPG maintains inventories at each stage of the nuclear fuel supply chain to ensure that supply disruptions do not impact on generation capability. OPG must ensure that its reactors are not shut down due to lack of fuel, and in that respect must ensure that each step in the supply chain is not substantially delayed due to lack of materials. As noted earlier, OPG's strategy for ensuring an available supply of uranium concentrates is to maintain a combination of supply contracts and inventory which provide a minimum of 100 per cent of delivery requirements for two years and a

Numbers may not add due to rounding

Filed: 2010-05-26
EB-2010-0008
Exhibit B3
Tab 5
Schedule 1
Table 1

Table 1
Working Capital Summary - Nuclear ($M)
Calendar Years Ending December 31, 2007 to 2012

Line No.	Working Capital Item	Opening Balance	Closing Balance	(a+b)/2 Rate Base Value
		(a)	(b)	(c)
	2007 Actual:			
1	Cash Working Capital	N/A	N/A	16.0
2	Fuel Inventory	184.3	233.0	208.7
3	Materials & Supplies	382.4	418.4	400.4
4	Total			625.1
	2008 Actual:			
5	Cash Working Capital	N/A	N/A	15.9
6	Fuel Inventory	233.0	300.7	266.9
7	Materials & Supplies	418.4	412.8	415.6
8	Total			698.4
	2009 Actual:			
9	Cash Working Capital	N/A	N/A	14.3
10	Fuel Inventory	300.7	333.0	316.9
11	Materials & Supplies	412.8	456.0	434.4
12	Total			765.6
	2010 Budget:			
13	Cash Working Capital	N/A	N/A	9.2
14	Fuel Inventory	333.0	381.7	357.3
15	Materials & Supplies	456.0	481.9	468.9
16	Total			835.5
	2011 Plan:			
17	Cash Working Capital	N/A	N/A	4.0
18	Fuel Inventory	381.7	377.9	379.8
19	Materials & Supplies	481.9	488.7	485.3
20	Total			869.1
	2012 Plan:			
21	Cash Working Capital	N/A	N/A	4.0
22	Fuel Inventory	377.9	343.8	360.9
23	Materials & Supplies	488.7	478.6	483.7
24	Total			848.5

management of its nuclear waste and nuclear fuel." An "approved reference plan" shall be defined as "a reference plan, as defined in the Ontario Nuclear Funds Agreement, which has been approved by Her Majesty the Queen in the right of Ontario in accordance with that agreement."

OPG shall transfer the balance in the Nuclear Liability Deferral Account, Transition to this account effective April 1, 2008.

Nuclear Development Variance Account
OPG shall establish a Nuclear Development Variance Account effective April 1, 2008 pursuant to O. Reg. 53/05. The account shall record variances between the actual costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities during the test period and those approved by the Board.

OPG shall transfer the balance in the Nuclear Development Deferral Account, Transition to this account effective April 1, 2008.

NEW VARIANCE AND DEFERRAL ACCOUNTS
OPG shall record interest on the balances in these accounts using the interest rates set by the Board from time to time pursuant to the Board's interest rate policy. OPG shall apply interest to the opening monthly balance of these accounts until the balances are fully recovered.

OPG shall establish the following six new accounts effective April 1, 2008:

Capacity Refurbishment Variance Account
OPG shall establish a Capacity Refurbishment Variance Account pursuant to O. Reg. 53/05 section 6 (2) 4 to record variances between the actual capital and non-capital costs, and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to a generation facility referred to in O. Reg. 53/05 section 2 during the test period and those forecast costs approved by the Board. This account shall include assessment costs and pre-engineering costs and commitments.

Nuclear Fuel Cost Variance Account
OPG shall establish a Nuclear Fuel Cost Variance Account as proposed in its application to record the difference between the forecast and the actual cost of nuclear fuel expensed in the test period. OPG shall determine the variance based on the

variance in the total cost of the fuel bundles. OPG shall determine the difference between the nuclear fuel cost rate, expressed in $/MWh using the nuclear fuel cost as reflected in the revenue requirement approved by the Board and the production forecast approved by the Board, and the actual cost of nuclear fuel on a $/MWh basis. OPG shall apply this difference to its actual nuclear production during the test period. The resulting amount shall be recorded as the cost variance.

<u>Income and Other Taxes Variance Account</u>
OPG shall establish an Income and Other Taxes Variance Account as proposed in its application to record the financial impact on revenue requirement of:

- Any differences that result from a legislative or regulatory change to the tax rates or rules of the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario), as modified by the regulations under the *Electricity Act, 1998* to determine payments in lieu of corporate income taxes and capital taxes and the regulations under the *Electricity Act, 1998* to determine payments in lieu of property tax to the Ontario Electricity Financial Corporation.
- Any differences in municipal property taxes that result from a legislative or regulatory change to the tax rates or rules for its regulated assets under the *Assessment Act, 1990*.
- Any differences that result from a change in, or a disclosure of, a new assessing or administrative policy that is published in the public tax administration or interpretation bulletins by relevant federal or provincial tax authorities, or court decisions on other taxpayers that OPG will incorporate in determining its actual payments in lieu of corporate income taxes and capital taxes.
- Any differences that result from tax assessments or re-assessments (including re-assessments associated with the application of these rates and rules to OPG's regulated operations or changes in assessing or administrative policy including court decisions on other taxpayers).

OPG shall calculate the income tax provision resulting from the revenue requirement approved by the Board and file it with the Board. That tax provision shall be used to calculate any variations in taxes recorded in the variance account.

<u>Bruce Lease Net Revenues Variance Account</u>
OPG shall establish a variance account to capture differences between (i) the forecast costs and revenues related to Bruce that are factored into the test period payment amounts for Pickering and Darlington, and (ii) OPG's actual revenues and costs in respect of Bruce. The revenues and costs factored into the test period payment

Board Staff Interrogatory #067

Ref: Ex. F2-T2-S3, Attachment 1, Attachment 2

Issue Number: 6.7
Issue: Are the proposed expenditures related to continued operations at Pickering B appropriate?

Interrogatory

There appear to be a variety of cost estimates provided by OPG that range significantly ($184M - $300M) for the full Pickering B Continued Operations project.

- The initial OPG news release on Feb. 16, 2010 notes "*OPG will also invest $300 million to ensure the continued safe and reliable performance of its Pickering B station*".
- In this subsequent OPG application the following is found:
  - In the Business Case (Attachment 1), the table on page 2 shows a total estimated cost of $190.2M.
  - The estimate provided to the OPA is $184M as shown in the letter received from the OPA in the table under "INFORMATION PROVIDED BY OPG..." (Attachment 2).
- In OPG's *"2009 Sustainable Development Report"* subsequently issued on June 8, 2010, it states on page 42 that the cost estimate is $300M. The report specifically notes *"Pickering B Nuclear Refurbishment: Refurbishment of Pickering B will not be pursued. OPG will invest approximately $300 million to continue the safe and reliable performance of the plant for about the next ten years".*

a) Please explain this substantial range in cost estimates provided by OPG over a relatively short period of time (about 5 months) for the same project.

b) Please also identify the estimated cost the Board should consider to be the most accurate estimate and explain why. Please also explain the level of confidence OPG has in that estimated cost in quantitative terms (e.g., +/-15%, +/-30%, etc).

Response

a) The $184M estimate provided to the OPA and the $190.2M in the business case are equivalent. The $184M represents the cost in 2010 dollars (unescalated) of the Continued Operations initiative during the business planning period (2010 – 2014). The $190.2M is the same number expressed in dollars of the year (escalated).

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The $300 million was announced in the context of incremental investments in Pickering *"to continue the safe and reliable performance of the plant for about the next 10 years"* and is a conservative estimate. Pickering A and B are expected to operate until 2018/2020 under continued operations.

b) The estimated cost that the OEB should consider in this rate application is $190.2M, as shown in OPG's Pickering B Continued Operations BCS and the 2010 – 2014 Nuclear Business Plan. The associated test period OM&A amounts are $92.9M plus $11.7M for the Fuel Channel Life Cycle Management project, as found at Ex. F2-T2-S3, Chart 2. OPG considers the estimate to be a budgetary estimate, with a plus 30 per cent to minus 15 per cent range.

MR. PASQUET: There were two indices identified in OPG's interrogatory response, and these are commonly used by the uranium suppliers in response to OPG's request for proposals.

In general, a contract with a Canadian supplier is more likely to use a Canadian index, while an international supplier is more likely to use a US or other index.

However, the use of the particular escalation index in the contract is a function of what the market is offering at the time of the contracting -- of the contract, the location source and supply, and the negotiation that is undertaken.

The B part of the question, in response for proposals, OPG does not specify the particular index to be used. However, OPG asks that in the request for proposal, that to the extent that prices that are under the proposal will be subject to escalation, that escalation indexes are independently published and relevant to the supply.

MR. KEIZER: Moving on, then, to Board Staff Question No. 22, related to issue 6.7, which deals with Pickering B, continued ops.

MR. PASQUET: As indicated in the response to the interrogatory, the cost estimate that the OEB should consider is the $190.2 million number. There was no contingency that was built into this estimate, as indicated in Exhibit F2, tab 3, schedule 3, attachment 1, page 17, appendix C, as the vast majority of the work in that is base and outage OM&A work.

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The public announcement really provides a conservative upper bounds for continued operations at the site. The actual cost included an upper range of confidence, and then was subsequently rounded up to $300 million.

As indicated in the actual business case that was provided, the benefits of the project are relatively insensitive to costs. Doubling the project costs reduces expected value of continued operations to approximately slightly less than $1 billion.

But, again, I just want to reemphasize that the cost estimate for the purpose of this rate hearing is the $190.2 million.

MR. KEIZER: Then moving on to Board Staff Question No. 23 --

MS. HELT: Just a follow-up, I believe.

MR. CINCAR: I just want to confirm there was no contingency amount included in either of the estimates, the 190.2 or the 300 million?

MR. PASQUET: So the 190.2, that is correct. There was no contingency built in; that is correct.

The 300 million was a conservative upper bound and it was rounded up, but there wasn't specifically a block of contingency built in. It was just an upper bound for the -- for that project that was announced.

Again, we have had a number of discussions, a number of questions around that. It is the 190.2 that our rate hearing is based on.

MR. CINCAR: Thank you.

MR. KEIZER: Then moving on to Board Staff Question No. 23, relating to the benefit estimate of 1.1 billion.

MR. PASQUET: So as identified in the business case for continued operations, the initiative does have substantial value to the Ontario electrical system.

The net present value is calculated based on the -- on the difference between the estimated cost of Pickering B's output and the cost estimate for replacement generation over the period in question, ending in 2020. And that net present value was 1.1 billion in 2010 dollars.

As referenced in the business case, in performing sensitivity tests on the business case, OPG derived an estimate cost replacement generation using the equivalent of OPG's current regulated rate of $53 per megawatt, real, as well as $53 per megawatt-hour, nominal, escalated for inflation over the period of 2010 to 2020. And in both cases, the NPV was positive.

The B part of this question, OPG's modelling has approximately 2 percent of the remainder coming from Lennox, and none of the replacement energy or generation for Pickering is deemed to come from renewables.

OPG -- excuse me. So the C part of the question, OPG believes the natural gas price forecast is reasonable, as sensitivity cases were analyzed for low gas prices, and the range of gas prices that were analyzed were anything between, in US dollars, four-dollar gas to ten-dollar gas, and in both cases they yielded a positive net present value.

Chart 2
Pickering B Refurbishment and Continued Operations

Costs ($M)	Life-to-date 2007 (1)	Actual 2008	Actual 2009	Plan 2010	Plan 2011	Plan 2012	Information Source
Pickering B Refurbishment Project							
- Base OM&A	**35.9**	**9.0**	**4.3**	**1.2**	**0.0**	0.0	F2-T2-S1 Table 1
Pickering B Continued Operations Initiative							
- Base OM&A	0.0	0.0	1.6	9.8	17.7	14.7	F2-T2-S1 Table 1
- Outage OM&A	0.0	0.0	2.8	1.9	13.0	10.6	F2-T4-S1 Table 1
- Project OM&A	0.0	0.0	0.4	1.8	19.9	17.0	F2-T3-S1 Table 1
Subtotal Nuclear Operations OM&A (PB CO)	**0.0**	**0.0**	**4.8**	**13.5**	**50.6**	**42.3**	
Fuel Channel Life Cycle Management Project							
- Project OM&A	**0.0**	**0.0**	**2.5**	**9.7**	**7.7**	**4.0**	F2-T3-S1 Table 1

Note 1: F2-T2-S1 Table 2 shows 2007 actual costs, whereas this Chart presents all costs to year-end 2007.

6.1 Pickering B Refurbishment

There are no OM&A or capital costs budgeted for Pickering B refurbishment for the test period. The vast majority of Pickering B refurbishment Phase 1 activities have been completed as of the end of 2009, including preparation and approval of the EA and the ISR.

Pickering B Refurbishment base OM&A costs were $9.0M in 2008 and $4.3M in 2009. The 2010 - 2014 Business Plan includes expenditures of $1.2M in 2010 in order to obtain CNSC's acceptance of the final ISR report and to close out the Pickering B refurbishment project. The total actual and forecast costs for Phase 1 of Pickering B refurbishment is $50.4M as shown in Chart 2. Of this amount, $45.8M had been approved for release by the

Numbers may not add due to rounding.

Filed: 2010-05-26
EB-2010-0008
Exhibit F2
Tab 3
Schedule 1
Table 1

Table 1
Project OM&A Summary - Nuclear ($M)

Line No.	Facility Projects	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	Facility Projects (Released)						
1	Darlington NGS	26.8	28.2	38.2	30.5	4.0	0.4
2	Pickering A NGS	12.5	9.3	6.7	7.8	3.3	0.7
3	Pickering B NGS	22.0	37.2	15.0	17.3	2.6	0.1
4	Nuclear Support Divisions[1]	3.6	8.6	19.0	8.6	4.4	2.1
5	**Total Facility Projects (Released)**	65.0	83.4	78.9	64.3	14.4	3.3
6	**Facility Projects to be Released**	0.0	0.0	0.0	43.8	40.2	37.5
7	**Infrastructure**	37.1	39.6	39.4	33.0	33.0	33.1
8	**Listed Work to be Released**	0.0	0.0	0.0	(29.4)	20.7	37.4
9	**Subtotal Project OM&A (Portfolio)**	102.1	123.0	118.3	111.7	108.3	111.2
10	**P2/P3 Isolation Project**	9.5	13.5	22.5	20.6	0.0	0.0
11	**PB Continued Operations Projects**	0.0	0.0	0.4	1.8	19.9	17.0
12	**PB Refurbishment Project**	0.0	0.0	0.0	0.0	0.0	0.0
13	**Fuel Channel Life Cycle Mgmt Project**	0.0	0.0	2.5	9.7	7.7	4.0
14	**Total Project OM&A**	111.6	136.5	143.7	143.8	135.9	132.2

Notes:
1 Nuclear Support Divisions includes Engineering, Projects & Mods, Supply Chain, Programs & Training, Inspection Mtce and Commercial Services, Facilities and PINO.

Numbers may not add due to rounding.

Table 3
OM&A Project Listing - Nuclear
Projects <$5M Total Project Cost[1]

Line No.	Sponsoring Division	Number of Projects	Total Project Cost ($M)	Average Cost Of All Projects ($M)
		(a)	(b)	(c)
	Facility Projects			
1	Darlington NGS	13	26.5	2.0
2	Pickering A NGS	12	21.3	1.8
3	Pickering B NGS	15	22.4	1.5
4	Nuclear Support Divisions[2]	12	15.6	1.3
5	**Total**	52	85.7	1.6

Notes:
1 Projects with expenditures during Test Period.
2 Nuclear Support Divisions includes Engineering, Projects & Mods, Supply Chain, Programs & Training, Inspection Mtce and Commercial Services, Facilities and PINO.

APPENDIX B: Impacts on Generation of Pickering B Continued Operations

Title: Pickering B Continued Operations

	Work Program Impacts	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Pick B	Life Cycle Mgmt & Insp Programs	27	65	0	45	N/A	N/A	N/A	N/A	N/A	N/A	N/A	137
	Other Planned Outage Activities	1	46	56	26	N/A	N/A	N/A	N/A	N/A	N/A	N/A	129
	Total Incremental PO Days	28	111	56	71	N/A	N/A	N/A	N/A	N/A	N/A	N/A	266
	Total Incremental/Decremental TWh	-0.3	-1.2	-0.7	-1.1	4	9.5	14.4	14.2	11.3	6.4	3.4	61.9
Pick A	Total Incremental/Decremental TWh	N/A	N/A	N/A	N/A	0.6	7.8	7.8	7.7	7.8	8	3.3	43.1
PA & PB	Total Incremental/Decremental TWh	-0.3	-1.2	-0.7	-1.1	4.6	17.3	22.2	21.9	19.1	16.4	6.7	105

APPENDIX C: COST SUMMARY

ONTARIOPOWER GENERATION	Summary of Estimate	Date	17-Feb-10
		Project #	NA

Facility Name:	Pickering B
Project Title:	Pickering B Continued Operations

Estimated Cost in Million $

Year	2010	2011	2012	2013	2014	2015	2016	Totals	%
Life Cycle Mgmt & Insp Programs	1.8	8.8	4.9	4.4	5.2			35.1	
Other Planned Outage Activities	1.3	8.3	9.7	4.8	2.5			26.6	
Component Improvements	8.6	13.6	10.6	15.6	9.5			57.8	
Feeder Replacements					8.9			8.9	
Fuel Channel Life Mgmt Project	1.3	4.9	3.9	2	0.5			12.5	
Enhanced Water Lancing		12	7.8	3.6	7.8			31.2	
Other Projects	0.5	3	5.3	6.3	3			18.1	
Interest	-								
Contingency									
Totals	13.5	50.5	42.2	36.7	47.4			190.2	

Prepared by:	Approved by:
Director, Business Support (Pick B)	Site Vice President, Pickering B

Integrated Safety Review and Related Issues

A detailed assessment of Pickering B against modern codes and standards was carried out as part of the Integrated Safety Review process during the assessment of the refurbishment of Pickering B. While the evaluations were done on the basis of refurbishing and continuing to operate Pickering B for an additional 30 years, there are potential cost impacts on the Continued Operations period to address issues identified in the Integrated Safety Review. The economic assessment of Continued Operations includes incremental costs to fund these potential issues.

Impact on Pickering A Operation

Units 1 and Unit 4 are currently in operation at Pickering A. The current predicted end-of-service lives for Pickering A Units 1 and 4 are the end of 2021 and 2027 respectively, assuming independent operation from Pickering B is feasible.

Pickering A's operation is linked to Pickering B through shared common systems and in particular, power supplies to some safety systems. OPG's assessment is that two units on the Pickering B station must be in operation in order to support the Pickering A units. As a result, significant modifications to systems to address this issue will be required to facilitate the operation of Pickering A in the absence of Pickering B. In addition to addressing the technical issues, these modifications and other mitigation actions would need approval by the CNSC.

While it would not be impossible to operate Pickering A after end of life of Pickering B, OPG at this time would not attempt to operate Pickering A with Pickering B shutdown. The costs to operate Pickering A independent of Pickering B would likely equal or exceed the system value.

Impact on Financial Outlook

Should the Pickering B Units be shutdown in the 2014-2016 time period, further review of the potential impact on depreciation costs, severance costs, and the decommission fund would be required.

4. ALTERNATIVES AND ECONOMIC ANALYSIS

The alternatives being analyzed are: (I) plan to operate Pickering B to 210,000 EFPH on the pressure tubes, then shut down the units versus (Ii) plan to operate the units to 240,000 EFPH before the units are shutdown. In order to have two units on the Pickering B station in operation to support the Pickering A units, the alternative of operating the Pickering B units to 240,000 EFPH includes an assumption of "modified" outages on Pickering Unit 7 in order to achieve the objective of aligning its life with that of Pickering Unit 8.

ALTERNATIVE 1 –NOMINAL LIFE CASE:
Plan to Operate all Pickering B Units until 210,000 EFPH on the pressure tubes.

In this alternative, no incremental inspections, maintenance, analytical or regulatory strategies would be put in place to try to continue to operate the units beyond 210,000 EFPH on the pressure tubes. The nominal predicted end-of-life dates for the Pickering B Units would be Q2 2014 for P5 and P6, Q1 2015 for P7, and Q2 2016 for P8. The assumption would be that, as 3 Pickering B units would be shutdown by Q1 2015, Pickering A Units 1 and 4 would also be shutdown in Q1 2015.

extension to the operating life of the Pickering B units. The Province concurred with this decision in a letter from the Minister of Energy and Infrastructure to OPG dated February 4, 2010 and provided at Ex. D2-T2-S1 Attachment 3.

The economic assessment of Pickering B Continued Operations contained in the attached business case (Attachment 1) shows that the initiative has substantial value to the Ontario electricity system. OPG estimates the net present value of this initiative to be approximately $1.1B (2010 dollars). This net present value is based on the difference between the estimated cost of Pickering B's output and the estimated cost of replacement generation. In addition, seeking to confirm its own estimates, OPG approached the Ontario Power Authority ("OPA") and requested that it provide an assessment of the system benefits associated with the Continued Operations initiative. In a letter from the OPA, which can be found at Attachment 2, the OPA concludes that:

> Based on the potential for substantial system benefits, the OPA supports a decision by OPG to proceed with an initial expenditure of funds in the period 2010 – 2012 to assess the feasibility of continued operation of Pickering NGS, and to maintain the option for continued operation should it prove to be feasible. System benefits should be re-assessed before committing additional funds required beyond 2012.

Section 3.0 provides background on the Pickering B Continued Operations initiative and Pickering B Refurbishment. Section 4.0 provides the status of Pickering B Refurbishment. Section 5.0 sets out the economic justification for the Pickering B Continued Operations initiative and section 6.0 sets out the risk assessment and a cost summary of the initiative.

3.0 BACKROUND

The previously assumed nominal end of life for the Pickering B units was 2014 (for Units 5 and 6), 2015 (for Unit 7), and 2016 (for Unit 8). The nominal end of life estimate for the station was predicated on the nominal design life of the key major component (i.e., the pressure tubes). The nominal design life of the pressure tubes was originally projected to be 210k Equivalent Full Power Hours ("EFPH").

5.3 Risk Assessment

OPG has identified risks to its ability to achieve the objectives of the Pickering B Continued Operations initiative. The two primary, but manageable, risks are the ability to demonstrate fitness-for-service for the pressure tubes (i.e., the risk that a major component does not continue to meet fitness-for-service requirements) and regulatory (i.e., the risk that OPG is unable to obtain CNSC approval of OPG's fitness-for-service assessment criteria for continued service life of the pressure tubes).

To address these risks, a component of OPG's work activity during 2010 - 2012 is designed to provide increased assurance that the units can be operated reliably until 2018 (for Units 5 and 6) and 2020 (for Units 7 and 8). This work includes the Fuel Channel Life Cycle Management Project, which is to be completed in 2012. This OPG-initiated industry effort is being coordinated through the CANDU Owners Group. Successful completion of this initiative would lead to greater certainty around the remaining service lives of all of the CANDU units in Ontario. OPG is also progressing in its ongoing discussions with the CNSC on regulatory issues related to determination of fitness-for-service. OPG needs to complete this work to satisfy the technological and CNSC regulatory issues associated with Pickering B Continued Operations. OPG expects that by undertaking this work activity, OPG will by late-2012 have a high level of confidence regarding its ability to extend the life of the pressure tubes at Pickering B.

A full description of the fitness-for-service, regulatory and other issues is provided in the business case for Pickering B Continued Operations which is attached as Attachment 1.

6.0 COST SUMMARY – REFURBISHMENT AND CONTINUED OPERATIONS

Chart 2, below summarizes OM&A actual and forecast expenditures on the Pickering B Refurbishment project and on Pickering B Continued Operations, from 2007 (Life to Date) to 2012. There are no actual or forecast test period capital expenditures over this period.

Board Staff Interrogatory #052

Ref: Ex. F2-T3-S3, Attachment 1, Tab 16
F2-T1-S1, Attachment 1, page 22

Issue Number: 6.3
Issue: Is the test period Operations, Maintenance and Administration budget for the nuclear facilities appropriate?

Interrogatory

This BCS relates to Fuel Channel Life Management (Project No. 62444). This project is to accelerate R&D (Research & Development) work to develop better information and the knowledge base with respect to degradation mechanisms and processes affecting the integrity of pressure tubes or fuel channels.

a) On page 22 of OPG's Nuclear Business Plan "Risks to Business Plan", it notes: "*End of Life Determination: The medium risk in the confidence level of attaining the planned effective full power hours (EFPH) for Darlington and Pickering B units is insufficient for effective business planning.*" Please clarify what the implications are with respect to the planned life extension of the Pickering B units and the planned refurbishment of the Darlington units in the event of each of the following scenarios:

   i) The project is delayed and the planned results and information are not produced in a timely fashion, i.e., in 2012;

   ii) The results and information are inconclusive or negative, i.e., do not support the higher end-of-life operating limits for Darlington (210,000 EFPH) and for Pickering B (240,000 EFPH).

b) If the confidence level of attaining the planned EFPH for Darlington and Pickering B units is insufficient for effective business planning, why does OPG consider the confidence level to be sufficient for Board approval of significant proposed costs related to Pickering B Continued Operations and the Darlington Refurbishment?

c) On page 9 of the Business Case Summary, it is stated that this project will be jointly funded between OPG and Bruce Power with cost sharing at a ratio of 5.5:3.5 (OPG:BP). Please explain the basis of this cost sharing ratio.

Response

a) Answers to questions a) i) and a) ii) are provided together as the implications of delay and the implications of inconclusive or negative results issues are interrelated:

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<u>Implications for Pickering Generating Station:</u>

If the results of the Fuel Channel Life Cycle Management ("FCLM") project were delayed, or were inconclusive or negative, OPG would not achieve high confidence by 2012 of achieving 240,000 Effective Full Power Hours ("EFPH") from each of the units.

i) In the case of a delay, to determine how to proceed, OPG would need to assess a number of factors, including the anticipated duration of the delay, Canadian Nuclear Safety Commission ("CNSC") regulatory requirements in effect at that time, and any preliminary results available that would increase confidence in the predicted end-of-life for the station.

ii) If the results were inconclusive or negative, OPG would need to:

- Undertake the activities required to determine the lives of the units and prepare for potential safe storage.

- Advise the OPA and IESO of the predicted end-of-life for the Pickering Generating Station units.

- Initiate planning for an orderly shut-down of the Pickering Generating Station units.

- Assess the impact on OPG's financial outlook.

<u>Implications for Darlington Generating Station:</u>

i) and ii)
As indicated at Ex. F2-T3-S3, Attachment 1, Tab 16, page 3, paragraph 3, the current "high confidence" life of Darlington Generating Station is 187,000 EFPH. The implications of delay, inconclusive or negative results of the FCLM project on Darlington Generating Station are that OPG would need to prepare for early refurbishment of the Darlington Generating Station units. OPG has recognized this risk and is currently working to be ready to start the refurbishment of the first Darlington Generating Station unit in 2015, if required, which is the earliest that OPG assesses that it would be ready to refurbish the first Darlington Generating Station unit.

If the results are inconclusive or negative, OPG would inform the OPA and the IESO as early as possible about any changes to the refurbishment dates for Darlington Generating Station, particularly if these dates are to be advanced.

b) The interrogatory references the 2010 – 2014 business plan presentation to the OPG Board of Directors, where inclusion of this statement as a "strategic risk" was to stress the critical importance of station end-of-life determination, and approval of the associated funding (such as the FCLM project).

Given the value to the Ontario electricity system of Pickering B Continued Operations as assessed by both OPG and the OPA (see Ex. F2-T2-S3, Attachment 2), the need to embark on this work now (as explained in response to part a) i) and a) ii) and Ex. L-01-072), and the significantly increased flexibility OPG would achieve in planning for the refurbishments of the Darlington Generating Station units if the FCLM project were successful, OPG believes that this is a prudent expenditure which should be approved by the OEB.

c) There are two areas of cost sharing under the FCLM project:

- Pressure tube burst testing: shared equally between OPG, Bruce Power and Atomic Energy of Canada Ltd. ("AECL"); and,

- Other R&D programs: shared equally between OPG and Bruce Power (47 per cent each), with a contribution from AECL (6 per cent).

When OPG project management and oversight costs and OPG contingency are added exclusively to OPG's share of the R&D costs, the approximate shares are: 55 per cent (OPG) 35 per cent (Bruce Power) and 10 per cent (AECL), as indicated in the business case summary.

8. POST IMPLEMENTATION REVIEW

The strategic work outlined in this Business Case is intended to provide greater certainty in the achievement of Continued Operations for Pickering B. The incremental work and expenditures required will be reviewed in each business planning cycle.

Physical Work (Inspections & Maintenance):

(i) Results of planned pressure tube inspection.

Technical Analyses / Regulatory Strategy:

(i) Verify that the Continued Operations work scope is being progressed.

Strategic Questions

(i) What is the current status of the plans for refurbishing the Darlington units and how have any changes to those plans affected the strategy for Pickering B Continued Operations?

(ii) How are the plans for new nuclear build progressing and how do any changes affect the strategy for Pickering B Continued Operations.

ONTARIO POWER GENERATION

Cost Plan - OM&A Cost Savings

Nuclear Operations 2010-2014 Business Plan

($ millions)	2010	2011	2012	2013	2014	Total
Total OM&A - 2009-2013 Approved BP	$1,679	$1,579	$1,617	$1,764		
Targeted Reductions (Note 1)	-$40	-$53	-$61	-$87		
Additional Expenditures (Note 2)	$14	$17	$20	$21		
Additional Savings (Note 3)	-$58	-$58	-$68	-$68		
Nuclear Operations OM&A Plan-over-Plan Reduction	**-$84**	**-$94**	**-$110**	**-$135**		-$423
Nuclear Operations OM&A 2010-2014 Submission	**$1,595**	**$1,485**	**$1,507**	**$1,629**		
Corporate Planning Guidelines 2010-2014	**$1,639**	**$1,579**	**$1,617**	**$1,764**		
Nuclear Operations Savings above Guidelines	**-$44**	**-$94**	**-$110**	**-$135**		
Pickering B Continued Operations Investment		$51	$42	$37		
Pickering A P2/P3 Project Timing	$9					
Total OM&A Submission 2010-2014	**$1,604**	**$1,535**	**$1,549**	**$1,666**	**$1,673**	

Note 1:	2010	2011	2012	2013
Pickering A	-$6.0	-$13.0	-$10.0	-$12.0
Pickering B	-$9.0	-$9.0	-$9.0	-$14.0
Darlington	-$9.0	-$9.0	-$11.2	-$21.4
Nuclear Programs & Training	-$10.0	-$14.4	-$20.8	-$25.4
Nuclear Supply Chain	-$0.5	-$0.5	-$0.5	-$2.0
Engineering & Modifications	-$2.0	-$3.5	-$5.2	-$7.0
Nuclear Waste Management	-$0.2	-$0.3	-$0.4	-$0.6
Inspection Maintenance & Commercial Services	-$2.3	-$2.9	-$3.9	-$4.3
Performance Improvement & Nuclear Oversight	-$0.2	-$0.2	-$0.2	-$0.2
CNO Office	-$1.0	$0.0	$0.0	$0.0
Targeted Reductions - Base and Outage	-$40.2	-$52.8	-$61.2	-$86.9

Note 2:	2010	2011	2012	2013
2010 Vacuum Building Outage	$14.0			
2011/2012 Turbine Work - PA		$7.2	$8.2	
Underfunded OM&A Project Portfolio		$5.0	$5.0	$10.0
NPT Shortfall on Targeted Reductions		$4.3	$6.3	$10.8
Additional Expenditures	$14.0	$16.5	$19.5	$20.8

Note 3:	2010	2011	2012	2013
Impact of Lower Labour Burden Rate	-$38.0	-$38.5	-$48 7	-$47.5
Impact of New Labour Rates	-$12.4	-$13.0	-$12.7	-$13.8
SAVHO Reallocation to Capital Projects	-$5.4	-$5.0	-$4.7	-$3.8
Continued Operations	-$2.0			
IM&CS Savings		-$1.3	-$2.1	-$3.3
Additional Savings	-$57.8	-$57.8	-$68.2	-$68 4

ONTARIOPOWER GENERATION

OPG Confidential	Page: 3 of 16
BUSINESS CASE SUMMARY	

Pickering B Steam Generator Maintenance Waterlancing 13 - 40645

Full Release Business Case Summary NK30-BCS-36340-00004-R000

1/ RECOMMENDATION:

We recommend a Full Release of $25M (including contingency) to complete Water Lancing on all four Pickering B units from 2008 to 2010 as recommended in the Steam Generators Life Cycle Management Plan (LCMP) (NK30-PLAN-33110-10008), and the Steam Generator Investment Review (30 May 2006) (N-REP-33110-10018)

The business objectives of this project is to:

- Reduce / eliminate the risk of forced outages due to tube leaks caused by sludge build up.
- Reduce/eliminate the need for future Chemical Cleaning campaigns
- Maintain critical assets until units end-of-life

Under-deposit pitting due to sludge build-up is one of the main failure mechanisms causing tube leaks in the steam generators. A multifunctional Steam Generator Review team recently completed a study of this type of failure and came to the following conclusions:

- A Fitness for Service strategy of inspecting and plugging of tubes will allow us to operate all units until their current End of Life dates; however, this strategy will lead to a deteriorating and perhaps irreversible SG performance that will result in a large financial penalty and likely loss of regulatory credibility.
- The current Life Cycle Plan involving Water Lancing every four years will substantially reduce the likelihood of forced outages (under a Fitness for Service strategy) and will therefore provide a significant financial benefit.
- Other variations of the current LCP such as targeted and enhanced Water Lancing may provide marginally greater value but cost more and involve greater risk.
- Changes in this strategy should be considered if End of Life, Forced Loss Rate, and Planned Outage projections change significantly.

Based on the recommendations of this study we are therefore requesting approval of a Full Release of $25M to conduct Water Lancing on each PB unit from 2008 to 2010. Should further analysis or more definitive refurbishment / EOL dates suggest there is more value in an alternative strategy, we will submit a superseding BCS outlining the opportunities and risks.

$000's (incl contingency)	Funding	LTD 2006	2007	2008	2009	2010	2011	Later	Total
Currently Released	N/A								
Requested Now	Full								-
Future Funding Req'd			486	6,318	11,487	6,287	395		24,973
Total Project Costs									-
Other Costs		-	486	6,318	11,487	6,287	395	-	24,973
Ongoing Costs									-
Grand Total		-	486	6,318	11,487	6,287	395	-	24,973

Investment Type	Class	(IEV) Impact on Ec Value	IRR	Discounted Payback
Sustaining	OM&A	[illegible]	N/A	N/A

Submitted By:

P. Tremblay
Senior Vice President Pickering B

Apr 1/07
Date:

Finance Approval:

D. Power
Director Investment & Business Planning

April 25/07
Date:

Line Approval (Per OAR Element 1.1 Project in Budget):

J. Hankinson
President & CEO

Date: