SCHOOL ENERGY COALITION

CROSS-EXAMINATION MATERIALS

OPG PANEL 3

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

Nuclear Level Common includes centralized costs required to manage the Nuclear business overall that are not directly attributable to any one plant or support organization. Typical costs include nuclear level consulting contracts. In addition, Nuclear Level Common includes the labour price variance, which is the difference between actual nuclear payroll costs incurred and the standard labour costing model used in the divisions to facilitate resource planning and cost reporting. For example, the business plan labour cost forecast is established using standardized labour rates calculated for job families, whereas actual costs reflect the true payroll cost for each employee.

Within the support divisions, the largest cost is with Programs and Training, reflecting the significant level of infrastructure associated with providing core services in the key areas outlined above, including developing and delivering training, managing the overall security function for the generating stations and support divisions, administrative support and records management. Further breakdown of Programs and Training functions, and explanation of year-over-year trends for all support divisions can be found in Ex. F2-T2-S2.

2.2 Resources Required to Execute Base OM&A Work Programs

Exhibit F2-T2-S1 Table 2 presents the mix of resources required to execute the broad range of base OM&A functions. Further details of each resource type are provided here.

<u>Labour:</u> The majority of base OM&A costs are labour, averaging 76.7 per cent of total base OM&A expenditures over the test period. Labour costs reflect staffing levels and wages; including negotiated labour agreements for unionized staff (see Ex. F4-T3-S1). The labour rates used to derive Nuclear base OM&A include staff wages and payroll benefit costs, and are therefore impacted by wage rate increases, payroll burden changes as well as accounting provisions for a 53rd fiscal week in 2012 (see Ex. F2-T2-T1 Table 3).

<u>Other Purchased Services:</u> After labour, the next largest cost element is other purchased services, averaging 8.4 per cent of total base OM&A over the test period. For the generating stations, other purchased services represents work done by specialized contractors, such as laundry services, maintenance contractors, material repairs, environmental compliance

Numbers may not add due to rounding.

Table 14
Total Work Program Regular Headcount or FTEs

Line No.	Division	2007 Actual (Headcount[1])	2008 Actual (Headcount[1])	2009 Actual (Headcount[1])	2010 Budget (FTEs)	2011 Plan (FTEs)	2012 Plan (FTEs)
		(a)	(b)	(c)	(d)	(e)	(f)
	Nuclear Stations						
	Darlington NGS						
	Operations & Maintenance						
1	- Operations	400	412	436	398	385	397
2	- Maintenance	620	576	549	580	583	582
3	- Fuel Handling	141	142	149	183	170	169
4	- Rad Prot, Chemistry & Envrnt	94	98	98	97	98	98
5	Station Engineering	195	204	221	201	191	183
6	Work Management	73	73	70	71	68	68
7	Support Services	88	94	97	96	95	95
8	Tritium Removal Facility	91	96	104	103	101	101
9	Subtotal	1,702	1,695	1,724	1,730	1,691	1,693
	Pickering A NGS						
	Operations & Maintenance						
10	- Operations	255	271	242	255	257	256
11	- Maintenance	326	338	336	326	295	292
12	- Fuel Handling	105	96	93	96	91	91
13	- Rad Prot, Chemistry & Envrnt	21	23	26	23	20	19
14	- Pickering Common Services	41	44	43	50	50	50
15	Station Engineering	154	149	149	141	133	129
16	Work Management	60	74	82	68	51	50
17	Support Services	35	34	37	34	29	28
18	P2/P3 Safe Storage & Isolation	108	117	126	55	0	0
19	Subtotal	1,105	1,146	1,134	1,048	925	915
	Pickering B NGS						
	Operations & Maintenance						
20	- Operations	359	368	368	367	366	361
21	- Maintenance	627	563	602	658	641	631
22	- Fuel Handling	148	142	151	149	141	130
23	- Rad Prot, Chemistry & Envrnt	120	122	149	136	119	119
24	- Pickering Common Services	84	90	87	101	101	102
25	Station Engineering	227	218	226	206	187	179
26	Work Management	81	79	78	72	64	61
27	Support Services	102	99	38	43	38	38
28	Continued Operations	0	0	0	52	87	73
29	Pickering B Refurbishment	50	24	11	1	0	0
30	Subtotal	1,798	1,705	1,710	1,784	1,743	1,693
	Nuclear Support Divisions						
31	Engineering	308	310	331	311	289	269
32	Projects & Modifications	366	368	398	356	337	337
33	Facilities Management	163	181	184	193	194	189
34	Programs & Training	766	890	803	738	705	692
35	Supply Chain	431	385	381	370	362	353
36	PINO	69	63	57	57	57	57
37	Inspection & Mtce Services	539	570	579	537	476	431
38	Commercial Activities	8	9	7	8	6	6
39	Waste & Transportation Services	22	22	22	22	22	22
40	Nuclear Level Common	4	4	2	2	2	2
41	**Subtotal**	2,676	2,802	2,764	2,594	2,450	2,358
42	**Total Nuclear Operations**	7,281	7,348	7,332	7,155	6,808	6,659

Notes:
1 Total regular staff numbers reflect staff currently working in and being paid by Nuclear (non home-base assignment).

related support costs from general indirect costs to IMS (non-energy revenue related) direct cost (-$4.4M); and, lower than planned staffing (-$2.0M).

- Commercial Services (-$2.0M) reflecting primarily lower than planned expenditures associated with Bruce lease renegotiation (-$2.0M).
- Waste & Transportation Services (-$1.3M) reflecting lower than planned conventional waste shipments, supplemented by divisional cost control efforts.
- Nuclear Level Common (-$19.2M) reflecting primarily: under expenditure on the labour price variance account (-$11.2M) as a result of actual labour costs being lower than plan due to the impact of senior staff attrition and junior staff hires and, lower actual overtime costs versus standard rates (e.g., greater than planned use of time-and-a-half versus double time work); P2/P3 safe storage project electricity credits and insurance premium rebate (-$3.6M); and, less than planned CNO level expenditures primarily due to unspent budget for nuclear level consulting contracts (-2.4M).

<u>2009 Actual versus 2008 Actual</u>

Exhibit F2-T2-S2 Table 1b shows that the 2009 actual base OM&A decreases by $35.9M (-2.9 per cent) relative to 2008 actuals, and presents those operating functions with reportable changes.

Considering that this year-over-year decrease includes labour cost escalation and payroll burden change of $13.5M (Ex. F2-T2-S1 Table 3), this year-over-year change indicates that cost control efforts are achieving gross cost reductions of $49.4M before escalation. Since most of these cost control efforts produce 10 per cent year-over-year changes at the operating function level, they are discussed in more detail below.

Within the stations, the reportable changes are:

- Pickering Common Services (-$3.4M) reflecting primarily completion of Waste Reduction and Waste Management Initiatives that had been undertaken in 2008.
- Support Services (-$8.5M) reflecting primarily Pickering B transfer of fire protection function to Maintenance in 2009 as noted above (-$7.4M).
- Tritium Removal Facility (+$3.7M) reflecting major planned outage work in 2009.

- Continued Operations (+$1.6M) reflecting initiative start-up in 2009.
- Pickering B Refurbishment (-$4.7M) reflecting project work plan.

Within the support divisions, the reportable changes are:

- Projects & Modifications (+$1.7M) reflecting primarily increased support for station outages.
- Records & Admin (-$6.2M) reflecting primarily the organizational transfer of departmental administrative assistants to line organizations to drive cost efficiency (-$3.6M, fully offset in station and support divisions), and divisional cost control initiatives (-$3.1M).
- Nuclear Programs & Training (+$26.2M) reflecting primarily a cost neutral organizational transfers from Performance Improvement and Nuclear Oversight to improve organizational alignment (+$21M), and an increase in CNSC operating license fees (+$3.9M). A corresponding change is noted in Performance Improvement and Nuclear Oversight (-$21M).
- Security (+$9.0M) reflecting continued progress in transitioning from contracted Durham Regional Police Services to a fully internal OPG security force, with 2009 reflecting a full year of incremental transition costs versus partial year in 2008.
- Supply Chain (-$13.4M) reflecting labour and overtime cost reductions (-$5.6M) resulting from the supply chain improvement initiative (Ex. F2-T2-S1 Attachment 4), and lower than planned inventory valuation and obsolescence provisions (-$7.4M).
- Inspection & Maintenance Services (-$7.5M) reflecting primarily: change in treatment of Bruce-related support cost from general indirect cost to IMS (non-energy revenue related) direct cost (-$4.4M); transfer of functions to Corporate Human Resources and Finance functions (-$2.1M), and profit from greater than planned work for non-nuclear customers (-$1.1M). Waste & Transportation Services (-$1.5M) reflecting reduction in planned heavy water ("D2O") shipments, supplemented by less than planned miscellaneous contract costs.
- Nuclear Level Common (-$10.0M) reflecting primarily P2/P3 safe storage project electricity cost credit and insurance premium rebate in 2008 (-$3.6M total), and labour price variance (-$6.8M) reflecting primarily the 2009 under expenditure noted above.

3.0 NUCLEAR NON-ENERGY REVENUE SOURCES

3.1 Heavy Water

3.1.1 Heavy Water Inventory

Heavy water is a manufactured product required for CANDU (Canadian Deuterium Uranium) reactor operations. Heavy water is required as a moderator for sustaining a nuclear reaction and as a heat transport medium in a CANDU nuclear reactor.

As of December 31, 2008 OPG owned 14,309 tonnes of heavy water, of which 13,359 tonnes is reactor-grade (radioactive), and 950 tonnes is virgin (non-radioactive) heavy water. Of the 14,309 tonnes of heavy water, 12,234 tonnes are in-service within OPG's ten operating CANDU nuclear units (6,209 tonnes) and within the reactors at the leased Bruce site (6,025 tonnes). The remaining 2,075 tonnes, primarily reactor-grade radioactive heavy water from the out-of-service Pickering A Units 2 and 3, is inventory and is stored in OPG-owned storage facilities or on loan/lease to other nuclear facilities (Atomic Energy of Canada, New Brunswick Power). OPG's inventory of virgin heavy water is stored in two OPG-owned storage facilities, one on the Bruce Power site and the other at Darlington.

Chart 1

Heavy Water (Tonnes)

as of December 31, 2008

	TOTAL
IN-SERVICE OPG 10 UNITS	6,209
IN-SERVICE BRUCE SITE	6,025
HEAVY WATER INVENTORY	2,075
TOTAL HEAVY WATER	14,309

3.1.2 Heavy Water Sales

OPG seeks opportunities to sell surplus quantities of heavy water from its heavy water inventory. Surplus quantities are defined as those quantities of heavy water not required to meet OPG's current and future needs. OPG's current and future needs for heavy water include 570 tonnes of heavy water inventory required to replenish heavy water, at a rate of three tonnes per year per reactor, required at the existing OPG and Bruce Power facilities (i.e., the Bruce Lease Agreement includes an obligation for OPG to provide 18 tonnes per year of heavy water to Bruce Power to replenish heavy water over the term of the lease). OPG also retains 900 tonnes of the heavy water inventory to meet OPG's future needs arising out of potential plant life extensions, restart (at Bruce Power) or new build decisions. OPG is also able to use these quantities for short term loan/lease to other nuclear facilities.

During 2009 and 2010, OPG expects to sell approximately 68 tonnes of surplus heavy water.

As of December 2010, the amount of heavy water held in inventory that is surplus to OPG's current and future needs is forecast to be 673 tonnes as set out in Chart 2 below.

Chart 2
Derivation Of Surplus Heavy Water(Tonnes)
as of December 31, 2010

	TOTAL
Heavy Water Inventory as of Dec 31, 2008	**2,075**
Heavy Water Sales 2009, 2010	**68**
Subtotal	**2,143**
Provision for Future Heavy Water Losses (OPG and Bruce Power)	**(570)**
Provision For Future Needs, e.g., Refurb, New Build	**(900)**
Surplus Heavy Water	**673**

OPG proposes to exclude any revenues (and costs) associated with the future disposition of 673 tonnes of surplus heavy water assets from nuclear non-energy revenues, effective March 1, 2011.

Surplus heavy water assets are the property of OPG and its shareholder. They are fully depreciated and were not within the prescribed asset rate base when regulation of the prescribed facilities commenced on April 1, 2005. OPG earns no regulated rate of return on these assets.

In EB-2007-0905, OPG proposed to include the net margin from the sale of surplus heavy water assets as an offset to the nuclear revenue requirement, consistent with the proposed treatment of these revenues in the information provided to the Province for the establishment of the interim regulated rate as of April 1, 2005. However, OPG noted in its evidence that in future it would consider other regulatory treatments for its nuclear non-energy revenues. There is no requirement under O. Reg. 53/05 to use the revenues from these non-regulated surplus heavy water assets as an offset to the nuclear revenue requirement.

The sale of these surplus heavy water assets will not impact the provision of OPG's regulated services to ratepayers as OPG has conservatively set aside sufficient quantities of heavy water to serve the future needs of OPG, including its contractual obligations to Bruce Power. The administration and sale of the surplus heavy water assets requires minimal business support. OPG has identified the direct and other support costs associated with the sale of the surplus heavy water and these have been removed from the nuclear revenue requirement as discussed below in section 4.0.

Surplus heavy water is not, and never has been, included in the prescribed facility rate base, is not required for the provision of regulated services and does not rely on the prescribed facilities for its production or management. For these reasons, effective March 1, 2011, OPG proposes to exclude the revenues (and costs) from surplus heavy water sales from the offset to the nuclear revenue requirement for non-energy revenues.

Total revenues for heavy water sales over the period 2007 - 2012 are summarized in Ex. G2-T1-S1 Table 1. Direct costs and other support costs are described in section 4 below.

3.1.3 Heavy Water Services

The heavy water service business consists of the provision of tritium removal (detritiation) services by processing heavy water through the Darlington Tritium Removal Facility ("TRF"). The bulk of the heavy water service revenue is from the provision of detritiation services to Bruce Power. Opportunities for providing detritiation services to others are limited. There is little market demand for this service because there are storage and capacity restrictions at the TRF processing facility. In addition, OPG is able to lease/loan some small quantities of heavy water inventories to third parties and these revenues are included under heavy water services.

Total revenues for heavy water services over the period 2007 - 2012 are summarized in Ex. G2-T1-S1 Table 1. Cost of goods sold and other support costs are described in section 4 below.

3.2 Isotope Sales

3.2.1 Cobalt-60

Cobalt-60 produced by OPG is used primarily in the health industry to sterilize surgical and medical supplies.

In Canada, the Canadian Nuclear Safety Commission ("CNSC") has the responsibility for setting and enforcing the regulations and standards for all activities involving the use of radioactive materials. In producing and handling cobalt, OPG works diligently to ensure compliance with such requirements.

Cobalt-60 is produced at Pickering B (Units 6, 7, and 8) by inserting adjuster rods containing cobalt-59 in the reactor core (the rods are used to adjust power levels). Over time the cobalt-59 absorbs a neutron and becomes cobalt-60. About every 24 months, in line with a planned outage, the adjuster rods containing cobalt-60 are replaced. The removed rods are cut up

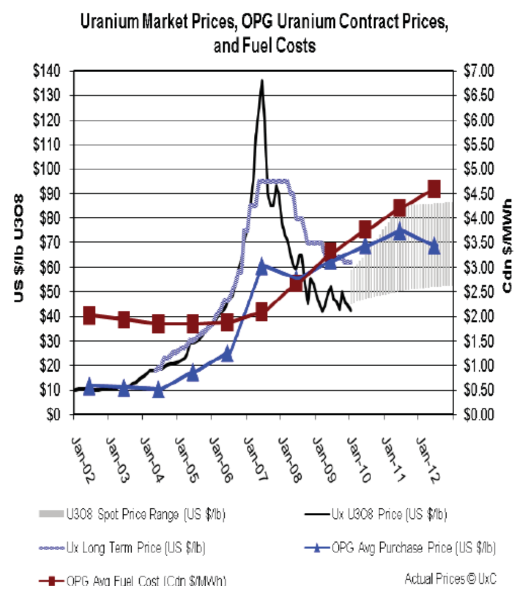
Board Staff Interrogatory #065

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.

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).

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.

AMPCO Interrogatory #003

Ref: Ex. B3-T5-S, Table 1

Issue Number: 2.1
Issue: What is the appropriate amount for rate base?

Interrogatory

a) With respect to OPG's nuclear fuel inventory over the period 2007 through 2012, please indicate the average cost of uranium in each year.

b) With respect to OPG's nuclear fuel inventory for 2008 through 2010, please indicate the amount included in rates and the amount approved by the Board.

c) Please provide any benchmarking data OPG has with respect to the level of nuclear materials and supplies included in working capital.

Response

a) Please see Table 1 below.

Table 1

Year	Closing Balance – Fuel Inventory (Ex. B3-T5-S1) ($M)	Average Cost of Uranium Concentrate in Closing Year Inventory (Cdn$/lb U)
2007	233.0	49.6
2008	300.7	59.4
2009	333.0	66.7
2010	381.7	76.0
2011	377.9	82.2
2012	343.8	77.4

b) In its Decision and Payment Amounts Order in EB-2007-0905, the OEB accepted and approved OPG's proposed nuclear working capital forecast of $705.4M for 2008 and $771.8M for 2009, which included nuclear fuel inventory of $281.1M and $330.1M for 2008 and 2009, respectively. The nuclear fuel inventory amounts included in the working capital that underpin the current payment amounts are found in Table 8-1 on page 133 of the Decision. The payment amounts established in EB-2007-0905 continue into 2010.

c) OPG has recently obtained a ScottMadden report ("2007 Utility Materials Management Benchmarks – Nuclear Generation") which indicates a median benchmark value for nuclear inventory of $32.8k per MW.

SEC Interrogatory #024

Ref: Ex. F2-T4-S1, page 5
Ex. F2-T4-S1, Table 1

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

Interrogatory

a) Please provide a table showing for 2007 through 2012 the costs of the Outage Improvement Strategy, the number of planned outages, the expected outage costs and the expected outage costs without implementation of the Outage Improvement Strategy.

b) Please provide the cost-benefit analysis that was undertaken for this initiative.

Response

a) Please see the table below:

Outage OM&A - Nuclear ($M)

	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
Outage Improvement Strategy OM&A Costs (includes training costs)	-	-	-	$2.1	$1.8	$1.9
Number of Planned Outages	6	3	7	9	4	4
Outage Costs	$208.8	$191.1	$246.8	$267.8	$210.1	$196.9
Net Savings from Outage Improvement Strategy (includes training costs)	-	-	-	$1.7	$5.9	$7.9
Expected Outage Costs without implementation of the Outage Improvement Strategy	-	-	-	$269.5	$216.0	$204.8

b) Attachment 1 contains the preliminary cost benefit analysis for the 2009 Outage Improvement Strategy Initiatives that was developed for the 2010 - 2014 Business Plan. Further refinements to this cost benefit analysis are anticipated. Consistent with ScottMadden's recommendation at Ex. F5-T1-S2, page 34 and discussed at Ex. L-14-016, OPG will be encouraging the functional/peer teams to refine and improve their initiatives throughout the remainder of the planning cycle and into implementation.

SEC Interrogatory #033

Ref: Ex. F2-T5-S2

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

Interrogatory

OPG has over forecast its nuclear fuel costs by between 7% to 15% for the period 2007 to 2009. Please provide a description of the forecast methodology used for fuel cost and what changes were made to that methodology in the current application to address the systemic forecast bias.

Response

OPG does not agree that there is a systemic bias in the forecasting of fuel costs. Indeed, as noted in Ex. F2-T5-S2 there are instances where actual nuclear fuel unit price is both higher and lower than forecast over the three years in question.

Generation variances are the main factor causing actual fuel cost to diverge from forecast amounts. Actual fuel costs have been lower than forecast in most cases due to a lower volume of fuel used, as a result of generation being below forecast. Ex. F2-T5-S2 describes all variances between actual and forecast fuel costs for the 2007, 2008 and 2009 historical years.

A second component of fuel costs reflects the price estimate for fuel used in generation. Ex. F2-T5-S1 describes the process used by OPG to manage the fuel process including steps taken to manage the risks of a volatile uranium supply market. Please also refer to Ex. L-1-065. The process OPG follows includes diversification of supply contracts and balances the security of uranium supply with pricing. OPG believes this approach to be a balanced and prudent method to manage uranium purchases.

The last component of fuel cost variances as seen in Ex. F2-T5-S2 is fuel efficiency and represents the reactor efficiency and fuel burn-up rate actually achieved in the nuclear generation process.

SEC Interrogatory #038

Ref: Ex. G2-T1-S1, page 4

Issue Number: 7.2
Issue: Are the proposed test period nuclear business non-energy revenues appropriate?

Interrogatory

a) Please provide the reference in the legislation/regulations which excludes any surplus heavy water from regulation or excludes any fully depreciated assets.

b) Please provide the estimated current market value of the 673 tons of heavy water.

c) Has OPG undertaken any studies or analysis as to the commercial of the surplus heavy water? If so provide these studies.

Response

a) There is no reference in the legislation/regulations which excludes surplus heavy water or fully depreciated assets from regulation, nor is there any reference which includes these assets. The legislation is silent on this point.

   Regulation 53/05 of the *Ontario Energy Board Act* (the “Act”) prescribes nine facilities for the purposes of section 78.1 of the Act, the section under which the OEB sets OPG’s payment amounts.

   Since 2005, surplus heavy water has not formed part of the rate base of any of the prescribed facilities. Accordingly, OPG has earned no return on those assets. Surplus heavy water is also not required to support the operation of any of those facilities, nor does it rely on those facilities for its production or management. For these reasons and as set out in Ex. G2-T1-S1, page 4, lines 26-30, OPG proposes to exclude the revenues (net of costs) from surplus heavy water sales as an offset to the nuclear revenue requirement.

b) Ex. G2-T1-S1, Chart 2 incorrectly shows surplus heavy water at 673 tonnes. The correct value is 537 tonnes. The market for heavy water is restricted to a small number of potential clients whose requirements are far less than 537 tonnes. OPG therefore expects that an extended time will be required to sell the current inventory of surplus heavy water. Because of the illiquid nature of this market, OPG is not able to provide an estimate of the surplus heavy water market value.

c) OPG has not undertaken any studies or analysis as to the commercial market potential of the surplus heavy water.

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) Provides the confidential breakdown of quantities subject to market pricing versus indexation for contracts B, C, and D.

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.

VECC Interrogatory #028
(NON-CONFIDENTIAL VERSION)

Ref: Ex. G2-T1-S1, page 5

Issue Number: 7.2
Issue: Are the proposed test period nuclear business non-energy revenues appropriate?

Interrogatory

Lines 5-16 discuss the "Heavy Water Services" business, and refer to Exhibit G2, tab 1, schedule 1, Table 1 as summarizing the total revenues from "Heavy Water Services". However there appears to be no line item quantifying the "Heavy Water Services" revenues as a distinct revenue stream. Please provide a table showing the revenues from "Heavy Water Services" from 2007-2012, including a description of the methodology used to forecast such revenues in 2011 and 2012. In the event the revenues from "Heavy Water Services" form a component of the line item "Heavy Water Sales and Processing", please separate out the revenues from "Heavy Water Sales" that OPG is proposing to exclude from the revenue requirement from the "Heavy Water Services" that OPG is proposing to maintain as an offset to the Revenue Requirement.

Response

Ex. G2-T1-S1, Table 1, line 1 combines all revenues from Heavy Water Sales and Processing to avoid disclosing commercially sensitive information relating to heavy water sales.

The table below provides revenues from 2007 – 2012 for surplus heavy water sales and other heavy water services.

Revenues ($M)	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
Surplus HW Sales (now excluded)	[redacted]	[redacted]	[redacted]	[redacted]	-	-
Other HW Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Heavy Water Sales & Processing	30.3	28.5	25.5	23.1	17.3	15.6

For other heavy water services (primarily detritiation services), 2011 – 2012 forecasts were determined by examining the annual capacity of facilities such as the Tritium Removal

Facility, and then holding discussions with existing external clients including Bruce Power to determine their requirements. This information was used to develop forecast information.

of the Act) to be used by him, in an operation referred to in clause (C), (D), (E) or (F), in the preventing, reducing or eliminating of pollution of a kind referred to in this subparagraph, and

(iv) that has, upon application by the taxpayer to the Minister of the Environment, been accepted by that Minister as property the primary use of which is to be the preventing, reducing or eliminating of pollution of a kind referred to in subparagraph (iii),

and for the purposes of paragraphs (*a*) and (*b*)

(*c*) where a corporation (in this paragraph referred to as the "predecessor corporation") has, as a result of an amalgamation within the meaning assigned by subsection 87(1) of the Act, merged at any time after 1973 with one or more other corporations to form one corporate entity (in this paragraph referred to as the "new corporation"), the new corporation shall be deemed to be the same corporation as, and a continuation of, the predecessor corporation;

(*d*) where a corporation (in this paragraph referred to as the "subsidiary") has been wound up at any time after 1973 in circumstances to which subsection 88(1) of the Act applies, the parent (within the meaning assigned by that subsection) shall be deemed to be the same corporation as, and a continuation of, the subsidiary; and

(*e*) this class shall be read without reference to subparagraph (*b*)(i) where paragraph (*c*) or (*d*) applies to the taxpayer and the property was acquired before 1992.

NOTE: Application provisions are not included in the consolidated text; see relevant amending regulations.
SOR/78-146, s. 1; SOR/79-426, s. 7; SOR/94-140, s. 24; SOR/94-686, s. 79(F); SOR/97-377, s. 8; SOR/2010-93, s. 32(F).

Class 25

(100 PER CENT)

Property that would otherwise be included in another class in this Schedule that is property acquired by the taxpayer

(*a*) before October 23, 1968, or

(*b*) after October 22, 1968 and before 1974, where the acquisition of the property may reasonably be regarded as having been in fulfilment of an obligation undertaken in an agreement made in writing before October 23, 1968 and ratified, confirmed or adopted by the legislature of a province by a statute that came into force before that date,

if the taxpayer was, on October 22, 1968, a corporation, commission or association to which, on the assumption that October 22, 1968 was in its 1969 taxation year, paragraph 62(1)(*c*) of the former Act (within the meaning assigned by paragraph 8 (*b*) of the *Income Tax Application Rules*),

(*c*) would not apply; and

(*d*) would have applied but for subparagraph (i) or (ii) of that paragraph.

NOTE: Application provisions are not included in the consolidated text; see relevant amending regulations.
SOR/94-686, ss. 48, 79(F).

Class 26

(5 PER CENT)

Property that is

(*a*) a catalyst; or

(*b*) deuterium enriched water (commonly known as "heavy water") acquired after May 22, 1979.

NOTE: Application provisions are not included in the consolidated text; see relevant amending regulations.

Numbers may not add due to rounding.

Table 13

Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Operations - Year Ending December 31, 2010 ($M)

Line No.	Class	Undepreciated Capital Cost at Beginning of Year	Cost of Acquisitions	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)-(j)+(i) Undepreciated Capital Cost at End of Year
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	1,360.3	192.8	0.0	0.0	1,553.1	96.4	1,456.7	4%	0.0	58.3	1,494.8
2	**1-rolling start**	127.9	22.0	0.0	0.0	149.9	0.0	149.9	4%	0.0	6.0	143.9
3	**1.1**	61.2	1.8	0.0	0.0	63.1	0.9	62.1	6%	0.0	3.7	59.3
4	**2**	1,426.4	0.0	0.0	0.0	1,426.4	0.0	1,426.4	6%	0.0	85.6	1,340.9
5	**8**	269.6	48.4	0.0	0.0	318.1	24.2	293.8	20%	0.0	58.8	259.3
6	**10**	34.1	12.1	0.0	0.0	46.2	6.1	40.2	30%	0.0	12.1	34.2
7	**12**	5.3	15.2	0.0	0.0	20.5	7.6	12.9	100%	0.0	12.9	7.6
8	**17**	535.4	60.5	0.0	0.0	595.9	30.2	565.7	8%	0.0	45.3	550.7
9	**38**	20.5	0.0	0.0	0.0	20.5	0.0	20.5	30%	0.0	6.2	14.4
10	**42**	0.3	0.3	0.0	0.0	0.5	0.1	0.4	12%	0.0	0.0	0.5
11	**45**	0.5	0.0	0.0	0.0	0.5	0.0	0.5	45%	0.0	0.2	0.3
12	**50**	3.6	0.0	0.0	0.0	3.6	0.0	3.6	55%	0.0	2.0	1.6
13	**52**	0.0	6.1	0.0	0.0	6.1	0.0	6.1	100%	0.0	6.1	0.0
14	**Total**	3,845.2	359.3	0.0	0.0	4,204.4	165.6	4,038.8		0.0	297.1	3,907.4

Table 14

Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Operations - Year Ending December 31, 2011 ($M)

Line No.	Class	Undepreciated Capital Cost at Beginning of Year	Cost of Acquisitions	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)-(j)+(i) Undepreciated Capital Cost at End of Year
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	1,494.8	269.2	0.0	0.0	1,764.0	134.6	1,629.4	4%	0.0	65.2	1,698.9
2	**1-rolling start**	143.9	144.0	0.0	0.0	287.9	0.0	287.9	4%	0.0	11.5	276.4
3	**1.1**	59.3	1.8	0.0	0.0	61.1	0.9	60.2	6%	0.0	3.6	57.5
4	**2**	1,340.9	0.0	0.0	0.0	1,340.9	0.0	1,340.9	6%	0.0	80.5	1,260.4
5	**8**	259.3	47.1	0.0	0.0	306.4	23.6	282.9	20%	0.0	56.6	249.8
6	**10**	34.2	11.8	0.0	0.0	46.0	5.9	40.1	30%	0.0	12.0	34.0
7	**12**	7.6	14.8	0.0	0.0	22.4	7.4	15.0	100%	0.0	15.0	7.4
8	**17**	550.7	56.5	0.0	0.0	607.2	28.3	578.9	8%	0.0	46.3	560.9
9	**38**	14.4	0.0	0.0	0.0	14.4	0.0	14.4	30%	0.0	4.3	10.1
10	**42**	0.5	0.2	0.0	0.0	0.7	0.1	0.6	12%	0.0	0.1	0.6
11	**45**	0.3	0.0	0.0	0.0	0.3	0.0	0.3	45%	0.0	0.1	0.1
12	**50**	1.6	10.5	0.0	0.0	12.1	5.2	6.9	55%	0.0	3.8	8.3
13	**Total**	3,907.4	556.0	0.0	0.0	4,463.4	206.0	4,257.4		0.0	298.9	4,164.4

Numbers may not add due to rounding.

Numbers may not add due to rounding.

Table 15
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Operations - Year Ending December 31, 2012 ($M)

Line No.	Class	Undepreciated Capital Cost at Beginning of Year	Cost of Acquisitions	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)-(j)+(i) Undepreciated Capital Cost at End of Year
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	1,698.9	277.4	0.0	0.0	1,976.3	138.7	1,837.6	4%	0.0	73.5	1,902.8
2	**1-rolling start**	276.4	85.0	0.0	0.0	361.4	0.0	361.4	4%	0.0	14.5	346.9
3	**1.1**	57.5	22.9	0.0	0.0	80.4	11.5	69.0	6%	0.0	4.1	76.3
4	**1.1-rolling start**	0.0	20.9	0.0	0.0	20.9	0.0	20.9	6%	0.0	1.3	19.7
5	**2**	1,260.4	0.0	0.0	0.0	1,260.4	0.0	1,260.4	6%	0.0	75.6	1,184.8
7	**8**	249.8	52.6	0.0	0.0	302.4	26.3	276.1	20%	0.0	55.2	247.2
8	**10**	34.0	13.1	0.0	0.0	47.1	6.6	40.6	30%	0.0	12.2	34.9
9	**12**	7.4	16.4	0.0	0.0	23.8	8.2	15.6	100%	0.0	15.6	8.2
10	**17**	560.9	108.1	0.0	0.0	669.0	54.0	614.9	8%	0.0	49.2	619.8
11	**17-rolling start**	0.0	48.8	0.0	0.0	48.8	0.0	48.8	8%	0.0	3.9	44.9
12	**38**	10.1	0.0	0.0	0.0	10.1	0.0	10.1	30%	0.0	3.0	7.0
13	**42**	0.6	0.3	0.0	0.0	0.9	0.1	0.8	12%	0.0	0.1	0.8
14	**45**	0.1	0.0	0.0	0.0	0.1	0.0	0.1	45%	0.0	0.1	0.1
15	**50**	8.3	8.4	0.0	0.0	16.7	4.2	12.5	55%	0.0	6.9	9.8
17	**Total**	4,164.4	653.9	0.0	0.0	4,818.3	249.6	4,568.8		0.0	315.1	4,503.2

Numbers may not add due to rounding.

Updated: 2008-03-14
EB-2007-0905
Exhibit G2
Tab 1
Schedule 1
Table 1

Table 1

Other Revenues - Nuclear ($M)

Line No.	Revenue Source	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
	NGD-Related Revenues:					
1	**Heavy Water Sales & Processing**	17.4	18.9	30.3	27.0	22.5
2	**Isotope Sales (Cobalt 60 + Tritium)**	7.2	11.0	7.0	9.3	9.6
3	**Inspection & Maintenance Services**	39.3	51.2	90.6	73.2	44.9
4	**Total NGD-Related Revenues**	63.9	81.0	127.9	109.5	76.9
5	**NGD-Related Direct Costs**	25.9	33.8	63.8	47.2	29.3
6	**NGD-Related Contribution Margin**	38.0	47.2	64.1	62.3	47.7
7	**Ancillary Services**[1]	2.8	3.1	2.8	3.0	3.1
8	**Other**[2]	0.6	2.7	1.7	0.2	0.1

1 Ancillary Services revenues for 2005 are for April 1, 2005 to December 31, 2005. Ancillary Services related to Nuclear prescribed facilities are discussed in Ex. G1-T1-S1.
The 2006 actuals are the reported numbers in OPG's financial statements based on estimates at year end.
The 2007 actuals are based on preliminary IESO statements. This number varies slightly from final IESO statements due to adjustments made after year end.

2 Other includes (i) revenue of $2.3M in 2006 and $0.6M in 2007 due to sale of spare parts and miscellaneous inventory by Nuclear Supply Chain, (ii) revenue $1.0 M from equipment rental in 2007 and (iii) revenue earned from services provided by Nuclear Programs and Training to an external party over the period 2005-2009.