Numbers may not add due to rounding.

Table 1
Centrally Held Costs ($M)
OPG

Line No.	Corporate Costs	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Pension/OPEB Related Costs**	178.8	116.7	(27.7)	118.5	145.4	213.1
2	**OPG-Wide Insurance**	19.1	16.3	17.0	16.9	17.4	18.0
3	**Nuclear Insurance**	7.6	7.8	7.3	8.6	11.3	13.4
4	**Performance Incentives**	40.8	45.3	40.3	45.8	46.2	46.7
5	**IESO Non-Energy Charges**	20.5	22.4	75.5	54.7	62.8	69.2
6	**SR&ED Investment Tax Credits**	0.0	(30.0)	(22.1)	(10.0)	(10.0)	(10.0)
7	**Other**	31.1	25.0	31.4	26.4	28.1	(1.4)
8	Total	297.9	203.5	121.7	260.9	301.2	349.0

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UNDERTAKING J10.12

Undertaking

To provide the status of proposed Bill C-15.

Response

Bill C-15 is in Debates at Second Reading.

DAVIES

DAVIES WARD PHILLIPS & VINEBERG LLP

Canada: Federal Government Reintroduces Proposed Changes to Nuclear Liability Legislation

21 April 2010

Article by Sarah V. Powell , Alexandria J. Pike and Michel Pelletier

On April 16, 2010, the federal government reintroduced Bill C-15 – *Nuclear Liability and Compensation Act* to amend and replace Canada's existing nuclear liability regime with respect to nuclear incidents. Bill C-15 is in substance identical to numerous other bills that have been introduced by the federal government over the past three years to amend and replace the existing *Nuclear Liability Act*, each of which has died on the Order Paper with the prorogation of Parliament. The most significant change proposed by these bills is the increase in the maximum liability for operators of nuclear installations for damage resulting from a nuclear incident from $75 million to $650 million (per nuclear installation). This amount would be publicly reviewed at least every five years by the federal government and, if appropriate, could be increased by regulation. Bill C-15 would require the first public review of the maximum liability for operators to be completed within 15 months of Bill C-15 coming into force. The federal government has been attempting to modernize Canada's nuclear liability regime for decades, but earlier attempts have either met with constitutional challenge or died on the Order Paper. Bill C-15 would bring Canada's nuclear liability regime more in line with international standards and is consistent with the Harper government's commitment to modernize Canada's nuclear regulatory framework.

http://www.mondaq.com/canada/article.asp?articleid=98676&print=1

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Ontario

ONTARIO ENERGY BOARD

FILE NO.: EB-2010-0008

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	Cathy Spoel	**Member**
	Marika Hare	**Member**

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MR. MILLAR: I produced this only as a platform to ask these questions, but you will see it is discussing this very bill, and I have highlighted a couple of portions, the first saying:

"Bill C-15 is in substance identical to numerous other bills that have been introduced by the federal government over the past three years to amend and replace the existing Nuclear Liability Act, each of which has died on the Order Paper with the prorogation of Parliament."

Then if you skip down a few sentences:

"The federal government has been attempting to modernize Canada's nuclear liability regime for decades, but earlier attempts have either met with constitutional challenge or died on the Order Paper."

Do you see that?

MR. BELL: Yes.

MR. MILLAR: So what gives you confidence that the fourth, fifth time is the charm here? Why do you think it will get through this time, where it hasn't been so lucky in the past?

MR. BELL: It is an estimate. There has to be a time associated with it, and there is some degree of likelihood, we feel, it is reasonable to expect 2011.

There is nothing that we are aware of or at the time of putting this information together that would indicate otherwise.

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MR. MILLAR: Fair enough. I know you can only use the information you have in front of you. But would this be the type of case where something like a variance account would be appropriate? We have a piece of legislation that has been ill-fated in the past. You've got something like $6 to $7 million in your revenue requirement that you may or may not incur.

And I can push this to the variance account panel, Mr. Keizer, if you would like, but I thought I would try it on this panel first.

MR. KEIZER: It might be better, because they're dealing with the criteria of the variance account and otherwise.

MR. MILLAR: Thank you for that.

MS. CHAPLIN: Mr. Millar, if you're moving to a new area, would this be a convenient time to break?

MR. MILLAR: Oh, I'm sorry. Yes, it would, Madam Chair.

MS. CHAPLIN: Okay. We will rise now for 15 minutes.

--- Recess taken at 3:05 p.m.

--- On resuming at 3:24 p.m.

MS. CHAPLIN: Please be seated. Mr. Millar?

MR. MILLAR: Thank you, Madam Chair.

I have some questions now about rate base, Issue 2.1. To whom would I direct those questions? Or should I just fire away and you can take --

MR. HALPERIN: Fire away.

MR. MILLAR: Okay. I think you may need to turn your

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ONTARIO ENERGY BOARD

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	Cathy Spoel	**Member**
	Marika Hare	**Member**

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reasons why we are doing what we are doing.

MR. MILLER: And let's assume, for the purpose of this question, that the results come back negative and you have spent the 100-some-odd million on continued operations. I assume that money would essentially have been wasted; is that right?

MR. PASQUET: So there is a spectrum of results which may come from that project. It may come out that you won't get 240,000 full power hours. You may get a number slightly less than that. You may get a spectrum of results.

But, in essence, if we -- if the project came to say that you don't get any added life over currently what is stated today, then that money would be lost; that is correct.

MR. MILLER: Okay. You have requested a variance account with regard to this project, but I take it -- and if this is for another panel, I will put it to them, but I will try with you first. Obviously if it is a variance account, it captures variances. I assume that the $92 million you are proposing goes directly into the revenue requirement for the test years?

MR. PASQUET: That is correct.

MR. MILLER: Okay. So there would be no opportunity for the Board to make a finding of imprudence after the fact, at least for that $92 million?

MR. PASQUET: Could you repeat the question, please?

MR. MILLER: It may be something for the variance account panel. What I'm saying is the $92 million you are requesting would go into the revenue requirement now. The variance account only captures differences from that. So I am assuming it wouldn't be open to the Board to make a finding of imprudence if it later turned out that all of this money was spent?

Mr. Keizer is probably going to tell me to ask somebody else.

MR. KEIZER: I think it would probably be best to pass on to the variance account.

MR. MILLAR: You know what I am going to ask, so you can be ready.

MR. KEIZER: Duly noted.

MR. MILLAR: Thank you. Just a couple of more questions.

I would like to talk about your costing estimates for this project. We have already discussed there is a total of $92.9 million for the test years; is that correct?

MR. PASQUET: That's correct.

MR. MILLER: But the total costs of the project are something in excess of that. I understand that at least for the purposes of this application, you are estimating a total cost of 190.2 million; is that correct?

You could flip to page 30 of the Staff booklet. It is an excerpt from Staff IR 67. Or indeed, it is in the business case summary.

MR. PASQUET: That's correct.

MR. MILLER: My understanding is the total cost of the project is about $190 million?

MR. PASQUET: That's correct. I believe the business case is 195, but approximately 190.

MR. MILLER: So in that range, anyway?

MR. PASQUET: That's correct.

MR. MILLER: So what we were after in Board Staff 67 is it seems you have had quite a range of cost estimates for this project, and if I could -- if you could look at page 30, at line 14, it states that your initial news release on this indicated a number of about $300 million. That was on February 16th, 2010.

And then the application itself, as we just discussed, it is somewhere around $190 million.

I understand there was an estimate provided to the OPA of around $184 million. That is at line 21 of the IR.

And then at line 25, you will see a report issued after the application filed, again showing the cost estimate of around $300 million.

Do you see that?

MR. PASQUET: In your actual Board interrogatory, there --

MR. MILLER: Yes. I put the question to you again, essentially.

MR. PASQUET: I see the question in the interrogatory.

MR. MILLER: Okay. Then we put that to you both in that interrogatory, and if you flip ahead to page 32, we asked about it again in the technical conference.

But let me ask you now. We have a variety of estimates, I guess two chief ones, something around $190 million and then something around $300 million, and they seem to keep popping up sequentially.

Can you give me a better idea of why we have such a variety of cost estimates here?

MR. PASQUET: So I will talk to the -- the 190 million is basically the -- represents the 184 in 2010 dollars, and that was talked to in the interrogatory, and there was an understanding associated with that.

As I talked about in the technical conference, the number in this estimate and in our rate application -- so in our business case -- we are estimating $190 million for the cost of this particular project.

And the number that you quoted is around 90 million for this rate application. That is what is in our rate application and that is what our estimate is.

The 300 million was a very conservative estimate. It basically looks at the outer bounds of possibility associated with the project, and round up to 300 million. It is not what is in our rate application. It is not what is the case of the estimate. It was basically a conservative estimate.

What we are asking for and what we are proposing in this application is, in fact, the 190 million, and specifically approximately 90 million in this -- in the test period.

MR. MILLER: Plus a variance account?

MR. PASQUET: Plus a variance account.

MR. MILLER: You say you rounded up to get to 300 million. What do you mean by that? That is in the technical conference, as well.

MR. PASQUET: Correct. So -- and so in any -- in a cost estimate that is budget-quality, there is a range. If you took the upper range of that, of the estimate, and you added the 30 percent to it and basically then rounded up, you would get to a number like 300.

Our current expectation is that we will be 190 million for the cost of this project.

MR. MILLER: Okay. But did you say that to get to this conservative bound, you increase that by 30 percent and then round it up?

MR. PASQUET: That is how you would get to 300 million.

That is not what is in our rate application. What is in our rate application is 190.

MR. MILLER: Well, if you round up by 30 percent, you are closer to 250, aren't you?

Mr. PASQUET: 250, and then you round it up, you get to 300.

MR. MILLER: Okay. So you round it up $50 million? That's a 6th or so. Okay. Well, I guess that is what you have done, so I will take your word on that.

I understand that the 190 -- the $190 million estimate does not include any contingency; is that correct?

MR. PASQUET: That is correct.

MR. MILLER: Why is that?

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MR. PASQUET: Since we are expensing this, we have looked at the costs of the work, except for the actual -- the fuel channel project, the work that we've done is work that we have done before.

We have done water lancing. We have done a number of the other pieces of work. And so we feel confident around the -- around the cost estimate.

And so as such, we have not built in a contingency into the project.

MR. MILLER: It is not unusual to have a contingency for OM&A work though, isn't it? Even for projects much smaller than this?

MR. PASQUET: A lot of projects do have contingency. In this one, we basically stated the costs as we believed they were going to be expensed.

MR. MILLER: And of course, if there is any contingency amount, that would be covered in the variance account; is that correct?

MR. PASQUET: That's correct. But there is in no contingency built into the business case summary.

MR. MILLER: The 300 million estimate, could I count that rounding up as a contingency? Or is the 30 percent the contingency?

MR. PASQUET: The 30 percent.

MR. MILLER: Okay. So I take it you have set the record straight for me on why we shouldn't look at this 300 million, and that 190 million is, in fact, the number.

In fact, you are confident enough on that number that

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ONTARIO ENERGY BOARD

FILE NO.: EB-2010-0008 **REDACTED - PUBLIC**

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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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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

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ONTARIO ENERGY BOARD

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	Cathy Spoel	**Member**
	Marika Hare	**Member**

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Pickering B four years, for each reactor, a series of activities that would not be done if you were not planning to extend the life of those reactors four years each?

MR. PASQUET: That is correct. But the actual activity -- for example, let's just take water lancing for an example. We currently water lance today.

MR. RUBIN: Other reactors under other circumstances?

MR. PASQUET: The Pickering B reactors, we currently lance the Pickering B reactors today in order to keep the boilers clean. And so for the Pickering B continued operations project, we need to do a bit more than what we were currently planning on doing if we were going to stop life at 2014.

So the actual activity is basically more of what we are currently doing today.

MR. RUBIN: Okay. Yes, I understand that distinction. Thank you.

If we look at this as an incremental package of activities, some of which are the continuation of routine -- that's what I hear you saying.

MR. PASQUET: Correct.

MR. RUBIN: Is that some of this is the continuation of routine maintenance which you would have stopped doing at end-of-life or before end-of-life, except you're extending end-of-life, so you're not going to stop. That's what I hear you saying.

Roughly, is it like half of the total price tag of this COOP is -- consists of that kind of continued routine

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maintenance, or a third or...

MR. PASQUET: I would say the component which is new activity is only the fuel channel life management component, which would, I would say, would be about 10 to 20 percent of the entire package.

The balance of the activities are things that we are currently doing today as part of maintaining the reactor, the plant.

MR. RUBIN: Okay. Thank you.

We talked before about how you get from your best estimate to OPG's stated 300 million estimate. And you referred to it as, I believe, as rounding up the number twice. Is that about right, that it was rounded up to 250, and then 250 was rounded up to 300?

MR. PASQUET: So -- so if you take the 190, you add the budgetary estimate, which we said, which we just talked about was plus 30 percent, when you add the 30 percent and then you round it up, then you get 300.

MR. RUBIN: Right. Okay. Let me move on.

And I will now turn to a document you've already mentioned which is attachment 2 to F2-2-3, the letter from OPA's Amir Shalaby, commenting on the decision to do the continued operation.

And I guess my first question is: Were you your plans reviewed by any independent reviewers who aren't former colleagues of yours?

MR. PASQUET: Sorry, what -- the continued ops project?

for 2010 is based on the difference between the forecast expenditures for nuclear development for 2010 in OPG's 2010 - 2014 Business Plan compared to the forecast amounts included in the payment amounts in EB-2007-0905.

OPG also established a Nuclear Development Deferral Account, Transition in accordance with section 5.3 of the Regulation. The OEB approved recovery of the balance in this account as at December 31, 2007 in EB-2007-0905. The OEB also directed that the balance in the Nuclear Development Deferral Account, Transition as at April 1, 2008 be transferred into the Nuclear Development Variance Account.

6.4 Transmission Outages and Restrictions Variance Account

Exhibit H1-T1-S1 Table 1 presents the account balances for 2007, 2008, 2009, and the projected balance for 2010.

The OEB approved the recovery of the balance in this variance account as at December 31, 2007 over a period of three years in EB-2007-0905. The OEB also accepted OPG's proposal to stop recording additional transactions in this account effective April 1, 2008. Therefore, the only transactions in this account from 2008 to 2010 are the application of interest and the recording of amortization expense. After the account balance is fully amortized the account will end.

6.5 Capacity Refurbishment Variance Account

Exhibit H1-T1-S1 Table 1 presents the account balances for 2007, 2008, and 2009 and the projected balance for 2010. The derivation of these balances is shown in Ex. H1-T1-S1 Table 8.

This account was established pursuant to O. Reg.53/05, section 6(2)3, 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 prescribed generation facility and the amounts for these purposes included in the approved payment amounts. Entries in this account include:

(2) Ontario Power Generation Inc. shall record simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 23/07, s. 3.

Nuclear liability deferral account

5.2 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records, on and after the effective date of the Board's first order under 78.1 of the Act, the revenue requirement impact of changes in its total nuclear decommissioning liability between,

(a) the liability arising from the approved reference plan incorporated into the Board's most recent order under section 78.1 of the Act; and

(b) the liability arising from the current approved reference plan. O. Reg. 23/07, s. 3.

(2) Ontario Power Generation Inc. shall record interest on the balance of the account as the Board may direct. O. Reg. 23/07, s. 3.

Nuclear development deferral account, transition

5.3 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records, for the period up to the effective date of the Board's first order under section 78.1 of the Act, the costs incurred and firm financial commitments made on or after June 13, 2006, in the course of planning and preparation for the development of proposed new nuclear generation facilities that are associated with any one or more of the following activities:

1. Activities for carrying out an environmental assessment under the *Canadian Environmental Assessment Act*.
2. Activities for obtaining any governmental licence, authorization, permit or other approval.
3. Activities for carrying out a technology assessment or for defining all commercial and technical requirements to, or with, any third parties. O. Reg. 27/08, s. 1.

(2) Ontario Power Generation Inc. shall record simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 27/08, s. 1.

Nuclear development variance account

5.4 (1) Ontario Power Generation Inc. shall establish a variance account in connection with section 78.1 of the Act that records, on and after the effective date of the Board's first order under section 78.1 of the Act, differences between actual non-capital costs incurred and firm financial commitments made and the amount included in payments made under that section for planning and preparation for the development of proposed new nuclear generation facilities. O. Reg. 27/08, s. 1.

(2) Ontario Power Generation Inc. shall record interest on the balance of the account as the Board may direct. O. Reg. 27/08, s. 1.

Rules governing determination of payment amounts by Board

6. (1) Subject to subsection (2), the Board may establish the form, methodology, assumptions and calculations used in making an order that determines payment amounts for the purpose of section 78.1 of the Act. O. Reg. 53/05, s. 6 (1).

(2) The following rules apply to the making of an order by the Board that determines payment amounts for the purpose of section 78.1 of the Act:

1. The Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the variance account established under subsection 5 (1) over a period not to exceed three years, to the extent that the Board is satisfied that,
   i. the revenues recorded in the account were earned or foregone and the costs were prudently incurred, and
   ii. the revenues and costs are accurately recorded in the account.
2. In setting payment amounts for the assets prescribed under section 2, the Board shall not adopt any methodologies, assumptions or calculations that are based upon the contracting for all or any portion of the output of those assets.
3. The Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the deferral account established under subsection 5 (4). The Board shall authorize recovery of the balance on a straight line basis over a period not to exceed 15 years.
4. The Board shall ensure that Ontario Power Generation Inc. recovers 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 section 2, including, but not limited to, assessment costs and pre-engineering costs and commitments,
   i. if the costs and financial commitments were within the project budgets approved for that purpose by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., or
   ii. if the costs and financial commitments were not approved by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power

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Generation Inc., if the Board is satisfied that the costs were prudently incurred and that the financial commitments were prudently made.

4.1 The Board shall ensure that Ontario Power Generation Inc. recovers the costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities, to the extent the Board is satisfied that,

i. the costs were prudently incurred, and

ii. the financial commitments were prudently made.

5. In making its first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., the Board shall accept the amounts for the following matters as set out in Ontario Power Generation Inc.'s most recently audited financial statements that were approved by the board of directors of Ontario Power Generation Inc. before the effective date of that order:

i. Ontario Power Generation Inc.'s assets and liabilities, other than the variance account referred to in subsection 5 (1), which shall be determined in accordance with paragraph 1.

ii. Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations.

iii. Ontario Power Generation Inc.'s costs with respect to the Bruce Nuclear Generating Stations.

6. Without limiting the generality of paragraph 5, that paragraph applies to values relating to,

i. capital cost allowances,

ii. the revenue requirement impact of accounting and tax policy decisions, and

iii. capital and non-capital costs and firm financial commitments to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2.

7. The Board shall ensure that the balances recorded in the deferral accounts established under subsections 5.1 (1) and 5.2 (1) are recovered on a straight line basis over a period not to exceed three years, to the extent that the Board is satisfied that revenue requirement impacts are accurately recorded in the accounts, based on the following items, as reflected in the audited financial statements approved by the board of directors of Ontario Power Generation Inc.,

i. return on rate base,

ii. depreciation expense,

iii. income and capital taxes, and

iv. fuel expense.

7.1 The Board shall ensure the balances recorded in the deferral account established under subsection 5.3 (1) and the variance account established under subsection 5.4 (1) are recovered on a straight line basis over a period not to exceed three years, to the extent the Board is satisfied that,

i. the costs were prudently incurred, and

ii. the financial commitments were prudently made.

8. The Board shall ensure that Ontario Power Generation Inc. recovers the revenue requirement impact of its nuclear decommissioning liability arising from the current approved reference plan.

9. The Board shall ensure that Ontario Power Generation Inc. recovers all the costs it incurs with respect to the Bruce Nuclear Generating Stations.

10. If Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations exceed the costs Ontario Power Generation Inc. incurs with respect to those Stations, the excess shall be applied to reduce the amount of the payments required under subsection 78.1 (1) of the Act with respect to output from the nuclear generation facilities referred to in paragraphs 3, 4 and 5 of section 2. O. Reg. 23/07, s. 4; O. Reg. 27/08, s. 2.

7. OMITTED (PROVIDES FOR COMING INTO FORCE OF PROVISIONS OF THIS REGULATION). O. Reg. 53/05, s. 7.

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ONTARIO ENERGY BOARD

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	Cathy Spoel	**Member**
	Marika Hare	**Member**

OPG, it includes the amount of uranium and all phases of that process up to and including the fuel bundles before they're loaded into the reactor or there is nuclear inventory.

MR. MILLER: Right. But you were talking about that you are still incurring some of the costs from stuff you purchased previously, because it is only now that you are extracting it -- not extracting -- that you are actually consuming it in the plant. Did I understand that correctly?

MR. MAUTI: Some of it is timing. Some of it is we use an average accounting process to figure out the cost of the fuel bundle.

MR. MILLER: When you actually withdraw it and use it, you use an average cost, not the cost you purchased that particular bundle for?

MR. MAUTI: We don't purchase the bundle. We purchase the uranium. It gets converted, and whatnot. But it is an averaging process through all steps of that cycle.

MR. MILLER: Okay, thank you for that.

In Staff IR 65, we asked you -- you currently have a fuel cost variance account; is that correct?

MR. MAUTI: That's correct.

MR. MILLER: So, essentially, what that means is whatever you pay for -- whatever you pay for your fuel is what you will recover from ratepayers?

MR. MAUTI: We would always have to come back in a rate hearing and explain the strategy and the steps we took

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to acquire and convert the fuel into a fuel bundle and use it. So I don't think it is -- an automatic recovery is expected.

MR. MILLER: Okay, fair enough. It is subject to a prudency review?

MR. MAUTI: Correct.

MR. MILLAR: You say in that response, also, that it would be improper for the Board to use hindsight when considering prudency; is that fair enough?

MR. MAUTI: I think that would be a standard concept and construct, yes.

MR. MILLER: That is probably true. So I guess unless -- as long as you are getting contracts on the market, I assume that -- I shouldn't say I assume, but you will probably assume you will recover the amounts in that variance account?

MR. MAUTI: I believe we would have to demonstrate we have a balanced and prudent way that we go about acquiring all of our fuel and a balanced strategy, as we alluded to, and we have described in the evidence what we feel is a prudent way to go about doing that.

We don't feel that it should be our job to necessarily speculate or hedge on the price of uranium, and we want to make sure we have an approach that has those risks balanced.

MR. MILLER: What we were asking, I think, if you have any incentive to attempt to lower these costs. We have seen they have been going up. I have heard your

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explanation for that. But doesn't the existence of the variance account at least reduce any incentive to reduce nuclear fuel costs?

MR. MAUTI: I don't necessarily believe so, no. We have dedicated people and a professional group.

The ability of our staff to get the best price possible -- they don't necessarily view the existence of a variance account as being their saving grace in any form or any shape, so...

MR. MILLER: Okay.

MS. CHAPLIN: Mr. Millar, were you done with that area, not that I am planning a break? It is just that I had a question, but --

MR. MILLAR: I have a couple of more questions in this area, Madam Chair, but if you wish to --

MS. CHAPLIN: No, no. Go ahead.

MR. MILLAR: I was just trying to find my place here.

Okay, at page 20, this is again the response to Staff IR 65. You say that:

> "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."

Do you see that?

MR. MAUTI: The specific line reference, that would help me to find it quickly.

MR. MILLER: Yes, it is line 5, very close to the top on page 20.

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MR. MAUTI: Yes, I see it.

MR. MILLER: I want to explore when you actually have entered the market.

Yes, if you could turn to page 26 of the Staff booklet, and this shows a summary of your existing fuel contracts; is that correct?

MR. MAUTI: That's correct.

MR. MILLER: And you have four of them?

MR. MAUTI: That's correct.

MR. MILLER: And three of them were entered in the first half of 2006 -- or, pardon me, the negotiation, in any event?

MR. MAUTI: Correct.

MR. MILLER: And then the second was the latter half of 2007?

MR. MAUTI: Yes.

MR. MILLER: I guess to be fair, you also mentioned a couple of spot purchases you made in 2009, but I understand none since then?

MR. MAUTI: Correct.

MR. MILLER: So I guess I am asking how this meshes with your statement that you need to regularly enter the uranium market, if it appears that, aside from the spot purchases, you haven't been in the market since 2007?

MR. MAUTI: Part of the -- our strategy for nuclear fuel is a balanced approach between -- you know, we always -- as the evidence indicates, we look at quality, security of supply and cost. As part of that security of

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supply concept, we have a targeted level of uranium requirements that we would need, and we state in the evidence that 100 percent of the uranium concentrate needs for the first two years have to be sort of under contract and required.

What that means -- and then sort of a bit of a sliding scale after that over a ten-year period in terms of the amount of supply. So that as we go through some of these deliveries, if there's a period of time when we are outside of that bound, we ,for our security of supply reasons, may have to enter into the spot market to be able to secure the required amount that we would need, as per our strategy.

MR. MILLER: I'm sorry, I heard you say you need to have two years locked up, a two-year supply?

MR. MAUTI: Yes.

MR. MILLER: And then on top of that, that is when you would start -- you would arrange contracts to arrange for that, and then you would enter the spot market as necessary after that?

MR. MAUTI: That would be one strategy, and reason to go into the spot market, yes.

MR. MILLER: It just hasn't happened very often over the past few years?

MR. MAUTI: In 2009, it has. To date in 2010, it has not.

MR. MILLER: Okay. I have one final thing on nuclear fuel costs, and this relates to working capital amounts. And I want to make sure I understand this correctly.

I think if we turn to -- yes, if we turn to page 27 of the Board Staff booklet, this is a working capital summary. And as we discussed before, I understand that fuel inventory goes into rate base as a form of working capital; is that right?

MR. MAUTI: That is correct.

MR. MILLER: And if you look down to 2011 and 2012 at the bottom, you see the amounts, the rate base value is $379.8 million and then $360.9 million, respectively.

Do you see that?

MR. MAUTI: Sorry, the two numbers you mentioned were? I'm sorry.

MR. MILLER: Sorry, the "fuel inventory" lines, 18 and 22, if you carry across to the rate base value, which I take it is an average of the whole year, it is $379.8 million, and then $360.9 million?

MR. MAUTI: Okay. I see that.

MR. MILLER: And your nuclear cost -- so you would agree with me that is in rate base, so obviously it is earning a cost of capital?

MR. MAUTI: That's correct.

MR. MILLER: To the extent that those amounts are overstated, you would be earning additional return? Is that fair?

MR. MAUTI: I am not sure how you would define "overstated" or --

MR. MILLAR: If you have more -- if the Board approves a larger amount for working capital than you actually need or that you actually use in the test years, you would over-earn for that amount, and I guess the converse would be true, as well? Is that fair enough?

MR. MAUTI: That's correct, yes.

MR. MILLER: And my understanding is that for 2008 and 2009, the amount of working capital associated with fuel inventory was overstated by $14 million and $13 million respectively?

And my source for that is Board Staff Interrogatory No. 2. Again, I apologize that that is not in the booklet.

If Mr. Buonaguro has it handy, that would be helpful, or we could pull it up.

It is Board Staff IR No. 2. And if we could have that blown up so I can -- I see under "Nuclear" there is a "fuel inventory" line, right about the middle.

Then if you see the variance for 2008, it is $14.3 million, and then 2009 it is $13.3 million?

MR. MAUTI: I see those two numbers.

MR. MILLER: Again, the actual amounts are irrelevant in some sense.

My question is: Does the variance, the nuclear cost fuel cost variance account, capture those types of difference? In other words, does it capture the cost of capital associated with the rate base amounts from the working capital?

My understanding is it doesn't, but I wanted to put that to you.

MR. MAUTI: I don't believe that it does, but a future

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panel dealing with variance and deferral accounts may be able to confirm that.

MR. MILLER: So I will put that to them, as well.

Madam Chair, I do apologize. I am going over my time estimate. This is my last question on nuclear fuel. Did you wish to ask the panel some questions on that?

QUESTIONS BY THE BOARD:

MS. CHAPLIN: Yes. I just had a couple of questions.

I am looking at Exhibit F2, tab 5, schedule 1, page 12 of 12, which I believe is the larger version of the chart that is also used in the interrogatory.

So you have described how, in explaining the difference between current market prices and the fuel cost that is embedded in your application, that it seems that one of the big factors is this -- the inventory approach, because what you are using in the test period was purchased in a different physical time period.

So would it be true that over the longer term, we should see the fuel costs tracking the market prices in some sort of regular pattern? In other words, that there is a lag?

MR. MAUTI: I think that would be fair. Even if you look at the peaking of spot prices, according to the graph, approximately around January 2007 to January 2008, spot prices purchases of uranium were spiking up that year; the fuel cost did not substantially increase. It went up a little bit.

As prices started to come down, you see the lag effect

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Board Staff Interrogatory #002

Ref: Ex. B1-T1-S1

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

Interrogatory

Please complete the table below.

	(1) 2007 Actual	(2) 2008 Board-approved	(3) 2008 Actual	(4) 2008 variance (c-b)	(5) 2008 Board-approved	(6) 2009 Actual	(7) 2009 variance (f-e)	(8) 2010 Budget	(9) 2011 Test Year	(10) 2012 Test Year
HydroElectric										
Gross plant at cost										
Accumulated depreciation										
Net Plant										
Cash Working Capital										
Materials & Supplies										
Hydroelectric Rate Base										
Nuclear										
Gross plant at cost										
Accumulated depreciation										
Darlington Refurbishment (CWIP)										
Net Plant										
Cash Working Capital										
Fuel Inventory										
Materials & Supplies										
Total Working Capital										
Nuclear Rate Base										
Nuclear Rate Base without "Unamortized ARC"										

a) If the Hydroelectric 2008 Rate Base variance (col. 4) is in excess of 1% please calculate the over (under) earnings that results.

b) If the Hydroelectric 2009 Rate Base variance is (col. 7) in excess of 1%, please calculate the over (under) earnings that results.

c) If the Nuclear 2008 Rate Base variance (col. 4) is in excess of 1%, please calculate the over (under) earnings that results.

d) If the Nuclear 2009 Rate Base variance (col. 7) is in excess of 1%, please calculate the over (under) earnings that results.

e) If the Nuclear without Unamortized ARC 2008 Rate Base variance (col. 4) is in excess of 1%, please calculate the over (under) earnings that results.

f) If the Nuclear without Unamortized ARC 2009 Rate Base variance (col. 7) is in excess of 1%, please calculate the over (under) earnings that results.

Response

The requested table is completed below. "Board Approved" values have been taken from the EB-2007-0905 Rate Order with supplemental rate base information from page 133 of the OEB's "Decision with Reasons".

	(1) 2007 Actual	(2) 2008 Board-approved	(3) 2008 Actual	(4) 2008 variance (c-b)	(5) 2009 Board-approved	(6) 2009 Actual	(7) 2009 variance (f-e)	(8) 2010 Budget	(9) 2011 Test Year	(10) 2012 Test Year
HydroElectric										
Gross plant at cost	4,396.5	4,433.2	4,416.8	(16.4)	4,480.6	4,438.6	(42.1)	4,485.0	4,538.0	4,585.5
Accumulated depreciation	507.8	570.2	569.5	(0.7)	633.1	631.2	(1.9)	693.6	756.7	820.2
Net Plant	**3,888.7**	**3,857.8**	**3,847.3**	**(10.5)**	**3,847.5**	**3,807.4**	**(40.2)**	**3,791.4**	**3,781.3**	**3,765.3**
Cash Working Capital	21.8	21.8	23.6	1.8	21.8	26.0	4.2	23.7	21.5	21.5
Materials & Supplies	0.6	0.6	0.6	0.0	0.6	0.7	0.0	0.7	0.6	0.6
Hydroelectric Rate Base	**3,911.1**	**3,880.2**	**3,871.5**	**(8.7)**	**3,869.9**	**3,834.0**	**(35.9)**	**3,815.7**	**3,803.4**	**3,787.4**
Variance - %				-0.2%			-0.9%			

	(1) 2007 Actual	(2) 2008 Board-approved	(3) 2008 Actual	(4) 2008 variance (c-b)	(5) 2009 Board-approved	(6) 2009 Actual	(7) 2009 variance (f-e)	(8) 2010 Budget	(9) 2011 Test Year	(10) 2012 Test Year
Nuclear										
Gross plant at cost	4,321.1	4,525.5	4,498.9	(26.6)	4,733.2	4,679.5	(53.7)	5,355.3	5,547.1	5,741.7
Accumulated depreciation	1,446.1	1,737.8	1,733.0	(4.8)	2,037.1	2,023.7	(13.5)	2,278.8	2,500.3	2,745.4
Darlington Refurbishment (CWIP)									125.5	306.0
Net Plant	**2,875.0**	**2,787.7**	**2,765.9**	**(21.8)**	**2,696.0**	**2,655.8**	**(40.2)**	**3,076.5**	**3,172.2**	**3,302.3**
Cash Working Capital	16.0	16.0	15.9	(0.1)	16.0	14.3	(1.7)	9.2	4.0	4.0
Fuel Inventory	208.7	281.1	266.9	(14.3)	330.1	316.9	(13.3)	357.3	379.8	360.9
Materials & Supplies	400.4	424.4	415.6	(8.8)	441.7	434.4	(7.3)	468.9	485.3	483.7
Total Working Capital	**625.1**	**721.5**	**698.4**	**(23.1)**	**787.8**	**765.6**	**(22.3)**	**835.5**	**869.1**	**848.5**
Nuclear Rate Base	3,500.1	3,509.1	3,464.2	**(44.9)**	3,483.8	3,421.4	**(62.4)**	3,912.0	4,041.3	4,150.8
				-1.3%			**-1.8%**			
Nuclear Rate Base without "Unamortized ARC"	2,084.7	2,282.1	2,180.5	**(101.6)**	2,362.8	2,261.6	**(101.2)**	2,355.4	2,518.0	2,660.7
Variance - %				**-4.5%**			**-4.3%**			

a) and b)
The variances in the regulated hydroelectric rate base are less than 1 per cent.

c) The 2008 actual nuclear rate base was 1.3 per cent lower than approved by the OEB. If this lower base for 2008 had been incorporated into the calculation of payment amounts in EB-2007-0905, it would have reduced OPG's revenue requirement by approximately \$3M over the 21-month test period.

d) The 2009 actual nuclear rate base was 1.8 per cent lower than that approved by the OEB. If this lower base for 2009 had been incorporated into the calculation of payment amounts in EB-2007-0905 it would have reduced OPG's revenue requirement by approximately $5M over the 21-month test period.

e) The 2008 actual nuclear rate base excluding the unamortized asset retirement cost ("ARC") was 4.5 per cent lower than approved by the OEB. If this lower base excluding unamortized ARC for 2009 had been incorporated into the calculation of payment amounts in EB-2007-0905 it would have reduced OPG's revenue requirement by approximately $5M over the 21-month test period.

f) The 2009 actual nuclear rate base excluding the unamortized ARC was 4.3 per cent lower than that approved by the OEB. If this lower base excluding unamortized ARC for 2009 had been incorporated into the calculation of payment amounts in EB-2007-0905 it would have reduced OPG's revenue requirement by $8M over the 21-month test period.

OPG notes that the amounts in parts c) / d) and e) / f) above are not additive, but rather the impacts shown in c) / d) are largely included in the impacts shown for e) / f).

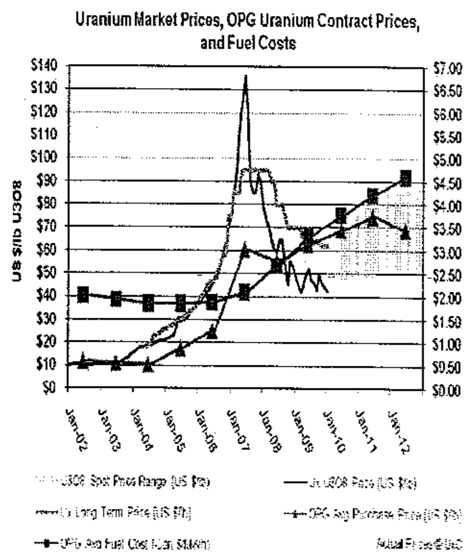
Board Staff Interrogatory #065

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

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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.

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UNDERTAKING J4.5

Undertaking

To provide the dollar value of the two spot market purchases for 2009.

Response

The dollar values of the two spot market purchases in 2009 were $9.19M and $9.20M.

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ONTARIO ENERGY BOARD

FILE NO.: **EB-2010-0008**

VOLUME: **5**

DATE: **October 15, 2010**

BEFORE: **Cynthia Chaplin** **Presiding Member and Vice-Chair**

Cathy Spoel **Member**

Marika Hare **Member**

Pickering units, and we compared it to what our understanding or our judgment is what the system energy value would be, in the event that we weren't running Pickering. And so we subtracted the two, and that's how we came up with the 1.1, which is an actual benefit to ratepayers.

MS. CHAPLIN: So -- but what do you mean by the cost to Pickering? Just the incremental cost associated?

MR. PASQUET: No.

MS. CHAPLIN: So you used an all-in --

MR. PASQUET: All-in.

MS. CHAPLIN: Sorry.

MR. PASQUET: Sorry. I apologize. We did not include just the incremental cost. We used the total cost of Pickering.

MS. CHAPLIN: Okay, thank you.

Just one more question on nuclear fuel. And you may have already answered this, but so I -- but have you commissioned any external analysis of your strategy and review of the success?

MR. MAUTI: I don't believe we have, no.

MS. CHAPLIN: Okay. Is that something that you have -- is it something that you've considered?

MR. MAUTI: Again, I guess the strategy that we feel we're following is providing us the value on our unit costs. I know, from a benchmarking sense, we're at sort of the top end. And irrespective of the fact there's even other CANDUs in the benchmarking exercise that we have done

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with ScottMadden and which is defined in the benchmarking report as being Bruce Power, our costs are competitive to theirs.

From that sense, sort of we feel that that's a good indication of our ability to be competitive, especially with another CANDU organization who does have cost efficiency as one of their sort of assumed goals in terms of managing their fuel.

So from that end, we feel it's an appropriate strategy which is putting us in a good position.

MS. CHAPLIN: Okay. And I'm looking at Exhibit -- interrogatory L-14, schedule 20, and this is under issue 6.6. And there have been some questions around -- and I'm looking at the public version, the non-confidential version.

And you were asked about -- there you were asked -- the question was -- made a reference to price risk being fully borne by ratepayers. And OPG's response was that the underlying premise of the question was incorrect, and there was a bit of discussion about that already.

And I'm wondering, on the assumption that the procurement is prudent and is found to be prudent, isn't it the case that the result of the operation of the deferral and variance accounts will be that ratepayers bear the market price risk?

MR. MAUTI: The ratepayers would bear the risk, whether that's positive or negative to what our forecasts could be, depending on how the market works in relation to what our forecast is.

MS. CHAPLIN: Okay. And on what -- what's the rationale or thinking around why it's appropriate for -- and I realize a decision was made in the last proceeding. I understand that. But what's the current thinking and rationale around why that's an appropriate risk for ratepayers to bear?

MR. MAUTI: From my understanding of how variance and deferral accounts work, the major component of variation within our fuel cost is the price of uranium, which, at least since the 2004 time period, has had a great degree of volatility, something that even if you go to just using the market basis, would subject our estimate of our fuel forecast costs to be subject to a great deal of volatility that is somewhat beyond our control in terms of the market price itself.

And so we feel that's an appropriate use of sort of variance and deferral account process through the OEB. And I'm sure our variance and deferral account panel can maybe talk about the appropriateness of that account, as well, going forward.

MS. CHAPLIN: Okay, thank you. I think Ms. Spoel does have a question.

MS. SPOEL: Yes, I have one quick question. I notice that the costs of the tritium removal facility are all included within the costs, the OM&A costs, for Darlington; am I correct?

MR. PASQUET: Correct.

The OEB approved new payment amounts for OPG in December 2008, which were effective as of April 1, 2008. As a result, OPG had a revenue shortfall for the period April 1, 2008 to November 30, 2008. Rider C was established to allow OPG to recover nuclear payment rider A (for recovery of nuclear variance and deferral accounts) for this period. With the exception of interest and amortization, no additional amounts will be recorded in this account during the test period related to nuclear payment rider C.

4.0 NEW ACCOUNTS

OPG requests approval to establish two new variance accounts:

- the IESO Non-Energy Charges Variance Account; and
- the Pension and Other Post Employment Benefits Cost Variance Account.

4.1 IESO Non-Energy Charges Variance Account

IESO non-energy charges are applied to all load customers in the Ontario wholesale market. They are made up of a number of different components including; Uplift Charges, Debt Retirement Charges, Rural Rate Assistance, Transmission Charges, Global Adjustment, etc. For a detailed description of IESO non-energy charges, please refer to Ex. F4-T4-S1.

These charges are incurred by OPG to operate the regulated facilities and cannot be avoided (while maintaining the ability to operate) nor can the energy to which the charges are attached be supplied cost-effectively by an alternate source. Further, they are beyond management's ability to control.

These charges are difficult to forecast for two reasons. First, the charges fluctuate based on the changes in the wholesale market (Global Adjustment being the largest and most volatile of the components). Second, they are based on consumption which itself can fluctuate hour-to-hour, or month-to-month. As a result of these two factors, the total amount of IESO non-energy charges is very difficult to accurately forecast.

As seen in Ex. F4-T4-S2 Tables 1 and 2, variances associated with both nuclear and regulated hydroelectric facilities have been material and have occurred in both directions in

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recent years. For example, in 2008 actual non-energy charges were under budget by 74 per cent or $7.9M for nuclear and 42 per cent or $1.8M for regulated hydroelectric. Conversely, 2009 saw actual charges exceed budget by 95 per cent or $17.6M for nuclear and 108 per cent or $6.6M for regulated hydroelectric. Further, the quantum of these charges has increased dramatically since 2007, largely driven by depressed market prices and a corresponding increase in Global Adjustment charges. A variance account for the total of IESO non-energy charges associated with both nuclear and regulated hydroelectric facilities will protect both OPG and ratepayers from over or under collection of these charges. Starting on the effective date of new payment amounts, proposed to be March 1, 2011, this account will record the difference between the IESO non-energy charges underpinning in the approved payment amounts and the actual IESO non-energy charges.

4.2 Pension and Other Post Employment Benefits Cost Variance Account

OPG requests approval to establish a new variance account to be called the Pension and Other Post Employment Benefits Cost Variance Account. This account would record the difference between the pension and other post employment benefits ("OPEB") costs reflected in OPG's approved payment amounts and the actual pension and OPEB costs for the prescribed facilities and associated tax impacts.

As discussed in EB-2007-0905, OPG's pension and OPEB costs are difficult to forecast and often result in variances that are material[1]. As indicated in the Impact Statement filed by OPG on September 30, 2010 (Ex. N-T1-S1, pages 2 to 4), the difference between the forecast included in this application for pension and OPEB costs and the updated projection of pension and OPEB costs is material (i.e., greater than $250M). This updated projection of pension and OPEB costs for the prescribed facilities is based on a projected actuarial accounting assessment of OPG-wide costs for the test period provided by OPG's external actuaries, Mercer, using data as of August 2010. The letter from Mercer setting out its updated OPG-wide projection is presented in Attachment 1 to this exhibit. This OPG-wide projection is then assigned to the prescribed facilities using the same methodology as was

[1] EB-2007-0905, Ex. J1-T3-S1, Page 13. Forecast variances of between $11M under-forecast and $130M over-forecast on a company-wide basis.

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Ontario

ONTARIO ENERGY BOARD

FILE NO.: EB-2010-0008

VOLUME: 8

DATE: October 21, 2010

BEFORE:	Cynthia Chaplin	Presiding Member and Vice-Chair
	Cathy Spoel	Member
	Marika Hare	Member

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this, but I'll ask the question and if you can answer, you can answer.

If you look to our booklet of documents for this panel, you will see Undertaking J1.4 at page 58. It is 58 at the top.

This undertaking asks you to break out the IESO non-energy charges and the energy withdrawals from the grid.

I wanted to take you, in particular, to table 2 of that undertaking response. It is at page 59.

I just wanted to -- and this is showing us the energy withdrawals from the grid for your -- for your regulated and unregulated businesses; is that right?

MR. STAINES: I believe that is what it is.

MR. MILLAR: If we look at the total at the bottom, I see, I guess, it is 1.6 million megawatt-hours.

Do you see that?

MR. STAINES: Yes, I do.

MR. MILLAR: And if you look up to "total nuclear," 807,000 megawatt-hours, that is about half of that amount; is that correct?

MR. STAINES: That's correct.

MR. MILLAR: And if you look down to the "corporate facilities" amount at the bottom, we see about 21,000 megawatt-hours?

MR. STAINES: Yes, I see that.

MR. MILLAR: And that is less than one percent; is that fair?

MR. STAINES: That's fair.

MR. MILLAR: And I understood from the previous panel -- and I am not sure if you can confirm this or not, but there had been no energy initiatives undertaken at your regular nuclear facilities?

MR. STAINES: I am not aware of that.

MR. MILLAR: Okay. We will look to the transcript for that, I guess.

Again, I ask you these only because some of the questions were punted to this panel. If you can't answer them, then you can't.

Can you confirm for me that OPG seeks to pass through all of its costs related to IESO non-energy charges incurred by its regulated facilities on to ratepayers through the payment amounts?

MR. STAINES: That's my understanding.

MR. MILLAR: And can you tell me if you have undertaken any review of your nuclear facilities to determine if any cost-effective energy efficiency investments can be made to reduce consumption, and therefore the non-energy charges?

MR. STAINES: I don't believe that is under my mandate, to look at the nuclear side of the business.

We're dealing with the corporate cost.

MR. MILLAR: Okay.

MR. STAINES: And only the bottom item that deals with the corporate facilities.

MR. MILLAR: Okay. I do understand, so if you can't answer, you can't answer. Thank you for that.

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Numbers may not add due to rounding.

Table 1
Update of Ex. H1-T1-S1 Table 1[1]
Summary of Deferral and Variance Accounts
Closing Account Balances - 2007 through 2009 and 2010 Amount Proposed for Recovery ($M)

Line No.	Account	Year End Balance 2007[2]	2008	2009	2010 Proposed for Recovery
		(a)	(b)	(c)	(d)
	Regulated Hydroelectric:				
1	Hydroelectric Water Conditions Variance	6.3	(21.6)	(55.3)	(68.9)
2	Ancillary Services Net Revenue Variance - Hydroelectric	7.2	(2.4)	(16.0)	(9.5)
3	Income and Other Taxes Variance	0.0	(0.2)	(0.3)	(7.5)
4	Tax Loss Variance	0.0	20.2	47.1	78.7
5	Interim Period Shortfall (Rider D)	0.0	(0.3)	(2.2)	(2.3)
6	Over/Under Recovery Variance - (2010)	0.0	0.0	0.0	(8.0)
7	Total	13.5	(4.2)	(26.6)	(17.4)
	Nuclear:				
8	Pickering A Return To Service Deferral	183.8	129.5	81.8	33.2
9	Nuclear Liability Deferral	130.5	132.3	86.2	39.1
10	Nuclear Development Variance	11.7	(21.7)	(55.6)	(105.0)
11	Transmission Outages and Restrictions Variance	1.8	1.4	0.7	0.1
12	Ancillary Services Net Revenue Variance - Nuclear	(1.8)	(1.9)	(0.6)	1.0
13	Capacity Refurbishment Variance	0.0	(5.7)	(0.3)	(1.3)
14	Nuclear Fuel Cost Variance	0.0	(1.4)	(15.7)	9.3
15	Bruce Lease Net Revenues Variance	0.0	256.6	324.5	296.6
16	Income and Other Taxes Variance	0.0	(7.8)	(12.1)	(25.2)
17	Tax Loss Variance	0.0	105.9	247.2	413.3
18	Interim Period Shortfall (Rider B)	0.0	0.3	6.6	6.6
19	Over/Under Recovery Variance - Nuclear (Rider A&C)	0.0	0.6	10.7	10.8
20	Over/Under Recovery Variance - (2010)	0.0	0.0	0.0	11.6
21	Total	325.9	588.1	673.3	690.1
22	Grand Total	339.4	583.9	646.7	672.7

Notes:

1 Figures reflect corrections, adjustments and 2010 year-to-date updates as described in Ex. H1-T1-S2, Section 3. Updated values are in shaded cells

2 2007 balances are as approved by OEB in Payment Order EB-2007-0905 with the exception of Hydroelectric Water Conditions, Ancillary Services Net Revenue-Hydroelectric, Transmission Outages and Restrictions and Ancillary Services Net Revenue-Nuclear variance accounts. The individual balances provided for these four accounts by OPG in EB-2007-0905 were not correct, but the total balance for all four accounts is correct. OPG is proposing to correct the individual account balances as part of this Application. There is no financial impact of making this correction as the errors in the individual accounts are offsetting.

CLEARANCE OF DEFERRAL AND VARIANCE ACCOUNTS

1.0 PURPOSE

This evidence describes OPG's proposed approach for clearing the deferral and variance account balances described in Ex. H1-T1-S1.

2.0 SUMMARY

OPG is requesting test period payment riders for regulated hydroelectric and nuclear production to amortize audited deferral and variance account balances as of December 31, 2010. These riders will reflect disposition for the period March 1, 2011 to December 31, 2012 of a portion of total deferral and variance account balances for regulated hydroelectric and nuclear production, and will be calculated as described in sections 3, 4 and 5 of this exhibit.

The balances as at December 31, 2010 will consist of unamortized amounts that were approved by the OEB for the period up to December 31, 2007; amounts that were recorded in 2008 and 2009 pursuant to the methodology approved by the OEB in EB-2007-0905; and, amounts to be recorded in 2010 pursuant to the methodology approved by the OEB in EB-2009-0174. OPG is proposing to clear the 2010 actual balances rather than 2009 actual balances as the bulk of the change in balances in 2010 consists of amortization as approved in EB-2009-0174 and an addition to the Tax Loss Variance Account.

The EB-2007-0905 Decision and Order approved the clearance of deferral and variance account balances as at December 31, 2007. The Order stated that these balances were to be cleared over 21, 33 or 45 months from April 1, 2008, as shown in the chart below:

Account	Recovery Period (Months)
Hydroelectric Water Conditions Variance Account	21
Ancillary Services Net Revenue Variance Account - Hydroelectric	21
Ancillary Services Net Revenue Variance Account – Nuclear	33
Transmission Outages and Restrictions Variance Account	33
Nuclear Liability Deferral Account	33
Nuclear Development Deferral Account	33
Pickering A Return to Service Deferral Account	45

The EB-2009-0174 Decision and Order approved the continuation of the nuclear payment rider A beyond December 31, 2009, as well as the continued amortization and recovery of the approved December 31, 2007 balances in the following accounts:

- Ancillary Services Net Revenue Variance Account – Nuclear
- Transmission Outages and Restrictions Variance Account
- Pickering A Return to Service Deferral Account
- Nuclear Liability Deferral Account
- Nuclear Development Deferral Account

This decision has been reflected in the amortization amounts to be recorded for 2010 and the projected variance and deferral account balances as at December 31, 2010.

As noted in Ex. H1-T1-S1, the EB-2009-0038 Decision and Order authorized the Tax Loss Variance Account. The balance in this account has been allocated to hydroelectric and nuclear sub accounts as described in Ex. H1-S1-T1, section 4.3.

OPG proposes to apply payment riders on its regulated hydroelectric and nuclear production to recover the portion of the December 31, 2010 variance and deferral account balances to be amortized during the test period.

The methodology and rationale for the proposed recovery of deferral and variance account balances is described in section 3.0. The recovery of hydroelectric variance account balances is discussed in section 4.0. The recovery of nuclear deferral and variance account balances is discussed in section 5.0.

3.0 METHODOLOGY

The use of payment riders in the form of a $/MWh rate is consistent with the OEB's Decisions in EB-2007-0905 and EB-2009-0174.

Riders are calculated in three steps. First, an amortization period is determined for each account. Second, based on each account's amortization period, the amount to be amortized during the test period is determined. Finally, the total amount to be amortized during the test period is divided by forecast energy production to determine the payment amount rider.

OPG proposes that the same payment riders be used for both years of the test period as this is easier to implement, and administer than different riders for each year. As the payment riders are based on forecast production, any differences between forecast and actual production will cause a variance which will be tracked in the Nuclear and Hydroelectric Over/Under Recovery Variance Accounts consistent with EB-2009-0174. Interest will be recorded on a monthly basis at the OEB's prescribed interest rate.

4.0 RECOVERY OF HYDROELECTRIC VARIANCE ACCOUNTS

The method of calculation of the hydroelectric payment rider is shown in Ex. H1-T2-S1 Table 1 using the projected balances that were filed on May 26, 2010. The rider will be set during the finalization process for the payment amounts order as described in Ex. H1-T1-S2.

OPG proposes to amortize the balance in the Tax Loss Variance Account over the 46 month period from March 1, 2011 to December 31, 2014. This extended amortization period was chosen to lessen ratepayer impact.

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Consistent with the Order in EB-2007-0905, OPG proposes to clear the balances in the remainder of the Hydroelectric variance accounts by the end of the test period, in this case from March 1, 2011 to December 31, 2012.

OPG proposes a single payment rider beginning March 1, 2011 to recover all hydroelectric account balances. The use of one clearance period for most accounts is administratively simple and aligns with the end of OPG's test period. It is also consistent with the recovery period for hydroelectric variance accounts approved by the OEB in EB-2007-0905.

The balance in each variance and deferral account as at December 31, 2010 is amortized on a straight line basis commencing March 1, 2011 and ending December 31, 2012, or December 31, 2014 in the case of the Tax Loss Variance Account. The total amortization expense over this 22-month period March 1, 2011 to December 31, 2012 is divided by the production forecast for that period to calculate the payment amount rider.

5.0 RECOVERY OF NUCLEAR DEFERRAL AND VARIANCE ACCOUNTS

The method of calculation of the nuclear payment rider is shown in Ex. H1-T2-S1 Table 2 using the projected balances that were filed on May 26, 2010. The rider will be set during the payment order finalization process as described in Ex. H1-T1-S2.

Because the current $2.00/ MWh Rider A continues until changed by the OEB, there will be an over collection of revenue related to Rider A for January and February of 2011. OPG has estimated this over collection based on forecast nuclear production for those months and has adjusted the December 2010 projected balance in the Nuclear Deferral and Variance Over/Under Recovery Variance Account in Ex. H1-T2-S1 Table 2. OPG proposes to clear the adjusted balance in this account.

Consistent with the payment order in EB-2007-0905, OPG proposes a single payment rider to recover nuclear account balances.

OPG proposes to amortize the projected December 31, 2010 balances in the Nuclear deferral and variance accounts on a straight line basis using amortization periods for the various accounts as follows.

The balance remaining in the Pickering A Return to Service (PARTS) Deferral account will be amortized over 12 months (January 1, 2011 to December 31, 2011), consistent with the OEB's EB-2007-0905 Decision which established a 45-month amortization period for this account commencing April 1, 2008.

The balance in the Tax Loss Variance Account will be amortized over the 46 month period from March 1, 2011 to December 31, 2014. This extended amortization period was chosen to lessen ratepayer impact.

All other account balances will be amortized over the 22 months commencing March 1, 2011 and ending December 31, 2012. The use of a single clearance period for the majority of accounts is administratively simple and is aligned with the end of OPG's test period.

Having determined the amortization amount for each account, the sum of these amortization amounts for the individual accounts is then divided by the nuclear production forecast for the period March 1, 2011 to December 31, 2012 to calculate the payment amount rider.

Numbers may not add due to rounding.

Table 2
Update of Ex. H1-T1-S1 Table 8 to Correct Omission of 2009 Fuel Channel Life Cycle Management Project Costs*
Capacity Refurbishment
Summary of Cost Deferrals and Variances - 2008 through 2010 ($M)

Line No.		Jan-Mar 2008	Apr-Dec 2008	2009	2010
		(a)	(b)	(c)	(d)
	Forecast Costs - EB-2007-0905 / EB-2009-0174[1]				
1	Pickering B Refurbishment	0.0	4.6	5.1	5.5
2	Darlington Refurbishment	0.0	13.9	22.7	21.1
3	Fuel Channel Life Cycle Management Project	0.0	0.0	0.0	0.0
4	Pickering B Continued Operations	0.0	0.0	0.0	0.0
5	Total Forecast Costs	0.0	18.5	27.8	26.6
	Actual Costs[2]				
6	Pickering B Refurbishment	0.0	6.1	4.3	1.2
7	Darlington Refurbishment	0.0	6.7	21.7	5.5
8	Fuel Channel Life Cycle Management Project	0.0	0.0	2.5	9.7
9	Pickering B Continued Operations	0.0	0.0	4.8	13.5
10	Total Actual Costs	0.0	12.8	33.3	29.9
	Variance				
11	Pickering B Refurbishment (line 6 - line 1)	0.0	1.5	(0.8)	(4.3)
12	Darlington Refurbishment (line 7 - line 2)	0.0	(7.2)	(1.0)	(15.6)
13	Fuel Channel Life Cycle Management Project (line 8 - line 3)	0.0	0.0	2.5	9.7
14	Pickering B Continued Operations (line 9 - line 4)	0.0	0.0	4.8	13.5
15	**Variance** (line 10 - line 5)	0.0	(5.7)	5.5	3.3

3.1

Notes:
- * Updated values are in shaded cells.
1. 2010 forecast figure derived from EB-2007-0905 OEB approved forecast as described in Decision and Order in EB-2009-0174.
2. Value for 2010 is OPG's current forecast of the 2010 actual value.

Numbers may not add due to rounding.

Table 3
Update of Ex. H1-T1-S1 Table 9 to Correct 2008 and 2009 Actual Production*
Nuclear Fuel Cost Variance
Summary of Annual Amounts 2008 through 2010

Line No.	Account	2008	2009	2010[1]
		(a)	(b)	(c)
1	**Reference Plan[2] - Fuel Costs ($M)**	108.2	180.4	288.7
2	**Reference Plan[2] - Nuclear Generation (TWh)**	38.3	49.9	88.2
3	**Reference Plan Fuel Rate ($/MWh)** (line 1 / line 2)	2.84	3.62	3.27
4	**Actual Fuel Costs ($M)**	97.6	154.9	173.6
5	**Actual Generation (TWh)**	34.9	46.8	46.2
6	**Actual Fuel rate ($/MWh)** (line 4 / line 5)	2.80	3.31	3.76
7	**Fuel Rate Variance ($/MWh)** (line 6 - line 3)	(0.039)	(0.305)	0.486
8	**Nuclear Fuel Cost Variance ($M)** (line 7 x line 5)	(1.4)	(14.3)	22.4

6.7

Notes:

* Updated values are in shaded cells.

1 2010 figures derived from EB-2007-0905 OEB approved forecast as described in Decision and Order in EB-2009-0174.

2 Reference Plan for 2008 and 2009 is budget as per EB-2007-0905.

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Numbers may not add due to rounding.

Table 4
Update of Ex. H1-T1-S1 Table 10 to Correct 2008 and 2009 Actual Production*
Bruce Lease Net Revenue
Summary Calculation of Year End Account Balances - 2008 to 2010

Line No.	Account	2008	2009	2010	
		(a)	(b)	(c)	
1	**Actual Lease Net Revenue[1] ($M)**	(179.9)	37.4	115.0	
	Reference Plan:				
2	**Lease Net Revenue - Apr 08-Dec 2009 ($M)**	191.9	191.9	191.9	
3	**Production - Apr 08-Dec 2009 (TWh)**	88.2	88.2	88.2	
4	**Rate Credited to Customers per Payment Order EB-2007-0905 ($/MWh)**	2.18	2.18	2.18	
5	**Actual Production (TWh)**	34.9	46.8	46.2	
6	**Amount Credited to Customers in Payment Order EB-2007-0905 ($M)**	75.9	101.8	100.5	
	(line 4 x line 5)				
7	**Lease Net Revenue Variance ($M)** (line 6 - line 1)	255.8	64.4	(14.3)	305.9

* Updated values are in shaded cells.
1 See Ex. H1-T1-S1 Table 10a for derivation.

4.0 MODIFIED CLEARANCE PROPOSAL

To respond to concerns expressed by intervenors, OPG is modifying its proposal to clear the actual audited balances as at December 31, 2010 rather than the forecast balances. OPG is providing for an external audit of the actual balances prior to the fixing of the payment amounts and payment riders through the finalization process for the payment amounts order. Therefore, OPG proposes that the OEB use its actual, rather than forecast, balances as at December 31, 2010 as verified by OPG's auditors for setting the payment riders. OPG does not propose any changes to the recovery periods or methodology set out in Ex. H1-T2-S1.

The expected timing of the Board's decision (i.e., late January or early February 2011) would allow OPG sufficient time to have its December 31, 2010 actual balances audited by OPG's external auditors. These actual balances, the auditors' report and any proposed adjustments to the accounts resulting from the OEB's Decision would be available for intervenors and Board staff to review and comment on during the review process for the payment amounts order. The auditors' report would provide additional assurance to the OEB with respect to the accuracy of the balances and is expected to be available in early February 2011. This timing is consistent with the proposed effective date for new payment amounts of March 1, 2011.

5.8

Board Staff Interrogatory #137

Ref: Ex. H1-T1-S1, pages 1-3, Table 1 and Ex. A2-T1-S1, Attachment 3, page 20

Issue Number: 10.2
Issue: Are the balances for recovery in each of the deferral and variance accounts appropriate?

Interrogatory

Table 1 shows Grand Totals of $629.1 M in 2009 and $579.1 M in 2008 for deferral and variance account balances whereas OPG's consolidated financial statements for Prescribed Assets (ExhA2-1-1 Attachment3/p20) show net regulatory assets and liabilities recorded by Prescribed Facilities of $796 M for 2009 and $468 M for 2008.

a) Please state whether or not OPG is of the view that the 2008 and 2009 grand total amount of account balances in Table 1 claimed for disposition should agree to the amounts shown for 2008 and 2009 in the consolidated financial statements. If not, please explain why not.
b) Please explain the differences between the amounts shown in the two above-noted references for 2009 and 2008 and provide a reconciliation of the differences.

Response

a) No, the grand total amount of account balances in Ex. H1-T1-S1, Table 1 for 2008 and 2009 should not agree to the total amount of net regulatory assets shown in the consolidated financial statements for Prescribed Assets for the respective years.

   The amounts in Ex. H1-T1-S1 are presented in the periods to which they relate and include only variance and deferral accounts that are established by the OEB. The amounts in the financial statements are presented in the periods in which they are recognized for accounting purposes and include regulatory assets and liabilities that are recognized as a result of accounting requirements rather than as a result of being required by the OEB. The main sources of differences are identified in part b).

b) The requested reconciliation is presented in Chart 1 below.

Chart 1
Reconciliation of Variance and Deferral Account Balances to Financial Statements
As At December 31, 2008 and 2009

	Dec. 31 2008 ($M)	Dec. 31 2009 ($M)	Notes
Net regulatory assets per Financial Statements	**468**	**796**	Ex. A2-T1-S1, Attachment 3, Note 6 to the financial statements for Prescribed Assets
Remove Regulatory Asset for Future Income Taxes	-	(163.8)	Regulatory asset for future income taxes is recognized effective January 1, 2009 for accounting purposes only, as per Notes 3, 6 and 10 to the financial statements for Prescribed Assets (Ex. A2-T1-S1, Attachment 3)
Tax Loss Variance Account amount for 2008 booked in 2009	126.1	-	Total Tax Loss Variance Account balance for 2008 and 2009 was recognized in 2009 for accounting purposes when the EB-2009-0038 Decision and Order was issued. Amount for 2008 is presented as part of 2008 balance in Ex. H1-T1-S1. Refer to Ex. L-12-041.
Income and Other Taxes Variance Account amount for 2008 booked in 2009	(12.1)	-	Amount of this variance account for 2008 activity was recognized in 2009 for financial accounting purposes. The 2008 amount (excl. interest) is found at Ex. H1-T1-S1, Table 13, column (a). Difference is due to interest.
Other timing differences	(2.9)	(3.1)	Reconciliation adjustments in 2009 pertaining to 2008, and difference due to rounding
Ex. H1-T1-S1, Table 1	**579.1**	**629.1**	

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Board Staff Interrogatory #143

Ref: Ex. H1-T1-S1, Table 10a

Issue Number: 10.2
Issue: Are the balances for recovery in each of the deferral and variance accounts appropriate?

Interrogatory

Table 10a shows separate amounts for Bruce Lease Net Revenue for Jan 1 to Mar 31 of $(33) M and Apr 1 to Dec 31 of $(179.9) M in 2008. The Jan.1 to Mar. 31 (stub) period amounts are not recorded in the account as the account came into effective on Apr 1, 2008.

a) Please explain how the amounts in the Apr 1 to Dec 31, 2008 nine-month period were derived for each line item including the basis of allocations for this nine-month period as compared to the three-month period of the Jan.1 to Mar. 31, 2008.

b) Using the same table format of Table 10a, please provide the monthly amounts for each of the line items (i.e., lines 1 to 14) for the period from Jan to Dec 2008 (in tabular format of 12 columns representing the 12 months of 2008).

c) Did OPG's external auditors verify the information in Table 10a?

Response

a) The amounts for the nine-month period April 1, 2008 to December 31, 2008 were derived as follows (line number refers to corresponding lines in Ex. H1-T1-S1, Table 10a:

Line	Item	Method of Derivation
1	Lease Revenue	Actual monthly revenue per accounting records
2	Services Revenue	Actual monthly revenue per accounting records (Note 5)
4	Depreciation	Actual monthly expense amount per accounting records (Note 1)
5	Property Tax	Actual monthly expense amount per accounting records
6	Capital Tax	Actual monthly expense amount per accounting records (Note 1)
7	Accretion	Actual monthly expense amount per accounting records (Notes 1, 2)
8	(Earnings) Losses on Segregated Funds	Actual monthly amount per accounting records (Note 3)

9	Used Fuel Storage and Disposal	Actual monthly expense amount per accounting records (Notes 1, 2)
10	Waste Management Variable Expenses	Application of proportion of 9/12 to actual annual amount per accounting records (Notes 1, 2)
11	Interest	Application of proportion of 9/12 to actual annual expense amount per accounting records (Note 4)
12	Income Tax	Calculated based on actual taxable income for the nine months Apr-Dec 2008 in Ex. G2-T2-S1, Table 6, Column (a).

<u>Notes:</u>

(1) Amounts exclude impact of entries into the Nuclear Liability Deferral Account during Q1 2008.

(2) Allocation of OPG's total expenses related to nuclear liabilities to Bruce is discussed in Ex. G2-T2-S1, pages 10-11; Ex. C2-T1-S2, Sections 3.1 and 3.3; Ex. L-1-130.

(3) Allocation of OPG's total (earnings) losses on segregated funds to Bruce is discussed in Ex. G2-T2-S1, page 11 and Ex. L-1-142.

(4) Allocation of OPG's total interest expense to Bruce is discussed in Ex. G2-T2-S1, page 12.

(5) Due to their small magnitude, variances for revenues related to Cobalt-60 and Site Services revenue are computed and recorded in the Bruce Lease Net Revenues Variance Account at the end of the year rather than on a monthly basis.

b) Refer to Table 1 in Attachment 1.

OPG notes that the following amounts in Ex. H1-T1-S1, Table 10a for January 1 to March 31, 2008 should be corrected to reflect proper classification as follows:

- Line no. 1 "Lease Revenue" – $64.4M
- Line no. 2 "Services Revenue" – $2.7M
- Line no. 4 "Depreciation" – $15.3M
- Line no. 10 "Waste Management Variable Expenses" – $0.9M

The amount of Total Bruce Revenue (line no. 3) and the amount of Total Costs (line no. 13) are unaffected.

OPG notes that the following amounts in Ex. H1-T1-S1, Table 10a for April 1 to December 31, 2008 should be corrected to reflect proper classification as follows:

- Line no. 1 "Lease Revenue" – $193.5M
- Line no. 2 "Services Revenue" – $6.3M
- Line no. 4 "Depreciation" – $45.7M
- Line no. 10 "Waste Management Variable Expenses" – $2.7M

The amount of Total Bruce Revenue (line no. 3) and the amount of Total Costs (line no. 13) are unaffected.

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The above corrections are for presentation purposes only and do not impact the entries into, or balance of the Bruce Lease Net Revenue Variance Account.

c) OPG's external auditors examined the derivation and balance of the Bruce Lease Net Revenues Variance account as part of their overall audit of OPG's company-wide and prescribed facilities' financial statements. The information in Ex. H1-T1-S1, Table 10a underlies the calculation of the entries into the account during 2008. The auditors expressed an unqualified opinion on the overall compliance of OPG's 2008 and 2009 financial statements (Ex. A2-T1-S1, Attachments 1, 2, 3) with Generally Accepted Accounting Principles ("GAAP").

The method of allocation of costs and revenues related to Bruce assets was also reviewed by an external consultant, Black & Veatch (Ex. F5-T2-S1, pages 16-18). Black & Veatch found (see Ex. F5-T2-S1, page 18) that "the methodology is appropriate and properly reflects the costs OPG incurs and revenues it realizes."

Numbers may not add due to rounding.

Table 10a
Bruce Lease Net Revenue Variance Account
Calculation of Bruce Lease Net Revenue - Actual 2008 and 2009 and Projected 2010

Line No.	Account	Jan 1 - Mar 31 2008	Apr 1 - Dec 31 2008	2008	2009	2010
	Revenue[1]:					
1	**Lease Revenue**	64.3	193.8	258.1	41.4	234.3
2	**Services Revenue**	2.7	7.6	10.4	7.3	12.4
3	**Total Bruce Revenue**	67.1	201.4	268.5	48.7	246.6
	Costs[2]:					
4	**Depreciation**	15.3	45.7	61.0	60.4	34.5
5	**Property Tax**	(13.1)	12.1	(1.0)	12.9	13.1
6	**Capital Tax**	0.9	2.7	3.6	3.4	1.1
7	**Accretion**	66.7	200.7	267.4	279.3	282.4
8	**(Earnings) Losses on Segregated Funds**	21.8	162.2	183.9	(386.2)	(268.8)
9	**Used Fuel Storage and Disposal**	3.2	10.8	14.0	14.4	16.7
10	**Waste Management Variable Expenses**	0.9	2.7	3.6	3.1	0.9
11	**Interest**	4.8	14.5	19.3	18.7	13.2
12	**Income Tax**	(0.1)	(70.1)	(70.1)	5.3	38.6
13	**Total Costs**	100.4	381.2	481.7	11.3	131.7
14	**Bruce Lease Net Revenue** (line 3 - line 13)	(33.3)	(179.9)	(213.2)	37.4	115.0

Notes:
1 Ex G2-T2-S1 Table 2 for 2008, 2009 and 2010.
2 Ex G2-T2-S1 Table 5 for 2008, 2009 and 2010.

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production purposes, which are currently exempt from PST but which will be subject to restrictions with regard to claims for HST input tax credits, OPG will incur an additional cost.

The recoverable portion of HST paid on purchases of goods and services, including applicable energy purchases, can be claimed as input tax credits on returns filed monthly. The non-recoverable portion will form part of the expenditure of the underlying item (e.g., OM&A, capital inventory, etc.).

OPG's forecast for the test period incorporates a net reduction to costs as a result of OPG becoming subject to HST. Since OPG is currently exempt from PST on most machinery and equipment purchases and will be subject to the restriction on input tax credits for energy purchases for non-production purposes, the net cost reductions related to HST are forecast to be relatively small, at less than approximately $5M annually. The impact of HST has also been incorporated into the computation of the cash working capital component of rate base effective July 1, 2010, as discussed in Ex. B1-T1-S2.

Where applicable, OPG pays duty under the *Customs Act* (Canada) on goods imported into Canada; however, currently most of these imports are either exempt or have duty free status through the North American Free Trade Agreement. For supply and installation contracts, the contractor's price includes duty, if applicable, on the goods imported to perform the work. Any duty paid forms part of the expenditure on the underlying item (e.g., OM&A, capital, inventory, etc.).

10.0 PROPERTY TAX EXPENSE

OPG is responsible for both the payment of municipal property taxes and a payment in lieu of property tax to the Province of Ontario. The total of these two payments is intended to represent what a commercial generating company would pay as property tax on OPG's assets based on full Current Value Assessment ("CVA"), and represents OPG's property tax expense. OPG's property tax expense for the regulated hydroelectric and nuclear facilities is presented in Ex. F4-T2-S1 Tables 1 and 3, respectively. The treatment of municipal property taxes and payment in lieu of property tax is consistent with that approved by the OEB in EB-

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allows the benefit of CCA to be applied against taxable income and passed on to ratepayers sooner.

OPG has followed this approach consistently in calculating the income taxes, because it is to the benefit of ratepayers and consistent with our actual tax returns.

MR. KEIZER: Moving on, question 31 is a confidential question, so we will leave that, as we established in the practice this morning, to the end.

We then move to question 32, which relates to the impact of the harmonized sales tax.

MR. HEARD: Harmonized sales tax came into effect on July 1st, 2010. OPG is in the process of compiling the data for its first HST return. Therefore, our actual cost reductions to date haven't been determined at this time.

However, we do estimate that the savings for the month of July are relatively small at approximately $570,000, which would work out to be approximately $3.4 million on an annualized basis.

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

MR. SHEPHERD: Sorry. I am just doing the math in my head. The savings for the month of July are 570; is that what you said?

MR. HEARD: Yes. That is about the estimate.

MR. SHEPHERD: And that annualizes to 3 million?

MR. HEARD: 3.4 million.

MR. SHEPHERD: You mean for 2010?

MR. HEARD: Yes, for 2010.

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MR. SHEPHERD: That is not an annual number. That is a half year.

MR. HEARD: Right. I'm sorry, I should have said that.

MR. SHEPHERD: The full year number would be --

MR. HEARD: Twelve times that.

MR. SHEPHERD: -- 7 million; is that right?

MR. HEARD: Actually, I don't know that, as I look at that. The month of July is the number that I have at the $570,000 number. But to look at this, I don't know the 7 million number.

MR. SHEPHERD: So you can't extrapolate the 570,000 to 12 times that as a rough approximation of the annual number?

MR. HEARD: I am just not sure if there are other factors affecting the timing there that would impact the amount of savings.

MR. SHEPHERD: Is there some way you can tell us what the annual number is?

MR. HEARD: Yes. I just don't have that information with me. That's all I am saying.

MR. SHEPHERD: So you can undertake to estimate the annual number?

MR. HEARD: I could.

MR. SHEPHERD: Thanks.

MS. HELT: Thank you. We will note that as JT1.9.

UNDERTAKING NO. JT1.9: TO PROVIDE ESTIMATE OF THE ANNUAL NUMBER FOR HST.

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UNDERTAKING JT 1.9

Undertaking

To provide estimate of the annual number for HST.

Response

The annualized amount of net HST savings is estimated to be approximately $6M.

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IMPACT STATEMENT

This exhibit has been prepared to show the impact of three changes since OPG filed its application in May 2010. The three changes are:

1. Increased fees for 2011 and 2012 from the Canadian Nuclear Safety Commission ("CNSC") which impact Nuclear Base OM&A;
2. Changes to Management compensation as a result of the *Public Sector Compensation Restraint to Protect Public Services Act, 2010* (the "Public Sector Compensation Restraint Act"); and
3. Changes to forecast pension and other post employment benefit ("OPEB") costs, primarily as a result of changes to forecasts of discount rates and actual pension fund performance.

Each of these matters is described separately below.

CNSC Fees

As indicated in the response to interrogatory L-12-027, OPG has been informed by the CNSC of increased regulatory fees for the test period. Licensing costs include the cost of CNSC staff directly involved with OPG issues, as well as an allocation for the associated regulatory support effort, indirect regulatory activities and overheads. The drivers of the increased fees include: alignment of regulatory practices to International Atomic Energy Agency guidance documents; the demand for CNSC attention to planning for industry-wide refurbishment activities and new nuclear; and the CNSC need to recruit and train staff to meet the anticipated demands.

The estimated revenue requirement impact of the increase in CNSC fees is $13M over the test period.

Management Compensation

The Public Sector Compensation Restraint Act was introduced after OPG's business plan for

2010-2014 had been approved. The Act addresses restrictions to increases in compensation for employees that do not collectively bargain compensation. For OPG, the Public Sector Compensation Restraint Act will impact Management employees.

As indicated in interrogatory L-01-075, OPG included an increase of 3 per cent in each of 2011 and 2012 in its Management compensation levels. As a result of the *Public Sector Compensation Restraint Act*, OPG is removing Management wage escalation for the period to April 1, 2012 from its test period revenue requirement for the regulated facilities, reducing costs by $12M.

Pension and OPEB Costs

As discussed in section 6.3.2 of Ex. F4-T3-S1, the projection of pension and OPEB costs requires an estimate of the value of the benefit obligations and the pension fund assets. Pension and OPEB costs are subject to significant variability to the extent that forecast assumptions, such as the discount rates, and assumed pension fund performance are different from actual values as of the end of the year preceding the forecast year.

The pension and OPEB costs forecasts in OPG's application for 2011 and 2012 were based on discount rates (presented in Chart 8 of Ex. F4-T3-S1) forecast during the 2010-2014 business planning process. Since the beginning of 2010, these discount rates have declined significantly. This decline has caused an increase in the forecast pension and OPEB costs for the test period. Specifically, the discount rates used to project pension, other post retirement benefits and the long-term disability plan costs have decreased from 6.80%, 7.00% and 5.25%, respectively, to 5.70%, 5.70% and 4.40%, respectively, as of the end of August 2010. The updated estimates of discount rates were provided by external actuaries.

Chart 8 of Ex. F4-T3-S1 also shows that pension cost forecasts were based on assumed rates of return on the pension fund assets of 9.0% in 2009 and 7.0% in 2010. The actual return for 2009 was approximately 15%, and the 2010 actual return as of the end of August 2010 is approximately 2.5%. The net effect of the updated returns for the two years is to offset, in part, the increase in pension costs due to changes in forecast discount rates.

OPG's updated total pension and OPEB costs for 2011 and 2012 have been projected by external actuaries as of the end of August 2010. The chart below shows the portion of these updated costs for 2011 and 2012 attributable to the prescribed facilities, as compared to the amounts included in the application per Ex. F4-T3-S1, Chart 9. The total projected increase over the two test years is $251.5M for nuclear and $12.7M for regulated hydroelectric.

Updated Pension and OPEB Costs ($M)

	Nuclear		Regulated Hydroelectric	
	2011	**2012**	**2011**	**2012**
Pension Cost				
As per Chart 9, Ex. F4-T3-S1	114.0	162.8	5.8	8.1
Projection as of August 2010	210.2	245.9	10.6	12.3
Increase	96.2	83.1	4.8	4.2
OPEB Cost[1]				
As per Chart 9, Ex. F4-T3-S1	159.3	166.7	8.0	8.3
Projection as of August 2010	196.5	201.7	9.9	10.1
Increase	37.2	35.0	1.9	1.8
Total Test Period Increase	251.5		12.7	

[1]Supplementary pension plans costs are included with OPEB costs.

Conclusion

The first two changes considered in this impact statement are effectively offsetting and OPG does not propose to revise its revenue requirement or payment amounts to reflect them.

Given the potential for significant variability between the updated forecast and actual pension and OPEB costs, OPG is not proposing to revise its proposed payment amounts or payments riders to address the projected increase in these costs. Instead, OPG proposes to address the forecast change to pension and OPEB costs by requesting that the OEB establish a variance account to record the revenue requirement impact of differences between forecast and actual pension and OPEB costs. For the 2011-2012 test period, OPG would bring the balance in this account forward for disposition during its next payment amounts application. OPG will file additional evidence supporting this request when it files the update to its variance and deferral account evidence with updated forecasts of balances for December 31, 2010.

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Ontario

ONTARIO ENERGY BOARD

FILE NO.: EB-2010-0008

VOLUME:	**12**	
DATE:	**October 28, 2010**	
BEFORE:	**Cynthia Chaplin**	**Presiding Member and Vice-Chair**
	Cathy Spoel	**Member**
	Marika Hare	**Member**

MR. LEE: That's correct.

MR. MILLAR: And December is a few months ago now. Are you proposing to update the short-term debt numbers using a more recent data set?

MR. LEE: I don't believe that is the case. We're being consistent in terms of our approach.

MR. MILLAR: Sorry. I don't mean update for 2012. I mean update for 2011, given the fact it is now almost a year -- this data is getting on a year old.

MR. PUGH: What we've done is we filed our information based on as it existed with our business plan. For several different components of our revenue requirement, we hadn't really proposed to update any of the specific parameters of it.

MR. MILLAR: I only ask because you are proposing to update the 2011 ROE number based on updates you receive from the Board.

I am not suggesting it is right or it is wrong. I am just asking if you are proposing a similar update for the short-term debt numbers. I take it the answer is no?

MR. PUGH: I think a lot of intervenors would accuse us of cherry-picking if we took selected things and updated them.

MR. MILLAR: So the answer is no?

MR. PUGH: The answer is no.

MR. MILLAR: Okay. Thank you.

I have one more set of questions on the cost of capital, and this may be a somewhat theoretical discussion.

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Ontario

DEC 17 2009

The Honourable Jake Epp
Chair
Ontario Power Generation
700 University Avenue
Toronto ON M5G 1X6

Dear Mr. Epp:

Thank you for forwarding a copy of OPG's proposed 2010-2014 Business Plan.

We have reviewed the business plan and are satisfied with OPG's focus and alignment of its operating and capital expenditures to support the core business of effectively managing its assets and liabilities in the best interests of the people of Ontario. We are also pleased to see OPG's projected costs remaining relatively flat over the five-year period. We urge you to continue to pursue ongoing opportunities to reduce operating costs and overhead and to improve financial performance.

The government looks to OPG to play a key role in advancing its priorities for the electricity sector over OPG's planning period. OPG's role includes actions to develop new and refurbished supplies of low-emission and renewable generation. Our staffs look forward to reviewing more detailed plans for OPG's proposed strategic projects, including financial and cost analysis, as they are developed.

This letter constitutes our concurrence with the business plan. Concurrence is given subject to the realization that the plan, including the projected financial performance, may change from time to time and have to be adapted to reflect changing circumstances, and that any such changes will be discussed in advance with staff at the ministries of Energy and Infrastructure and Finance.

Sincerely,

Gerry Phillips
Minister of Energy and Infrastructure

Dwight Duncan
Minister of Finance

Board Staff Interrogatory #149

Ref: Electricity RRR (Version dated: July 9, 2007)

Issue Number: 11.1
Issue: What reporting and record keeping requirements should be established for OPG?

Interrogatory

The Board's Reporting and Record Keeping Requirements (Version dated: July 9, 2007) listed reporting requirements for generators in section 6.

a) Please indicate whether OPG would be able to provide the section 6 information on a regular basis.

b) Can OPG file the following information with the Board on a quarterly basis?
   i) Deferral and variance accounts for the prescribed facilities – report 60 days after quarter end.
   ii) Financial reports issued to the public according to the established reporting schedule.
   iii) Nuclear unit capability factor and hydroelectric availability (for the regulated hydroelectric facilities).

c) Can OPG provide the following information with the Board on an annual basis by April 30th each year?
   i) Audited financial statements for the prescribed facilities as in Exh.A2/Tab1/Sch1/ Attachment 3.
   ii) OPG corporate annual report.
   iii) Trial balance for the prescribed facilities (details to be determined).
   iv) Employee FTE count.
   v) Capital additions (details to be determined) and work in progress.

Response

a) The information listed in section 6 of the referenced document could be provided on a regular basis with the following exceptions and cautions:

6.1.1 Items 7 and 8	There may be confidentiality concerns regarding these items.
6.1.1 Item 11	The depreciation asset lives are established at the station, rather than unit, level for OPG's nuclear facilities. For regulated hydroelectric stations, OPG does not establish an overall depreciation asset life for a particular unit, station or plant group. Individual asset classes for regulated hydroelectric facilities are depreciated over their respective estimated service lives.

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6.1.1 Item 12	Not applicable to regulated facilities.
6.1.1 Item 13	Can fluctuate on a daily or hourly basis so "regular" reporting is not possible.

OPG notes that "regular basis" is not defined in this question. OPG expects it would work with Board Staff to develop a reasonable schedule for the filing of information.

b) i) Yes, and these balances would be unaudited. Audited balances will be available as part of OPG's audited annual consolidated financial statements, which are discussed in part (b) (ii) below.

ii) OPG understands that "financial reports" in this question refer to OPG's publicly available Management's Discussion & Analysis ("MD&A") and unaudited interim (quarterly) consolidated financial statements prepared during a given year ending December 31, as well as OPG's annual MD&A and audited annual consolidated financial statements as filed with the Ontario Securities Commission ("OSC") pursuant to the *Securities Act*. Based on the current filing requirement applicable to venture issuers, OPG can file this information with the OEB within 60 days of each quarter-end (with the exception of the year-end), and within 120 days of the year-end (i.e., by April 30 of the subsequent year). Should reporting obligations pursuant to the *Securities Act* change, OPG would have to reassess its ability to file its MD&A and financial statements within the indicated times frames above.

iii) Subject to response to b) ii) above, OPG can file the nuclear unit capability factor and hydroelectric availability (for the regulated facilities) that are included in the quarterly/annual MD&A filed with the OSC within 60 days of each quarter-end (with the exception of year-end), and within 120 days of the year-end (i.e., by April 30 of the subsequent year).

c) i) OPG does not believe that it would be able to provide the requested financial statements by April 30 of each year. In fact, OPG believes that the financial statements for the prescribed facilities, as filed in Ex. A2-T1-S1, Attachment 3, should not be a component of ongoing reporting and record keeping requirements. OPG does not believe that these statements provide helpful information to assess and monitor the performance of OPG's prescribed assets for rate making purposes as discussed below.

In preparing these financial statements in accordance with generally accepted accounting principles ("GAAP"), OPG was required to establish allocation methodologies for certain items that are not relevant for rate making purposes because of differences between regulatory constructs and accounting requirements under GAAP (as noted in Ex. A2-T1-S1, section 3.0).

In certain instances, the Prescribed Facilities' financial statements contain information that is different from that which is submitted for rate-making purposes. Some examples are:

- The deemed debt amounts are different between the financial statements and OPG's Application because the amounts in the application have been computed using the methodology approved by the OEB in EB-2007-0905, while those in the financial statements are computed using the year-end equivalent of rate base and year-end actual outstanding debt.

- The cash working capital amounts differ between the application and the financial statements. The cash working capital balance in rate base is determined using a separate lead/lag approach, as discussed in Ex. B1-T1-S2, whereas the financial statements include an allocation of accounts receivable and accounts payable balances.

- Income tax expense in the financial statements is also not the same as the regulatory tax expense presented in Ex. F4-T2-S1, as it was determined without the application of regulatory constructs.

Based on these and other differences, presenting information in the form of financial statements may in fact create greater confusion. The problem is well illustrated by those interrogatories in this proceeding that request reconciliations of these financial statements to regulatory information in the pre-filed evidence which cannot be accomplished.

In addition, as part of the preparation of these financial statements, OPG is required to include information that is inconsistent with how OPG operates and, hence, is not used by management to make decisions or for any other internal purpose. This includes balances related to corporately held functions such as cash management and accounts receivable securitization. OPG manages cash on a corporate-wide basis; the cash balance and the statement of cash flows included in the Prescribed Facilities' financial statements were only included because GAAP financial statements generally require this information. This information does not serve any business or regulatory purpose.

Further, in cases where information is not available from OPG's financial systems to meet the note disclosure requirements for these statements, significant judgement and effort is required to determine the allocations to the prescribed facilities. For example, OPG does not track a number of balance sheet items, including a number of working capital balances, by business unit and, as such, had to make allocation assumptions when attributing these balances to the prescribed facilities. (OPG notes that it is its understanding that certain other utilities regulated by the OEB that produce similar stand-alone statements already track the necessary information as part of their internal systems. As such, OPG's situation is different in this regard.)

The preparation of OPG's 2009 Prescribed Facilities' financial statements and comparative data for 2008 involved significant human resource, internal control and external audit effort. OPG estimates that the total cost of this effort was over $400k including the cost of the external audit of $225k. This cost estimate does not consider future costs for potential system and process changes to capture the required information should these statements become a continuous reporting requirement. OPG's financial systems and processes are not designed to easily extract, manipulate and aggregate all of the required information for these statements within a sufficient time frame to have them available for the OEB by April 30 of each year.

Based on the above considerations, OPG believes that a more practical and less costly approach would be to file only selected sections of the financial statements (determined jointly with the OEB staff) that are relevant for rate making purposes, to the extent that they are not already included in OPG's corporate consolidated financial statements. This information could be filed with the OEB by June 30 of each year.

ii) The preparation of a corporate annual report is not a statutory requirement. Should OPG decide that this effort is no longer justified for business purposes, it would be inappropriate for OPG to be required to continue preparing an annual report solely for regulatory purposes because all of the relevant financial and non-financial information pertaining to OPG's prescribed facilities would already be provided in its annual MD&A and consolidated financial statements. However, if OPG produces an annual report in a given year, OPG would be able to file it with the OEB following its release.

iii) OPG would be unable to file a trial balance for the prescribed facilities by April 30. Because OPG has significant regulated and unregulated operations within the same legal entities, a trial balance is not available for the prescribed facilities on stand-alone basis. Most items are not tracked in OPG's systems specifically for the prescribed facilities in a manner that would enable a trial balance to be produced. OPG would be required to make numerous manual allocation assumptions (or aggregate existing allocation models for various items currently maintained outside of its general ledger), as it did in order to prepare the financial statements for the prescribed facilities discussed in part c) i) above. The task of allocating general ledger account balances to the prescribed facilities in order to produce a complete trial balance will involve even greater effort than that involved in the preparation of the Prescribed Facilities' financial statements.

Generally, OPG believes it would be able to file with the OEB supporting records for selected sections of the Prescribed Facilities' financial statements (as proposed in part c) i)) by the same date as the sections themselves, i.e., by June 30 of each year.

iv) OPG can provide the OEB with headcount information pertaining to the prescribed facilities as of the preceding year-end by April 30 of the following year in the same manner as presented in Ex. F4-T3-S1, Chart 1, as this information is available for all business units on a consistent basis.

v) OPG's ability to file information on capital additions for the prescribed facilities by April 30 depends on the details that the question notes are "to be determined." OPG assumes that by "capital additions" and "work in progress" Board staff means "in service additions" and life-to-date "construction work in progress" balances. OPG is also unclear as to the format and level of granularity of the information that may be required.

Subject to further clarification on the details of the requirements, OPG generally believes that it has the necessary information regarding in-service additions and construction work in progress for the prescribed facilities for the preceding year that it can provide to the OEB by April 30 of each year.

OPG notes that segmented information (separating nuclear and regulated hydroelectric facilities) for year-end construction in progress (for fixed assets) and development in progress (for intangible assets) balances is already included in OPG's annual consolidated financial statements (e.g., Ex. A2-T1-S1, Attachment 2, page 151 in Note 19 to OPG's financial statements).

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long as wholesalers are purchasing for their own consumption only, quarterly reporting would not be required.

6 GENERATOR

6.1 Reporting

6.1.1 Under Review

All generators that can be considered to be load displacing (generating for own use) are exempted from the following monitoring requirements. It shall be the obligation of a generator, that is not load displacing, and is an IMO market participant, to authorize the IMO to provide in the form and manner required by the Board a summary of market monitoring information. Generators who are not IMO market participants shall provide in the form and manner required by the Board a summary of market monitoring information.

A generator shall provide in the form and manner required by the Board, by the last day of the second month after implementation and within 10 days of information changes, the following information for each generating station:

1. name of generating station;
2. name of owner;
3. size (installed capacity in MW) and number of units;
4. type of generator (such as hydro-electric, natural gas fired, coal fired, oil fired, wind turbine, biomass, photo-voltaic, etc.); indicate whether the facility has been EcoLogo certified by the Federal Environmental Choice Program (Guideline on Renewable Low Impact Electricity);
5. address, and if not an IMO market participant, also identify the distributor;
6. type of capacity (i.e. baseload, intermediate, and/or peak capacity facilities);
7. type of ancillary services generator is selling to IMO, if appropriate;
8. type of operating reserves generator is selling to IMO, if appropriate;
9. designate facility as dispatchable or non-dispatchable; if a generator designates its facility as non-dispatchable, then it receives the MCP without the need to submit an offer to sell to the IMO;
10. connection entity (to IMO-controlled grid or distribution system);
11. facility's expected remaining life span by each generation unit.;
12. emission constraints (i.e. plant caps and/or overall caps on all owned facilities on NO_x, SO_2, CO_2, and Hg [mercury]); and
13. production constraints (e.g. fluctuating water levels may affect hydroelectric plants).

ELECTRICITY REPORTING AND RECORD KEEPING REQUIREMENTS
(Version dated: July 9, 2007)

6.1.2 All generators that can be considered to be load displacing (generating for own use) and all generators with a station capacity of less than 25 MW that are not IMO market participants are exempted from the following monitoring requirements. It shall be the obligation of a generator, that is not load displacing, and is an IMO market participant, to authorize the IMO to provide in the form and manner required by the Board a summary of market monitoring information. Generators who are not IMO market participants and have a station capacity of 25 MW or greater shall provide in the form and manner required by the Board a summary of market monitoring information.

A generator shall provide in the form and manner required by the Board, quarterly, on the last day of the month following the period end, a summary of monthly market monitoring information, which would include:

1 monthly production levels (actuals in MWh);
2 number of units out of service and specify the length of time; and
3 monthly capacity factor.

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Ontario

ONTARIO ENERGY BOARD

FILE NO.: EB-2010-0008 **REDACTED - PUBLIC**

VOLUME: Technical Conference

DATE: August 26, 2010

MR. KEIZER: Again, moving on to Board Staff No. 39, dealing with reporting and record keeping.

MR. BARRETT: Yes. I will address part (a) of this response. The question is: Why does OPG believe it should not have to provide this information?

If you look at L-1-149, you will see that we provided a number of reasons why we should not be required to produce these audited financial statements on an ongoing basis.

Just to summarize that section of the response, we indicated that was expensive, that there was a significant additional administrative burden associated with the production of these statements, and that we did not see them providing any real value, given that they are prepared on a GAAP basis, and, therefore, don't have a good alignment with parts of the rate filing.

And there is significant additional detail around these points in the interrogatory.

MR. REEVE: In answer to part (b) of the question, OPG cannot change its current segment disclosure in its general purpose corporate audited financial statements that are filed with the Ontario Securities Commission, as these statements must be prepared in accordance with Canadian generally accepted accounting principles. In accordance with GAAP, the segmented disclosure must be presented consistent with OPG's management reporting structure, and the current segment disclosure reflects this structure.

MR. KEIZER: Thank you. Then moving on to the Board

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Board Staff Interrogatory #150

Ref: Report of the Board (EB-2006-0064)

Issue Number: 12.2
Issue: What processes should be adopted to establish the framework for incentive regulation, or other form of alternative rate regulation, that would be applied in a future test period?

Interrogatory

The Board Report, *A Regulatory Methodology for Setting Payment Amounts for the Prescribed Generation Assets of Ontario Power Generation Inc.*, EB-2006-0064, November 30, 2006, stated that, "The Board will implement an incentive regulation formula when it is satisfied that the base payment provides a robust starting point for that formula."

a) Please provide OPG's views, with explanation, as to whether the payment amounts arising out of the Board's decision of this application would serve as an appropriate and robust starting point for setting or adjusting payment amounts based on an incentive regulation formula.

b) If OPG does not consider that the payment amounts arising out of the Board's decision of this application would serve as an appropriate and robust starting point for setting subsequent payment amounts based on an incentive regulation formula, please explain what conditions or factors need to be considered to establish appropriate rebased rates going into an incentive regulation formula-based approach.

c) If OPG does not believe that the payment amounts arising out of the Board's decision of this application would serve as an appropriate and robust starting point for setting subsequent payment amounts based on an incentive regulation formula, please provide OPG's views that its next payment amount application, scheduled for payment amounts for 2013, should be based on 2013 payment amounts calculated based on a Cost of Service approach, along with a proposal for an incentive mechanism for adjusting payment amounts in 2014 and subsequent years.

d) Please identify the process that OPG believes the Board should follow to examine alternative methodologies for setting OPG's payment amounts following the completion of the subject proceeding. Please provide details of each major step, including timing, in the process identified.

Response

a) and b)

The payment amounts arising out of the Board's decision on this Application will not serve as an appropriate starting point for an incentive regulation mechanism. The appropriate starting point for incentive regulation cannot be determined until the form of incentive regulation is known. For example, for certain forms of incentive regulation, a change in the design of the payment amounts may be appropriate. In addition, this Application only covers the 2011 - 2012 period and future changes in OPG's business environment will need to be considered when establishing the starting point for incentive regulation.

In OPG's view, the most logical and efficient sequencing is to complete the current cost of service application to set the payment amounts for 2011 - 2012 before moving to consider what future incentive mechanism should be used. Once the form of the incentive mechanism is known, then OPG will be in a position to file the necessary information to support a review by the OEB to establish a robust set of payment amounts as the starting point for the incentive mechanism.

c) Assuming that a determination on the form of incentive regulation is made during 2011, then OPG's next payment amounts application should be used to set the base rates for incentive regulation. OPG believes that a cost of service approach should be used to set those base rates. Without knowing the specifics of the form of incentive regulation that will be approved by the OEB, OPG is not in a position to advise whether or not it would make more sense to use a one-year test period (i.e., 2013) as the base and then use the incentive regulation mechanism to set the payments amounts in 2014 and beyond or whether the base rates should be set using a two-year test period (i.e., 2013 - 2014) with the mechanism being used to set the payment amounts in 2015 and beyond. The term of the base rate period should be an issue in the future incentive regulation proceeding.

d) OPG believes that following its decision on OPG's payment amounts application, the OEB should convene a new proceeding to determine the future method of regulating OPG. This proceeding should cover the appropriate structure for this future method and how best to achieve that structure.

OPG proposes the following specific steps and timing in relation to that proceeding:

- Following the completion of the current proceeding and the issuance of the OEB's final order in this application, OPG would file an application in 2011 setting out its proposal for incentive regulation, including as needed the provision of expert evidence.

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- Intervenors, and potentially Board staff, would be provided an opportunity to file evidence seeking changes to OPG's proposed methodology or proposing their own methodologies.

- An interrogatory process would be used by both OPG and intervenors/Board staff to gather information about the various methodologies being proposed. The interrogatory process would also be used by intervenors/Board staff to get information that might be required for their proposals.

- A technical conference would be held to ensure that the parties understood the specifics of the proposals that were being put forward by the various parties.

- A short, focused hearing would be held to test the incentive regulation proposals that had been put forward.

- This would be followed by an argument phase leading to a decision by the OEB by the end of 2011. OPG would incorporate the results of this decision into an application that it would make for the post-2012 period (assuming that OPG was seeking new payment amounts beginning in 2013).

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Ontario

ONTARIO ENERGY BOARD

FILE NO.: **EB-2010-0008** **REDACTED - PUBLIC**

VOLUME: **Technical Conference**

DATE: **August 26, 2010**

MR. KEIZER: Again, moving on to Board Staff No. 39, dealing with reporting and record keeping.

MR. BARRETT: Yes. I will address part (a) of this response. The question is: Why does OPG believe it should not have to provide this information?

If you look at L-1-149, you will see that we provided a number of reasons why we should not be required to produce these audited financial statements on an ongoing basis.

Just to summarize that section of the response, we indicated that was expensive, that there was a significant additional administrative burden associated with the production of these statements, and that we did not see them providing any real value, given that they are prepared on a GAAP basis, and, therefore, don't have a good alignment with parts of the rate filing.

And there is significant additional detail around these points in the interrogatory.

MR. REEVE: In answer to part (b) of the question, OPG cannot change its current segment disclosure in its general purpose corporate audited financial statements that are filed with the Ontario Securities Commission, as these statements must be prepared in accordance with Canadian generally accepted accounting principles. In accordance with GAAP, the segmented disclosure must be presented consistent with OPG's management reporting structure, and the current segment disclosure reflects this structure.

MR. KEIZER: Thank you. Then moving on to the Board

Staff Question No. 40.

MR. BARRETT: Dealing first with part (a), it references the fact that we did not identify stakeholdering as part of our proposed process.

Our position would be, once we have a developed process -- proposal, then we think that would be the time to do any stakeholdering around that proposal. We think that is the most efficient way to conduct stakeholdering.

And with respect to part (b), which suggests that we might already have developed a proposal, the answer is: No, we have not yet determined a form of incentive regulation.

I would characterize our work at this stage as at a fairly preliminary stage. The schedule we proposed is aggressive, and I will acknowledge that, and we are working hard to try and meet it.

MR. KEIZER: I think subject to the one confidential question that we will deal with at the end, that completes Board Staff's questions for the corporate panel.

We then move on to the AMPCO questions, and the first appears at page 19 of the compendium, which at Question No. 4.

MR. BARRETT: Yes. In Question No. 4, we were asked whether Mr. Luciani had done any quantitative analysis supporting his materials, and he did not produce any quantitative analysis.

MR. LORD: Just to follow up, the response is clear he hadn't performed any quantitative analysis for Ontario.