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Ontario

BY E-MAIL

August 19, 2010

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, Suite 2700
Toronto ON M4P 1E4

Dear Ms. Walli:

Re: Ontario Power Generation Inc.
2011-2012 Payment Amounts for Prescribed Generation Facilities
Board File Number EB-2010-0008

Pursuant to Procedural Order No. 4, please find enclosed Board Staff's technical conference questions. Please forward the non-confidential set of questions to Ontario Power Generation Inc. and all other registered parties to this proceeding. Please forward the confidential set of questions to Ontario Power Generation Inc. and parties who have signed the Declaration and Undertaking.

Yours truly,

Original signed by

Violet Binette
Project Advisor, Applications & Regulatory Audit

Board Staff Questions for Technical Conference
Ontario Power Generation Inc.
2011-2012 Payment Amounts
EB-2010-0008
Non-Confidential

The following questions relate to responses to Board Staff interrogatories, unless otherwise specified.

Issue 2.1
What is the appropriate amount for rate base?

1. Ref: ExhL/Tab1/Sch2
Please provide the specific calculations that OPG used to generate the revenue requirement impact amounts presented in each of the responses c) to f).

2. Ref: ExhL/Tab1/Sch3
OPG states that due to the relative stability of its sustaining capital requirements and the fact that OPG is able to finance its sustaining capital expenditures from operating cash flow, OPG has not been required to reprioritize its planned projects at the corporate level in response to funding shortages in the time period identified.

   a) Did OPG take into account its overall financial situation and requirements, and the impact on proposed Payment Amounts, when it was determining the number and level of capital projects that would be funded from operating cash flow in 2011 and 2012?
   b) Other than depreciation, please specify the primary source of operating cash flow.

3. Ref: ExhL/Tab1/Sch5
The Post Implementation Review Report, re: Additional Feeder Cut and Weld Tooling, indicates (see p.2 Economic Value) "… since the approval of the BCS in 2007, OPG has significantly reduced the number of feeders to be replaced each year, thereby reducing the overall potential for revenue".

   Please explain what prompted, the reduction in the number of feeders to be replaced. Please provide the timing of those events.

Issue 2.2
Is OPG's proposal to include CWIP in rate base for the Darlington Refurbishment Project appropriate?

4. <u>Ref: ExhL/Tab1/Sch11</u>
   Does OPG view the Darlington Refurbishment project as an “electricity infrastructure” project?

Issue 3.3
Should the same capital structure and cost of capital be used for both OPG’s regulated hydroelectric and nuclear businesses? If not, what capital structure and/or cost of capital parameters are appropriate for each business?

5. <u>Ref: ExhC1/Tab1/Sch1</u>
   <u>Ref: ExhL/Tab10/Sch15</u>
   Exhibit C1/Tab1/Sch1/page 3/section 4.1 states that:

   > The Cost of Capital Report establishes a revised base ROE and a modified automatic ROE adjustment mechanism. Given that the revised base ROE and the refined automatic ROE adjustment mechanism represent the same concepts that were adopted for OPG’s prescribed assets in EB-2007-0905, both are applicable to OPG at the approved capital structure and appropriate to the business risks of the prescribed assets.
   >
   > OPG has applied the adjusted ROE of 9.85 per cent as set by the OEB for use in 2010 cost of service applications in the OEB’s letter of February 24, 2010. When calculating the final payment amounts, OPG proposes that the ROE be updated using data for the month that is three months prior to the effective date of the new payment amounts as required by the Cost of Capital Report.

   In its response to part a) of a Pollution Probe interrogatory at ExhL/Tab10/Sch15, OPG confirms that the ROE should be updated based on data three months prior to the effective date per the methodology in the Board’s Cost of Capital Report, but states that it is proposing different ROEs for 2011 and 2012. The ROE for 2011 would be calculated per the methodology documented in the Board’s Cost of Capital Report, which is documented in Appendix B of that Report. However, since the Consensus Forecasts forecast of the 10-year Government of Canada bond yield only goes out 12 months, OPG is proposing to use a 2-year forecast from Global Insights.

   a) Please confirm whether the proposal documented in ExhL/Tab10/Sch15 is a change from OPG’s pre-filed evidence. Otherwise, please identify where in the prefiled evidence OPG’s proposal is documented.
   b) OPG proposes to use the Global Insight forecast for estimating the 2012 ROE. One of the features of the Consensus Economics *Consensus Forecasts* estimates is that they represent a consensus of estimates from

various forecasting and financial agencies. The resulting forecasts dampen the effect of optimistic or pessimistic forecasts of a specific firm or analyst. The resulting estimate also, inherently, makes use of the expertise and information available to all of the forecasting agencies used.

i) Please provide OPG's views on the moderating attributes of the Consensus Forecasts estimate, as stated above, in contrast with a forecast from a single economic forecasting agency like Global Insights.
ii) Please provide Global Insight's 12-month and 24-month forecasts of the 10-year Government of Canada bond yield based on January 2010 data.
iii) If possible, please calculate the ROE for 2010 that would have resulted from using Global Insights data instead of Consensus Forecasts, based on January 2010 data. In other words, instead of the 9.85% ROE documented in the Board's letter of February 24, 2010, what ROE would have been calculated if Global Insight data was used instead?
iv) Please provide the most current estimates of the Global Insight data for the 10-year Government of Canada bond yield.
v) What other forecasting agencies is OPG aware of that provide forecasts beyond 12 months outlook?
vi) Please provide 12-month and 24-month forecasts of the 10-year Government of Canada bond yield from economic forecasting agencies, other than Global Insight, that OPG is aware of.
vii) Does OPG concur that forecasting error increases the further out the projection, and thus that it would be preferable to use forecasts from several agencies, rather than relying on a single agency's forecast, to develop the projected ROE?

c) In part b) of ExhL/Tab10/Sch15, OPG documents that the Board's Cost of Capital Report established a 550 basis point equity risk premium "ERP"). Please confirm OPG's understanding of whether the 550 basis point ERP documented in the Board's Cost of Capital Report pertains to the starting point ROE of 9.75%, and that the ERP for any ROE calculated based on the methodology documented in Appendix B will vary, depending on the data used in the calculations. If OPG views the 550 basis point ERP as being constant, please explain.

6. <u>Ref: ExhL/Tab10/Sch21</u>
In the response to part c) of this interrogatory from Pollution Probe, Ms. McShane documents various factors or opportunities that a diversified firm could take advantage of and which investors would value as part of a firm's diversification.

a) Does Ms. McShane view that all of these factors apply, or are available to OPG?

b) If not, please identify which factors documented would not pertain to OPG because of its line of business and structure and/or because of legislative or regulatory constraints or the structure and operation of the Ontario electricity market.

7. Ref: ExhL/Tab1/Sch14

In its response to this interrogatory from Board staff, OPG states that the Board's Cost of Capital Report, which was issued on December 11, 2009, supercedes the precedents.of the Decisions cited, where the Board had stated that notional debt should attract the weighted average cost of long-term debt. OPG goes on to state that its understanding of page 54 of the Board's Cost of Capital Report is that: "if there is no actual debt underlying a component of the capital structure, then the deemed long-term debt rate should apply."

a) Please confirm that OPG's proposal presumes that its "Other Long-term Debt Provision" is a separate component of its deemed capital structure. If not, please explain.
b) Please provide copies of Decisions supporting OPG's proposal that notional debt, corresponding to OPG's "Other Long-term Debt Provision", would attract a deemed debt rate.

8. Ref: ExhL/Tab1/Sch16
Ref: ExhL/Tab10/Sch35

In the response to part b) iii) of ExhL/Tab1/Sch16, in support of the sharp increases in short-term rates based on Global Insights' data, OPG states:

> Global Insight states in its forecast that 1 it expects a strong recovery in the Canadian economy in 2010 and expects the Bank of Canada to begin raising rates toward the end of 2010. Rate increases are expected to continue into future periods "since rates cannot stay at low levels as the economy heats up".

In the response to a Pollution Probe interrogatory at ExhL/Tab10/Sch35, Ms. McShane states:

> The capital markets have improved markedly since early 2009 and capital market indicators (e.g., the MVX) point to lower market volatility at the present time (mid-2010). The TSX Composite has recovered from its financial crisis trough (having lost 50 per cent of its value between mid-June 2008 and early March 2009), but at the end of July 2010, it was still over 20 per cent below its 2008 peak. There are still significant risks of a significant market correction, given the persistence of global imbalances, the potential for a double-dip recession and the sovereign debt crisis in Europe.

It appears that Ms. McShane is expressing caution about the rate and level of recovery coming out of the 2008 economic downturn, while such caution is not apparent in the Global Insights' forecasts from December 2009.

a) Please reconcile the economic outlooks expressed in these interrogatory responses.
b) If Ms. McShane's perspectives are more realistic, please provide OPG's views on whether the short-term rate forecasts based on the Global Insights December 2009 forecast remain current.
c) Please provide any update of the Global Insights' Canadian Forecast Summary to the December 2009 copy provided as Attachment 1 to ExhL/Tab1/Sch16.

Issue 4.2
Are the capital budgets and/or financial commitments for 2011 and 2012 for the regulated hydroelectric business appropriate and supported by business cases?

9. Ref: ExhL/Tab1/Sch11
OPG indicates that capital costs for the visitor centre at the Saunder's facility were not included in the capital expenditure evidence in the EB-2007-0905 proceeding.

Is the $12 million visitor centre at the Saunder's hydroelectric facility a "value enhancing" or a "regulatory" or a "sustaining" capital project.

10. Ref: ExhL/Tab1/Sch 20
In part c) of the IR response, OPG's states that incremental benefits, and associated costs (from Niagara Plant Group projects approved since the start of the Niagara Tunnel Project), "have not been included in the Niagara Tunnel Project Net Present Value analysis since these decisions were taken after the approval of the tunnel project. However, business cases and other analyses for projects undertaken subsequent to approval of the tunnel that use the increased water made available by the tunnel include these incremental benefits".

a) Please provide an estimate of the net impact of the projects approved since the start of the Niagara Tunnel Project on the Niagara Tunnel Project Net Present Value Analysis.
b) Please clarify also what mechanisms or processes, if any, that have been adopted to ensure that the cost/benefits accruing from the increased diversion flows and related energy production that are forecast from the new tunnel are appropriately accounted for, i.e., not accounted for more than once.

11. Ref: ExhL/Tab1/Sch 21
    Does OPG continue to be at risk in its design-build contract with Strabag for Niagara Tunnel Project cost over-runs?

Issue 4.5
Are the capital budgets and/or financial commitments for 2011 and 2012 for the nuclear business appropriate and supported by business cases?

12. Ref: ExhL/Tab1/Sch 31
    This interrogatory and response relates to a Business Case Summary found at Ex. D2-T1-S2, Attachment 1, Tab 31.

    a) Based on the selected alternative (Alternative 1 as outlined on page 6 of the Business Case Summary), please confirm the extent to which continued operation of the Pickering A units 1 and 4 is dependent on the continued operation of the Pickering B units.
    b) In particular please confirm whether Board staff's understanding as follows is correct with respect to:
       i) the assumption that the nominal service lives of the Pickering B units will be extended to the period 2018-2020 as a result of the Pickering B Continued Operations Project, and that
       ii) the shutdown of any of the Pickering B units during this period (starting as early as 2018) will affect the viability of the power supplies to the Pickering A Inter Station Transfer Bus (ISTB) capacity and thus in turn affect the continued operability of the Pickering A units with respect to meeting ISTB regulatory and/or other requirements.

13. Ref: ExhL/Tab1/Sch32
    What impact does the 3 year deferral of stage II of the Weld Overlay project have on 2011 and 2012 rate base?

Issue 5.1
Is the proposed regulated hydroelectric production forecast appropriate?

Issue 5.2
Is the proposed nuclear production forecast appropriate?

14. Ref: Ex. E2-T1-S1, page 12, lines 23-24
    In prefiled evidence and response in ExhL/Tab1/Sch038, OPG states that SBG conditions in 2008 and 2009 did not materially affect production at its nuclear facilities and does not expect that anticipated SBG conditions in 2011-2012 will affect nuclear production. However, SBG conditions do affect production at Bruce Nuclear facilities as indicated in OPG's response to Board Staff IR #035 and Energy Probe IR#025.

a) What threshold level of SBG could be expected to have a material impact on OPG's nuclear production?
b) Based on projected revenues and costs for regulated hydroelectric and nuclear production, what is the relative impact on OPG's net revenues of 1 TWh reductions of production from both generation types as the result of SBG conditions?
c) In response to Energy Probe IR#025, OPG states that spilling water at Sir Adam Beck G.S. is the preferred response to SBG conditions for "safety reasons". What are the specific safety reasons that govern this choice?
d) Given a choice between curtailing production at hydroelectric or nuclear generating stations in response to SBG conditions, what decision factors other than the cited "safety reasons" – both financial and technical – would be considered when making this choice?

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

15. Ref: ExhF2/Tab1/Sch1/ Attachment 1
In response to Board Staff IR#46, OPG notes "The interrogatory incorrectly refers to "refurbishment costs on Units 4 and 1". The Unit 1 and Unit 4 return to service project was not a refurbishment."

a) Please explain why the above distinction is material.
b) If the distinction is material, please explain why OPG referred to it as a refurbishment in various documents. For example:

"OPG News Release, July 29, 2005
….
Refurbished unit will deliver 515 MW of additional "clean air" electrical capacity
[Toronto]: Ontario Power Generation (OPG) today announced ….
starting up the newly refurbished Pickering 'A' Unit 1 reactor…"

OPG 2004 Annual Report (p.31)
"OPG's top operational risks ….related to the refurbishment of the Pickering A nuclear facility."

16. Ref: ExhF2/Tab1/Sch1/ Attachment 1
With respect to OPG's response to part b) of Board Staff IR#46:

a) Does OPG have a reference document detailing the extent and risks to future station and/or unit operation at Pickering A, Pickering B and Darlington associated with steam generation tube corrosion, feeder pipe wall thinning and pressure tube-calandria tube contact?

b) If the response to a) is affirmative, please provide a copy of the document.
c) Of the identified issues (i.e., steam generation tube corrosion, feeder pipe wall thinning, and pressure tube-calandria tube contact), are any of these issues considered to be station and/or unit life-limiting relative to the average station service lives (Pickering A units 1 and 4 – 2021; Pickering B – 2014; Darlington – 2019) identified in the OPG 2008 Regulated Depreciation Review Report (provided as Attachment 1 to Board Staff IR#115)?

17. <u>Ref: ExhF2/Tab3/Sch3</u>
Board Staff IR#47 requested that OPG aggregate the contingency amounts (General and Specific) for all of the OM&A Business Case Summaries, for the 2008-2009 period, and identify how much of those contingency amounts were utilized by OPG. Board staff does not understand OPG's response in terms of how much of those contingency amounts were utilized.

a) Of the $39.8M in contingency amounts aggregated by OPG, please clarify in dollar terms how much was utilized.
b) Please also clarify if the $18.7M referred to as "Contingency Approved (AISC)" in the table is incremental to the $39.8M in the BCSs.
c) Please also clarify the distinction between a "General" and "Specific" contingency and why only certain projects have a "Specific" contingency.

Issue 6.5
Has OPG responded appropriately to the observations and recommendations in the benchmarking report?

18. <u>Ref: ExhF5/Tab1/Sch2/p.26</u>
In response to Board Staff IR#58, OPG explained its response to ScottMadden's piloted top-down staffing analysis using the OPGN Radiation Protection (RP) function.

a) The response notes that 1 position was eliminated while ScottMadden recommended the elimination of 13 positions. Please elaborate on why only 1 position was eliminated.
b) As also requested in Board Staff IR#58, please explain how "OPG plans to build on this pilot in terms of other segments of the organization".

19. <u>Ref: ExhF5/Tab1/Sch2/p.37</u>
In response to Board Staff IR#62, OPG explained "Of the original 33 initiatives … three were either cancelled due to a low return on investment or in one case, directly incorporated into base work".

Please identify the two initiatives that were cancelled and the estimated return on investment for each that OPG refers to as "low".

36. Ref: ExhF2/Tab3/Sch3/Attachment 1/Tab16
Ref: ExhF2/Tab1/Sch1/Attachment1/p.22

In regard to OPG's response to Board Staff IR#52, please clarify when an operating life of 187,000 EFPH (Effective Full Power Hours) for the Darlington units is projected.

Issue 6.6
Is the forecast of nuclear fuel costs appropriate?

20. Ref: ExhF2/Tab5/Sch1/p.7-8
In response to Board staff IR#65, OPG notes "OPG believes its purchasing strategy of procuring a portfolio of indexed and market priced contracts continues to be appropriate….OPG, which must regularly enter the uranium market for a portion of its supply needs, to mitigate the variations in extremes in market prices."

a) OPG's response appears to indicate that all purchases are made under long term (indexed and market priced) contracts. OPG's previous application (F2-T5-S1, p.7) noted "OPG has recently implemented a revised spot market procurement process to facilitate potential future spot market purchasing."
   i) Please explain if OPG has made any short-term purchases on the spot market since the last application and please provide a breakdown of short term spot market vs. long term contract purchases for the period of 2007 to 2010.
   ii) If OPG has not made any short-term purchases on the spot market since the last application, please explain why the revised spot market procurement process discussed in the previous application was not utilized.

b) In regard to regularly entering the uranium market for a portion of OPG's supply needs, Chart 3 in the current application (F2-T5-S1, p.9) shows a summary of the 4 existing uranium concentrate supply contracts and indicates 3 of the 4 existing contracts were all entered into in the 1st half of 2006 and the 4th contract in the 2nd half of 2007. Please elaborate on how this constitutes regularly entering the uranium market.

21. Ref: ExhL/Tab14/Sch20
In its response to the interrogatory from VECC, OPG states:

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

a) Does the response to the interrogatory mean that contracts with Canadian suppliers in Canadian dollars use the Canadian CPI as the year-over-year price escalator, while contracts in U.S. dollars, and presumably with U.S. and maybe other international suppliers use the U.S. GDP-IPI (Gross Domestic Product – Implicit Price Index) as the price escalator? Please explain.
b) If the answer to a) is in the affirmative, please provide OPG's views on why the Canadian CPI is preferred instead of other measures or proxies for inflation, such as the Canadian GDP-IPI. Please comment on the strengths and weaknesses of various indices for proxying inflation in input prices for businesses, particularly capital-intensive businesses like OPG.

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

22. <u>Ref: ExhF2/Tab2/Sch3/Attachment 1, Attachment 2</u>
Board Staff IR#67 requested an explanation regarding the various cost estimates provided by OPG for the Pickering B Continued Operations project. OPG's response regarding $190.2M vs. $184M is clear. However, the drivers underlying the difference of about $110M between the $190.2M and $300M cost estimates is not clear to Board staff.

Please explain in detail the drivers underlying that difference of about $110M. Please also explain if a contingency amount has been included in each of those estimates of $190.2M and $300M.

23. <u>Ref: ExhF2/Tab2/Sch3/Attachment 1, Attachment 2</u>
Board Staff IR#69 requested that OPG identify and explain the assumptions underlying this benefit estimate of $1.1B.

a) The response clarified that OPG did not use the current payment amounts of $53/MWh unchanged to make the business case for Pickering Continued Operations. Board Staff IR#69 noted that if the current payment amounts had not been used "please identify the assumed payment amounts to make the Business Case and to estimate the benefits". OPG's response was "(ii) Not applicable." Board staff is of the view that the assumed payment amounts are quite applicable to such an estimate of the benefits, particularly in relation to the estimated cost of replacement generation. Please add a Table 3 (similar to the Table 1 format) showing the assumed payment amount for each year.
b) OPG's response also noted replacement generation would be over 85% Ontario-based gas-fired, combined cycle generation and the remainder from a diverse set of fuel types, including other natural gas-fired and oil-fired generation. Please clarify how much of that remainder is assumed

to be produced by Lennox and to what extent, if any, production is assumed to come from renewable generation under the FIT program.

c) Given the assumption that virtually all of the replacement generation is gas-fired generation, the gas price forecast is relatively important. That gas price forecast was prepared some time ago by OPG and seems relatively bullish in terms of gas prices given recent price trends. For example, OPG has assumed 5.7 and 6.6 US$/mmBTU for 2010 and 2011, respectively, while the current Henry Hub spot price is only about 4.3 US$/mmBTU and the U.S. Energy Information Administration (EIA), in its Short-Term Energy Outlook —August 2010 (p.1), is projecting that the Henry Hub natural gas spot price will not exceed 5 US$/mmBTU through 2011 – average 4.69 US$/mmBTU for 2010 and 4.98 US$/mmBTU in 2011. Does OPG believe its gas price forecast remains reasonable or would OPG lower the gas prices in its forecast if OPG was preparing that forecast today?

24. Ref: Exh.F2/Tab2/Sch3, pages 5-6
In response to Board staff IR#71:

a) OPG notes that a detailed cost estimate was not prepared associated with the independent operation of Pickering A (i.e., Pickering B operations cannot be extended) in making the decision that OPG would not continue to operate Pickering A as well as reaching the conclusion that the cost would equal or exceed the system value to do so.
   i) Please confirm that OPG has made that decision without any cost estimate at all (i.e., not necessarily "detailed") after spending billions of dollars on returning to the Pickering A units to service;
   ii) Please also confirm that decision has been approved by both the OPG Board and OPG's Shareholder without any cost estimate requested or provided;
   iii) If there was a ballpark cost estimate, please provide it;
   iv) If there was not even a ballpark cost estimate, please explain how OPG can conclude with confidence that the cost would equal or exceed the system value.

b) Please elaborate on why the dependency of Pickering A on Pickering B is more complex and please also explain why it is not just a matter of maintaining and continuing to operate the shared and common services if Pickering A continued to operate.

Issue 6.9
Are the "Centralized Support and Administrative Costs" (which include Corporate Support and Administrative Service Groups, Centrally Held Costs and Hydroelectric Common Services) and the allocation of the same to the regulated hydroelectric business and nuclear business appropriate?

25. Ref: ExhF4/Tab4/Sch1/p.4
Board staff IR#88 discusses the significant increase in IESO Non-Energy Charges, primarily due to the substantial increase in the Global Adjustment and requested a table summarizing IESO Non-Energy costs and kWh consumed for each OPG facility. In the tables in OPG's response, the IESO Non-Energy Charges for Pickering B are approximately equivalent to Darlington and Pickering A combined in each of the 3 years (2007-09) and Pickering B accounts for about half of the total nuclear station consumption. Please explain why Pickering B's consumption is so high relative to OPG's other nuclear stations.

26. Ref: ExhF4/Tab4/Sch2/p.4
In response to Board Staff IR#89 which discussed Nuclear Insurance costs almost doubling in 2012 relative to 2009, OPG notes that the increase is due to the proposed new Bill C-15 and that bill has passed first reading to date. If Bill C-15 does not ultimately receive Royal Assent, please clarify if there would be any change in nuclear insurance costs in the test years.

27. Ref: ExhF3/Tab1/Sch1
Ref: ExhL1/Tab1/Sch87
Ref: OPG Correspondence of July 23, 2010
In the correspondence, OPG states that it "has dedicated substantial resources to the development of a customized Sharepoint software system to assist in the interrogatory response process."

What is the cost of the substantial resources? Is this cost reflected in the Regulatory Affairs expenses?

28. Ref: ExhL/Tab1/Sch 103
The interrogatory requested OPG to complete a table which includes itemizing the Regulatory Affairs Budget. The table requested information for 2008 and 2009 Board-approved.

OPG responded that it would not be able to provide Board-approved amounts because"….OPG did not present, and therefore the OEB could not have approved, forecasts for the individual components of Regulatory Affairs costs in 2008 and 2009.

Please edit the table as follows: Replace the column headings titled "2008 Board Approved" and "2009 Board Approved" with "2008 Regulatory Affairs Budget per EB-2007-0905 and "2009 Regulatory Affairs Budget per EB-2007-0905". Please complete the table.

Issue 6.11
Are the amounts proposed to be included in the test period revenue requirement for other operating cost items, including depreciation expense, income and property taxes appropriate?

29. Ref: ExhL/Tab1/Sch112
To OPG's knowledge, are there any major differences in the nuclear equipment life assumed by OPG and that assumed by the other CANDU owners worldwide?

30. Ref: ExhF4/Tab2/Sch1/Table8
Ref: ExhG2/Tab2/Sch1/Table9
Ref: ExhL/Tab1/Sch120
Ratepayers have been responsible for the benefits and obligations of Bruce A and Bruce B since April 1, 2005. Since benefits follow costs, the Bruce regulatory tax losses should be available to reduce Bruce income taxes for the lives of those losses.

Losses that arose in 2005 can be carried forward for 10 years. Those incurred in 2006 and after can be carried forward 20 years.

In EB-2007-0905, OPG identified regulatory tax losses associated with Bruce operations. OPG also stated that actual tax losses were fully utilized on a corporate basis in 2007 when it made the offer of $990 million of regulatory tax losses to shelter future regulatory taxable income. In EB-2010-0008, ExhF4/Tab2/Sch1/Table8, OPG has deducted $390.0 million as the portion of the $990.2 million in tax losses attributable to Bruce.

In ExhG2/Tab2/Sch1/Table9, Bruce tax losses were $169.5 million for the period April 1 to December 31, 2008 and $93.1 million for 2009. OPG recognizes the stand-alone treatment in Note 1 at the bottom of this exhibit.

While the calculations may have to be checked, the total regulatory tax losses available would be $390.0 at December 31, 2007, some amount for the first quarter 2008, and $262.6 for the 21 month period 2008-2009, or more than $652.6 million. These regulatory tax losses would shelter the Bruce regulatory taxable income for many years to come.

Reductions in tax losses result from taxable income, not from net income calculated on a GAAP basis. The regulatory construct followed by OPG in the Bruce current income tax calculations in ExhG2/Tab2/Sch1/Table7 could be followed until the losses of over $600 million were utilized.

a) Does OPG agree with the method of calculating the Bruce regulatory tax losses available?
b) What tax loss was incurred for the first quarter 2008?

c) Does OPG agree with the carry forward periods identified above?
d) Since the regulatory tax losses are so large, OPG would not need to record regulatory CCA for several years in the future. What impact will this have on the future income tax calculations?
e) Should regulatory CCA be restated for 2005-2007, 2008-2009, 2010-2012 given the size of the tax loss carry-forwards?

31. Ref: ExhL/Tab1/Sch122
This question relates to notices of assessment and has been filed in confidence.

32. Ref: ExhF4/Tab2/Sch1
Ref: ExhL/Tab1/Sch3
OPG states the impact of the harmonized sales tax has been incorporated in the calculation of working capital effective July 1, 2010. OPG also states that it was 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. OPG forecasted that the net cost reductions related to HST are relatively small, at less than approximately $5M annually. Have the actual net cost reductions to date been minor?

Issue 7.3
Are the test period costs related to the Bruce Nuclear Generating Station, and cost and revenues related to the Bruce lease appropriate?

33. Ref: ExhG2/Tab1/Sch1, page 5, lines 19-26
Board Staff IR#126 requested an estimate from OPG of the impacts on costs and revenues of Bruce Nuclear exercising its option to assume responsibility for low level radioactive waste. OPG's response was that it was not applicable because Bruce Nuclear had not exercised this option.

Assuming that Bruce Nuclear does exercise this option in 2011, what is the impact on OPG revenues and costs in 2011 and 2012?

34. Ref: ExhG2/Tab1/Sch1, page 4, lines 12-21
Ref: ExhL/Tab1/Sch127
OPG states that supplemental revenue from the Bruce Lease is subject to a market price limitation, i.e., if HOEP averages less than $30/MWh, then supplemental revenue is reduced.

a) Explain the details of this market price limitation in the lease agreement.
b) What is the probability that this market price limitation will take effect in 2011 or 2012 as it did in 2009?
c) OPG is forecasting surplus baseload conditions (SBG) in 2011 and 2012. SBG is usually associated with low, sometimes negative, market prices. In 2009, SBG conditions resulted in 0.6 TWh of total production losses

for OPG with 0.19 TWh attributable to regulated hydroelectric facilities (Answer to AMPCO IR#019). OPG projects SBG impacts on regulated hydroelectric generation of 0.5 TWh in 2011 and 0.8 TWh in 2012. In 2009, supplemental rent was eliminated because of the market price limitation. Considering that the expected SBG levels in 2011 and 2012 exceed the 2009 levels, why does OPG expect no impact on supplemental rent revenues as a result of low market prices?

d) Explain the entry in ExhG2/Tab2/Sch1-Table 3 for supplemental rent in 2009 of negative $11.3 M. Did this represent a payment from OPG to Bruce Nuclear, i.e., a refund of supplemental rent? If so, under what lease provisions was this calculated? Could this situation recur in future years?
e) What is the current average HOEP in 2010, year-to-date, measured as per the lease agreement?
f) OPG states that the potential reduction in supplemental rent from this market price limitation is accounted for as a derivative. Please explain the nature of this derivative, the terms and conditions of this derivative and the variables that would affect the value of this derivative?

Issue 8.1
Have any regulatory or other bodies issued position or policy papers, or made decisions, with respect to Asset Retirement Obligations that the Board should consider in determining whether to retain the existing methodology or adopt a new or modified methodology?

35. Ref: ExhL/Tab1/Sch129
OPG is continuing to investigate the impact of the Board approved revenue requirement treatment on its ability to fully recover its nuclear liabilities. OPG states that it is in the preliminary stages of a complex analysis and that there are no results to review. Does OPG have a terms of reference for this investigation? If affirmative, can OPG provide the terms of reference?

Issue 8.2
Is the revenue requirement amount for nuclear liabilities related to nuclear waste management and decommissioning costs appropriately determined?

36. Ref: ExhL/Tab1/Sch132
This interrogatory relates to impact of the Darlington refurbishment project on ARO and ARC.

a) Please explain how OPG determined that a discount rate of 4.8 per cent was appropriate.
b) Please provide a descriptive summary of how the Darlington refurbishment project creates reductions and/or increases in ARC among the other nuclear stations.

Issue 9.2
Is the hydroelectric incentive mechanism appropriate?

37. Ref: Ex. E1-T2-S1
The current design of the hydroelectric incentive mechanism is based on the value of energy as measured by HOEP. The current mechanism does not include payments from the Global Adjustment Mechanism (GAM) as part of the value of energy.

a) How would the inclusion of GAM payments as part of the value of generation and the cost of pumping affect operation of the PGS?
b) What would be the impact of including GAM payments on the forecasted price spreads between off-peak and on-peak prices in 2011 and 2012?
c) In response to Board Staff IR#136, OPG states that one of the reasons that market price spreads are expected to decline from 2009 levels in 2011 and 2012 is the addition of more baseload generation from the re-commissioning of Bruce Power units and the addition of wind generation.
d) Adding more baseload generation is likely to depress off-peak prices, particularly if SBG is expected to increase in 2011 and 2012 compared to 2009 (as per the response to AMPCO IR#019 and pre-filed evidence, Ex. E1-T1-S2-Table1). Would addition of more baseload generation not have the opposite effect and increase the market price spreads in 2011 and 2012, not reduce them compared to 2009 spreads?

Issue 10.3
Is the disposition methodology appropriate?

38. Ref: ExhL/Tab1/Sch147
In response to this IR relating to approval of forecast balances in deferral and variance accounts, OPG stated that Purchase Gas Variance Accounts used by the regulated gas utilities was a precedent. Please explain the applicability in this case, as the Purchase Gas Variance Accounts are reviewed on a quarterly basis and represent just one of many accounts held by the gas utilities.

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

39. Ref: ExhL/Tab1/Sch149
The Board requires audited financial statements for regulated businesses to be filed annually.

a) Why does OPG believe it should be exempt from this requirement?

b) Would OPG be able to file segment disclosure in its corporate audited financial statements? Possible segments are: regulated prescribed business, Bruce, and non-regulated business activities.

Issue 12.2
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?

40. <u>Ref: ExhL/Tab1/Sch150</u>
In the response to part d) of this interrogatory, OPG proposes that, following completion of this current proceeding, in 2011, it would file an application with its proposal for an incentive plan. Following its application, "[i]ntervenors, and potentially Board staff, would be provided an opportunity to file evidence seeking changes to OPG's proposed methodology or proposing their own methodologies."

a) OPG has not proposed any form of stakeholdering prior to filing its incentive regulation proposal. Please explain why OPG is not proposing to invite discussion with stakeholders prior to filing its application?
b) Does OPG's proposal not to stakeholder, and the timelines indicated in the response to d) of ExhL/Tab1/Sch150 (i.e. a Decision by the end of 2011 probably means that OPG would be filing its application in 2011 Q2) mean that OPG has already determined the form (or range of forms) of incentive regulation that its considers suitable for rate regulation of the prescribed assets? Please explain your response.