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Ontario

BY E-MAIL

July 22, 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. 1, please find enclosed Board Staff's interrogatories. Please forward the enclosed to Ontario Power Generation Inc. and all other registered parties to this proceeding.

Yours truly,

Original signed by

Violet Binette
Project Advisor, Applications & Regulatory Audit

Board Staff Interrogatories
Ontario Power Generation Inc.
2011-2012 Payment Amounts
EB-2010-0008

General

Issue 1.3
Is the overall increase in 2011 and 2012 revenue requirement reasonable given the overall bill impact on consumers?

1. Ref: Letters of Comment
Following publication of the Notice of Application, did OPG receive any letters of comment? If so, please confirm whether a reply was sent from OPG to the author of the letter. If confirmed, please file that reply with the Board. If not confirmed, please explain why a response was not sent and confirm if OPG intends to respond.

Rate Base and Capital Expenditures

Issue 2.1
What is the appropriate amount for rate base?

2. Ref: ExhB1/Tab1/Sch1
Please complete the table below.

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	2007 Actual	2008 Board-approved	2008 Actual	2008 variance (c-b)	2008 Board-approved	2009 Actual	2009 variance (f-e)	2010 Budget	2011 Test Year	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.

3. Ref: ExhB1/Tab1/Sch2 p.5-8
OPG states that it has calculated cash working capital by applying the net lag days resulting from the EB-2007-095 lead/lag study.

There appear to be differences, between the charts filed in this proceeding (Charts 3 and 4) and the comparable charts filed in EB-2007-0905, in the lead lag days for some of the expense categories.

Please explain the reason for the differences.

4. Ref: ExhA1/Tab6/Sch1
Ref: Exhibit B1/Tab1/Sch1 p4
Ref: ExhD1/Tab1/Sch 2
It is understood that O.Reg. 53/05, amongst other things, sets rules pertaining to the recovery of capital costs incurred or financial commitments made by OPG associated with the adding to and/or the refurbishment of generating capacity that are to apply in the setting of just and reasonable rates under section 78.1 of the Ontario Energy Board Act.

Please prepare a table that lists those capital projects that are closing to rate base during 2009, 2010, 2011 and 2012 on the basis of sections 5 and 6 of O.Reg. 53/05. For each project please indicate the section/subsection of the regulation that applies.

5. Ref: ExhA2/Tab 2/Sch1 p10 ln 28-31
Please indicate whether there have been instances in the preparation of the 2010, 2011 and 2012 capital budgets where corporate prioritization of specific projects was undertaken because of (i) corporate constraints with respect to spending or borrowing, or (ii) if the funding guidelines were exceeded in the business unit plan submissions. If there have been

instances, please elaborate on what happened to the top 3 projects (in dollars) that were subject to the corporate prioritization process.

6. Ref: ExhA2/Tab2/Sch1 p.13
   Please provide a copy of the three most recently completed Post Implementation Review Process project appraisals.

7. Ref: ExhB1/Tab1/Sch1/Table 2
   Please add two rows at the bottom of the table to show the amount of "Asset Retirement Costs/Nuclear Liabilities" that is included in line 1(Gross Plant at cost) and in line 2 (Accumulated Depreciation and amortization) amounts. Also show what was included for 2008 Board-approved and 2009 Board-approved.

8. Ref: ExhA2/Tab2/Sch1 Attachment 1 p6
   The 2010-2014 Business Plan (dated June 3, 2009) indicates that work is proceeding on the feasibility study to refurbish the Pickering B nuclear generating station. The evidence (Exh F2/Tab2/Sch3 p.3 ln 29) also states that further work was put on hold in 2009 pending the decision on whether or not to proceed with the refurbishment project, with the end result being OPG's decision to discontinue the project.

   Please confirm the date on which OPG decided not to proceed with the refurbishment project. Why wasn't this consideration mentioned in the 2010-2014 Business Plan?

9. Ref: ExhB1/Tab1/Sch1 p.6
   Please describe any initiatives OPG has undertaken since 2008 to improve (i.e. reduce) its working capital requirements. If such initiatives have been undertaken, please elaborate.

10. Ref: ExhB1/Tab1/Sch1
    OPG as a publicly accountable enterprise for financial accounting reporting purposes will be required to adopt IFRS starting in 2011.
    a) Assuming all else remains the same, does OPG anticipate that reporting under IFRS will impact the recording of "actual " capital expenditures, including capitalization of overheads, and rate base as compared to the test period amounts presented in the evidence?
    b) Has OPG undertaken any reviews to estimate the impact of IFRS reporting in relation to capital assets including capitalization requirements?
    c) If yes to b) above, please provide the results of the reviews or studies and provide an estimate of the resulting differences between reporting under CGAAP and IFRS for the test period.

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

11. Ref: ExhD2/Tab2/Sch 2
OPG is seeking approval to include CWIP in rate base for the Darlington Refurbishment Project, effective March 1, 2011 and refers to *The Report of the Board on The Regulatory Treatment of Infrastructure Investment in Connection with Rate Regulated Activities of Distributors and Transmitters in Ontario* ("Report"), dated January 15, 2010 in support of its request. Please explain why OPG believes that the Report, which speaks to Distributors and Transmitters), should also apply to nuclear generators. Did OPG consider cost recovery mechanisms other than CWIP? If so, please identify the other options and explain why CWIP was selected.

12. Ref: ExhB1/Tab1/Sch 1 p4 ln 15-18
The evidence states that the Darlington Refurbishment CWIP balance of $72.9M as of December 31, 2010 and the annual capital budget of $105.2M in 2011 and $255.8M in 2012 are included as in-service additions for the purposes of establishing Gross Plant balances and rate base amounts described in Exh B3-T3-S1 Table 2.

    Exh B3-T3-S1 Table 2 shows no in-service dollar amounts, related to Darlington Refurbishment CWIP, in 2010 while the opening balance for 2011 shows $72.9 M. Pease explain this discrepancy. Please calculate the impact on the Revenue Deficiency if the $72.9 M were treated as in-service in 2011 rather than subsumed in the opening balance for 2011.

Capital Structure and Cost of Capital

Issue 3.1
What is the appropriate capital structure and rate of return on equity?

13. Ref: ExhC1/Tab1/Sch1
Ref: ExhC1/Tab1/Sch3/Table2
OPG proposes that the cost of capital parameters be updated in accordance with the Board's 2009 Cost of Capital Report based on data three months prior to the proposed effective/implementation date of March 1, 2011. This would correspond to using data from Bloomberg, *Consensus Forecasts* and Bank of Canada for November, 2010.

    OPG proposes that the return on equity ("ROE") and the deemed long-term debt rate based on November, 2010 data would be used for both the 2011 and 2012 revenue requirement calculations.

However, OPG has provided separate forecasts for each of 2011 and 2012 for the short-term debt rate and for its actual/embedded debt.

a) Please explain why OPG believes that it is appropriate to use different estimates for 2011 and 2012 for some of the cost of capital parameters but not for all.
b) OPG has forecasted a deemed short-term debt rate under its commercial paper program of 0.61% for 2010, 1.94% for 2011 and 3.43% for 2012. These amounts appear to be based on the Global Insight forecasts of 0.46% for 2010, 1.79% for 2011 and 3.28% for 2012 plus 15 basis points. However, OPG is proposing that the deemed long-term debt rate, for the unfunded portion of deemed long-term debt capitalization, and the ROE be held constant for setting the 2011 and 2012 revenue requirements. Please provide an explanation for why OPG believes that forecasted market conditions that affect the bankers' acceptance rate (and hence the short-term debt rate that OPG may have to face) will not also affect rates for medium and long-term debt and for market-based rates of return.

Issue 3.2
Are OPG's proposed costs for its long-term and short-term debt components of its capital structure appropriate?

14. <u>Ref: ExhC1/Tab1/Sch2/p9-10</u>
<u>Ref: Hydro One Networks Inc. Decision with Reasons, EB-2007-0272, pp. 51,54-55</u>
<u>Ref: Hydro One Remote Communities Decision with Reasons, EB-2008-0232, pg. 12</u>
<u>Ref: London Hydro Inc. Decision with Reasons, EB02008-0235, pp. 36-37</u>

In the first reference, OPG states:

> Consistent with the methodology approved in EB-2007-0905, OPG has used a provision for long-term debt to reconcile the debt component of OPG's regulated capital structure with the proposed rate base that financing supports. OPG's other long-term debt provision is determined based on:
>
> - The difference between the debt resulting from the application of OPG's proposed capital structure to its proposed regulated rate base.
> - The project-related and corporate long-term debt assigned or allocated to OPG's regulated operations as discussed above.
> - The portion of short-term debt allocated to regulated operations. This calculation is described in Ex. C1-T1-S3.

a) Please confirm whether OPG's definition of "Other Long-Term Debt Provision" is the same as that of "notional debt" as used in the Hydro One Network's Inc. Transmission, Hydro One Remote Communities Inc., and London Hydro Inc. rate applications cited in the references noted above. Please explain your answer.
b) In view of the Board's decisions in the cited electricity transmitter and distributor rate applications, where the Board determined that notional debt should attract the actual or embedded weighted average cost of debt if available, and would only attract the deemed debt rate if the utility had no actual debt, please provide OPG's reasons for proposing that the unfunded portion of debt capitalization should attract the deemed debt rate rather than OPG's forecasted weighted average cost of debt for each of the 2011 and 2012 test years.

15. <u>Ref: ExhC1/Tab1/Sch2/p10</u>
In the reference, OPG states that:

> As discussed in Ex C1-T1-S1, OPG has used the cost of capital methodology contained in the Report of the Board on the Cost of Capital for Ontario's Regulated Utilities in EB-2009-0084 ("Cost of Capital Report"). OPG's other long-term debt provision is consistent with the definition used by the OEB to describe the deemed debt component of the approved capital structure for electricity distributors. Page 54 of the Cost of Capital Report states that "the deemed long-term debt rate will be used where an electricity distribution utility has no actual debt".

Exhibit C1/T2/S2/Table 6 shows Existing and Planned Long-Term debt for the Calendar Year ending December 31, 2011. Similarly, Exhibit C1/T2/S2/Table 7 shows Existing and Planned Long-Term Debt for the Calendar Year ending December 31, 2012.

a) Given that Tables 6 and 7 of Exhibit C1/T2/S2 show that OPG will have actual or embedded debt during the test year period, please explain how OPG's proposed use of the deemed long-term debt rate is consistent with the quoted guideline from page 54 of the Cost of Capital Report.
b) Please provide versions of Exhibit C1/T1/S1/Table 1 and C1/T1/S1/Table 2 using the weighted average cost of Existing/Planned Long-Term Debt (the Cost Rate in Line 2 of each table) for each of 2011 and 2012 as the Cost Rate for the Other Long-Term Debt Provision in Line 3 of each table for the same year.

16. <u>Ref: ExhC1/Tab1/Sch3/p2-3</u>
On page 2 of this exhibit, OPG states that it has used "*the Global Insight forecast as the basis for the bankers' acceptances interest rate forecast after adjusting for the spread differential between*

bankers' acceptances and the yield on treasury securities. For 2010 the bankers' acceptances rate used is 0.46%, for 2011 it is 1.79% and for 2012 it is 3.28%."

a) Please provide the source document or data of the Global Insight forecast used and the derivation of the bankers' acceptance rate forecasts documented in the evidence.
b) Is the reference bankers' acceptance rate used based on one-month or a three-month bankers' acceptances' or a combination thereof? Please explain your response in detail.
c) Please explain the reasons for the expected increase in the bankers' acceptance rates, specifically,
   i) Please explain the reason for the increases in 2011 and 2012.
   ii) What domestic or international economic phenomena are expected to drive the increases in the rates?
   iii) What evidence in 2010 is there that the rates are increasing in the direction and magnitude forecasted?

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?

17. <u>Ref: ExhC1/Tab1/Sch1</u>
In the reference, OPG provides the report, "Technology-Specific Capital Structures: An Assessment", by Ms. Kathleen McShane of Foster Associates. The report conducts analyses to assess different business risk and appropriate costs of capital related to the regulated hydroelectric and nuclear generation assets of OPG. In this report, the analyses are based on data of publicly traded U.S. and Canadian utilities. For several analyses, Ms. McShane identifies that there are insufficient utilities in the sample with concentrations of hydroelectric or nuclear generation similar to that of OPG to derive sufficiently accurate or meaningful estimates of technology-specific returns or capital structures.

a) Please explain whether a review of utilities from other jurisdictions, such as the United Kingdom, Australia or Norway, might provide examples of generating utilities with concentrations in nuclear or hydroelectric generation similar to that of OPG and that could provide information on relative risk and hence a return differential from utilities with a more diversified generation portfolio.
b) Was an investigation of utilities from outside of Canada and the United States considered? Please explain your response.

Capital Projects

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?

18. Ref: Exh D1/Tab1/Sch 2 Table 1
    OPG indicates that it is spending about $12 M in capital on a visitor centre at the Saunders facility and the $12 M is deemed in-service in 2010. Please confirm whether OPG's existing Payment Amounts are recovering any costs related to this initiative. Please confirm whether OPG's proposed Payment Amounts for 2011 and/or 2012 will recover costs related to this initiative, and if so what percentage of the costs are being recovered from rate-payers, from the shareholder and from the unregulated Hydroelectric business units. If ratepayers are bearing costs associated with the initiative, please explain the benefits the ratepayers will realize from this investment.

19. Ref: ExhD1/Tab1/Sch1
    Please provide variance explanations for (i) the difference between 2008 actual and 2008 Board-approved and (ii) between 2009 actual and 2009 Board-approved for Hydroelectric Capital Expenditures

20. Ref: ExhD1/Tab1/Sch 2 Attachment 1 Tab1
    The Financial Sensitivity Analysis presented on page 7 of the Niagara Tunnel Project Business Case Summary (BCS) shows a Levelized Unit Energy Cost (LUEC) of 6.8 cents and a Revenue Requirement of 8.7 cents per kWh.

    a) Please confirm which per kWh rate would be included in the calculation/determination of Payment Amounts when the project is put into service (assume a full year, say 2014).
    b) Please confirm whether or not the Hydroelectric Payment Amount of 3.738 cents per kWh proposed for the 2011-12 test period does not include any costs associated with the Niagara Tunnel project.
    c) Please confirm whether the "economic analysis" included in the BCS for other Niagara Group projects include the additional "flow" resulting from the Niagara Tunnel project they will be able to harness. If there are such benefits please identify them, and explain why OPG chose not to include them in a Net Present Value analysis of the Niagara Tunnel Project.

21. Ref: ExhD1/Tab1/Sch 2 attachment 1 Tab1 p6
    The BCS states that "the estimated project cost of $1,600 M includes a negotiated target price for completion of the Niagara Tunnel by Strabag…." In this regard please clarify whether or not OPG continues to be at risk for Niagara Tunnel Project cost overruns?

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?

22. <u>Ref: ExhD2/Tab1/Sch1</u>
    Please provide variance explanations for (i) the difference between 2008 actual and 2008 Board-approved and (ii) between 2009 actual and 2009 Board-approved for Nuclear Capital Expenditures.

23. <u>Ref: ExhD2/Tab1/Sch1 Table 2</u>
    Please add additional rows to the table (Capital Expenditures Summary-Nuclear Operations) such that "Facility Projects To Be Released" and "Listed Work To Be Released" are sub-categorized by Site.

24. <u>Ref: ExhD2/Tab1/Sch 2 Attachment 1, Tab 2</u>
    The BCS for the Fuel Handling Power Track Modifications indicates that the project assumes a Project/Station End of Life of 2018 (p.14).

    In light of OPG's plans to refurbish the Darlington units and extend their service life by 30 years, please clarify whether the Fuel Handling Power Track Modifications improvements will continue to be useful beyond 2018.

25. <u>Ref: ExhD2/Tab1/Sch 2 Attachment 1, Tab 3</u>
    a) The (Partial Release) BCS for the Improve Maintenance Facilities project indicates that the Full Release BCS was scheduled for May 2009.
       i) Has this occurred? If not, please elaborate on the cause for the delay and what the new target date is for the Full Release BCS.
       ii) If yes, please provide a copy of the Full Release BCS.
    b) On page 9 of the BCS it is stated:
       "In the Full Release BCS the following items will be included as per Nuclear Oversight Committee/Board of Directors specific request:
       - Analysis of existing space currently used by Maintenance staff for the various functions and an explanation of why each function must be moved to the new location (eg. tabulate: function/space currently used for the function/why the function must be moved to a new location).
       - Detailed benchmarking data for similar building construction on a cost-per-square foot basis."
    Please provide the aforementioned information.

26. <u>Ref: ExhD2/Tab1/Sch 2 Attachment 1, Tab 4</u>
    The BCS for the New Change Room Facility (p.3) states that "The new CCR is being constructed in time to support the March 2009 Vacuum Building Outage at Darlington."

    Please confirm whether or not the CCR project is completed. If it isn't, please provide a status update.

27. Ref: ExhD2/Tab1/Sch 2 Attachment 1, Tab 8
The BCS for the Steam Generator Controls Replacement identifies 30 May 2008 as a key milestone date (Attachment C, p.15) for a Full Release (Phase 1) BCS.

a) What is the status of the Full Release BCS?
b) Please clarify whether the replacement SG Controls will continue to be useful beyond the projected station end-of-life of 2018.

28. Ref: ExhD2/Tab1/Sch 2 Attachment 1, Tab 15
The BCS for the Pickering B Chemistry Standards project identifies that this project would be completed by 15 December 2008 (p19). What is the status of this project?

29. Ref: ExhD2/Tab1/Sch2 Attachment 1 Tab 29
The evidence indicates that OPG capitalized $11.8M of 2009 expenditures for engineering, fabrication and installation of some of the modifications and $0.2M of MFA (Minor Fixed Assets) tools associated with the 2009 Darlington Vacuum Building Outage (VBO).

a) Have the same or similar modifications been used in the previous Darlington Vacuum Building Outage? Were any of those modifications applied to the 2009 VBO as re-usable modifications?
b) On page 2 of the BCS, it is stated that “significant savings could be realized over the life of the station if the designs and assemblies were developed as permanent, reusable assemblies”. Please provide further details on the scope and extent of these future savings.
c) In view of the long (12-year) cycle between Vacuum Building Inspections, what provisions have been made to ensure that the equipment, components and systems that have been disassembled and put away in storage will be readily retrievable and available for future use?

30. Ref: ExhD2/Tab1/Sch2 Attachment 1 Tab 30
The BCS identifies Alternative 1 as the recommended alternative, and as being the most economical option to meet the back-up heating steam supply to Pickering A and B in the event of a six-unit shutdown in winter. Alternative 1 includes a new Auxiliary Heating System with increased heating steam capacity (including a new oil-fired boiler with capacity of 70,000 lb/h, sufficient to accommodate six shutdown units, i.e., two Pickering A, and four Pickering B units).

Based on the above, is the selection of Alternative 1 predicated on the assumption that the Pickering A units will be shut down concurrent with the projected end of life dates (extension of nominal end of life from 2014-2016 to 2018-2020) of the Pickering B units resulting from the Pickering B Continued Operations?

31. Ref: ExhD2/Tab1/Sch 2, Attachment 1, Tab 31
The evidence indicates that the recommended permanent solution for the Pickering A Inter Station Transfer Bus (ISTB) capacity is Alternative 1 and is dependent on Pickering B (U5/6 and U7/8) for the supply of power to the ISTB.

Given this interdependency between Pickering A and Pickering B, please clarify to what extent the long term operability of the Pickering B units and their implications on the Pickering A units were considered during the assessment of the various alternatives, in particular, with respect to the alternatives based on Pickering A independent solutions.

32. Ref: ExhD2/Tab1/Sch 2 Attachment 1, Tab 32
The BCS for the Feeder Repair by Weld Overlay project states that "At the conclusion of Stage I, an updated economic analysis and revised BCS will be prepared using vendor provided budgetary estimates for Stage II, and a formal decision meeting will be held to determine whether to recommend proceeding with weld overlay tool detailed design and manufacture. The basis for the decision meeting may be found in Attachment D."

Please provide a status update with respect to the following:
a) Has Stage I been completed in the meantime?
b) If Stage I has been completed, what were the technical results? Based on these results, has a recommendation and/or decision been made to proceed with Stage II or to cancel the project?
c) If Stage II is to proceed, has a revised BCS with updated economic analysis been prepared and what is its status?

33. Ref: ExhD2/Tab1/Sch 2 Attachment 1, Tab 33
a) Were the feeders in the Upper Feeder Cabinet inspected for fitness-for-service during the refurbishment of Pickering A units 1 and 4?
b) If the response is affirmative, what were the results of the inspections relative to the need for development of the Upper Feeder Cabinet Inspection Robot for Pickering A (and B) at this time?
c) Does OPG still intend to pursue feeder cabinet inspection work with Bruce Power in the future? If not, what are the implications on the BCS scope and preferred alternative?

34. Ref: ExhD3/Tab1/Sch1
Please provide variance explanations for (i) the difference between 2008 actual and 2008 Board-approved and (ii) between 2009 actual and 2009 Board-approved for Corporate Group Capital Expenditures. Please provide the resulting over (under) earning that resulted in 2008 and 2009 due to the difference between actual and Board-approved.

Production Forecasts

Issue 5.1
Is the proposed regulated hydroelectric production forecast appropriate?

35. Ref: ExhE1/Tab1/Sch1/p5/line 30-31
    Surplus Baseload Generation ("SBG") forecasts are based on Ontario electricity demand and generation supply forecasts:

    a) Are these forecasts prepared by OPG or another agency?
    b) What is the source and reference for these forecasts? Please file any reference documents.
    c) If prepared by another agency, did OPG provide specific inputs to the forecast, or, advise on the inputs?
    d) What economic and supply forecast factors are most important in determining the level of SBG?

36. Ref: ExhE1/Tab1/Sch1/p6/lines 2-4
    The SBG estimates are 0.2 TWh in 2010, 0.5 TWh in 2011 and 0.8 TWh in 2012.

    a) How many hours of operation of the Niagara Plant Group would these energy levels equate to?
    b) The SBG levels increase year-to-year. What mitigation actions has OPG considered to minimize SBG over the 2011-2012 period?
    c) Is OPG expecting to be compensated by any other agency for its actual (if they occur) SBG levels in the 2010-12 period?
    d) Does OPG plan to seek such compensation?
    e) Does OPG consider SBG to be eligible for CMSC payments?

37. Ref: ExhE1/Tab1/Sch2/Table 1
    Table 1 summarizes the hydroelectric production forecast. Line 17 of Table 1 is the total TWhs from the regulated plants.

    Is the line 17 total equal to total energy delivered net of SBG, i.e., potential production is line 17 plus line 21 (SBG)?

Issue 5.2
Is the proposed nuclear production forecast appropriate?

38. Ref: ExhE2/Tab1/Sch2/Table 1c
    Nuclear generating plants are baseload suppliers, similar to the regulated hydroelectric generation plants. In the recent past, nuclear plants have been affected by SBG conditions. SBG has been factored into the hydroelectric production forecast in this application.

a) Why is SBG not expected to be a factor in the nuclear production forecast?
b) Are there significant cost implications if SBG is included in the nuclear forecast versus the hydroelectric forecast?

39. Ref: ExhE2/Tab1/Sch2/Table 1c
The history of actual Forced Loss Rate (FLR) day equivalents compared to planned in the 2007-09 period is a consistent underestimate of the impact on the Pickering A and B facilities and an overestimate on the Darlington plant.
a) FLR averaged 219 days over 2007-09 for Pickering A and189 days for Pickering B. Why does OPG expect these rates to fall to an average of 42 days (-81%) for Pickering A and 56 days (-70%) for Pickering B in the 2010-12 period?
b) What specific factors or actions taken by OPG will result in these significant reductions in FLRs?
c) Does OPG have any examples from other jurisdictions where this type of improvement in FLRs has occurred?

40. Ref: ExhE2-1-1/Attachment 4/pages 1-2
OPG has included a "forecast for major unforeseen events" in this application. This forecast was not included in the previous application, EB-2007-0905.
a) What is the FLR day equivalent for the nuclear fleet of the 2 TWh per year reduction from unforeseen events?
b) Is this methodology considered to be a substitute for improving the estimates of FLRs?
c) Do other jurisdictions use similar methodologies for their production forecasts?

Operating Costs

Issue 6.1
Is the test period Operations, Maintenance and Administration budget for the regulated hydroelectric facilities appropriate?

41. Ref: ExhF1/Tab2/Sch1/Tables 1 & 3
From 2008 to 2012, the Niagara Plant Group OM&A costs increase by about 19% (Table 1). This includes an increase in 2012 relative to 2011 following the conclusion of the Niagara Bridge Divestiture Program as referenced in the application (F1-T2-S2, p.2). The number of staff FTEs in the Niagara Plant Group also increase by 8% over the same 2008 – 2012 period, which includes a minor FTE reduction following the conclusion of the Niagara Bridge Divestiture Program (Table 3). Please identify the primary drivers underlying these OM&A cost and FTE increases and provide an explanation for each.

Issue 6.2
Is the benchmarking methodology reasonable? Are the benchmarking results and targets flowing from those results for OPG's regulated hydroelectric facilities reasonable?

42. Ref: ExhF1/Tab1/Sch1/p.18-22
The results of the Navigant Consulting OM&A unit energy cost benchmarking are summarized in Chart 4 on page 18. The application provides several reasons why the unit cost for SAB PGS is much higher than the other hydroelectric facilities. For example, the application notes on page 22 *"In addition to its role in pumping water for use during peak periods (which is typical for PGS's), Sir Adam Beck PGS is used to: 1) control the cross-over elevation of the Sir Adam Beck canals, 2) assist in automatic generation control, and 3) provide for flexibility and optimization of operations at the Sir Adam Beck complex."* However, between 2006 and 2008, the unit cost almost doubled (increased from 47.1 to 81.2 cents/kWh) and is consistently in the 4^{th} quartile (ranging from 22.1 to 81.1 cents) amongst the other PGS comparators. Board staff considered that the rising unit cost may be due to addressing the issue of increased SBG but staff understands from the May 2009 IESO 18-month Outlook report that SBG events became a prominent issue following the benchmarking period, in early 2009.
a) Please explain why the unit cost almost doubled between 2006 and 2008.
b) The application appears to suggest that none of the other 15 PGS comparators in the Navigant results provide functions beyond pumping water for use during peak periods, with references to the SAB PGS being "unique". For example, do none of the other PGS units provide other functions such as Automatic Generation Control?
c) Is OPG able to provide a listing of those 15 PGS comparators (with or without their respective unit costs)? If so, please provide the list.
d) On page 16 it notes that, since March 2009, the "*operational performance has been excellent*" in relation to SAB PGS. What has the unit cost been since March 2009?

43. Ref: ExhF1/Tab1/Sch1/p.16 and Attachment 1/p.10, 34
As noted in the application and referenced in the interrogatory above, the Navigant benchmarking results show the unit cost of the SAB PGS almost doubled and the SAB PGS provides many important functions in the Ontario electricity market. The summary report prepared by Elenchus, in relation to OPG's stakeholder consultation meetings (in November 2007) prior to the previous payments application, notes that the SAB PGS is over half a century old and is relatively inefficient, with about a 50% efficiency loss when water is pumped (i.e., for each MWh used to pump water, 0.5 MWh is generated) and that efficiency loss is attributable to the age of the equipment. The application also notes on page 16 that the unit had to be

“dismantled and shipped to the manufacturer’s facility in Montreal” and the repairs *“took over ten months”*. In Attachment 1 (p. 34), which is page 13 of the Business Plan, it further identifies *“• SAB PGS Unit rehabilitation on G2-5 planned for 2011-2014. PGS Unit transformers also scheduled for replacement 2009-11. Unit breakers and governors planned for replacement 2011-13.”* Attachment 1 (p.10) further notes OPG has conducted a *“preliminary review of expansion of the existing Sir Adam Beck PGS reservoir”.*

a) Given all of the above, please explain if OPG has investigated a full replacement of the PGS equipment. If not, please explain why. If so, what is the estimated cost of a full replacement?
b) Please identify the total estimated cost of all of the recent and planned material investments in relation to the SAB PGS (i.e., dismantling and shipping to the manufacturer’s facility, rehabilitation, transformer replacements, breaker and governor replacements, etc.).
c) What efficiency improvement could likely be achieved with state-of-the-art equipment?
d) Please also elaborate on the results of the preliminary review of SAB PGS expansion.

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

44. Ref: ExhF2/Tab1/Sch1/Table1

In relation to aggregate Nuclear OM&A Costs, please provide variance explanations for the difference:

a) between 2008 actual and 2008 Board-approved amounts; and
b) between 2009 actual and 2009 Board-approved amounts.

45. Ref: ExhF2/Tab2/Sch1/p.1

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

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

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

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

a) Were many of the reductions in costs and FTEs expected regardless of the seven key initiatives and other cost control measures identified in this application?
b) Please identify the estimated FTE and cost savings associated with each new initiative as well as each additional new cost saving measure OPG refers to in the application.
c) Further to the above, please reproduce Table 1 in F2-T1-S1 (Operating Costs Summary – Nuclear) up to Line #9 (Total OM&A) in the following manner. Exclude the costs associated with the following extraordinary and/or non-recurring items:
   - Temporary increase in OM&A costs/FTEs approved by the Board to address the backlog issue
   - Isolation and safe storage of Pickering A units 2 and 3 (project now completed)
   - Major VBO outage completed for Darlington in 2009 (occurs once every decade)
   - Major VBO outage completed for Pickering in 2010 (occurs once every decade)

- Discontinuation of Service Agreements with Bruce Power amounting to $145M in savings for the 2010-2012 period (as identified on page 19 of the Nuclear Business Plan in Attachment 1)
- Pickering Continued Operations
- Darlington Refurbishment

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

46. Ref: ExhF2/Tab1/Sch1/ Attachment 1
On page 22 of OPG's Nuclear Business Plan it discusses "Risks to Business Plan" (F2-T1-S1, Attachment 1) and notes: "*Corrosion of Pickering A Calandria Vault: The corrosion of structural components and cooling systems is being caused by moisture in the vault atmosphere and radiolysis forming nitric acid which attacks the carbon steel components in the reactor vault."* It also notes in OPG's "2009 Annual Information Form" (p.37): *"The uncertainty associated with the electricity volume produced by OPG's CANDU nuclear generating units is primarily driven by the condition of the station components and systems, which are subject to the effects of aging. Significant factors identified to date include steam generation tube corrosion, feeder pipe wall thinning and pressure tube-calandria tube contact. Because no nuclear generating station utilizing CANDU technology has yet completed a full life cycle, there is a risk that additional unforeseen technological or equipment issues could materialize."*
   a) Please explain why the Pickering A Calandria Vault issue is showing up now, a relatively short period after the expenditure of the significant refurbishment costs on Units 4 and 1 just a few years ago? Was this issue overlooked at the time or is there another reason why there is an increase in the corrosion of components and equipment in the calandria vault?
   b) Please also elaborate in relation to the issues identified, steam generation tube corrosion, feeder pipe wall thinning and pressure tube–calandria tube contact, and the degree and significance of the impact of each of the issues on Pickering A, Pickering B and Darlington.

47. Ref: ExhF2/Tab3/Sch3
Please 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.

48. Ref: ExhF2/Tab3/Sch3/Attachment 1/Tab12
This BCS relates to Fire Safety Assessment (FSA) Upgrade (Project No. 26003). The BCS does not incorporate the FSA requirements of the Pickering A Safe Storage Project and states that the latter will be dealt with separately.
   a) In view of the integrated nature of the original configuration and layout of the four-unit Pickering A station, why are the FSA requirements of the

Safe Storage Project dealt with totally separate from the Pickering A FSA covering units 1 and 4?

b) What are the associated FSA expenditures for the Safe Storage Project?

49. Ref: ExhF2/Tab3/Sch3/Attachment 1/Tab13

This BCS relates to Darlington Environmental Qualification Discovery Work and Scope Reduction (Project No. 38458). This project is to meet regulatory requirements with respect to the Environmental Qualification (EQ) of essential (safety related) equipment, components, barriers and structures in order to ensure their operability and functionalities under adverse environments resulting from certain design basis accidents, e.g., a major steam line rupture.

Please clarify if the project costs include required modifications or upgrades to affected equipment, barriers and structures for EQ compliance.

50. Ref: ExhF2/Tab3/Sch3/Attachment 1/Tab14

This BCS relates to Probabilistic Risk Assessment Upgrade (Project No. 62440). This project is for the upgrade of the Probabilistic Safety Assessments or PSA (sometimes also referred to as Probabilistic Risk Analysis or PRA) for Pickering B and Darlington by December 31, 2010, in compliance with an operating licence requirement for these stations. The PSAs must be compliant with the requirements of the Canadian Nuclear Safety Commission Regulatory Standard S-294, “Probabilistic Safety Assessment (PSA) for Nuclear power Plants”.

Based on the limited data in Attachment “A” of the BCS, it is surmised that the combined costs of the analysis services to be contracted out to upgrade the Pickering A, Pickering B and Darlington PSAs and of the general contingencies amount to $23.4M out of the total project costs of $26.8M. As discussed in the BCS, the upgrade of the Darlington PSA will require the most work with relatively minor updating required for the Pickering B and Pickering A PSAs.

a) Please clarify what the basis is of the magnitude of the combined costs of the analysis services to be contracted out and of the general contingencies.
b) Please also clarify how these costs are allocated with respect to the respective PSAs for Pickering A, Pickering B and Darlington.

51. Ref: ExhF2/Tab3/Sch3/Attachment 1/Tab15

This BCS relates to Pickering B Unit 7 Calandria Tube Replacement (Project No. 40669). This project is to replace one calandria tube (Channel A13) in Pickering B Unit 7 as a result of a leak of the Annulus Gas System (AGS) from this location into the heavy water moderator surrounding the calandria tubes, thereby affecting continued safe operation of the unit.

a) What was the final project cost compared to the BCS release estimated costs of $19.8M?
b) The BCS does not provide any clarification with respect to the root cause of the annulus gas leak. Please explain in detail the root cause of the annulus gas leak and why there was a need to replace the calandria tube.
c) The absence of a developed calandria tube cutting tool prior to the replacement of the calandria tube indicates that this may have been an unanticipated problem. Please identify whether this was an isolated incident or whether it is a potential generic issue affecting all Pickering B units and possibly the two Pickering A units. Please also identify if there are any implications with respect to the planned Pickering B Continued Operations project. If so, please explain.

52. Ref: ExhF2/Tab3/Sch3/Attachment 1/Tab16
Ref: ExhF2/Tab1/Sch1/Attachment1/p22
This BCS relates to Fuel Channel Life Management (Project No. 62444). This project is to accelerate R&D (Research & Development) work to develop better information and the knowledge base with respect to degradation mechanisms and processes affecting the integrity of pressure tubes or fuel channels.

a) On page 22 of OPG's Nuclear Business Plan "Risks to Business Plan, it notes: "*End of Life Determination*: *The medium risk in the confidence level of attaining the planned effective full power hours (EFPH) for Darlington and Pickering B units is insufficient for effective business planning*." Please clarify what the implications are with respect to the planned life extension of the Pickering B units and the planned refurbishment of the Darlington units in the event of each of the following scenarios:
   i) The project is delayed and the planned results and information are not produced in a timely fashion, i.e., in 2012;,
   ii) The results and information are inconclusive or negative, i.e., do not support the higher end-of-life operating limits for Darlington (210,000 EFPH) and for Pickering B (240,000 EFPH).
b) If the confidence level of attaining the planned EFPH for Darlington and Pickering B units is insufficient for effective business planning, why does OPG consider the confidence level to be sufficient for Board approval of significant proposed costs related to Pickering B Continued Operations and the Darlington Refurbishment?
c) On page 9 of the Business Case Summary, it is stated that this project will be jointly funded between OPG and Bruce Power with cost sharing at a ratio of 5.5:3.5 (OPG:BP). Please explain the basis of this cost sharing ratio.

Issue 6.4
Is the benchmarking methodology reasonable? Are the benchmarking results and targets flowing from those results for OPG's nuclear facilities reasonable?

53. Ref: ExhF2/Tab1/Sch1/p.13
The application notes that the targeted performance improvement by 2014 with respect to Total Generating Cost for the Pickering stations is below median. It also notes *"this reflects the reality of OPG's initial starting point in terms of the material condition of these plants".* Please elaborate on the "material condition" of the Pickering stations and to what extent it is a factor (relative to comparator nuclear plants) in terms of not being able to achieve the median by 2014.

54. Ref: ExhF2/Tab1/Sch1/p.16
On page 16 it notes *"A preliminary assessment of combining the operations of Pickering A and B was also undertaken as a separate initiative by OPG, and some initial cost savings in Base OM&A were included in the 2010 - 2014 Business Plan, as further described at Ex F2-T2-S1 (page 19 of 34). Further action on this initiative has been delayed until after the completion of the 2010 Pickering Vacuum Building Outage."* The Pickering VBO was completed on May 28, 2010 according to the OPG website. Given the completion of the 2010 Pickering Vacuum Building Outage, is further action on this initiative now underway? Please also elaborate on "further action".

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

55. Ref: ExhF5/Tab1/Sch1/p.138
In regard to 3-Year Capital Costs per MW DER (Design Electrical Rating), ScottMadden's Observation in the Phase 1 Benchmarking Report was that Darlington had the third lowest capital costs of any plant in the peer group and Pickering A and B were both in the best quartile. The report notes *"One contributing factor for OPG appears to be the capitalization threshold. The minimum expenditure threshold for capitalization at OPG for generating assets is $200k per unit whereas the majority of the companies in the industry have adopted minimum capitalization thresholds that are significantly lower".* Please explain why OPG has a significantly higher capitalization threshold than the majority of the companies in the industry.

56. Ref: ExhF5/Tab1/Sch2/p.22
The Phase 2 Benchmarking Report notes that *"the initial 150 fleet improvement initiatives had been consolidated down to 46 key initiatives. Consolidation primarily resulted from the grouping of related initiatives, the elimination of lower priority initiatives, and the balancing of*

workloads….Factors considered during prioritization included: (a) the business benefit or impact, (b) the required investment of financial and human resources, (c) the logical sequencing of work, (d) the balance of workload over the planning horizon, and (e) the degree of culture change required. In the end, a total of 33 fleet-wide improvement initiatives were approved for incorporation into the site and support unit business plans."

a) Please identify the 13 initiatives that were not approved and please explain whether OPG has any future plans in terms of these 13 initiatives.
b) Please identify those initiatives (of the 13) that would have had a material business benefit or impact (but were eliminated for other reasons noted above) and, for such initiatives, please explain: (i) the estimated benefit; and (ii) the specific reason OPG decided not to pursue it.

57. Ref: ExhF5/Tab1/Sch2/p.25
In regard to "offsite staffing" levels, the Phase 2 Benchmarking Report notes *"This comparison highlighted considerable differences between companies with respect to the number of offsite employees supporting nuclear stations"* and that a nuclear comparator *"reported 697 offsite employees supporting 10 stations and 17 units whereas OPGN reported 3,414 offsite employees supporting three stations and 10 units. The study team did not have adequate time to delve into the business drivers behind these variances"*. Please explain why OPG requires almost 5 times the number of offsite employees to support almost half as many units.

58. Ref: ExhF5/Tab1/Sch2/p.26
Section 3.3.2 of the Phase 2 Benchmarking Report notes that ScottMadden piloted a top-down staffing analysis using the OPGN Radiation Protection (RP) function as an example and the recommended changes for future consideration by OPG include *"a potential reduction of 53 FTEs…(28%)"*. The report then notes *"Of the potential 48 FTEs reduced, 35 would potentially be reassigned to other functional organization through improved resource alignment while 13 would be eliminated altogether. These changes were still being considered by OPGN at the time this report was prepared."* Please clarify whether the potential reduction was actually 53 or 48 FTEs. Please also identify if this recommendation was implemented by OPG and how OPG plans to build on this pilot in terms of other segments of the organization.

59. Ref: ExhF5/Tab1/Sch2/p.29
The report notes ScottMadden developed the observations and recommendations presented in Figure 15 for the future consideration of OPG. The observations included *"OPGN does not have a designated Plant Manager responsible for core perform functions at each station. Instead, the Plant Manager function is performed by two separate Directors: the Director of Operations and Maintenance (DOM), and the Director of Work*

Management (DWM)". The associated recommendation was to *"Consider adopting a single Plant Manager model in lieu of the current dual DOM/DWM roles"* and *"In light of the change required by the 33 fleet improvement initiatives, it might be best to postpone implementation of this recommendation until 2012 or beyond".* Does OPG plan to implement this recommendation now or in 2012? If not, please explain why.

60. Ref: ExhF5/Tab1/Sch2/p.32
In section 4.2, the report notes *"Without downplaying the success achieved during the current planning cycle, we believe that opportunities remain for continuous improvement beyond the current business planning horizon".* Did ScottMadden identify any such "opportunities" that remain? If so, please identify those opportunities and provide an explanation for each. Please explain why the remaining opportunities are not being pursued.

61. Ref: ExhF5/Tab1/Sch2/p.34
In section 4.4, it notes *"At the time of ScottMadden's departure from the project, some issues remained open with respect to the financial targets in selected business unit plans".* Please identify the issues that remained open, the associated financial targets and the related business units.

62. Ref: ExhF5/Tab1/Sch2/p.37
In section 4.6, a ScottMadden Observation was *"OPGN managers noted that complex, cross-functional initiatives generally "die on the vine" when assigned to the line organization for implementation"*. The reasons cited include:

"- *The Tyranny of Daily Events: Team members who have full-time responsibility for daily work are unable to dedicate adequate time and focus on the change initiative*
- Diffuse Accountability: Too many "participants" but no clear leadership and single point of accountability."

ScottMadden's associated Conclusions were:

"- Without adopting a revised approach to implementing and monitoring change initiatives, OPGN is at risk of not successfully implementing the improvement initiatives that have been agreed upon and incorporated into its business unit plans;
- Due to time limitations, ScottMadden was unable to perform an analysis as to whether OPGN has the structure, process, and methodologies in place to manage transformational change initiatives of the scope envisioned".

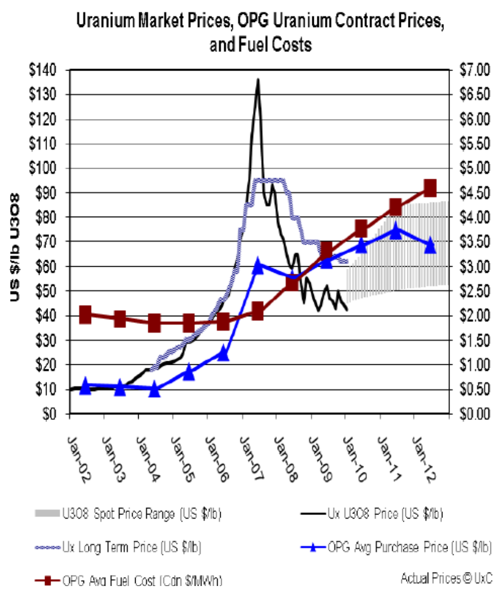
Has OPG adopted a revised approach to implementing/monitoring change initiatives? If so, please elaborate. What further actions does OPG plan to ensure that OPG Nuclear has the structure, process, and methodologies in place to manage transformational change initiatives?

63. Ref: ExhF5/Tab1/Sch2/p.36
In section 4.6, another Observation of ScottMadden is *"At the time this report was prepared OPGN had incorporated the 33 initiatives into the business plans but had not yet established a formal implementation strategy."* The initiatives and gap-based planning are discussed in the application but there seems to be no discussion of a formal implementation strategy to achieve the plan discussed in the application. Has OPG established a formal implementation strategy? If so, please explain that strategy. If not, please explain why.

64. Ref: ExhF5/Tab1/Sch2/p.37
In section 4.6 of the Phase 2 Benchmarking Report it discusses how there can be too little accountability or consequences if initiatives are not implemented successfully and on time. OPG notes on page 13 of F2-T1-S1 *"Another step undertaken was to build management accountability for the timely implementation of the improvement initiatives into Nuclear's 2010 scorecard, which is the basis for the annual incentive plan payout."* Given the importance of these initiatives, please elaborate on the consequences in terms of incentive plan payout if a certain initiative that OPG has included in its business plan is not implemented successfully and/or business plan targets are not met; i.e., for those directly accountable, how much of the incentive payout will either successful or unsuccessful implementation constitute (e.g., 25%, 50%)? Please also explain if such consequences would be limited to reducing the incentive payout.

Issue 6.6
Is the forecast of nuclear fuel costs appropriate?

65. Ref: ExhF2/Tab5/Sch1/p.7-8
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?

66. Ref: ExhF2/Tab5/Sch1/p.8
On page 8, it notes *“OPG is proposing to continue the Nuclear Fuel Cost Variance Account. Over 2008 and 2009, uranium market prices were lower than those forecast by OPG in EB-2007-0905, resulting in a credit in the Nuclear Fuel Cost Variance Account … OPG is forecasting a debit amount for 2010, such that overall there will be a net debit balance in this account owing to OPG from ratepayers for the period 2008 - 2010.”* Why is OPG forecasting a debit balance given the declining prices noted above and the current credit balance?

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

67. Ref: ExhF2/Tab2/Sch3/Attachment 1, Attachment 2
There appear to be a variety of cost estimates provided by OPG that range significantly ($184M - $300M) for the full Pickering B Continued Operations project.
- The initial OPG news release on Feb. 16, 2010 notes “*OPG will also invest $300 million to ensure the continued safe and reliable performance of its Pickering B station*”.
- In this subsequent OPG application the following is found:
    - In the Business Case (Attachment 1), the table on page 2 shows a total estimated cost of $190.2M.
    - The estimate provided to the OPA is $184M as shown in the letter received from the OPA in the table under “INFORMATION PROVIDED BY OPG…” (Attachment 2)
- In OPG’s *“2009 Sustainable Development Report”* subsequently issued on June 8, 2010, it states on page 42 that the cost estimate is $300M. The report specifically notes *“Pickering B Nuclear Refurbishment: Refurbishment of Pickering B will not be pursued. OPG will invest approximately $300 million to continue the safe and reliable performance of the plant for about the next ten years”.*

a) Please explain this substantial range in cost estimates provided by OPG over a relatively short period of time (about 5 months) for the same project.
b) Please also identify the estimated cost the Board should consider to be the most accurate estimate and explain why. Please also explain the level of confidence OPG has in that estimated cost in quantitative terms (e.g., +/-15%, +/-30%, etc).

68. Ref: ExhF2/Tab2/Sch3/ p.11-12
The application notes that OPG is seeking recovery of the variance between actual and forecast 2008 and 2009 costs for the Pickering B Refurbishment and the Pickering B Continued Operations initiative through the Capacity Refurbishment Variance Account as detailed in Ex. H1-T2-S1. OPG also seeks to recover the forecast difference between 2010 expenditures and amounts underpinning current payment amounts, consistent with the methodology approved in EB-2009-0174.
a) Please clarify what the above means given there were no forecast expenditures for Pickering B Continued Operations for 2008 through 2009.
b) OPG submitted an application in June 2009 and that process was not completed until October 2009 (EB-2009-0174). Please also explain why OPG proceeded to make expenditures on Pickering B Continued Operations in 2009 and 2010 before issuing a news release and bringing it to the attention of the Board.

69. Ref: ExhF2/Tab2/Sch3/ p. 2, 7
The application notes on page 2 that *"The economic assessment of Pickering B Continued Operations contained in the attached business case (Attachment 1) shows that the initiative has substantial value to the Ontario electricity system. OPG estimates the net present value of this initiative to be approximately $1.1B (2010 dollars). This net present value is based on the difference between the estimated cost of Pickering B's output and the estimated cost of replacement generation*". It also notes on page 7, *"The calculated benefit to the system includes the value of being able to operate the two units at Pickering A to 2020, estimated at approximately $400M".*
a) For each year over the applicable period, please identify and explain all of the assumptions underlying this estimate of $1.1B including:
   - A breakdown of the replacement generation (by technology type) and the associated price paid to each;
   - Total electricity demand;
   - Spot market price;
   - Capability factors and total generating cost per MWh for both Pickering B and Pickering A;
   - Natural gas prices;
   - etc.

b) Further to the above, it appears the current payment amounts have been used to make the Business Case (p.18), with about $53 / MWh continuing to be unchanged for the next 10 years.
   i) Is that understanding correct?
   ii) If so, does OPG believe that is a realistic assumption given the trend in payment amounts since OPG's assets became regulated in 2005 and OPG's request in this application that the OEB establish payment amounts of $55.34 per MWh for the nuclear facilities exclusive of riders (A1-T3-S1, p.2)? If not, please identify the assumed payment amounts to make the Business Case and to estimate the benefits.

70. <u>Ref: ExhF2/Tab2/Sch3/ p.4</u>
The application notes on page 4 that OPG has decided to pursue the continued operation work program on Pickering B rather than refurbish Pickering B and the major factors in this decision included "the economics of the Pickering B refurbishment". Please elaborate on the reasons for the decision against refurbishment of Pickering B, particularly the factor noted above.

71. <u>Ref: ExhF2/Tab2/Sch3/ p.5-6</u>
The application notes that Pickering A's operation is linked to Pickering B through shared common systems and a number of interdependent systems at the Pickering site. It further states that, while it would be possible to operate Pickering A after end of life of Pickering B, OPG is not planning to operate the two units at Pickering A with Pickering B shut down and therefore extending the service lives of Units 7 and 8 at Pickering B until 2020 will allow the two Pickering A units to operate until at least 2020.
a) Please explain what the estimated cost would be to operate Pickering A without Pickering B.
b) Please also explain how Pickering B operated when the Pickering A units were not in service (i.e., before refurbishment) given the shared common and number of interdependent systems.
c) Please also identify the expected service lives of the Pickering A units that were identified in the Business Case that was made for refurbishment of the two units. Given OPG's statement in this application referenced above, please also explain how that Business Case for Pickering A was made given that the assessment of the feasibility of refurbishing Pickering B began after those Pickering A units were refurbished and returned to service.

72. <u>Ref: ExhF2/Tab2/Sch3/ p. 6-10</u>
It notes on page 6 *"If OPG attempted to delay this incremental maintenance and inspection work effort until later, i.e., closer to 2014, the Pickering B Continued Operations option would no longer be available to OPG."* It also discusses the primary risks on page 9 and notes the two primary risks will be addressed by 2012 (i.e., CNSC approval, Fuel Channel Life Cycle

Management project). Page 2 of the attached Business Case also identifies the risk to be "medium" as opposed to "low" at this time. The forecast costs from 2010-2012 are over $106M (chart 2 on p. 10) and, if one of those risks is realized, the benefit to ratepayers would be $0.

a) Please explain, on what basis, OPG has reached the conclusion the option would no longer be available.
b) Please also explain why it cannot be delayed until 2012 (i.e., next application) when the primary risks will have been addressed (i.e., risks are "low") and the Board can make a much more informed decision that could avoid further stranded costs associated with the nuclear facilities?

73. Ref: ExhF2/Tab2/Sch3/p.7, 9

Page 7 identifies other benefits such as the deferral of adding new transmission infrastructure in the Oshawa area that would be required with the shut-down of the Pickering stations. The IESO's Reliability Outlook: December 2009 (p.7) notes *"Pickering Generating Station: While two units at Pickering A were restarted and another two retired, the four Pickering B units will reach their end of service life within the next decade.* ***The IESO has identified transmission requirements in the area regardless of whether these units continue to operate or are shut down.****" (emphasis added).* Hydro One's current transmission rate application (EB-2010-0002) notes projects scheduled to be in-service within 2010 to 2011 include Cherrywood TS x Claireville TS and Hydro One is also proposing to add transformation capacity in the Oshawa area (Enfield TS - formally Oshawa Area TS) with an in-service date of 2014.

a) Please clarify the new transmission investment that OPG believes would be deferred due to Pickering Continued Operations.
b) On page 9, OPG discusses the risks in relation to the Pickering B Continued Operations initiative (i.e., the risk that a major component does not continue to meet fitness-for-service requirements, and the risk that OPG is unable to obtain CNSC approval of OPG's fitness-for-service assessment criteria for continued service life of the pressure tubes). It notes that OPG believes these risks are "manageable".
    i) Given the application also notes OPG will not have a high level of confidence regarding Continued Operations until late-2012, if one of the above risks is realized (i.e., Pickering cannot be continued) and the "required" new transmission is then also not available because it was deferred, where would this leave the supply situation in the Oshawa area?
    ii) Has OPG consulted with Hydro One Networks and the OPA, specifically, regarding the potential for this outcome (i.e., learning Pickering is not viable in 2013 or 2014 and no work done on the required new transmission due to the plan for Pickering)? If so, please elaborate.
c) In regard to the risk associated with CNSC approval, it notes in OPG's "2009 Annual Information Form" (page 13), under Pickering B Continued

Operations, that *"OPG anticipates the CNSC will complete its review of this report by mid-2010"*. As it is now mid-2010, has the CNSC completed its review? If not, when does OPG now anticipate it will be completed?

Issue 6.8
Are the 2011 and 2012 human resource related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate?

74. Ref: ExhF4/Tab3/Sch1
Please provide the aggregate compensation costs (inclusive of Total Wages, Benefits, Pension/OPEB) in a table over the 2007-2012 period broken down in terms of Nuclear, Hydroelectric, allocated Corporate and Total.

75. Ref: ExhF4/Tab3/Sch1
The evidence indicates that OPG's labour agreements will expire as follows:

Power Workers Union - March 31, 2012
Society of Energy Professionals - December 31, 2010.

Please complete the table below to capture the projected general salary and wage percent increases built in to the 2011 and 2012 test year OM&A budgets for Management, Power Workers Union and Society of Energy Professionals employees.

GENERAL SALARY & WAGE INCREASES						
	2011			2012		
	effective date	%	$ impact on OM&A	effective date	%	$ impact on OM&A
Management						
Power Workers						
Society						
Total						

76. Ref: ExhF4/Tab3/Sch1/p.7 (Chart 3)
Given the technical and knowledge requirements associated with the regulated operations, particularly nuclear, please explain why the base salary is highest in the Corporate group in relation to Society staff.

77. Ref: ExhF4/Tab3/Sch1/p.12 (Chart 7)
Given the description of the Annual Incentive Plan (AIP) award program, please explain why the AIP percentage (8%) is essentially the same for Administrative staff as Professional staff.

78. Ref: ExhF4/Tab3/Sch1/p.14
The application notes *"The budget for AIP is now based on corporate OPG performance and is further influenced by Fleet (Nuclear, Thermal, Hydro, and Corporate Functions) performance."* Does this mean incentive payment (i.e., AIP) amounts related to the Regulated Operations are influenced by performance of the Non-Regulated Operations?

79. Ref: ExhF4/Tab3/Sch1/p.14-15
Section 5.4.4 discusses "Authorization Bonuses and Leadership Allowances". It notes that employees in nuclear who are authorized by the CNSC and are required to maintain their licenses as a requirement of their job, receive a licence retention bonus of up to 28% of their base salary and that bonus is pensionable. It also notes Authorized Training Supervisors are eligible to receive 75% of those authorization bonuses. It further notes Management Group employees who are required to work shifts are paid a leadership allowance (in lieu of shift premiums) which provides an additional 30 – 40% of base salary, of which 10% is pensionable and if they are licensed, also receive the same license retention bonus. It also discusses such allowances and bonuses are necessary to attract and retain staff and to provide appropriate incentives to staff to keep their licences current.
   a) Please clarify if this means certain staff are eligible to receive a bonus of up to 68% of their base salary of which about half is pensionable.
   b) How many OPG staff are eligible for these bonuses?
   c) Are the bonuses of similar magnitude at the comparators discussed in the application such as Bruce Power? And are they pensionable to the same extent?

80. Ref: ExhF4/Tab3/Sch1/p.29 (Chart 10)
In section 6.2 (Benchmarking), it discusses the Agency Review Panel Report which recommended that OPG use a group of public sector and private sector organizations for comparing compensation levels. In response to this recommendation, 24 private and public sector organizations that are *"similar in asset size and organization scope as OPG"* were identified and Chart 10 provides a list of the Agency Review Panel Comparator Group. Staff notes that 50% of the public sector organizations used (6 of 12) are in the health care sector where governments have been attempting to get costs under control for many years.
   a) Why does OPG believe the use of a disproportionate share of organizations in the health care sector is appropriate to assess whether compensation levels are appropriate at an electric utility?

b) Does OPG believe this is consistent with the intent of the Agency Review Panel Report?
c) What actions has OPG undertaken to comply with the Agency Review Panel Report recommendations?

81. Ref: ExhF4/Tab3/Sch1/p.30-31
It notes on page 30 that OPG participates in a study of the Power Services Industry conducted by Towers Perrin and Chart 11 provides a range of positions throughout OPG and compares them to the 75^{th} percentile of market data. It notes *"This chart indicates that while some positions are paid above market and some are below market, OPG is slightly above the 75^{th} percentile of market on an overall basis".* Based on chart 11 (p.31), about 64% of OPG's positions are above the 75^{th} percentile and, on an overall basis, OPG is 6% above the 75^{th} percentile.
a) Why does OPG consider 6% to be "slightly" above?
b) How much lower would OPG's total compensation costs be if OPG's positions were at the 75^{th} percentile (i.e., not 6% above) on an overall basis?
c) Why has the Towers Perrin study used the 75^{th} percentile as a benchmark instead of the 50^{th} percentile?

82. Ref: ExhF4/Tab3/Sch1/p.32 (Chart 12)
Chart 12 provides a wage comparison between PWU positions in Bruce Power and OPG and it notes this information is contained in the collective agreement. The *ScottMadden HR Metrics Analysis* report (F5-T3-S1) included in the application identifies four "Areas for Improvement" on page 26 and two of those areas are:
- "*Benefits costs (including pension) make OPG's loading factor a bit higher than the median for peer group companies"*
- *"The existing compensation structure at OPG involves higher fixed costs for the company since a smaller percentage of compensation is variable based on company performance than peer group companies"*

Given the above, please provide the same comparison to Bruce Power based on total compensation (i.e., also including benefits and pension).

83. Ref: ExhF4/Tab3/Sch1/p.34 (Chart 13)
Chart 13 provides a comparison of the salaries for Society-represented employees at OPG, Hydro One, and Bruce Power LP. OPG and Bruce Power LP are similar in their pay ranges. It notes *"Comparing OPG to Hydro One both companies have roughly the same upper limits for all salary bands. Hydro One differs from OPG on its salary bands for senior salary bands (MP6 and MP5). Hydro One's bands are broader in that they have lower starting salaries than OPG for these salary bands."* MP2 through MP4 appear to be quite comparable to Hydro One. Please explain why minimum

bands for MP5 and MP6 at OPG exceed those for Hydro One by about $20,000.

84. Ref: ExhF4/Tab3/Sch1/p.16
Please provide copies of:
a) the most recent actuarial valuation in relation to the pension plan.
b) the most recent actuarial valuation in relation to post-employment benefits.

85. Ref: ExhF4/Tab3/Sch1
Benefit costs are identified but it is not clear how accounting estimates of future benefits are included in total current compensation. Please provide a schedule that shows how the forecast pension and post-employment benefit expense is allocated to compensation expense categories for historic, bridge and test periods. Please separate the historic, bridge, and test period cash benefits expense from the non-cash or accounting estimates by year, and provide totals.

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?

86. Ref: ExhF3/Tab1/Sch1
The application notes that about 70% of Corporate Costs are allocated to the regulated businesses and therefore about 70% of those costs are recovered through the regulated payment amounts. The Nuclear Phase 1 Benchmarking Report (Ex. F5-T1-S1) identifies one of the key drivers affecting OPG Nuclear's Total Generating Cost performance gap to be Corporate Costs. A business plan has been provided for the Nuclear and Hydroelectric businesses. Please provide the business plan relating to Corporate Costs.

87. Ref: ExhF3/Tab1/Sch1/Table 1
In the application, certain Corporate functions have been benchmarked such as Finance and Human Resources. In terms of OM&A costs, those two functions have either declined or remained relatively stable over the five year period in the application. In contrast, Corporate Affairs has increased 27% and Corporate Centre has increased 46% over the five year period.
a) Given OPG was preparing an OEB application in 2007 (i.e., also a factor at that time), please explain why these two areas have increased to such a degree.

b) In addition, has OPG ever undertaken to benchmark its aggregate Corporate Costs against other utilities given the Nuclear Phase 1 Benchmarking Report (Ex. F5-T1-S1) identifies one of the key drivers affecting OPG Nuclear's Total Generating Cost performance gap to be Corporate Costs? If so, please provide the results. If not, please explain why.

88. <u>Ref: ExhF4/Tab4/Sch1/p.4</u>
The application discusses a significant increase in IESO Non-Energy Charges, primarily due to the substantial increase in the Global Adjustment.

a) For the period 2007-2012, please provide a table summarizing IESO Non-Energy costs and kWh consumed (used to calculate the IESO Non-Energy costs) for each OPG facility.
b) Please explain how OPG is charged for the IESO Non-Energy charges when OPG provides energy to its own facilities (i.e., rather than consuming from the market). For example, when the OPG facility is producing more than it is consuming.
c) Given the Global Adjustment is not expected to decline going forward, has OPG undertaken initiatives to reduce its energy consumption (i.e., energy efficiency initiatives)? If so, please explain those initiatives and the associated results. If not, please explain why.

89. <u>Ref: ExhF4/Tab4/Sch2/p.4</u>
Nuclear Insurance costs almost double in 2012 relative to 2009. The application notes that it's due to an increase in federal government requirements for liability. Please explain those federal government requirements.

90. <u>Ref: ExhF5/Tab2/Sch1</u>

a) Please populate the following table (see attached)
b) Please prepare and populate a similar table for 2011
c) Please prepare and populated a similar table for 2012

Centralized Support and Adminstrative Costs

($ in thousands)	2010 Budget	Amount allocated and/or assigned and /or distributed					
		Unregulated Business Units		Regulated Hydroelectric		Regulated Nuclear	
		%	$	%	$	%	$
Human Resources Group	$ 54,000						
Executive Office	$ 5,563						
Law	$ 11,094						
Corporate Secretariat	$ 4,280						
COO	$ 5,281						
	$ 26,218						
Finance Grouo							
Controllership	$ 47,940						
Treasury	$ 3,457						
Risk Services	$ 3,602						
Internal Audit	$ 4,132						
CFO Office	$ 1,285						
	$ 60,416						
Coporate Affairs Group							
Sustainable Development	$ 2,972						
E8	$ 750						
Emergency Preparedness	$ 3,468						
Public Affairs	$ 16,615						
Regulatory Affairs / Strategic Planning	$ 8,739						
SVP Office	$ 1,291						
	$ 33,835						
Business Services & IT	$163,600						
Energy Markets Group	$ 22,000						
Real Estate							
Real Estate Services	$ 13,789						
Business Services	$ 18,017						
Facilities Services	$ 9,137						
Fleet Services	$ 306						
Vice President's Office	$ 417						
	$ 41,666						
Total Corporate Support & Administration	**$401,735**						
Centrally Held Costs							
Pension/OPEB							
OPG wide Insurance							
Nuclear Insurance							
Performance Incentives							
IESO Non Energy Charge							
SR&ED Tax Credits							
Other							
	$260,849						
Hydroelectric Common Support Costs							
Hydroelectric Buiness Unit	$ 32,352						
Ottawa-St. Lawrence Support	$ 5,937						
	$ 38,289						
Grand Total	**$700,873**						

91. Ref: ExhA2/Tab2/Sch1/Atachment 1/p. 10
Please reconcile the “Centrally Held Costs” amounts for 2009, 2010, 2011, 2012 shown in the table on page 10 with the amounts shown in Exhibit F4/Tab4/sch1/Table 1.

92. Ref: ExhF3/Tab1/Sch1/p1 ln25
OPG notes that cost allocation methodology was “….independently reviewed by Black & Veatch Corporation, and approved during EB-2007-0905.”

Please point to the specific reference from the EB-2007-0905 Decision which is the basis of OPG’s statement that the cost allocation methodology model was approved during EB-2007-0905.

93. Ref: ExhF3/Tab1/Sch1/p25
OPG states that the review of documentation, as recommended by Black and Veatch in their 2009 Report, including desktop procedures for business users will be prepared and finalized in 2010.

Is the review completed yet? If not, by when will it be completed?

94. Ref: ExhF3/Tab1/Sch 1 p22
OPG indicates that it expects to save about $100M by the end of the five year extension included in the new agreement with New Horizon System Solutions.
a) Please identify by year, starting with 2009, the annual projected savings.
b) Are the savings reflected in the proposed budgets for 2011 and 2012?
c) What is the annual dollar value of the newly agreed to contract?

95. Ref: ExhF3/Tab1Sch1/p33 ln 23
OPG states that the price for base services is further reduced, leading to an annual reduction of over $16M by 2015 for the same service level and volumes. Is this $16M in addition to the $100M savings referred to in the question above?

96. Ref: ExhF3/Tab1/Sch2/table 2
Table 2 shows $269.1M and $267.4M as the budget for Corporate Support and Administrative Costs allocated to Nuclear for 2008 and 2009 respectively. In the 2008-09 proceeding OPG showed $263.7 and $262.4 as the proposed budget for these two years.

Please explain the discrepancy.

97. Ref: ExhF5/Tab2/Sch1
Please confirm whether or not the 2009 Black & Veatch (B&V) report, “Review of Centralized Support and Administrative Cost Allocation

Methodology" and conclusions, includes Hydroelectric Common costs. And if so, are OPG's proposed allocations between regulated and unregulated Hydroelectric business units consistent with the report?

98. Ref: ExhF5/Tab2/Sch1 p8
The B&V report makes a distinction between services that are integral and those that are administrative. "….at OPG the majority of the costs of the CSA functions and services are integral to running the Business Segments (e.g., engineering and human resources). For many other companies, shared functions and services are not integral to running the business but are primarily administrative (e.g., financial accounting and invoice processing). Therefore, Service Providers and Service Recipients (Regulated Hydroelectric and Nuclear businesses) must work together closely to ensure the needs of the Service Recipients are met, the level of service is appropriate and the costs are correctly assigned or allocated."

Please elaborate as to whether this distinction materially influences or impacts the allocation "outcome" or "quantum" of methodology (i.e. would the actual amount that is charged to the regulated business differ just because the service is deemed or viewed as "administrative" rather than "integral"?

99. Ref: ExhF5/Tab2/Sch1 p8
The B&V report states that…."Black & Veatch used as a starting point a questionnaire used by Meyers, Norris Penny LLP, an independent consultant engaged to review the corporate service charges between the parent company, Enbridge Inc. and its subsidiary, Enbridge Gas Distribution ("Enbridge") to support Enbridge's cost allocation method. Black & Veatch adapted the Enbridge questionnaire to reflect: a) the different corporate arrangement (i.e. OPG's costs are allocated within a single corporate entity, Enbridge's are allocated from a separate affiliated entity to operating subsidiaries in multiple provinces and countries), b) the unique aspects of OPG's business and c) its shared cost methodology."

Please provide a representative example of the modification described on page 8. Please explain whether a "different corporate arrangement" would materially impact the results i.e. does it make a difference whether there is a single incorporated entity or an affiliated relationship when it comes to quantifying the corporate services that should be recovered in rates?

100. Ref: ExhF5/Tab2/Sch1 p8
Please list those services (collectively included in "Centralized Support and Administrative Costs") that the regulated business units determined are not necessary to their operations and so all the costs remain with the unregulated business units.

101. Ref: ExhF3/Tab1/Sch2
Please complete the table below and explain any variances that are in excess of either 10% or $1M, between actual and Board approved for each of 2008 and 2009.

Corporate Support & Administrative Groups						
	(a)	(b)		(c)	(d)	
(in millions)	2008 Board Approved	2008 Actual	variance (b)-(a)	2009 Board Approved	2009 Actual	variance (d) - (c)
Business Service and IT		$ 207.4			$ 207.2	
Finance		$ 58.1			$ 60.5	
Human Resource		$ 53.2			$ 53.8	
Corporate Affairs		$ 49.4			$ 47.1	
Corporate Centre		$ 21.5			$ 19.3	
Total		$ 389.6			$ 387.9	

Corporate Support & Administrative Groups Allocated to Hydroelectric						
	(a)	(b)		(c)	(d)	
(in millions)	2008 Board Approved	2008 Actual	variance (b)-(a)	2009 Board Approved	2009 Actual	variance (d) - (c)
Business Service and IT		$ 10.0			$ 10.6	
Finance		$ 4.9			$ 4.3	
Human Resource		$ 2.3			$ 2.3	
Corporate Affairs		$ 7.3			$ 6.5	
Corporate Centre		$ 1.8			$ 1.2	
Total		$ 26.3			$ 24.9	

Corporate Support & Administrative Groups Allocated to Nuclear						
	(a)	(b)		(c)	(d)	
(in millions)	2008 Board Approved	2008 Actual	variance (b)-(a)	2009 Board Approved	2009 Actual	variance (d) - (c)
Business Service and IT		$ 137.9			$ 137.1	
Finance		$ 32.1			$ 35.3	
Human Resource		$ 36.5			$ 36.3	
Corporate Affairs		$ 18.2			$ 18.2	
Corporate Centre		$ 12.9			$ 12.9	
Total		$ 237.6			$ 239.8	

102. Ref: ExhF4/Tab1/Sch1
Please complete the table below and explain any variances that are in excess of either 10% or $1M, between actual and Board approved for each of 2008 and 2009.

Centrally Held Costs						
	(a)	(b)		(c)	(d)	
(in millions)	2008 Board Approved	2008 Actual	variance (b)-(a)	2008 Board Approved	2009 Actual	variance (d) - (c)
Pension/OPEB related costs		$ 116.7			-$ 27.7	
OPG-wide Insurance		$ 16.3			$ 17.0	
Nuclear Insurance		$ 7.8			$ 7.3	
Performance Incentives		$ 45.3			$ 40.3	
IESO Non-Energy charges		$ 22.4			$ 75.5	
SR&ED Tax Credits		-$ 30.0			-$ 22.1	
Other		25.00			31.4	
Total		$ 203.5			$ 121.7	

Centrally Held Costs Allocated to Hydroelectric						
	(a)	(b)		(c)	(d)	
(in millions)	2008 Board Approved	2008 Actual	variance (b)-(a)	2008 Board Approved	2009 Actual	variance (d) - (c)
Pension/OPEB related costs		$ 4.2			-$ 1.0	
OPG-wide Insurance		$ 2.8			$ 2.9	
Nuclear Insurance		$ -			$ -	
Performance Incentives		$ 2.7			$ 1.9	
IESO Non-Energy charges		$ 4.3			$ 12.7	
SR&ED Tax Credits		-$ 0.1			-$ 0.3	
Other		$ 0.7			$ 1.2	
Total		$ 14.6			$ 17.4	

Centrally Held Costs Allocated to Nuclear						
	(a)	(b)		(c)	(d)	
(in millions)	2008 Board Approved	2008 Actual	variance (b)-(a)	2008 Board Approved	2009 Actual	variance (d) - (c)
Pension/OPEB related costs		$ 87.4			-$ 20.5	
OPG-wide Insurance		$ 3.2			$ 3.3	
Nuclear Insurance		$ 7.8			$ 7.3	
Performance Incentives		$ 31.3			$ 28.0	
IESO Non-Energy charges		$ 10.6			$ 36.1	
SR&ED Tax Credits		-$ 28.2			-$ 19.0	
Other		20.10			23.60	
Total		$ 132.2			$ 58.8	

103. <u>Ref: Exh/F3/Tab1/Sch 2</u>
The Board in its 2008-2009 Decision did not make any adjustments to the Regulatory Affairs budget on the clear expectation that OPG would be shortly filing another application.

In that OPG decided to defer the filing of the Payment Amounts application to 2010, the evidence indicates that inter-period variances in corporate support costs are in part due to Regulatory Affairs related activity.

Please complete the table below (feel free to add, as appropriate, to the Item listing).

Regulatory Affairs										
(in thousands)		(a)	(b)		(c)	(d)		(e)	(f)	(g)
ITEM	2007 Actual	2008 Board Approved	2008 Actual	variance (b)-(a)	2009 Board Approved	2009 Actual	variance (d) - (c)	2010 Budget	2011 Plan	2012 Plan
Recurring Costs (eg sal/wages, operating expenses)										
EB-2007-0905										
legal costs										
expert witnesses/consultants										
intervenor										
section 30										
other										
total										
EB-2010-0008										
legal costs										
expert witnesses/consultants										
intervenor										
section 30										
other										
total										
Other Regulatory Proceedings										
legal costs										
expert witnesses/consultants										
intervenor										
section 30										
other										
total										
OEB Annual Assessment										
Other										
total										
Grand total										

Issue 6.10
Is OPG responding appropriately to the findings in the Human Resources and Finance Benchmarking Reports?

104. <u>Ref: ExhF3/Tab1/Sch1/p.21</u>
The discussion of HR Benchmarking (ScottMadden HR Metrics Analysis Report) notes OPG is better than the peer group median on spending per HR FTE. This benchmarking was based on 2008 information. Based on the application, it appears this is the year (2008) that the number of OPG FTEs peaked. The Navigant Study, which was a major focus of the last proceeding, identified that OPG had about 12% more staff than the benchmark in 2006 as referenced on page 27 of the Board's Decision (EB-2007-0905). Please confirm whether this is a significant contributor towards a positive result in terms of spending per HR FTE. Please provide the 2009 spending per HR FTE.

105. Ref: ExhF5/Tab3/Sch1/p.9-10

Under General Observations, it notes the following:

- *"OPG has invested in quality HR technologies but they are not all being fully utilized"*
- *"HR is not forcing line management to use the systems as designed with manager self-service"*
- *"There is no focused HR technology function in HR which impacts the ability to develop an effective HR technology strategy for the company"*
- *"The hiring process is fairly manual despite the investment in Taleo; some operating units are using automated workflow while others are using paper-based approval processes"*

a) Does OPG plan to take any actions to address these issues?
b) Does OPG have similar problems in other segments of the organization?
c) How can the Board have confidence that proposed/future IT investments will be effectively utilized given ScottMadden's observations above?
d) Is the cost of the HR technologies in payment amounts? If yes, why should the cost be recovered in payment amounts if the technologies are not used?

106. Ref: ExhF5/Tab3/Sch1/p.12

In regard to "External Hire Rate", under "Observations" it notes *"OPG's External Hire Rate has decreased by 35.3% over the last five years and shows the lowest value in 2008. The very large utilities' median External Hire Rate has increased by 65.4% over the last five years".* The slide discusses factors such as high unionization levels at OPG. However, as discussed in the application, that has always been the case at OPG. The Nuclear Benchmarking report discusses the need for cultural change to make some of the changes needed to achieve the targets. Did ScottMadden identify that hiring more staff externally could assist in the cultural changes necessary?

107. Ref: ExhF5/Tab3/Sch1/p.20

On page 20, it discusses Loading Factor which is *Total Comp + Benefit Costs/Regular Labor Costs (Base Pay)*. It notes OPG's Loading Factor has increased by 1.9% over the last five years but has decreased by 2.4% since 2007 while the Median Loading Factor for the very large company size group has decreased by 0.7% over the last five years and decreased by 11.2% since 2007. This leaves OPG above the median. The recommendation is to target median peer group performance for loading factor. Does OPG plan to target the median? If so, how does OPG plan to achieve the median? If not, please explain why.

Hackett Group Finance Benchmark Progress Report

108. Ref: ExhF5/Tab3/Sch2

On page 1, OPG provides an introduction to the Hackett Group Finance Benchmark Progress Report. However, there is no discussion in regard to if and/or how OPG plans to respond to the Observations and Findings of Hackett. For example, some of those Observations and Findings include:

- Page 14: For “FTEs per OPG’s Revenue after Rebates” Hackett found 237.4 (OPG) vs. 212.0 (Peer). Based on the chart, essentially all of the difference is in *Planning and Strategy* (83.9 vs 66.1)
- Page 21: For “Cost per Transaction”, from 2006 to 2008 OPG increased from $8.53 to $10.99 vs. $6.27 (2008) for the Peer group
- Page 31: For “Average Number of Formal Training Hours for Finance Employees”, OPG declined from 42 (2006) to 32 (2008), while the Peer group requires about half the training hours at 18 (2008)

What are OPG’s plans in terms of responding to these Observations and Findings, particularly “Cost per Transaction”?

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?

109. Ref: ExhF4/Tab1/Sch1/Attachment1

OPG as a publicly accountable enterprise for financial accounting reporting purposes will be required to adopt IFRS on January 1, 2011. Page 5 of the 2009 Depreciation Review Committee (DRC) Report states, “The move to International Financial Reporting Standards (IFRS) has added another dimension to the DRC review….The 2009 DRC review addressed IFRS requirements and concluded that the components’ lives within each asset class are consistent.”

a) The above statements appear to suggest that there would be no changes to the basis upon which OPG’s depreciation expenses would be determined when IFRS is adopted. Please confirm, and provide an explanation.
b) Please provide the documentation including the analysis reviewed in the DRC’s review of this matter.
c) Please provide the reasons why the DRC has concluded that the components’ lives within each asset class are consistent.

110. Ref: ExhF4/Tab1/Sch1/Attachment1/p8

Please identify the methodology used to select the regulated nuclear and hydroelectric asset classes for review in 2009?

111. Ref: ExhF4/Tab1/Sch1/Attachment1/p8
Comparative data was obtained from other utilities as part of the DRC's regulated hydroelectric asset class review. Please outline the methodology used for benchmarking against other utilities.

112. Ref: ExhF4/Tab1/Sch1/Attachment1/p5&11
Why was a benchmarking approach not included in the regulated nuclear asset classes review given that there are a number of other CANDU reactor stations worldwide?

113. Ref: ExhF4/Tab1/Sch1/Attachment1/p8
What were the reasons for concluding that there is no evidence to support changes to the service lives for any regulated hydroelectric asset classes except for outdoor structures?

114. Ref: ExhF4/Tab1/Sch1
When is DRC review of the service lives of asset classes for generating stations, including Bruce stations, expected to reach 100%?

115. Ref: ExhF4/Tab1/Sch1
Please provide a copy of the 2008 Regulated Depreciation Review Committee Report.

116. Ref: ExhF4/Tab1/Sch1/p3
OPG stated that since it does not operate the nuclear units that are on lease to Bruce Power, the assessment of end-of-life dates for depreciation purposes for the Bruce Nuclear Generating Stations were not based on life limiting components. Key factors used included: information relating to the operation and refurbishment of the Bruce stations made publicly available by Bruce Power, publicly available information on the Bruce stations' performance since their lease to Bruce Power and information on plans for the Bruce stations were inferred from publicly available reports from the IESO and the OPA.
a) Why is the station end-of-service life dates for depreciation purposes for the Bruce Nuclear Generating Stations not determined based on life-limiting components used for the regulated nuclear stations?
b) Please explain the methodology used to determine end-of-service life dates for the Bruce Nuclear Generating Stations.
c) Why is significant reliance placed on "publicly available" information in the assessment of the end-of-service dates for the Bruce Nuclear Generating Stations given the complexity of the nuclear technology?
d) If technical data is not available to conduct an engineering analysis on the life-limiting components for Bruce Nuclear Generating Stations, why does OPG as owners of the stations not have an agreement in place to obtain this information?

117. Ref: EB-2007-0905, Payment Amounts Order, Appendix A, Table 3
  a) Please confirm that the approved revenue requirement before mitigation (line 4) of $6,173.0 M does not include any income tax PILs.
  b) Please confirm that the revenue deficiency before mitigation (line 5) of $767.0 M does not include any income tax PILs.
  c) Please confirm that the mitigation prescribed by the Board: 22% of revenue deficiency (line 6) of $168.6 M, does not include any income tax PILs.
  d) Please provide a calculation of regulatory income taxes for 2008 (9 months) and 2009 (whole year) based on the total test period revenue requirement before mitigation of $6,173.0 M. From the referenced Table 3, the total revenue requirement amounts for 2008 were $2,638.5 (506.2 + 2,132.3) M and $3,534.5 (674.2 + 2,860.3) M for 2009.

118. Ref: ExhF4/Tab2/Sch1/Table 6 Actual Regulatory Income Taxes for 2008 and 2009
  a) Please describe how OPG ensured that the calculations shown on Table 6 for actual 2008 and 2009 are consistent with the methodology used by Ernst & Young in ExhF4/Tab2/Sch1/Attachment1 for the years 2005 through 2007. Please provide the supporting analysis and worksheets.
  b) Are the numbers shown in Table 6 derived from the actual tax returns for 2008 and 2009? If not, please provide alternate calculations that are derived from the actual tax returns.
  c) In Table 7 the actual regulatory taxable income for January 1 to March 31, 2008 is shown as a profit of $77.6 M. In Table 6 the regulatory taxable income for the whole year 2008 is only $116.9 M. By subtraction, the regulatory taxable income for the 9 months of the prior 2008 test period was only $39.3 M.

      i) Please explain the steps OPG took to ensure that the financial and accounting cut-off procedures for the first quarter 2008 were correct, and that the procedures resulted in the correct taxable income for the first quarter.
      ii) Why was the taxable income for the first quarter 2008 so large in comparison to the last 9 months of 2008?

119. Ref: ExhF4/Tab2/Sch1/Table 9 Benchmark Regulatory Income Taxes 2008 and 2009
  a) Please provide the supporting documents and calculations that show how the regulatory earnings before tax were derived for 9 months 2008 of $40.7 M, and $49.5 M for the whole year 2009.
  b) Please provide the Budget numbers for the first quarter 2008, and the whole year 2008 that support the numbers shown for the last 9 months of 2008 Budget. Please provide any explanations necessary to understand the process in creating these numbers.

c) Why is one column called 2008 Budget and the other 2009 Plan? What are the differences between a Budget and a Plan?
d) Are the 2008 Budget and 2009 Plan the same numbers that were used in EB-2007-0905 to derive the Payment Amounts Order? If not, please explain and provide all of the necessary reconciliations to explain the differences.
e) Regulatory earnings are shown as $257.3 M in the 2009 Actual numbers in Table 6. In Table 9 the 2009 Plan shows regulatory earnings of only $49.5 M. Please explain the significant difference between the Actual and the Plan regulatory earnings for 2009.

The following interrogatories relate to tax information filed in confidence, but the interrogatories themselves do not require confidential treatment. The interrogatory responses may require confidential treatment.

120. Ref: ExhF4/Tab2/Sch1/page 10 - Tax Losses Prior to April 1, 2008
a) Please provide the T2 tax return Schedule 4 "Corporation Loss Continuity and Application" for each year from 1999 to 2007 for each company for which OPG provided tax returns on a confidential basis.
b) Please provide a summary of the losses incurred and applied in each year from 1999 to 2008 from the Schedule 4 documents provided in (a) above.
c) Please provide a reconciliation of tax return to regulatory similar to that provided in Table 12 for 2007 for each of 2008 and 2009 tax returns.

121. Ref: ExhF4/Tab2/Sch1/Table 6 Actual Regulatory Income Taxes for 2008 and 2009
a) Please provide the tax returns for 2008 and 2009, including Schedule 1, Schedule 4 and Schedule 8, for all of the companies already included in the confidential tax returns filed with the Board in this proceeding.
b) In EB-2007-0905, L-1-117, Attachment 1, OPG provided the forecast 2008 and 2009 Schedule 8 amounts for UCC and CCA. Please provide a Schedule 8 for 2008 and 2009 based on the actual tax return numbers for the UCC and CCA for OPG's regulated operations.

122. Ref: ExhA2-1-1/ Attachment 2 - 2009 Audited Financial Statements – Page 128

In the 2009 audited financial statements under *Note 11 Income Taxes* on page 128 OPG provided the following information.

> "In the third quarter of 2006, OPG received a preliminary communication from the Provincial Tax Auditors ("Tax Auditors") with respect to their initial findings from their audit of OPG's 1999 taxation year. Many of the issues raised through the audit were unique to OPG and related either to start-up matters and positions taken on April 1, 1999 upon commencement of operations, or matters that were not adequately addressed through the *Electricity Act, 1998.* In 2008, all outstanding tax matters related to the

1999 tax audit were resolved. As a result, OPG reduced its income tax liability by $106 million.

The audit of OPG's taxation years subsequent to 1999 commenced in 2009. Should the ultimate outcome materially differ from OPG's recorded income tax liabilities, the Company's effective tax rate and its earnings could be affected positively or negatively in the period in which the matters are resolved."

a) Please provide all Notices of Assessment and Reassessment, as well as the related statements of adjustments for all tax years from 1999 through 2009.
b) Please provide the correspondence from the Provincial Tax Auditors that explains each of the 1999 tax matters and how these matters were resolved.
c) Does the resolution of these tax matters affect the calculation of the regulatory tax losses, the balance in the Tax Loss Variance account, benchmark tax expense and the balance in the Income and Other Taxes Variance account? If not, please explain. If yes, please provide updated evidence.
d) Did the reduction in the tax liability by $106 M increase the tax losses available for carry forward? Please explain and update the evidence as required.
e) To which tax years(s) does the $106 M relate?
f) How much of the $106 million relate to regulatory taxes? Please explain and provide the analysis.
g) Does the resolution of these tax matters affect the work that Ernst & Young performed in reconciling the tax returns to regulatory for 2005, 2006 and 2007 as already submitted in evidence? Please explain fully.
h) Are the PILs income tax proxies for 2011 and 2012 affected by the resolution of the tax matters? Please explain. Please update the evidence where required.

Other Revenues

Issue 7.1
Are the proposed test period regulated hydroelectric business revenues from ancillary services, segregated mode of operation and water transactions appropriate?

123. <u>Ref: ExhG1/Tab1/Sch1/p5-6/lines 18-31,1-16</u>
OPG discusses the impact of the DC intertie on SMO transactions and revenues. OPG proposes to use the actual SMO results from the second half of 2009 as an indicator of SMO revenues over the test period claiming that an average of the previous three years' revenues will overstate expected revenues for 2011-12.

a) What is the comparative economics of exports through the intertie compared to SMO transactions?
b) Are net unit revenues higher for intertie transactions compared to SMO transactions?

124. Ref: ExhG1/Tab1/Sch1/p7-8/lines 23-32, 1-4

OPG claims that a three year average of net water transactions as specified in the Decision with Reasons in EB-2007-0905 will overstate actual revenues for the test years. OPG claims that actual net revenues realized in 2009 will be more representative of the lower market prices expected in 2011-12.

a) Does OPG have a market price forecast for 2011 and 2012?
b) What economic factors does OPG expect to result in reduced market prices over the 2011-12 period?
c) OPG is expecting SBG conditions to result in reduced Ontario hydroelectric production. What is the potential and opportunity for OPG to increase water transactions with New York when SBG occurs in Ontario?
d) What is the minimum market price for water transactions to be profitable with New York?
e) Under SBG conditions, would any sale, at any price equal to or higher than the minimum, be preferable to spilling water?

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

125. Ref: ExhG2/Tab1/Sch1/p4-5

OPG proposes that revenues (and costs) associated with the future disposition of 673 tonnes of surplus heavy water be excluded from nuclear non-energy revenues as of March 1, 2011. OPG previously used net revenues from heavy water sales as an offset to the nuclear revenue requirement.

a) What is the origin of the surplus heavy water? Was it manufactured by OPG as a by-product of operating the regulated nuclear facilities, or, is it produced by a separate manufacturing process unrelated to the nuclear generating facilities?
b) OPG states that the direct costs of heavy water sales are excluded from the nuclear revenue requirement. Are the costs of storing heavy water (as opposed to the direct costs for heavy water sales) also excluded from the nuclear revenue requirement?
c) Are the heavy water storage facilities included in the regulated nuclear asset rate base?

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

126. Ref: ExhG2/Tab2/Sch1/p5/lines 19-26
News stories in early July 2010 state that Bruce Power is planning to ship radioactive steam generators from the Bruce NGS to Sweden for recycling.
    a) Has Bruce Power exercised its option to retrieve the low level radioactive waste (steam generators) from OPG?
    b) If this option has been exercised, what are the impacts on OPG's revenues and costs?

127. Ref: ExhG2/Tab1/Sch1/p8/lines 1-8
Supplemental rent for refurbished Bruce A units is significantly lower than for non-refurbished units.
    a) What is the expected impact of this different rent on OPG's net Bruce rent revenues in 2011 and 2012?
    b) How is this different supplemental rent calculated?
    c) What is the economic rationale for this difference in supplemental rents?

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?

128. Ref: ExhC2/Tab1/Sch1&2/Tables1-5
Please file policy positions or papers, or decisions from any energy regulatory or other bodies that were issued since the EB-2009-0905 decision with respect to the revenue requirement methodology for recovering nuclear liabilities?

129. Ref: ExhC2/Tab1/Sch1/p1
OPG has stated that for the 2011-2012 test years, it has proposed to maintain the revenue requirement treatment for nuclear liabilities approved by the Board in EB-2007-0905 for Pickering, Darlington and the Bruce facilities. However, OPG also states it is continuing to investigate the impacts of the Board approved revenue requirement treatment on its ability to fully recover its nuclear liabilities. Based on the results of this investigation, OPG may propose modifications to the existing treatment or an alternative treatment in a future application.
    a) Can OPG please provide the results of its continuing investigation into this matter to date?
    b) Is OPG planning to propose any modifications to the existing treatment or an alternative treatment in its next application?

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

130. Ref: ExhC2/Tab1/Sch2/p7-9&Tables2&5
The Board approved a GAAP approach to determine the net revenue impact for the nuclear liabilities associated with the Bruce facilities in the EB-2007-0905 decision. Please indicate how the revenue requirement derived for the Bruce in the test period (2001-2012) complied with GAAP and how the calculations for 2009 (historic year) tied to information in OPG's 2009 consolidated financial statements for Prescribed Assets.

131. Ref: ExhC2/Tab1/Sch1&2/Tables1-5
OPG as a publicly accountable enterprise for financial accounting reporting purposes will be required to adopt IFRS starting in 2011. OPG's revenue requirement request for nuclear liabilities (asset retirement obligations) for the test period (2011-2012) was determined under a Canadian GAAP basis of accounting.
    a) Will OPG's accounting for nuclear liabilities under IFRS effective on January 1, 2011 be different from Canadian GAAP?
    b) If no to a) above indicate why not.
    c) If yes to a) above,
        i) Specify the accounting changes and their impacts on treatment of nuclear liabilities in the test period
        ii) Identify any financial differences and resulting revenue requirement impacts arising from the adoption of IFRS accounting in the test period.

132. Ref: ExhC2/Tab1/Sch2/Table1
For the Darlington Refurbishment Adjustment of $497.4 M on line 2 and $475.2 M on line 23 for 2010, please provide the calculations including assumptions used in deriving these amounts.

133. Ref: ExhC2/Tab1/Sch2/Table2
For the Darlington Refurbishment Adjustment of $(204.4) M on line 3 and $(182.1) M on line 21 for 2010, please provide the calculations including assumptions used in deriving these amounts.

134. Ref: ExhC2/Tab1/Sch2/Table3&4
Please provide a descriptive summary of the Darlington Refurbishment Asset Retirement Obligation information contained in Tables 3 and 4 including how the derived amounts are linked to the calculations of the other tables of Schedule 2.

Design of Payment Amounts

Issue 9.1
Is the design of regulated hydroelectric and nuclear payment amounts appropriate?

135. Ref: ExhI1/Tab2/Sch1/Table 1
Ref: ExhI1/Tab3/Sch/Table 1
Separately, for each of Regulated Hydroelectric and Nuclear, please provide calculations showing the payment amounts separately for 2011 and 2012 per the following format:

Line No.	Description	2011		2012
1	Revenue Requirement ($M)			
2	Forecast Production (TWh)			
3	Payment Amount ($/MWh)			
	(line 1 / line 2)			

Issue 9.2
Is the hydroelectric incentive mechanism appropriate?

136. Ref: ExhE1/Tab2/Sch1/p3/lines 1-22
The incentive mechanism generated incremental market revenues of $23.2 million in 2009, compared to a forecast of $12 million – a 93% increase. OPG expects these revenues to fall to $13.3 M. in 2011 and $16.3 M. in 2012 because market price spreads are expected to decline relative to 2009. Actual hourly production at Niagara was 25% higher than forecast for 2009.
a) What market price spread is OPG assuming for 2011 and 2012?
b) What are the major factors in OPG's expectations that market price spreads will decline?
c) What is OPG's forecast of total hourly production for the Niagara complex for 2011 and 2012?
d) If the actual market price spread were to equal the 2009 spread ($14.8/MWh) in 2011 and 2012, what would be the total hourly volume required to result in $12 M of annual incremental market revenues?

Deferral and Variance Accounts

Issue 10.1
Is the nature or type of costs recorded in the deferral and variance accounts appropriate?

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

137. Ref: ExhH1/Tab1/Sch1/p1-3&Table 1
Ref: ExhA2-1-1 Attachment3/p20
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.

138. Ref: ExhH1/Tab1/Sch1/p3-4&Table3
Table 3 shows the balances for the Ancillary Services Net Revenue – Hydroelectric variance account. Please provide a breakdown of amounts for each ancillary service (e.g., operating reserve, reactive support/voltage control service, automatic generation control and black start capability) by year.

139. Ref: ExhH1/Tab1/Sch1/p4-5&Table13
OPG indicates that the results of a tax audit is a credit back to ratepayers for Investment Tax Credits based on expenditures that qualify as Scientific Research and Experimental Development ("SR&ED") activities, which were recorded in the Income and Other Taxes Variance Account. Were the SR&ED activities related to only regulated activities? If no, please explain the basis on which the investment tax credits were allocated to regulated and non-regulated activities.

140. Ref: ExhH1/Tab1/Sch1/p10&Table11
The derivation of Hydroelectric Deferral and Variance Over/Under Recovery Variance Account balance in Table 11 (lines 3&7) show Hydroelectric Actual Production of 19.3 TWh for 2010.
    a) Is the production of 19.3 TWh actual or forecast?
    b) Please indicate how the production amount shown in lines 3 and 7 was derived.

141. Ref: ExhH1/Tab1/Sch1/p14&Table10

Table 10 shows a summary of amounts recorded in the Bruce Lease Net Revenues Variance Account including Actual Production (TWh) at line 6 for the years 2008 to 2010.

a) Please provide the source of the actual production for Bruce facilities production shown in line 5.
b) Were the actual production amounts for Bruce facilities for the years 2008 to 2009 in line 5 verified by OPG's external auditors?

142. Ref: ExhH1/Tab1/Sch1/Table10a

Table 10a shows the details for the Bruce Lease Net Revenues Variance Account including amounts for (Earnings) Losses on Segregated Funds in line 8.

a) Please explain the basis upon which the overall amounts for the (Earnings) Losses on Segregated Funds are allocated between Bruce and OPG's prescribed nuclear facilities.
b) On what basis are the Earnings on Segregated Funds of $268.8 M for 2010 determined?
c) Given the market volatility for investments, why should any reliance be placed on the 2010 forecast of Earnings on Segregated Funds of $268.8 M?

143. Ref: ExhH1/Tab1/Sch1/Table10a

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?

144. Ref: ExhH1/Tab1/Sch1/ Pages 6-8 - Tax Loss Variance Account

The methodology established in EB-2007-0905 was to examine each year or part of a year in isolation in order to determine the period in which regulatory tax loss carry-forwards would be fully utilized.

According to the evidence shown in EB-2010-0008, ExhF4/Tab2/Sch1/Table6, OPG became taxable for regulatory purposes after 2008, some time around mid-year 2009. Therefore, there should be no gross-up for tax on tax related to any variances that arose with respect to the nine-month test period ended December 31, 2008.

Please explain why OPG made all adjustments subject to tax in the information provided at ExhH1/Tab1/Sch1/Page7.

145. Ref: ExhH1/Tab1/Sch1/ Table 4 - Tax Loss Variance Account
On line 6 of the upper table OPG has prorated the 21-month 2008-2009 test year revenue requirement reduction of $341.2 million to derive a 12-month amount for 2010 of $195 million.

a) Why has OPG assumed that there is a linear relationship between 2010 and the prior test period?
b) Why did OPG not use actual regulatory profit for 2008, 2009 and first quarter 2010 to forecast 2010 whole year?

Issue 10.3
Is the disposition methodology appropriate?

146. Ref: ExhH1/Tab2/Sch1
OPG proposes to amortize the balance of $412.8 M in the Tax Loss Variance Account over a 46-month period from March 1, 2011 to December 31, 2014 to lessen the impact on ratepayers. Why is OPG not proposing the same approach to lessen the impact on ratepayers regarding the disposition of another large balance of $315.3 M in the Bruce Lease Net Revenues Variance Account?

147. Ref: ExhH1/Tab2/Sch1
OPG is proposing to clear its deferral and variance account balances covering a three-year period from 2008 to 2010, which consists of audited account balances for 2008 and 2009 and forecasted balances for 2010.
a) Please provide a precedent(s) for rate-regulated entities whereby the balances of their deferral and variance accounts were approved on a forecast basis by the Board.
b) OPG has indicated that deviations between actual and projected values will be captured in the Hydroelectric and Nuclear Deferral and Variance Over/Under Recovery Variance Accounts for subsequent true-up. How is the added complexity of truing-up all account balances administratively simple and verifiable?

c) The Board generally requires deferral and variance account balances sought for disposition to be supported by audited financial statements. In Ontario Regulation 53/05, several account balances of OPG approved for disposition by the OEB were required to be based on "…the audited financial statements approved by the board of directors of Ontario Power Generation Inc." [5.1(1), 6(2) 5, 6(2)7] However, the 2010 account balances proposed for disposition were not supported by audited financial statements. In the absence of such independent audit assurance, why should the OEB approve the 2010 balances?

148. Ref: ExhH1/Tab2/Sch1
Please recast the information in ExhH1/Tab2/Sch1 and Tables 1 and 2 based on the clearing of the account balances as of December 31, 2009 and the proposed disposition rate riders for nuclear and hydroelectric.

Reporting and Record Keeping Requirements

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

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

Methodologies for Setting Payment Amounts

Issue 12.1
When would it be appropriate for the Board to establish incentive regulation, or other form of alternative rate regulation, for setting payment amounts?

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?

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