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BY E-MAIL

March 26, 2008

Board Secretary
Ontario Energy Board
2300 Yonge Street, Ste. 2701
Toronto ON M4P 1E4

Attention: Ms. Kirsten Walli, Board Secretary

Dear Ms. Walli:

Board Staff Interrogatories - Board File # EB-2007-0905
Payment Amounts for OPG's Prescribed Facilities

Please find attached Board Staff Interrogatories for the above proceeding.

Yours truly,

Original signed by

Allan Fogwill
Director - Applications

Encl.

EB-2007-0905

Ontario Power Generation Inc.

Payment Amounts for Prescribed Generating Facilities

2008 and 2009 Revenue Requirement

Board Staff Interrogatories

RATE BASE (Exhibit B)

1.1 Is the rate base appropriately determined in accordance with regulatory and accounting requirements? (B1T1S1) (B1T1S1)

1) Section 5.1 of Regulation 53/05[1] authorizes a deferral account that records for the period up to the effective date of the Board's first order the revenue requirement impact of any change in OPG's nuclear decommissioning liability arising from an approved reference plan. Section 6(2)7 lists four items that are to be included in the calculation of the revenue requirement impact. As at December 31, 2007, the deferral account balance was $131 million made up of the following items ($ millions).

Return on rate base	$ 75
Depreciation expense	54
Fuel expense	(5)
Capital tax	3
Interest expense	4
	$ 131

Page 11 of OPG's 2007 financial statements indicates that the "return on rate base" component of the deferral account is based on a five per cent return on equity.

a) Five per cent of the $1,386 million increase in the fixed asset and nuclear waste management liability, which was required by a new reference plan as at December 31, 2006, equals $69.3 million. Please provide the calculation of OPG's figure of $75 million.

[1] All section references going forward are to O. Reg. 53/05

b) Did any of the $1,386 million increase in the fixed asset and nuclear waste management liability relate to OPG's Bruce nuclear plant? If so, was that amount excluded from OPG's calculation of "rate base" for purposes of the section 5.1 deferral account?

c) Regulation 53/05 does not contain any provisions on how OPG is to calculate "rate base" for purposes of this deferral account. Are there any differences between the rate base calculation used for section 5.1 purposes and the rate base calculation proposed for the test years?

CAPITAL STRUCTURE AND COST OF CAPITAL (Exhibit C)

2.1 What is the appropriate capital structure for OPG's regulated business for the 2008 and 2009 test years? Should the same capital structure be used for both OPG's regulated hydroelectric and nuclear businesses? If not, what capital structure is appropriate for each business? (C1/T1/S1, C1/T2/S1, C2/T1/S1)

2) Footnote 95 (p. 85) references Standard & Poor's Key Credit Factors: Assessing US Vertically Integrated Utilities' Business Risk Drivers. Please provide a copy of this document.

2.2 What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business? (C1/T1/S1, C1/T2/S1, C2/T1/S1)

3) With respect to its prescribed assets, OPG is requesting an ROE of 10.5%. Revenues associated with the incentive mechanism are associated with production from the prescribed hydroelectric facilities. While the application notes that OPG's current ROE in relation to its prescribed assets is 5%, footnote #10 in Table 1 of C1-T2-S1 appears to clarify that OPG earned an "incremental" ROE of 2.21% in 2006 on output from its prescribed hydroelectric assets over the 1900 MWh threshold for a total ROE of 7.21%. Is that interpretation of Table 1 correct? Does OPG expect the incremental ROE to occur under its proposed incentive mechanism during the test years? If so, what is the anticipated value of the incremental ROE for the test years?

4) Ms. McShane notes on page 92: "In order to estimate the common equity ratio for OPG that would permit the application of the benchmark return to its regulated operations, I selected a sample of vertically integrated utility companies

with significant generation operations in order to estimate the incremental cost of equity for regulated generation company like OPG" and concludes at page 95: "the incremental equity returns at a 45% equity ratio are at the upper end of the range, i.e. in the range of approximately 1.25% to 1.50%." Is the "benchmark" ROE based on utilities that are primarily "wires"? Were the vertically integrated utilities listed in Schedule 28 used to establish a premium of 1.50%? If not, what premium was added in relation to Schedule 28? What is the average cost of capital for the utilities in Schedule 28?

5) Ms. McShane relied upon U.S. utilities in arriving at her conclusion concerning cost of capital. Given that OPG's regulated operations consisting of 9,938 MW of generation (6,606 MW of nuclear and 3,332 MW of hydroelectric), please advise why the following were considered comparable utilities.

a) Allete – A total of 1,761 megawatts of generation, of which 74% steam-electric stations, 20% purchased, 6% derived from hydroelectric, and 0% from nuclear. It also appears to be involved in the real estate business.

b) Black Hills – A total of 1,000 MW of power generation capacity with 0% nuclear and 0% hydroelectric.

c) Empire District – A total of 1,255 MW with 0% nuclear.

d) IDACORP – "IDACORP, Inc. is an energy-focused holding company… an investor in affordable housing and other real estate investments, and Ida-West Energy Company (Ida-West), an operator of small hydroelectric generation projects…Idaho Power is a combination hydro-thermal utility with 17 hydroelectric developments, two natural gas-fired plants, one diesel-powered generator, and part ownership in three coal-fired generating plants." (Copied from the IDACORP website).

6) On page 45-46, Ms. McShane's report states that a financing flexibility allowance of 50 basis points needs to be added to the "bare-bones" ROE:

"The financing flexibility allowance is an integral part of the cost of capital as well as a required element of the concept of a fair return…In the absence of an adjustment for financial flexibility, the application of a "bare-bones" cost of equity to the book value of equity, if earned, in theory, limits the market value of equity to its book value. The fairness principle recognizes the ability of competitive firms to maintain the real value of their assets in excess of book value and thus would not preclude utilities from achieving a degree of financial integrity that would be anticipated under competition… As a government-owned utility, OPG has not raised equity capital in the public equity markets; therefore it does not incur out-of-pocket equity financing and market pressure costs … The addition of an allowance for financing flexibility of 50 basis points to the "bare-bones" return on equity estimate of 9.25-10.25% derived from both the DCF and equity risk premium tests respectively, results in an estimate of the fair return on equity of 9.75%-10.75%."

Given that, as a government-owned utility, OPG has not raised equity capital in the public equity markets and does not incur financing and market pressure costs, and given that the fairness principle is cited in relation to competitive firms, why would it be appropriate for the Board to approve a financing flexibility allowance for OPG?

7) Ms. McShane noted the following on page 54:

"The proper application of the stand-alone principle to the determination of the deemed capital structure (and return on equity) for OPG's regulated operations ignores the happenstance of ownership; the capital structure should reflect the business risks of OPG's regulated operations irrespective of the identity of the shareholder. This approach ensures that the shareholder is properly compensated for the total risk borne."

The Government Backgrounder (23 February, 2005) stated the following:

"The Ontario government has established prices for electricity produced by Ontario Power Generation (OPG) effective April 1, 2005. These prices are designed to:

a) Better reflect the true cost of producing electricity

b) Ensure a reliable, sustainable and diverse supply of power in Ontario

c) Protect Ontario's medium and large businesses by ensuring rates are stable and competitive

d) Provide an incentive for OPG to contain costs and to maximize efficiencies

e) Allow OPG to better service its debt while earning a rate of return that balances the needs of customers and ensures a fair return"

Based on the above, Board staff has the following questions:

a) The Government/shareholder established the current ROE of 5% and a capital structure of 45% equity and 55% debt. In forming her opinion concerning the current cost of capital, did Ms. McShane consider any of the above listed policy objectives, initially considered by the Government/shareholder? If not, why not? If the underlying purpose of an ROE is to compensate shareholders properly, of what significance is the fact that it was the Government/shareholder which set the ROE?

b) In the Government Backgrounder, the rate of return set was described as balancing the needs of the customers and ensuring a 'fair return'. Please describe the events which have occurred since April 2005, and/or those events which are anticipated, which cause the return to no longer be fair.

c) Standard & Poor's stated: "The government's demonstrated willingness to financially assist the publicly owned generator is reflected in a two-notch rating enhancement to the stand-alone long-term corporate credit rating on OPG." (A2/T3/S1/Attach. C) Dominion Bond Rating Service stated about the ownership of OPG: "The implied support of the Province provides significant support to OPG's credit ratings." (A2/T3/S1/Attach. A)

Ms. McShane's report takes the position that "the happenstance of ownership" should be ignored.

As the primary purposes of an appropriate cost of capital is to permit the regulated entity to maintain an investment grade credit rating, and as credit rating agencies do <u>consider</u> ownership to be a significant factor when assigning a rating, please explain why the ownership of OPG is not a factor to be considered when determining the appropriate cost of capital.

8) Ms. McShane's analysis underlying the cost of capital recommendations appears to be premised on the treatment of OPG as a typical generation utility, with the most appropriate benchmark or peer in Canada identified as TransAlta (page 88). Within this context, Ms. McShane appears to imply that if the Board approved the application as is, OPG would receive an "A" rating from the credit rating agencies.

a) If OPG is a typical utility, with ownership an attribute that is not relevant, can Ms. McShane please explain why the rating of OPG by DBRS (A-low) has not changed at all since 2003 while OPG's ROE has increased from negative 0.6% to positive 13.5% and cash flow/total gross debt has improved from negative 3.4% to 26.6%?

b) Also, given that DBRS has not changed its rating following this significant improvement in OPG's financial position and credit metrics, can Ms. McShane please elaborate on why the approval of a change in ROE from 5% to 10.5% to its prescribed assets would have a credit rating impact?

c) The McShane report finds TransAlta Corp. to be the most appropriate Canadian benchmark. Given that TransAlta Corp has a generation mix of 58% coal-fired, 29% gas, 9% hydro, 4% wind and no nuclear, why is it considered to be the closest peer for OPG's regulated operations? What impact would the difference between the number and scope of deferral and variance accounts between the two have on the comparison?

d) While the McShane report discusses the risks associated with nuclear generation (page 55-78), it does not mention risks OPG's base load hydro and nuclear generation avoid which other generators, including TransAlta, face. For example, one of the major challenges fossil generators (e.g., coal and natural gas) face are the existing and future environmental compliance costs associated with acid rain, smog and climate change. Morningstar's title of a recent (November 2007) credit rating report on TransAlta Corp states "Industry economics and the risk of emissions legislation challenge TransAlta" suggests that this risk is significant. Please advise if the absence of this risk was taken into account in the relative business risk analysis. If not, why not?

9) Page 71 of Ms. McShane's report states: "OPG faces significant risk of lost revenues due to longer and more frequent than anticipated outages and higher than expected costs to maintain and repair existing nuclear facilities. Every one TWh shortfall in production at a variable payment of $40 per MWh … is equal to an approximately $40 million reduction in revenues ... A 2.5 TWh production shortfall translates into a reduction in ROE of approximately 1.5 percentage points." In the Ontario market, lost nuclear output tends to be replaced by production from another facility owned by OPG. This understanding appears to be confirmed by the President and CEO of OPG in a May 18, 2007 press release:

'The flexibility of OPG's diversified portfolio of generating assets was clearly demonstrated in the first quarter as our fossil stations increased their production to offset lower nuclear production …." said President and CEO Jim Hankinson'.

What is the adjustment to risk that would result if it was assumed the outages losses were replaced by production from other OPG assets?

10) On page 39 of her report, Ms. McShane concludes "an expected equity risk premium estimate for a benchmark Canadian utility in the approximate range of 5.0-5.5%". Prior to that, the report notes the achieved utility equity risk premiums were 4.1-4.8% for Canadian electric and gas utilities from 1956-2006. It is unclear how the substantial difference relative to historic equity risk premiums was arrived at. Please clarify.

11) In arriving at an ROE of 10.5%, Ms. McShane notes on page 50: "I have given primary weight to the cost of attracting capital, as measured by both the equity risk premium and DCF tests". The report further notes "the results of the comparable earnings test are also entitled to significant weight". Please quantify "significant weight" in terms of the 12.5% comparable earnings test results.

12) Ms. McShane notes on page 59 that there are other generators whose marginal costs are similarly low, which can result in OPG's regulated facilities not being dispatched and concludes "That risk will rise as additional low marginal cost generation" becomes available. Is this referring to the natural gas generators that have recently contracted with the OPA as being lower marginal cost generation relative to OPG's nuclear and hydro facilities? If so, please identify some examples that would pose dispatch risk for OPG's nuclear and hydro facilities. If not, please clarify the reference to "additional" generation.

2.3 Is it appropriate to establish a formula for an adjustment mechanism? Is the formula proposed appropriate? (C1/T1/S1, C1/T2/S1, C2/T1/S1)

2.4 Are OPG's proposed costs for its long-term and short-term debt components of its capital structure appropriate? (C1/T1/S2, C1/T1/S3, C1/T2/S2, C1/T2/S3)

2.5 What are the implications of the deferral and variance accounts on OPG's financial risk? How should the implications be considered when determining the appropriate return on equity?

13) It appears that Ms. McShane, in arriving at her cost of capital recommendations, has assumed that all of the nine variance and deferral accounts requested by OPG will be approved and also concluded that approval of those accounts does not result in a reduction of risk and therefore no reduction in the cost of capital. Specifically, Ms. McShane notes on page 62, "The use of deferral and variance accounts … does not change the utility's fundamental risks." Please explain why the use of these deferral and variance accounts does not change the risk to OPG.

CAPITAL PROJECTS (Exhibit D)

3.1 Are the costs and financial commitments OPG is seeking to recover under section 6(2)4 incurred to increase the output of, refurbish or add operating capacity to a prescribed facility? (D1/T1/S1 and D2/T1/S1)

3.2 If so, are the costs and financial commitments within project budgets approved for that purpose by the board of directors of OPG?

Ref: D1 Tab 1 Schedule 1 page 3

14) The Application refers to "slower than expected progress" with the Niagara Tunnel project in 2006. In note 15 to the 2007 audited financial statements the difficulties are described as slower than expected progress by the tunnel boring machine through a fractured rock formation, resulting in 'considerable uncertainty' with respect to the construction schedule and a delay in the in-service date. The note advises that the uncertainty will remain until the tunnel boring machine advances sufficiently to establish a consistent tunneling performance; that there is a 'potential that the schedule delay could impact the project cost'; and that the contractor is investigating alternatives, including the re-alignment of the tunnel, to mitigate the impact of the schedule delay.

a) Has a consistent tunneling performance been established? If not, when does OPG anticipate that will occur?

b) What are the alternatives that are being explored by the contractor, and to what extent will they mitigate the impact of the schedule delay? What is the impact of these alternatives on the project costs and costs associated with other related projects that would be incurred by OPG in the test period?

Ref: D2 Tab 1 Schedule 1 chart 1and table 1

15) Please confirm that the entries for P2/P3 Isolation Project on line 4 in chart 1 includes operating costs as well as capital in contrast to table 1 which only includes capital.

Ref: D1 Tab1 Schedule 1 Attachment F page 4

16) The Application refers to the end of the "25 Hz market" in 2009 which is currently served by two units at the Sir Adam Beck 1 (SAB 1) station. What are OPG's assumptions for the use of these 25Hz units after April 1, 2009?

3.3 If the costs and financial commitments are not within project budgets approved by the board of directors of OPG, are the costs and financial commitments prudent?

3.4 In section 6(2) 4, what is a "firm financial commitment" and a "pre-engineering commitment"?

3.5 Is the additional capital spending (beyond the levels being recovered under section 6(2)4)) appropriate?

3.6 Will OPG's accounting policies result in capitalization of an appropriate amount of costs incurred in 2008 and 2009 with respect to the construction or acquisition of capital assets? (A2T2S1)

17) The application notes that, prior to beginning work on a project, approval is required for the release of funds to undertake the work and the documentation for seeking approval consists of a business cases summary (BCS). Considerations during the review and assessment of the proposal include looking at the quality of the project cost estimates and proposals for measurement and verification of the claimed project benefits. Those considerations do not appear to include assessing whether the estimated benefits exceed the costs. Please explain if such a cost-benefit assessment is carried out, particularly for "discretionary investments" in the "value enhancing" category? If not, can OPG please explain why?

18) What amount of indirect cost is attributed to construction work in progress (CWIP) in 2005, 2006 and 2007 on an actual basis and in 2008 and 2009 on a forecast basis? Please provide the basis of allocation for such indirect costs to CWIP. In your response please identify any amounts attributable to activities in the corporate office, including but not limited to: the board of directors, executive office, and corporate functions such as legal, finance and human resources.

19) Please provide a breakdown of the interest carrying charge amounts added to CWIP and other capital assets in each rate-regulated business segment in 2005, 2006 and 2007 on an actual basis and in 2008 and 2009 on a forecast basis.

20) What was the interest rate(s) used for each year/period, how were these rates determined and what was the source?

PRODUCTION FORECASTS (Exhibit E)

4.1 Is the methodology used by OPG to generate the proposed hydroelectric and nuclear business production forecasts appropriate?

Hydroelectric Production Forecast (Reference E1.T1.S1.)

21) What is the historical relationship between deviations in forecasted OPG production and deviations from forecast median water levels?

22) What is the historical long-term trend for Lake Erie outflows and St. Lawrence River flows? Does the current forecast reflect this longer- term trend? If not, why not?

Ref: Table 1: Comparison of Production Forecast – Regulated Hydroelectric

23) Regulated hydroelectric has different values for 2005, 2006 and 2007 Budget production levels from the forecast information filed with the OEB. Deviations of actual production from this original forecast that are the result of weather and water conditions are accumulated in a variance account. Has OPG used a different forecast for hydroelectric production in its application than it used in the original forecast?

24) Can OPG provide a table that shows the actual production deviations from the original forecast levels and attribute reasons for these deviations?

25) OPG states that:

> "the annual mean flows for both the Niagara and St. Lawrence Rivers in 2005 were very similar to the annual mean flow corresponding to the 2005 budget forecast"

Actual production exceeded the budget by about 0.3 TWh and actual production deviates from original forecast levels by 0.7 TWh. According to section 5(1) (a), deviations from the original forecast are recoverable only if caused by deviations of actual water conditions from the forecast. Has OPG booked deviations from forecast in the variance account that are based on the original forecast?

<u>Nuclear Production Forecast (Reference E2.T1.S1.)</u>

26) How often over the last 5 to 10 years has an approved Integrated Plan (IP) been adjusted because of impacts on the two-year outage planning horizon? What is the probability that the current IP will be adjusted for the Test Years because of outage planning?

27) Does OPG co-ordinate its outages with Bruce Nuclear?

28) Does OPG share critical maintenance resources with Bruce Nuclear? If so, how does this affect OPG's outage planning? How is OPG compensated for the use of these resources?

29) Has the IESO ever rejected an OPG outage schedule? If so, on what grounds?

30) OPG has a Fleet Level Uncertainty Adjustment of 0.5 TWh/year (1% of forecast production). Does OPG change this level over time to reflect ageing factors?

31) OPG states that because of concurrent or unexpected events over the last few years, actual lost production has exceeded the budgeted adjustment of 0.5 TWh/year. Why does OPG expect that recent reforms to outage management processes will be effective in reversing this trend when previous reforms did not?

32) Given that actual outages exceeded planned outages by 12% in 2005, 52% in 2006, and 40% in 2007 why does OPG believe that the forecast number of planned outage days for 2008 and 2009, described in the evidence as 'a significant improvement' from those experienced in 2005 and 2006 and a reduced "forced loss rate" from 2007 levels by 2009, is likely to be realized?

33) When does OPG expect to know whether it will reschedule planned outages for Pickering A in 2008 and 2009? What impact would this new schedule have on costs in 2008 and 2009?

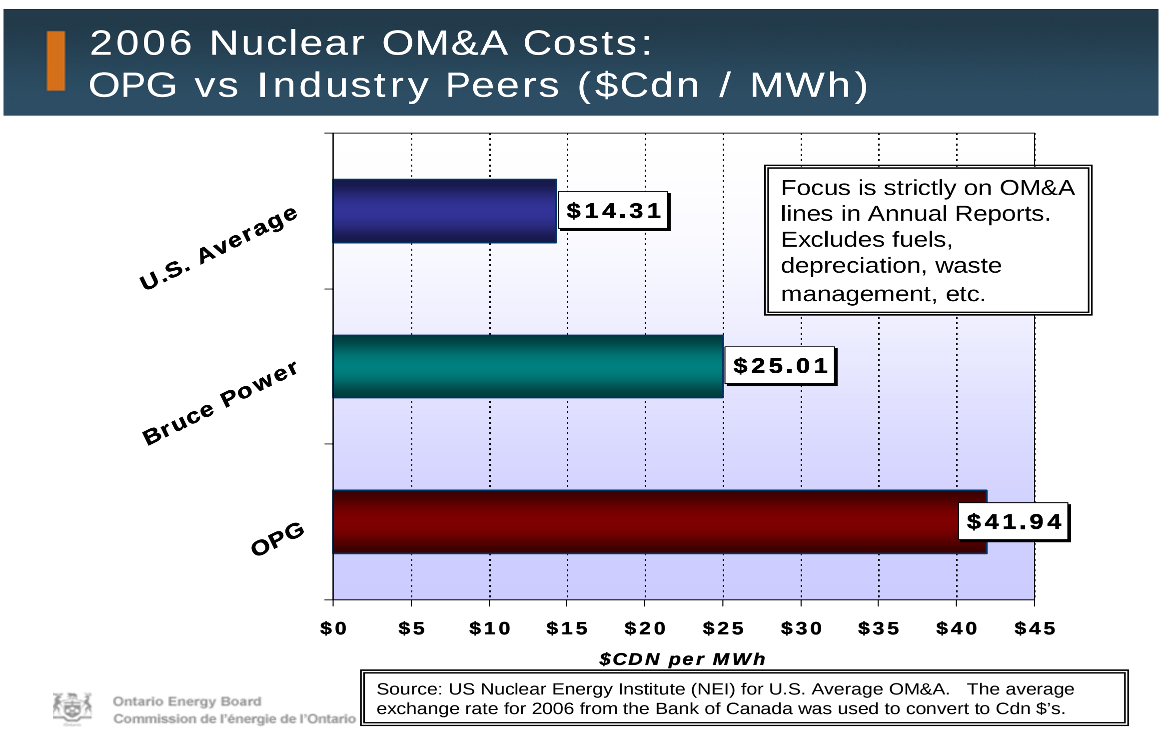
4.2 Has the methodology been appropriately applied to create the production forecasts?

OPERATING COSTS (Exhibit F)

5.1 Are the Operation, Maintenance and Administration ("OM&A") budgets for the prescribed hydroelectric and nuclear business appropriate? (F1/T1/S1, F2/T1/S1)

34) The following chart shows OM&A costs per MWh for OPG Nuclear, Bruce Power and the U.S. Nuclear Average for 2006. The information regarding Bruce Power is from its Annual Report. The latter is based on public information from Global Energy Decisions posted on the Nuclear Energy Institute (NEI) website and has been converted to $2006 CDN. The chart excludes costs associated with nuclear waste management and depreciation at both Bruce and the US nuclear generators. The chart focuses strictly on the nuclear OM&A lines – as well as output (TWh) – of the Annual Reports and the NEI, and compares, to the extent possible, the same costs. Based on this comparison, OPG is about three-fold higher than the U.S. Nuclear average and almost twice as high as Bruce Power.

Please explain the reasons that contribute to the cost differential between a) the average costs of US nuclear generators; and b) the costs of Bruce Power? Does OPG see the differential narrowing or growing over the next five years?



Bruce Power: www.brucepower.com/uc/GetDocument.aspx?docid=2429

NEI:
www.nei.org/filefolder/u.s._electricity_production_costs_and_components.xls

35) Please identify the primary drivers underlying the following trends in relation to nuclear OM&A (F2/T1/S1/Table 1):

a) Excluding the one-time extraordinary item (P2/3 Impairment Charges/Write-Off) in 2005, Total OM&A increases by 25.6% ($442.5M) from 2005 to 2009;

b) Base OM&A increase of 32% ($331.6M) from 2005 to 2009; and

c) Allocation of Corporate costs up by 20.8% ($74M) from 2005 to 2009.

36) Please identify the primary drivers underlying the following trends in relation to hydroelectric OM&A (F1/T1/S1/Table 1):

a) Base OM&A increase of 22.4% ($10.6M) from 2005 to 2009;

b) Project OM&A rising by 83.3% ($5.5M) from 2005 to 2009; and

c) Allocation of Corporate costs up 69.6% ($19.2M) from 2005 to 2009. Please also explain why this percentage increase is over triple the percentage increase for nuclear operations of 20.8%.

37) Please identify the primary drivers underlying the following increases in relation to Corporate OM&A (F3/T1/S1/Table 1) from 2005 to 2009):

a) CIO ($40.8M, 27.3%);

b) Finance ($12.3M, 21.9%); and

c) HR ($14.5M, 87.9%)

<u>Ref.: F2/T1/S1, Table 1 and Ex. F2/T2/S1, Table 3</u>

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

39) Table 1 of Ex. F2/T1/S1 indicates a significant planned increase (567) in Total Regular Staff FTEs in 2008 compared to 2007 with a corresponding planned decrease in Non-Regular Staff FTEs. What are the implications on operating costs and, possibly planned work programs, if the planned staffing targets are not achieved or if staffing levels have to be augmented through increased non-regular staff FTEs? What are the implications on the hiring of new full time employees related to potential changes in the capital and OM&A projects

schedules, including the deferrals described in the cover letter of the evidence update?

40) At the bottom of Table 1 in F2/T1/S1, the number of Nuclear FTEs is provided for each year. There has been a relatively constant increase in the “Total Regular Staff FTEs – Nuclear” from 7,311.7 in 2005 to 8,109.1 in 2008. While it declines to 7,933.8 in 2009, there is a net increase of 8.5% or 622 FTEs (about 155.5 per year).

a) Over the same period, there is a coincident decline of a similar magnitude for “Non-Regular Staff FTEs”. Is this trend a matter of contract staff being made permanent? If not, please explain the reason(s) for the increase in Regular Staff FTEs.
b) Similar FTE figures, by year, were not provided for the regulated hydroelectric business in Table 1 in F1/T1/S1. Please provide those FTE figures.

Ref.: F2/T2/S1, Table 3

41) Table 3 shows that the number of Operations FTEs for Pickering A in 2008 and 2009 are comparable to those planned for Pickering B and Darlington in those years and, in fact, are higher than those for Pickering B. While it is recognized that staffing numbers for a two-unit station such as Pickering A can not be simply pro-rated from those for a four-unit station, please explain why the Pickering A Operations FTEs are as high as indicated.

Ref.: F2/T2/S1, Chart 2 (p.37) and Chart 3 (p.38)

42) Chart 2 indicates that the number of elective backlogs per unit for Pickering B increased in 2007 compared to 2006 and that they will remain relatively high in 2008 and 2009, compared to the industry standard of 350 work orders per unit. Given these projections, please confirm that the relatively lower base OM&A costs for Equipment Performance Improvement Initiatives planned for Pickering B in 2008 and 2009 (compared to those for Darlington and Pickering A), and as indicated in Chart 3, are appropriate.

5.2 Are the proposed depreciation rates and resulting expense appropriate? (B1T1S1)

43) Ref: F3/T2/S1/page 4-6. Please explain the steps taken by OPG to implement the recommendations of Gannett Fleming contained in their report “Review of Ontario Power Generation Inc. Depreciation Review Process”, dated March 1,

2007. If OPG has not implemented all of the recommendations, please advise which recommendations have not been implemented and the reasons why.

44) Please provide a schedule detailing the amortization rates of all components and major subcomponents of property, plant and equipment of the company's rate-regulated business segments, showing separately: tangible capital asset type, net book value (as of December 31, 2007), useful life years, amortization rate, effective date and the date last reviewed by the company's Depreciation Review Committee including explanations of any changes to useful life and amortization rate.

45) Please identify and describe which processes or review criteria used for historic changes to end of useful life were used for the prescribed hydroelectric and nuclear stations (or relevant groups of units in each station) and, are expected to be used in the future management of those assets.

46) Please provide a table showing the date to which each of the units in the OPG nuclear prescribed assets is currently licenced and the date to which the unit is currently planned to be in service for depreciation purposes. Please explain any differences between these dates.

47) Ref: F3/T2/S1/ Appendix B and A2-1-1 Appendix A Please explain how the extended useful lives for nuclear generation stations were established including details of the technical analysis for life limiting components with respect to each of the following changes shown in 2007 audited financial statements (page 45) and the Depreciation Review Committee Recommendations (Rate-Regulated Business) dated December 2007:

a) The service life of Pickering B nuclear generating station was extended to 2014 in 2006;
b) Effective January 1, 2008, the service life of Darlington nuclear generating station was extended from 2017 to 2019;
c) Effective January 1, 2008, the service life of Bruce A nuclear generating station was extended from 2030 to 2035; and
d) Effective January 1, 2008, the service life of Bruce B nuclear generating station was extended from 2012 to 2014.

48) The net fixed assets (in service) of the nuclear and hydroelectric rate-regulated segments for 2007 were $4,030 M and $3,871 M respectively; however, their respective annual depreciation expenses for 2007 were $426 M and $68 M respectively. Please explain why the depreciation expenses for nuclear were

over six times greater than that of hydroelectric although the net asset values of the segments were comparable.

49) Please provide a copy of any depreciation study, since April 1999, of the company's assets and associated amortization rates, and describe any associated changes made to amortization rates and the rationale.

5.3 Are the 2008 and 2009 human resource related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate? (F3/T4/S1)

50) The application notes that, when reviewing executive compensation, OPG looks at two comparator groups of: utilities (Canadian owned energy companies) and non-utilities (Canadian owned public & private large manufacturing & high tech firms).The objective is to position OPG's executive compensation at the 75th percentile against other utilities and the median or 50th percentile of comparable non-utility companies. The updated application now states "OPG has reviewed its philosophy in late 2007 and now also plans to conduct a comparison using the 50th percentile for the public and utility markets going forward." Is this comparison in addition to or in replacement of the objective outlined in the original application?

51) The application notes that employees in nuclear operations who are authorized by the CNSC and are required to maintain their licenses as a requirement of their job, receive a license retention bonus of between 14% - 20% of base salary and that full bonus is pensionable. Are these employees also eligible to receive the "goal sharing" incentive payments for unionized staff?

52) Chart 3 on page 8 shows "Average Employee Costs ($K) For Regulated Business – Year End 2006" for the nuclear operations. Please revise the table in the following manner:

a) Add a row (above "Base Salary") called "Total Wages" which aggregates Base Salary + Overtime + Incentives + Other;
b) Add a row (after "Benefits") that provides the average "Pension" amount; and
c) If possible, please also update all of the figures in the table for year end 2007.

Please provide the revised table in Excel.

53) Chart 9 (page 35) provides a range of OPG positions and compares them to the 75th percentile of market data which appears to be based on a study of the Power Services Industry in Canada by Towers Perrin. The application notes "while some positions are paid above market and some are below market, OPG is

slightly above market on an overall basis". Of the 34 positions, OPG is lower for 5 positions and higher for 28 positions. It also appears 11 or about one-third of the positions are between 15% - 28% higher for OPG. Given the above, on what basis did OPG conclude that OPG is "slightly above market on an overall basis"? Please quantify the difference.

54) Chart 10 shows a wage comparison between OPG and Bruce Power based on the last round of negotiations between the PWU and Bruce. The finding was: "OPG wages are generally lower -- on a weighted average basis, the differential between OPG and Bruce Power wages was 12.8% in 2006 and will grow to 13.3% in 2008". What are the results, on a similar weighted average basis, if the comparison is limited to nuclear employees in both companies?

55) In section 7.1, in discussing changes made to the pension promise, one change is that all new employees hired into manager positions or higher received the inclusion of incentive amounts in pensionable earnings. What percentage of the incentive amounts is included in pensionable earnings? Is there a standard practice for the recognition of incentives in pensionable earnings in other electricity generation companies in Canada?

56) The evidence states the most recent actuarial valuation, filed and current to January 1/05, showed the pension fund to be in a deficit position, The next actuarial valuation was to be performed as of January 1/08. If the updated valuation is now completed, please provide a copy; if it is not completed, please advise when it will be available.

57) Please explain the reasons for the changes in the evidence update related to the pension and OPEB cost assumptions including the inflation rate increase, and salary schedule escalation rate increase.

5.4 Are the corporate costs allocated to the regulated hydroelectric and nuclear businesses appropriate? (F3/T1/S1, F3/T1/S2, F4/T1/S1)

58) The application states "Approximately 70 percent of OPG's total corporate function and centrally held costs are either directly assigned or allocated to regulated operations." Has the regulated allocation increased or decreased relative to the historic years? If the allocations have changed, please explain why. Please support your explanation by replicating Table 1 in the application (F3-T1-S1) and include two columns for each year showing the total $ amounts allocated to: (1) non-prescribed assets; and (2) prescribed assets.

59) The R.J. Rudden study (F4/T1/S1) notes, and expresses some reservations with the fact that, OPG's process relies on "judgments" made by departmental managers to support specific identification and time estimation for cost allocation purposes. Rudden also raised the following concern on page 19, "the completeness and understandability of the documentation varies considerably among the CSA groups and sometimes among departments within the groups." As a result, Rudden recommended (emphasis in original):

- "<u>Documentation of the OPG methodology should be improved.</u> OPG has documented significant portions of its cost allocation methodology. However, several areas should be improved. Improvement in these areas is typically required after initial adoption and implementation of a cost allocation methodology."; and
- "A template should be used to document specific identification and time estimation. Exhibit C has a proposed template."

The application states "OPG has not developed templates to document time estimates, as recommended by R.J. Rudden, but it is something we may consider in the future (F3/T1/S1/page 19)." Please explain why OPG has not adopted the Rudden recommendation?

60) OPG states on page 2 of F3-T1-S2 that the increase in the forecast of IESO non-energy charges in 2008 is mainly due to the "inclusion of a forecast of the Global Adjustment and the OPG Rebate, which were not included in the 2005 - 2007 budgets for centrally held costs and which are not presented as part of 2005 - 2007 actual costs". That increase is over $15M (from the 2007 budget year). Board staff understands that: (1) the Global Adjustment is a settlement undertaken by the IESO that takes OPG regulated payments into account (as opposed to an additional cost to OPG); and (2) the OPG Rebate results from a revenue cap placed on OPG's non-prescribed coal facilities. Please explain the $15M increase, and indicate whether any amounts related to the OPG Rebate have been allocated to OPG's regulated operations.

5.5 Are the asset service fee amounts charged to the regulated hydroelectric and nuclear businesses appropriate? (F3/T3/S1, F3/T3/S2, F4/T1/S1)

61) Please identify the primary drivers underlying the following trends:

a) Asset Service Fees charged to the nuclear business increasing by 73.5% ($10.8M) from 2005 to 2009; and

b) Asset Service Fees charged to the hydroelectric business rising by 75% ($0.9M) from 2005 to 2009.

5.6 Are the amounts proposed to be included in 2008 and 2009 revenue requirements for other operating cost Items appropriate? (F3/T2/S1, F3/T2/S2, F4/T1/S1)

5.7 Is the forecast of nuclear fuel costs appropriate? (F2/T5/S1, F2/T5/S2)

62) The application (F2/T5/S1/page 2) notes OPG's nuclear fuel supply chain is made up of the following stages:

a) The purchase of uranium concentrate;

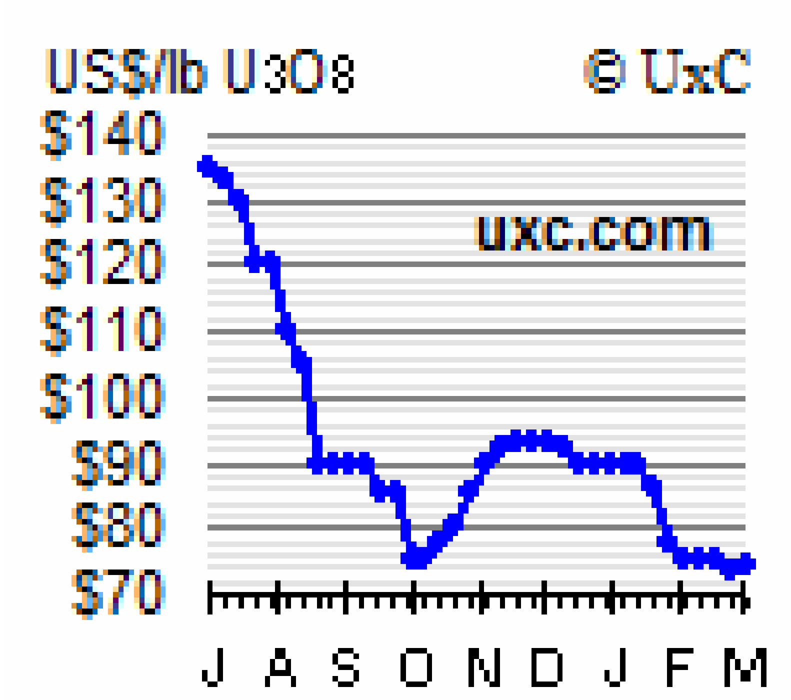
b) The purchase of services for the conversion of uranium concentrate to uranium dioxide; and

c) The purchase of services for the manufacture of fuel bundles containing the uranium dioxide.

During the test years, what is the percentage breakdown for the three stages in terms of the total nuclear fuel cost?

63) At the end of section 2.5.2, it states "OPG has recently implemented a revised spot market procurement process to facilitate potential future spot market purchasing." Please explain how the revised spot market procurement process facilitates future spot market purchases?

64) Above Figure 1.0 it states, "Spot market prices increased to an all time peak of US $136 per pound (US $354 per kgU) in 2007 before declining to around US $90 per pound (US $234 per kgU), as shown in the following Figure 1.0 based on the Ux Consulting Company's U308 weekly spot price, and this has impacted OPG's market priced and indexed contracts". Based on a more recent U308 weekly spot price as at March 3, 2008 from Ux Consulting, the decline appears to



have continued down to around $70 (please see accompanying chart). How has this decline to between $70 and $90 during the past seven months impacted OPG's market priced and indexed contracts?

65) The updated evidence shows that nuclear fuel costs for 2008 and 2009 were revised to $162.4 M and $204.2 M respectively. The revised costs compared to the 2007 actual of $113 M represent increases of $49.4 M (47%) for 2008 and $91.2 M (81%) for 2009.

a) Please provide a detailed calculation including the forecasted uranium prices and other assumptions showing how the nuclear fuel costs for 2008 and 2009 were derived. If independent sources were used to derive the forecast, please provide copies of the information provided by the independent sources.

b) In light of the significant increases in nuclear fuel costs from 2007 to 2008 and 2009, does OPG intend to change how it manages the risk associated with uranium prices? If so, what does OPG intend to do and when will it implement this change? If no change is planned, please explain why.

66) The application states that OPG has entered into two types of contracts. One is an indexed contract and is described as follows: "indexed pricing include base prices, set at the time of contract signing, but which escalate to the time of delivery by formula or by published indexes". This description appears to suggest they are only indexed if the market price escalates. If OPG entered into such a contract when the uranium price peaked, does it mean OPG would pay about $140 (i.e., not indexed to follow the subsequent decline in the market price to about $70) but if the market price had doubled the indexing provision would require OPG to pay about $280? If so, what benefits does indexing contracts provide?

5.8 Is the methodology for deriving the nuclear outage OM&A budget and the forecast of outage OM&A costs appropriate? (F2/T4/S1, F2/T4/S2)

5.9 Are the OM&A purchased services costs appropriate in the context of the OM&A budgets for the regulated facilities? (F2/T6/S1, F3/T5/S1, F3/T5/S2).

OTHER REVENUES (Exhibit G)

6.1 Are the proposals for the treatment of revenues from Segregated Mode of Operation, water transactions and congestion Management Settlement Credits appropriate? (G1T1S1)

Ref: G1 Tab 1 Schedule 1 page 13-15

67) The Application proposes not to include payments from the IESO to OPG for congestion management settlement credits in revenues to offset the revenue requirement. This differs from the proposed treatments for Segregated Mode of Operation and water transactions. The argument advanced in favour of this approach is that the IESO payments compensate OPG for costs incurred in not providing energy as dispatched.

a) What costs are incurred?

b) If the "costs" are foregone revenues, in what sense are these "opportunity costs" in the sense of standard economic theory (as opposed to rents)?

c) Why in the cases of Segregated Mode of Operation and water transactions does OPG propose to treat revenues for the non-use of facilities for Ontario load as appropriate to offset the revenue requirement but not those of congestion credits?

Ref: G1 Tab 1 Schedule 1 pages 5 to 13

68) The Application proposes that Segregated Mode of Operation and water transactions revenues be subject to a revenue-sharing formula. Given that the costs of operation are the same whether or not the generating units are dedicated to Ontario load, what is the rationale for offsetting only 50% of the extra revenues rather than 100% of the "extra" revenues?

6.2 Are the forecasts of ancillary services revenues appropriate? (G1T1S1)

Ref: G1 Tab 1 Schedule 1 table 1

69) Please provide a detailed listing of the ancillary service revenues, by service.

6.3 Are the forecasts of revenues from Heavy Water and tritium sales and services, radioisotope and nuclear inspection and maintenance services appropriate? (G2T1S1)

6.4 Are there revenues and related costs other than those included in the application, that OPG earns or incurs from the prescribed assets that should be included in the application?

6.5 Are OPG's forecasts of costs related to the Bruce Nuclear Generating Station, and costs and revenues related to the Bruce lease, accurate?

Ref: G2 Tab2 Schedule 1 tables 3 & 4

70) Section 6.(2) 5 limits the review of either revenues or costs related to the "lease of the Bruce Nuclear Generating Stations" to the "most recently audited financial statements that were approved by the Board of Directors of OPGI before the effective date of [the first order]". Note 18 to the 2007 statements states: "For 2004 through 2008", minimum payments under the lease are $190M annually"; that recorded revenues for 2007 and 2006 were $253M and $251M, respectively and that the net book value of the assets leased to Bruce as of Dec 31/07 was $1,201M. No figures are provided for OPG's costs in note 18; however, the Application does provide some costs related to the lease (ExG2T2S1 tables 3 & 4). Are the revenues and costs provided in the Application and related to the Bruce lease taken from most recently audited financial statements? If not, what is the source of those figures?

71) Section 6 (2) 10 provides that the net revenues earned with respect to any lease of the Bruce Nuclear Generating Stations (if any) are to be deducted from the prescribed payments. Note 18 provides only part of the revenues that must be accepted for 2008 and only one part of the cost determination (net assets). Please list all of the costs and revenues related to the lease of the Bruce Nuclear Generating Stations and indicate where they may be found in the 2007 audited financial statements.

NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING (Exhibit H)

7.1 The proposed rate base includes the estimated net book value of OPG's nuclear fixed assets, which in turn includes amounts related to OPG's obligations to decommission the nuclear plants and manage nuclear waste. Do the amounts fall within the parameters of O. Reg 53/05? The proposed revenue requirement includes depreciation of those nuclear fixed asset costs and a return on rate base. Is this method of recovering nuclear fixed asset removal and nuclear waste management costs appropriate? Or should alternative recovery mechanisms be considered? [H1/T1/S2]

72) The Ontario Nuclear Funds Agreement Reference Plan ("the Reference Plan") defines OPG's obligations for nuclear waste management and decommissioning.

Please provide a comprehensive executive summary from the most recent reference plan that explains how OPG's obligations were determined.

73) Is the Bruce facility included in the Reference Plan? Are nuclear waste management costs either explicitly, or implicitly, included in the Bruce lease agreement? Does Bruce Nuclear assume any liabilities or pay any costs, directly or indirectly, for nuclear waste management?

74) Does OPG make provision for its liability on decommissioning fund performance on an ongoing basis? If yes, how does it do so and what are the expected costs in the test period?

75) On page 21 of the OPG's Stakeholder Consultation summary report, it states, "Under the Ontario Nuclear Funds Agreement between OPG and the Province, OPG is required to make funding payments of approximately $450 million/year. These payments are not included in the revenue requirement. The revenue requirement is based on accrual accounting." Do these funds arise from the return on the fund? If not, how is OPG planning to provide the funding for this obligation?

76) The application says it is likely that OPG will cease to pay a provincial guarantee fee for the decommissioning fund when the update is complete. Does the application exclude the guarantee fee in the test period?

77) Please provide an explanation of how the Bruce Extraordinary Payment affects OPG's revenue requirements? Does the Bruce Extraordinary Payment increase the tax loss carry forward position of OPG?

78) Withdrawals from the Ontario Nuclear Fund for eligible expenditures must be approved by the Province. Does OPG anticipate withdrawing funds from the fund during the test period? Is OPG required to reimburse the fund for withdrawals and expenditures prior to plant decommissioning?

79) Please explain why OPG's proposed method of cost recovery for obligations to decommission nuclear plants is based on the useful lives of the nuclear stations rather than when the stations are actually decommissioned.

80) Please provide a breakdown by year for nuclear fixed assets decommissioning and nuclear waste management costs and the associated depreciation expenses for 2006 and 2007, which were capitalized and forecasted for 2008 and 2009. Please show how the amounts were calculated.

81) Please provide the accretion expense amounts for nuclear fixed assets decommissioning and nuclear waste management amounts forecasted for 2008 and 2009. Please show how the amounts were calculated.

82) In other jurisdictions are there alternative mechanisms available and used for the regulatory recovery of nuclear fixed assets decommissioning and/or nuclear waste management costs in other jurisdictions? If so, please outline what these are and how they are applied.

83) For 2008 and 2009, please provide a schedule that projects the beginning and ending aggregate recorded amount of the asset retirement obligations showing separately the changes attributable to:

a) liabilities incurred in the current period;
b) liabilities settled in the current period;
c) accretion expense;
d) revisions in estimated cash flows; and
e) any other change factors.

84) Please provide the key assumptions on which the carrying amount of the asset retirement obligations are based and any changes forecasted, including:

a) The total undiscounted amount of the estimated cash flows required to settle the obligations or a range of amounts when there is uncertainty as to the amount required;
b) The expected timing of payment of the cash flows required to settle the obligations, or a range when there is uncertainty as to the timing of settlement;
c) The credit-adjusted risk-free rate or rates at which the estimated cash flows have been discounted; and
d) Changes in these assumptions that have been made over the period 2006-2009 with rationale for changes.

DESIGN OF PAYMENT AMOUNTS (Exhibit I)

8.1 Are OPG's suggested changes to the hydroelectric incentive payment system appropriate? (I1/T1/S1)

Ref: Section 4.4, pages 7-8

85) What are the reasons OPG proposes a different incentive pricing mechanism for the Beck PGS?

Ref: Section 4.0 – 4.3; pages 5-8

86) The current incentive mechanism, i.e., prescribed hydroelectric asset output above 1900 MW per hour receives HOEP, was invoked more than 50% of the time.

a) What is the revenue generated by this incentive on an annual basis since its inception?

b) Without this mechanism, how would OPG have operated its hydraulic assets differently? What are the projected differences in production levels for 2005, 2006 and 2007?

c) What are the historical net revenue differences for 2005, 2006 and 2007 arising because of different production levels between the incentive and no incentive scenarios?

Ref: Section 5.2; pages 11-17

87) OPG proposes a new incentive mechanism based on its actual average hourly net energy production over the month instead of a fixed energy amount (1900 MW/hour). OPG claims that a mechanism based on actual monthly production will increase efficiency, will place more financial risk on OPG to meet hourly production volumes and will increase OPG's incentive to time shift its production. Please explain how this proposed mechanism will cause OPG to operate its hydraulic prescribed assets optimally? How would this proposed incentive mechanism affect OPG's operation of its non-prescribed assets?

88) OPG states that it is likely to earn a net premium of $12 million from this revised incentive system, with an estimated range of $5 million to $19 million. Did

OPG consider a revenue-sharing mechanism that would preserve an incentive for OPG and also benefit consumers directly by reducing revenue requirement? If not, why not?

89) How would the "notional purchase" volume be established and enforced? Would this require a specified hourly output level from the prescribed assets and a contractual obligation on OPG to make that level of supply available to the market? Why would OPG be "notionally obligated" to purchase from the market at market prices? Alternatively, could OPG increase production from its own fossil fueled plants (or other OPG generation) to make up the shortfall?

90) Has OPG commissioned any studies or analysis of this incentive mechanism by outside experts or OPG staff? If so, please provide copies of the studies or analysis.

Ref: page 17, lines 6-12

91) OPG claims that the proposed incentive mechanism will result in consumer benefits with an estimated annual value of between $80 million and $270 million, an incentive payment of $12 million in 2009 to OPG and unspecified market benefits from additional supply during peak demand periods. How did OPG calculate these specific benefits?

8.2 Is the fixed payment of 25% of revenue requirement an appropriate design for the nuclear facilities? (I1/T2/S1)

Ref: Section 3.0, pages 1-2; Sections 3.2 and 3.3, pages 7-8

92) OPG's rationale for a fixed (25%) - variable (75%) payment structure for the nuclear assets has three components: nuclear generation has a high proportion of fixed costs; generators in Ontario and other jurisdictions have fixed payments as part of their compensation; and the OEB has approved fixed-variable rate structures for other entities with a high proportion of fixed costs. Typically, fixed payments are awarded through a competitive process for capacity. Ontario's OPA-based supply contracts were competitively awarded and have a fixed payment "top-up" mechanism based on a total revenue requirement – but generators are required to operate to receive payments and can be "deemed to have run" to calculate their revenue requirement.

Given that it is not subject to any competitive procurement for capacity, why has OPG proposed a payment structure that includes a fixed payment for its nuclear units that is payable even when they do not operate?

93) Other regulated entities with a high proportion of fixed costs, e.g., electricity transmission and distribution networks and natural gas pipelines, do not have the level of outage risk of OPG's nuclear plants. Given that outage levels exceed OPG's own target levels, what is the rationale for ratepayers assuming any of OPG's nuclear outage risk?

94) All of the examples in the application appear to be "wires" or "pipeline" businesses where some proportion of fixed charges are the norm. Please provide some examples of specific regulated generators in North America that receive a fixed charge. Of those, please identify the generators that get paid a fixed amount whether they are available or not to run (i.e., during an outage).

<u>Ref: page 5, lines 7-14</u>

95) OPG cites a Market Surveillance Panel Report and an IESO report on operating reserve to support the assertion that Ontario market prices are often too low to allow generators to earn sufficient revenues. Given that OPG's prescribed assets receive payment amounts that are independent of market price levels, how are the conditions cited in these reports relevant to OPG?

<u>Ref: Section 3.1, pages 2-5</u>

96) OPG argues that the current energy-only payment structure does not reflect cost causality and results in higher financing costs because fixed costs are recovered through a mechanism that is based on variable energy usage. Does OPG have analysis that documents this claim of higher financing costs because of energy-only payments? Are there specific examples where OPG has incurred higher financing costs as a result of the current system of energy-only payments?

97) As base load plants, nuclear facilities do not vary from their projected output or energy sales except when they are offline because of unscheduled outages. Revenue variability from the nuclear plants is the result of these outages and not demand fluctuations. How will OPG's proposed fixed payment help to reduce unscheduled outages?

<u>Ref: page 9, lines 1-4</u>

98) OPG accepts that a variable payment structure is essential to provide incentives to maximize production from OPG's nuclear plant. As a starting position, OPG proposes the 25% fixed payment be reviewed for effectiveness in future periods. How does a 75% revenue requirement recovery through energy charges increase incentives for OPG to maximize production compared to payments based on a 100% energy charge?

DEFERRAL AND VARIANCE ACCOUNTS (Exhibit J)

<u>Forecast Variance Account Section 5(1)</u>

9.1 Are the costs and the revenues recorded in the variance account established under section 5(1) (the "forecast variance account") due to deviations from the forecasts set out in "Forecast Information for Facilities Prescribed under Ontario Regulation 53/05"? Were the costs incurred and the revenues earned or foregone on or after April 1, 2005?

9.2 Do the costs and revenues recorded in the forecast variance account conform to the requirements of section 5(1)?

9.3 Were the revenues recorded in the forecast variance account earned or foregone; were the costs prudently incurred; and were the revenues and costs accurately recorded as required by section 6(2)1?

99) In its evidence concerning the regulated hydroelectric and ancillary services variance account, OPG states that it has established and recorded a segregated mode and water transactions net revenue variance account. "Segregated mode" refers to the segregation by Saunders G.S. of some of its generation units from the Ontario grid and their reconnection to the Hydro Quebec grid to facilitate exports. Water transactions refer to water or equivalent energy transfers between OPG and the New York Power Authority made pursuant to treaty obligations for water sharing and hydraulic management. These additional accounts are not required by section 5(1) and result in credits for consumers.

a) For the purposes of receiving the regulated price, does OPG reduce total production volumes from the hydroelectric facilities by the segregated mode and water transactions volumes?

b) Segregated mode and water transactions appear to be analogous to an export sale. How does OPG account for export sales revenue and energy volumes from prescribed asset production, both hydro-electric and nuclear?

c) OPG states the following with respect to the segregated mode of operations revenue sharing proposal:

> "The proposed sharing mechanism recognizes that OPG is using prescribed assets to earn this revenue so it would only be fair to share a portion of the net revenues from SMO transactions"

Please detail all revenues derived from these assets, including export revenues.

Ref: Section 3.1.1; pages 3-6

100) Section 5(1) specifies that the forecast information is the basis for deviations of actual production from the hydroelectric production forecast based on changes in water conditions. Energy volumes in Table 3 (J1.Tl.Sl. Table 3) do not match those in the Production Forecast information (El .TI .S2.Table 1). Did OPG use a revised forecast for determining these deviations? If so, please produce the revised forecast and advise why it was used instead of the original forecast?

Ref: Section 4.4.2, page 17, lines 2-9

101) In the transmission outages and restrictions sub-account, OPG calculates the value of lost production on the basis of an hourly capability factor for the affected units. Is this an actual capability factor or a theoretical 100% factor?

102) For the Nuclear transmission outages which occurred at Darlington:

a) Why is the value of the one-day outage on Dec. 12, 2005 greater than the two-day outages of April25/26, 2006 and June 17/18, 2006?

b) Why are there no Congestion Management Settlement Credits payments for the 2006 outages?

Ref: Section 3.2, pages 5-6

103) Under what circumstances might the IESO refuse an OPG request for segregated mode of operation?

104) Does OPG ever engage in segregated mode of operation transactions when market prices in neighbouring markets are below $33/MWh? If yes, then on average how much energy is sold annually at prices under $33/MWh?

105) How does OPG assess and evaluate a segregated mode of operation request? What criteria does OPG use to determine if it will engage in these transactions?

106) OPG states that it will share "net revenues" from segregated mode of operation transactions. Does OPG net out segregated mode of operation related costs from total hydraulic production costs?

107) How often is OPG unable to fulfill a segregated mode of operation commitment? What penalties are associated with non-fulfillment?

Pickering Deferral Account Section 5(4)

9.4 Are all of the non-capital costs recorded in deferral account established under section 5(4) incurred after January 1, 2005, and associated with either the planned return to service of all of the units at the Pickering A Nuclear Generating Station or units the board of directors of OPG determined should be placed in safe storage?

Ref: J1/T1/S1 and A2-1-1 Appendix A

108) Are any OM&A costs in the Pickering deferral account also included in the total OM&A costs for nuclear?

109) The 2007 audited financial statement (page 42) states that the net balance in the account as of December 31, 2007 was $183 M (net of accumulated amortization of $125 M). It also states OPG commenced the amortization of the deferral account when Unit 1 of the Pickering A nuclear generating station was returned to service in November 2005. The amortization of $96 M was charged to depreciation and amortization expense in 2007 (2006 – $25 M). In addition, the evidence at J1/T1/S1 indicates that the amortization method used ensures that the opening balance of the account at the end of 2007 excludes costs that were already recovered through interim payments.

a) Section 6 (2) 3 requires amortization of the deferral account balance using the straight line method. How is OPG's proposal to use units-of-production method consistent with the section requirements?

b) The section also requires the Board to ensure recovery "over a period not to exceed 15 years." Notwithstanding OPG's decision to begin amortization of the balance in 2005, please confirm that the 15-year period referred to in the regulation begins at the effective date of the Board's first order under section 78.1 of the Act.

c) Please identify the amount collected and explain how it was collected by the "recovery through interim payments."

d) What were the cost differences, by year, of the costs identified on a "unit of production basis" versus the actual cost recovery through interim payments?

<u>Nuclear Liability Deferral Account section 5.1(1)</u>

9.5 Are the revenue requirement impacts of any change in OPG's nuclear decommissioning liability, arising from an approved reference plan approved after April 1, 2005, accurately recorded in the nuclear liability deferral account established under subsection 5.1(1), as required by section 6(2)7?

<u>Ref: J1/T1/S1 page 12</u>

110) The account includes amounts recorded for interest at six percent on the account's monthly balances, as well as interest at six percent on the debt component of the return on rate base. This appears to be a double counting of interest. Please explain. If it is a double counting, please submit a corrected account.

<u>Recovery Methods for Existing Variance and Deferral Account Balances</u>

9.6 Are OPG's proposed recovery methods including periods of recovery for the deferral and variance account balances consistent with the requirements of O. Reg. 53/05 sections 6(2)1, 6(2)3 and 6(2)7 and otherwise appropriate? (J1/T2/S1)

2008-2009 Deferral and Variance Accounts

9.7 What deferral and variance accounts, other than those mandated by Reg. 53/05, should be established for 2008 and 2009?

Ref: Section 3.1; page 3, lines 9-15

111) OPG proposes to change the carrying costs for the Pickering Deferral Account from an annual rate of 6% (section 5 (5)) to the weighted average cost of capital approved by the Board. Please explain the impact of this proposed change on the projected annual revenue requirement on an annual basis and on a NPV basis accumulated over the projected life of the account?

112) OPG proposes (J1/T3/S1 pages 1-2) that the interest rate applicable to all deferral and variance account balances (with the exception of the Pickering A Return to Service Deferral Account OPG for which it proposes to use the weighted average cost of capital) shall be the forecast interest rate applied to OPG's other long-term debt provision. On November 28, 2006, the Board approved a methodology to prescribe an interest rate for the deferral and variance accounts of natural gas and electricity rate-regulated companies (EB-2006-0117). The prescribed interest rate, which is updated quarterly, is equal to the three-month bankers' acceptance rate, as published on the Bank of Canada's website, plus a fixed spread of 25 basis points, effective May 1, 2006 for electricity LDCs.

Effective on the date of the Board's first payment order for OPG, will the company adopt the implementation the Board-prescribed interest rate for existing deferral/variance created by O. Reg. 53/05 (or amended regulations) and any new account(s) approved by the Board? If not, please explain why not?

113) On November 28, 2006, the Board approved a methodology to prescribe an interest rate for construction work in progress (CWIP) for natural gas and electricity rate-regulated companies (EB-2006-0117). The prescribed interest rate for CWIP is equal to the DEX Mid Term Corporate Bond Index Yield.

Effective on the date of the Board's first payment order for OPG, will the company adopt implementation of the Board-prescribed interest rate for CWIP? If not, please explain why not?

DETERMINATION OF PAYMENT AMOUNTS (Exhibit K)

10.1 Are regulatory income and capital taxes appropriately determined in accordance with regulatory and tax legislation requirements? (K1/T1/S2)

114) For income taxes purposes, are capital cost allowance deductions claimed on the fixed asset decommissioning and nuclear waste management provisions? If yes, please provide a breakdown of amounts capitalized and the related depreciation expenses and CCA for 2006, 2007 and forecasted for 2008 and 2009.

115) OPG's application (K1-T1-S2 and K1-T1-S3-Table 1) indicates that the proposed revenue requirement for the 21-month period ended December 31, 2009 has been reduced by $228 million through application of "certain tax losses accumulated over the interim period." At the February 6, 2008 hearing on the issues list, OPG's counsel stated the following in respect of tax losses:

> … there actually are not corporate tax losses anymore. They were actually used. But what we have done is, because we understood that the regulated assets were to be treated on a stand-alone basis, we have notionally preserved those tax loss carry-forwards that were attributable to the regulated business, and even though they "corporately" actually don't exist anymore, we are giving the customers of [sic] the benefits of those tax loss carry forwards. [Transcript, February 6, 2008, pp. 38 and 39]

a) Please confirm that OPG does not currently have any tax loss carry forwards that can be applied to reduce PILs payments required in 2008 and later years.

b) If OPG, as the corporate entity that pays PILs, does not have any tax loss carry forwards, does that mean that any tax losses incurred by the prescribed assets in 2005 through 2007 have been used to reduce PILs payments that otherwise would have been made by OPG in those years? If that is correct, how can the benefits of those losses be used twice – once to reduce corporate PILs payments in 2005 through 2007, and again to reduce PILs payments in respect of earnings from the prescribed assets in 2008 and 2009?

116) Starting April 1, 2005, OPG began accounting for income taxes (PILs) related to the prescribed assets using the taxes payable method, rather than the liability method that is required to be used by most commercial companies. Per Note 11 (page 36) of OPG's 2007 financial statements, it appears that had the company

followed the liability method of accounting, its December 31, 2007 balance sheet would have included an additional future tax liability of $436 million (the difference between a $205 million liability as shown in the financial statements and a $641 million liability that would have been booked had the liability method been adopted).

a) Given that OPG's prescribed assets were not subject to regulation by the OEB in 2005, 2006, and 2007, please explain the rationale for following the taxes payable method in those years.

b) The unrecorded future income liability of $436 million referred to in the preamble to this question presumably will turn into a real PILs liability in future periods as the temporary differences between book and tax deductions start to reverse. Is OPG proposing that those taxes be included in future payment amounts for the prescribed assets approved by the Board? If so, please explain why is it appropriate for electricity consumers in future periods to pay for a tax liability that OPG chose not to recognize in 2005, 2006, and 2007?

<u>Ref: F3/T2/S1/Table 8</u>

117) Please provide a copy of the actual 2006 T2 and CT 23 tax returns and supporting schedules for Ontario Power Generation Inc. From the 2006 tax returns, provide the following information:

a) Please identify any non-rate regulated corporate activities within OPG.

b) Please provide an Excel spreadsheet that shows OPG's 2006 tax return data from the T2 federal Sch1 allocated between regulated and non-regulated business segments. The first section should show the total OPG tax return data and then the split between regulated and non-regulated (please see schedule below).

c) Please provide a schedule for the calculation of Ontario 2006 CT 23 taxable income and income tax PILs allocated between regulated and non-regulated as described above for the T2 return (please see schedule below).

d) Please allocate the federal T2 Sch8 (Undepreciated Capital Cost and Capital Cost Allowance) amounts between regulated and non-regulated for each column, and for each tax class shown on the Sch8.

e) Please provide an Excel spreadsheet that allocates the Ontario capital tax as filed in the 2006 CT 23 return between regulated and non-regulated.

f) Please provide an analysis for the 2006 Cumulative Eligible Capital (CEC) and the deductions claimed.

No.	Per tax return	Non-Rate Regulated	Rate Regulated

118) Please provide a tax forecast for 2007, 2008 and 2009 for the rate-regulated business segments using the 2006 tax information (T2, S1 and S8, etc.) as the format and starting point. Note that the federal income tax rate was reduced for 2008 and 2009 from the rates shown at F3/T2/S1/Table 7.

10.2 Is the proposed treatment of OPG's loss carry forwards for the regulated business appropriate? (K1/T1/S2)

<u>Ref: page 1, lines 7-23</u>

119) OPG proposes to use its accumulated income tax losses to mitigate the increase in payment amounts by reducing the revenue requirements. OPG's application applies these tax losses so that there is a consistent payment amount increase across the two generation technologies.

a) Could these tax losses be applied differently to reduce one revenue requirement proportionally more than the other? Has OPG investigated alternative allocations?

b) If these tax losses were allocated to the two revenue requirements in a different manner would there be substantial differences in the mitigation impacts?

120) In the reconciliation of financial to regulatory accounting income for 2006, please explain why Incentive Revenue at Market Price and Interest Expense on Regulatory Assets were deducted in the determination of regulatory earnings before taxes. (C1/T2/S1/Table 1)

121) Please provide a non-capital loss carry-forward continuity schedule for income tax purposes on company-wide basis, allocated to the prescribed assets showing the origination of losses by year and their application to other years' taxable income. (F3/T2/S/Table 9)

122) Are losses arising from the non-regulated business segments in prior years being proposed to reduce/eliminate regulatory taxable income of the regulated business segments in 2008 and 2009? If so, provide the breakdown of these amounts being applied and the rationale for this treatment.

10.3 Are OPG's methods for removing Q1 2008 costs, revenues and production appropriate? (K1/ T1/S1)

<u>Ref: page 1, lines 16-30</u>

123) To adjust for the first quarter of 2008, OPG pro-rates costs, revenue and production based on causal factors and not a straight line 25%. OPG's discussion of these causal factors does not include any statistical or trend analysis. Please provide the supporting analysis for this allocation.