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Ontario

BY E-MAIL

May 8, 2008

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

Attn: Ms. Kirsten Walli, Board Secretary

Dear Ms. Walli:

Board Staff Questions to OPG - Technical Conference
Board File # EB-2007-0905 - Payment Amounts for
OPG's Prescribed Facilities

Enclosed are Board staff's questions for OPG for the May 13-14 Technical Conference.

Yours truly,

Original signed by

Richard Battista
Project Advisor

Encl.

EB-2007-0905

Ontario Power Generation Inc.

Payment Amounts for Prescribed Generating Facilities

2008 and 2009 Revenue Requirement

Technical Conference:

Board staff follow-up questions on OPG responses to interrogatories

CAPITAL STRUCTURE AND RETURN ON EQUITY (Exhibit C)

HYDROELECTRIC

1. According to the response in L-T1-S3 (Board Staff IR#3), OPG expects the incremental ROE associated with the hydro incentive mechanism to only be 0.3% in 2009 compared to 1.5% in 2006. Please explain why OPG expects the incremental ROE to be so much lower in 2009.

Cost of CAPITAL - written responses

2. In regard to L-T1-S4 (Board Staff IR#4), Ms. McShane confirmed the utilities listed in Schedule 28 were used to establish a premium of 1.5%. Is it correct to interpret that to mean that absent the adjustment for the U.S. utilities in Schedule 28, the recommended ROE would have been 9% (10.5% minus 1.5%)?

3. Does Ms. McShane know why Allete, Black Hills, Empire District and IDACORP, as discussed in L-T1-S5 (Board Staff IR#5), have among the highest common equity ratios of the utilities in Schedule 28? For example, the CER for Allete is 63% and Black Hills at 50%. Is it likely because they are relatively small utilities in terms of generation at about 10% the size of OPG's regulated operations?

4. Board staff understands from the response, in L-T1-S6 (Board Staff IR#6), that the rationale for the request for a 50 basis point financing flexibility adjustment is not based on the need to issue corporate debt in 2008 but because it has been provided to other Ontario utilities. Is that correct? Also, approximately how much incremental corporate debt does OPG plan to go directly to the market for in 2009?

5. With respect to L-T1-S9 (Board Staff IR #9), the response notes *"There would be no adjustment, even if the nuclear outage loss were replaced by another OPG owned generation facility. The assessment of the incremental equity risk premium for OPG (translated into an equity ratio) was made using samples of integrated utilities with a relatively high proportion of assets in diversified generation portfolios. The estimates of the incremental risk premium that Ms. McShane made are applicable to companies with diversified generation portfolios and with an ability to replace production from a plant experiencing an outage with production from other generating plants."* How many of the vertically integrated utilities in Ms. McShane's sample account for over 70% of the generation in the

jurisdiction that they operate in (similar to OPG)? In addition, how many of those utilities have a portion of their generation portfolio regulated and a portion unregulated?

6. The response in L-T1-S13 (Board staff IR #13) states, *"Ms. McShane did take into account the risk mitigating impacts on the cost of capital of the applied-for deferral accounts."* It appears Ms. McShane meant she took into account applied-for variance accounts (as well as deferral accounts) since she noted in that response *"the [water conditions] variance account is a key risk mitigator for OPG"* to clarify she had taken them into account. Please confirm. Also, given Ms. McShane did make adjustments for the requested variance and deferral accounts as explained in L-T1-S13, please identify what Ms. McShane's recommended ROE and capital structure would be under a scenario whereby none of the applied-for variance and deferral accounts were approved by the Board.

Cost of CAPITAL
written response 3

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)

7. OPG notes in L-T1-S34 (Board Staff IR #34) that OPG uses Electric Utility Cost Group (or EUCG) information, for cost comparison because it provides for an "apples to apples" comparison of costs. The response refers to A1-T4-S3, Section 9 where a few comparisons of OPG to EUCG have been provided. Can OPG please provide the more detailed EUCG information (i.e., study) for which those comparisons are based?

NUCLEAR

8. Further to L-T1-S34 (Board Staff IR #34):

   a. OPG states "*OPG does not know what is included in the Bruce Power OM&A cost shown in the above chart*". The chart below attempts to clarify what was (and was not) included from the Annual Reports of OPG and Bruce. The highlighted figures are the basis for those used in the interrogatory bar chart. To assist Board staff in better understanding what material items may differ for OPG (relative to Bruce Power), please provide a breakdown of what that "O&M" line item is comprised of for OPG.

NUCLEAR

2006 Annual Report pg 31-32 (OPG)

OPG - 2006			
$M			
Fuel	$122	$122	$0
O&M	$1,967	$1 967	$1,967
Nuclear Waste	$119	$0	$0
Amortization	$343	$0	$0
Property and capital taxes	$44	$0	$0
	$2,595	$2,089	$1,967
TWh	46 9	46 9	46 9
$ per MWh	$55 33	$44 54	$41 94

2006 Annual Report pg 32 (Bruce)

Bruce Power - 2006			
$M			
Fuel	$95	$95	$0
O&M	$912	$912	$912
Rent	$170	$0	$0
Amortization	$134	$0	$0
	$1,311	$1,007	$912
TWh	36.47	36.47	36.47
$ per MWh	$35.95	$27.61	$25.01

b. OPG also notes *"It is more meaningful, however, to benchmark costs based on a "plant to plant" comparison, using plants with similar size units, as discussed at Ex. A1-T4-S3. Unit size will affect production costs due to economies of scale. As per WANO Q4 2007 Report, the average size of a U.S. nuclear operating unit is approximately 900 MWs, while the Bruce Power average is around 840 MWs and OPG average is 700 MWs."* It is Board staff's understanding that part of the rationale for four smaller units (but more units) at Pickering was to achieve better economies of scale relative to the larger single unit plants often found in the U.S. (i.e., 2000 MW vs 900 MW). Is that understanding correct?

NUCLEAR

c. OPG's response in L-1-34 also indicates that Darlington compares favourably in benchmarking tests for comparable size nuclear units, but that such information is not available for the Pickering units. Does OPG have any available information for single CANDU 6 units, such as NB Power's Point Lepreau, Hydro Quebec's Gentilly or Korea's Wolsung Candu units, to allow for such a comparison against Pickering's OM&A budgets? If so, please file the information. If not, does OPG have any plans to do such benchmarking?

9. It appears from the response in L-T1-S40 that non-regular (contract) staff currently performing the duties are still needed (i.e., duties still need to be done) but are being converted to regular (permanent) staff.

NUCLEAR

   a. Is that a correct interpretation or is OPG not retaining the contract staff and hiring 567 new staff (from outside OPG) into permanent positions?
   b. If the former is a correct interpretation, what was the rationale for what appears to be eliminating the use of contract staff?

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

10. In referring to L-T1-S51 (Board staff IR#51), it clarifies that OPG staff eligible for the license retention bonus of between 14% - 20% are also eligible to receive the "goal sharing" bonus. How many OPG staff receive the license retention bonus?

CORPORATE

11. The response in L-T1-S53 (Board staff IR #53) notes "In standard compensation practice the term "on market" refers to a value that is within plus or minus 10 percent of the median values."

    a. Where can we find it documented that the term "on market" refers to a value that is within plus or minus 10% of the median values?
    b. Also, the response notes that based on this definition of "on market", OPG has 19 positions that are above market and those are over 7% higher than the "on market" definition. We are not certain how to interpret this. Does it mean the baseline (for calculating the 7%) is 10% above the median and therefore the 19 positions are about 17% higher than the median?
    c. We understand the rationale as explained in the response for use of a definition of "on market". However, as per the request in Interrogatory #53, please quantify how OPG compares against the median for all 34 positions without adjusting for that definition.

CORPORATE

12. The response in L-T1-S55 (Board staff IR#55) notes that, based on the survey by Watson Wyatt, bonuses were included in pensionable earnings by 59% of Energy, Resources and Utilities companies.
    a. Can OPG please provide a list of the companies in the Watson Wyatt survey?
    b. What percentage of that 59% included 100% of incentive amounts in pensionable earnings?

CORPORATE

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

13. With respect to L-T1-S60:
    a. Please clarify whether the Government made provisions for OPG to recover from consumers the Global Adjustment amounts paid by OPG for the 2005 to 2007 period.
    b. It is Board staff's understanding that OPG's payments for its regulated operations have a significant impact on the Global Adjustment and therefore on such an estimate. Does OPG plan to update the forecast of the Global Adjustment for this purpose based on the actual regulated payment amounts approved by the Board?
    c. L-T1-S60 indicates OPG has forecast the Global Adjustment and OPG Rebate for 2008 and 2009 at over $25M. A forecast of the Global Adjustment and OPG Rebate requires a forecast of all elements that impact the electricity line of the bill. Please provide OPG's detailed forecast for each of the test years that separately addresses each applicable factor addressed in the Board's most recent RPP Price Report and Navigant's accompanying Ontario Wholesale Electricity Market Price Forecast (links below). This includes OPG's assumptions on NUG contract impacts, OPA conservation spending ,OPA contract impacts, Standard Offer, coal prices, natural gas prices, weather, new OPA

HYDRO ELECTRIC

generation going into service, the HOEP, etc. The intent is for OPG to provide a detailed calculation that shows how the forecast for the Global Adjustment and OPG Rebate were arrived at.

- Regulated Price Plan Price Report **(issued Apr 11-08)**
- Ontario Wholesale Electricity Market Price Forecast **(issued Apr 11-08)]**

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

14. The initial application was submitted when the uranium price decline had just begun. OPG's response to IR #64 (L-T1-S64) notes that lower market prices would directly impact the "base" price of any new contracts. Given market prices have remained lower since the initial application was filed, please clarify what the primary driver was in terms of the increase in nuclear fuel costs when the application was recently updated? NUCLEAR

15. OPG's response in L-T1-S65 (Board staff IR#65) in relation to nuclear fuel costs indicates OPG has physically contracted for 100% in both 2008 and 2009. It notes *"Between 2003 and 2007 OPG negotiated eight new uranium supply contracts which now provide physical coverage and price diversity for a portion of expected requirements through 2017. The physical coverage is 100 percent of requirements in 2008 and 2009"*. OPG also provided clarification in L-T1-S64 (Board staff IR#64) that *"A decline (or increase) in market price does not impact existing indexed contracts"*. Please clarify what drives the request for a variance account within the context of these two responses. NUCLEAR

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Ontario

BY E-MAIL

May 9, 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 Questions (2nd batch) to OPG - Technical Conference
Board File # EB-2007-0905 - Payment Amounts for
OPG's Prescribed Facilities

Enclosed are Board staff's questions (2nd batch) for OPG for the May 13-14 Technical Conference.

Yours truly,

Original signed by

Richard Battista
Project Advisor

Encl.

EB-2007-0905
Ontario Power Generation Inc.
Payment Amounts for Prescribed Generating Facilities
2008 and 2009 Revenue Requirement

Technical Conference:

Board staff follow-up questions on OPG responses to interrogatories

Issue 4.1: Production Forecasts for Nuclear and Hydroelectric

CORPORATE

1. In its response to Staff IR #24 OPG provides a table that summarizes hydroelectric production for the years 2005-07 and compares actual production with the forecast production referenced in Section 5.(1) of O. Reg. 53/05. Deviations of actual production from forecast production are used to calculate amounts in the Water Conditions Variance Sub-Account.

   a) The forecasted and actual GWh in the table in the answer to the IR does not match the evidence provided in Exhibit J1/T1/S1 Table 3. Which set of numbers is correct?

   b) According to the answer to IR #24, total cumulative hydroelectric production for the period from 2005 to 2007 exceeded forecast production by 301 GWh which should result in a total net credit balance in the variance sub-account. However, in the filed evidence (Exhibit J1/T1/S1 Table 3) OPG shows total cumulative actual production lower than forecast production by 211.5 GWh, resulting in a net debit balance in the sub-account of $6.7 million. Which set of figures is correct?

HYDROELECTRIC

2. OPG provides another table in the answer to IR #21 showing budget forecasted production and actual production for 2002-2007. The actual production numbers for 2005-2007 do not match the filed evidence and the forecast numbers do not match either the filed evidence or the answer to IR #24.

   a) Which set of numbers is correct?

   b) Are the forecast numbers taken from different forecasts?

NUCLEAR

3. In response to IR #26, OPG states that the approved Integrated Plan (for nuclear outages) for 2008 was adjusted from the previously approved IP. These adjustments "...reflected an expectation for improved outage performance, reversing the trend from previous years."

   a) What specific actions by OPG have led to this expectation of reversing a long-established trend of under forecasting nuclear outages?

9

b) Is it realistic to expect this trend to reverse in the span of one year?

4. In response to IR #32, OPG states that it can not verify the percentage deviations from planned outages calculated by Board staff. The percentage deviations were derived from OPG's filed evidence (Exhibit E2/T1/S/1, page 13 of 26, lines 26-30) and reflect the difference between actual outages taken – planned plus forced extension to planned outages – and the planned outages.

   a) What is the effective difference between "planned outages" and "forced extension to planned outages"? Do not both result in lost production?

   b) Does OPG forecast "forced extensions to planned outages (FEPO)"?

   c) Does OPG adjust its forecasts of "planned outages" to reflect its previous experience with FEPO?

NUCLEAR

Issue 6.1: Treatment of revenues from Segregated Mode of Operation (SMO), water transactions and Congestion Management Settlement Credits

1. **Re: IR #67.** OPG proposes in its application to treat revenues from SMO transactions differently than regular operations, recognizing that SMO transactions result in capacity and energy being unavailable to Ontario consumers.

   a) Notwithstanding OPG's answer to IR #99, what is the practical difference between an SMO transaction and an export transaction over the interties through the IESO? Is exported energy also not available to Ontario consumers?

   b) Implicit in the province's decision to "prescribe" certain OPG assets was the consideration that the benefits of low-cost power from "mature" generation assets should accrue to Ontario ratepayers. Assuming this objective, please advise why OPG did not use 100% of net SMO revenues as an offset to the prescribed asset revenue requirement?

HYDROELECTRIC

Issue 9.3: Forecast variance account revenues

1. **Re: IR#99.** In its answer to IR#99, OPG states that it "...does not forecast or attribute export sales revenues and energy volumes from the prescribed assets or any other generation facility."

   a) On an annual basis, what are OPG's gross export revenues for the 2005 to 2007 period?

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b) OPG has used various methods to apportion to the prescribed assets corporate overhead and administrative costs that are not directly attributable to these assets. Could a similar proportional methodology be used to attribute corporate revenues, such as export revenues, which are also not directly assignable to a specific generation asset?

CORPORATE

By Electronic Filing and By E-mail

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May 9, 2008

Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
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Toronto ON M4P 1E4

Dear Ms Walli

Ontario Power Generation Inc. ("OPG")
Board File No.: EB-2007-0905
Our File No.: 339583-000001

The clarifications Canadian Manufacturers & Exporters ("CME") will be seeking at the Technical Conference next week with respect to OPG's Responses to Interrogatories are set forth below.

1. <u>Customer Bill Impacts and Planning and Budget Guidelines</u>

Information on the guidelines considered by OPG to budget its revenue requirement has been provided in response to SEC Interrogatory No. 45 (Ex.L, T14, S45) and elsewhere. Board Staff Interrogatory No. 7 (Ex.L, T1, S7) refers to the February 23, 2005, Government Backgrounder describing the objectives for the prices of electricity produced by OPG. One of these objectives is to "protect Ontario's medium and large businesses by ensuring rates are stable and competitive." The consumer bill impacts of the approximate $1B revenue deficiency OPG seeks are referenced in the response to CCC Interrogatory No. 48 (Ex.L, T3, S48). There, OPG notes that a 14% increase in its revenue requirement translates into a typical residential consumer bill impact of about 2.7%.

In the context of this information, at the Technical Conference, CME will be seeking clarification from OPG with respect to the following:

(a) To what extent does the objective that OPG's prices for electricity to "protect Ontario's medium and large businesses by ensuring rates are stable and competitive" influence the planning and budget process that has produced the approximate $1B revenue deficiency which OPG claims in this case? What is the inter-relationship between consumer bill impacts and OPG's spending plans?

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(b) The manner in which OPG calculates the bill impacts of its revenue requirement proposal on typical customers needs to be explained. In particular, CME wishes to understand how to calculate the bill impact of OPG's proposals on the medium and large Ontario businesses referenced in the Ontario Government's February 23, 2005 Backgrounder. Attached is a slide from a presentation made to CME on April 29, 2008, by a representative of the Ontario Ministry of Energy, showing the Pricing on a Large Industrial Bill per 1,000/MWh in 2007. Using this information, and the information OPG relies upon to derive the customer class "base line" for its customer impact calculations, please explain how the customer bill impacts of OPG's revenue requirement proposal on Ontario's medium and large businesses can be estimated?

(c) According to the Government's February 23, 2005 Backgrounder, prices for OPG production are to be designed to ensure that the electricity rates for Ontario's medium and large businesses are competitive. CME seeks clarification of the manner in which OPG considers the impact of its approximate $1B revenue deficiency claim on the competitiveness of Ontario's medium and large businesses:

(i) What comparisons does OPG make of the electricity prices for Ontario's medium and large businesses, which will result if its $1B revenue deficiency is approved, to prices being paid by competitors of those businesses located elsewhere?

(ii) What information is available to show the electricity prices which competitors of Ontario's medium and large businesses, located elsewhere, are paying for electricity?

CORPORATE

2. Stranded Debt Component of Electricity Prices

The stranded debt component of electricity prices in Ontario is referenced in the evidence filed by OPG and a number of other parties. CME seeks clarification of the extent to which payments on account of the stranded debt component of electricity prices have any influence on the "Mitigation of Payment Amount Increases" features of OPG's Application referenced in Ex.K1, T1, S2. In this context, can OPG clarify whether it does anything to track the extent to which the stranded debt component of electricity prices is or is not being paid down by the Ontario Government in a timely manner, and does the extent to which the stranded debt component of electricity prices is being or should be paid down have any influence on the "Mitigation of Payment Amount Increases" feature of OPG's proposals?

CORPORATE

3. Compatibility of OPG Application Budgets with its Presentation to the OPG Board of Directors

In response to CME Interrogatory No. 2 (Ex.L4, T1, S2), OPG produced copies of the PowerPoint presentations to its Board of Directors of its Hydro Business Plan 2008 to 2010 and its 2008 to 2010 Nuclear Generation Development and Services and Nuclear Operations Business Plans. A number of items in these presentations, including OM&A and Capital Costs, have been redacted. As a result, it is impossible for CME to determine the extent to which the information presented to the OPG Board of Directors reconciles with the Application materials. Without getting into numbers, CME will be seeking clarification of the extent to which words have been redacted from the materials produced and some clarification of the meaning of some of the phrases used in these presentations. For example, in Ex.L-4-2 Attachment 1 at page 6, CME will seek clarification of the meaning to be ascribed to the phrase "Hydro OM&A Submission" and "Hydro Capital Submission". There are a number of pages where words appear to have been redacted from the PowerPoint presentations and CME will be seeking clarification of these redactions. CME will also be seeking to ascertain whether OPG will produce an unredacted copy of the materials under the auspices of a Board Confidentiality Order and Confidentiality Undertakings executed by those who wish to consider unredacted copies of OPG's productions.

HYDROELECTRIC

CORPORATE

4. <u>Impacts of Capital Structure and Cost of Capital Differences Between OPG and Others</u>

A number of OPG's Interrogatory Responses pertain to the impacts of using an Equity Ratio and a Rate of Return on Equity ("ROE") different from those proposed by OPG. In order to have the estimated impact of these differences in one place, CME will be asking OPG to estimate the extent to which the revenue deficiency will be reduced in each of the following Equity Ratio/ROE scenarios:

(a) Equity ratio of 40% and ROE of 7.75%,

(b) Equity ratio of 47% and ROE of 7.1%, and

(c) Equity ratio of 45% and ROE of 7.64%.

CORPORATE

We hope that the foregoing will assist OPG witnesses in preparing for the Technical Conference next week.

Yours very truly,

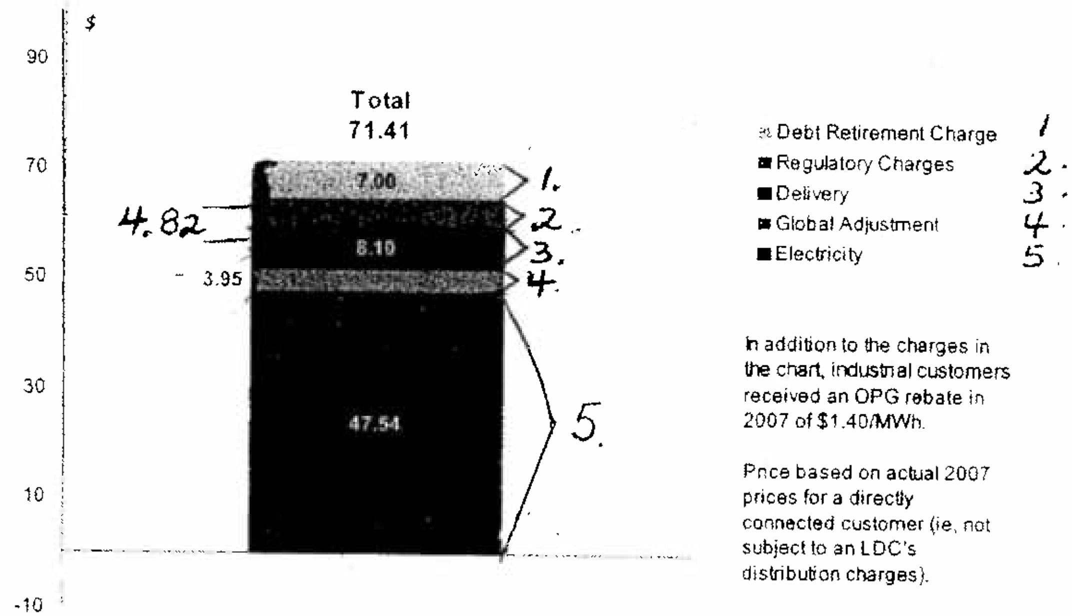
Peter C.P. Thompson, Q.C.

PCT\slc
enclosure
c. Interested Parties EB-2007-0905
Paul Clipsham (CME)
Vince DeRose (Borden Ladner Gervais)
Nadia Effendi (Borden Ladner Gervais)

OTT01\3453202\1

Energy

Pricing – Large Industrial Bill Per 1,000 kWh in 2007



In addition to the charges in the chart, industrial customers received an OPG rebate in 2007 of $1.40/MWh.

Price based on actual 2007 prices for a directly connected customer (ie, not subject to an LDC's distribution charges).

Source: Ministry of Energy using IESO figures

Ontario

EB-2007-0905

IN THE MATTER OF the Ontario Energy Board Act 1998, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an Application by OPG for an Order or Orders approving or fixing just and reasonable rates and other charges for the distribution of electricity commencing May 1, 2008.

SCHOOL ENERGY COALITION
Technical Conference Questions

1. **Ref:** SEC IR #4 [L-14-4]

Ref: J1/3/1: Pension/Other Post Employment Benefit ("OPEB") Cost Variance Account:

<u>*Follow-up:*</u>

a. Please provide any regulatory precedent for this account that OPG is aware of. CORPORATE

Base OM&A –Nuclear

2. **Ref: SEC IR #11 [L-14-11]**

Ref: F2/2/1, Table 1:

Original question (b): Base 2008 and 2009 OM&A for Pickering A increases considerably in the updated evidence, from $188.8 million to $197.7 million for 2008, and from $186.3 million to $201.3 million for 2009. Please explain.

Follow-up:

Please provide further detail on each of the explanations given. [we plan to ask various questions about each of the items listed in the response to L-14-11(b)] NUCLEAR

4. **Ref:** SEC IR #13 [L-14-13]

Ref: F2/2/1, pg. 5: please specify the increases in Base OM&A driven by changes driven by the CNSC.

Follow-up:

Clarification regarding the "Other areas" listed on pg. 2 of the response, for example:

NUCLEAR

- *What is the second full scope Darlington simulator and how does it help you meet operator staffing needs? How does it help you meet operator staffing needs?*
- *How do you arrive at $2.9 million by 2009 for the simulator?*
- *Is this driven by CNSC changes or demographic issues?*

5. **Ref:** SEC IR#14 [L-14-14]

F2/2/1, Table 2: "Other purchased services" increases from an average of $126 million in 2005 and 2006 to $162.3 million in 2007. The forecast for 2008 and 2009 ($160.5 million and $154.3 million respectively) remains close to the 2007 level. What was the reason for the large increase in "Other purchased services" costs in 2007. Why are those costs expected to remain close to the 2007 level in 2008 and 2009?

The Response refers to L-4-75 (CCC #75), which asked for a detailed 2008 and 2009 budget for other purchased services. This is the response:

> Other purchased services increases have been relatively constant in 2005, 2006 and 2007. The reason for the $98M increase from 2007 actual to 2008 plan is mainly due to:
>
> • Higher spending on contractor costs ($55M) to support the assessment work associated with refurbishment and new nuclear build programs.
>
> • Work by specialized service contractors ($35M) which is spread over >50 contracts associated with activities such as equipment repairs, improvements in the waste management program, process efficiency reviews and improvements, engineering initiatives to address obsolescence and safety issues.
>
> Other purchased services budget declines by ($17 million) from 2008 to 2009 mainly due to a reduction in contractor costs for associated with the assessment work on the refurbishment and new nuclear build programs.

Follow-up questions:

NUCLEAR

- *Does the reference to $55 million in assessment work refer to Pickering B?*
- *What else does it refer to?*
- *What is the $55 million made up of? How was that figure determined?*

6. Ref: **SEC IR #18 [L-14-18]**

Ref: F2/2/1, Table 4: please:

a. Expand Table 4 to show the total compensation for each year from 2005 to 20009 as well as the total year over year percentage increase in total compensation.

Follow-up:

- *The Table in Attachment 1 of L-15-18 shows a large % increase in OM&A base labour in 2006 over 2005. Also, Table 1 in L-16-16 (VECC IR #16)shows average compensation per FTE is $108.9k 2006 and $119.6k in 2006. Please explain the large increase in total and average labour costs in a single year.*

NUCLEAR

b. Provide average total compensation per FTE (divided by base pay, overtime, benefits and incentive pay) for 2005-2009.

The response refers to L-1-52 for 2006 and 2007. 2005 is attached to L-15-18.

Follow-up:

- *How does the chart on pg. 3 compare to the chart at L-1-52 (that one is broken down by PWU, Society and Management Group whereas the one at L-14-18, pg. 3 only has totals)*
- *Can you provide 2006, 2007 data for the chart at L-14-18, pg. 3?*

CORPORATE

<u>Outage OM&A- Nuclear</u>

10. Ref: SEC IR#38 [L-14-38]
Ref: Ex F3/1/1/Table 1, Ex F3/1/1/pg5 of 31: CIO Costs

Original question:

a. Please separately provide the amount related to the change of capitalization treatment and spending on project management system project costs.

Response: $14.3 million increase between 2006 and 2008 due to:

- $8 million for OEB payment amounts hearing;
- $4 million for related community engagement initiatives
- $1.8 for labour costs due to general escalation.

Follow-up:

- *has the $8 million been included in 2009 as well?*

CORPORATE

- *What are community engagement activities? Why are they increasing?* CORPORATE

CORPORATE:

Finance

11. Ref: **SEC IR#45 [L-14-45]**
Ref: Exhibit A2-2-1, pg. 2: Business Planning Overview

Follow-up:

L-14-45, Attachment 1: 2006 Business Plan

Pg. 2: there is a reference to the appropriate "return on equity"

- *What did OPG consider to be the "appropriate return on equity" at the time?*
- *Why is the first bullet point under "commitment to cost management" blacked out? It seems to refer to the need to contain costs in the regulated business (as the second bullet point refers to the non-regulated business) ?*

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L-14-45, Attachment 2: 2007-2011 Business Planning Information and Instructions

- *What is the date of this document?*
- *Pg. 3: reference to benchmarking its nuclear performance against other CANDU reactors? Has that been done? Are the results in evidence?*

NUCLEAR

13. Ref: **SEC IR#56 [L-14-56]**

Ref: Exhibit F3-1-1, pg. 18: Cost Allocation Methodology Review

a. The evidence states that one of R.J. Rudden's findings identified in its report was that "supporting analyses" were prepared by many central support and administrative costs groups and departments, including detailed analyses of activities, identification of specific resources, interviews to determine time estimates and reviews of invoices to determine historical usage.
   i. Please provide a copy of these supporting analyses.
   ii. The evidence says that "many" (as opposed to all) central support and administrative costs groups and departments prepared these supporting analyses. Please identify which groups did not provide such supporting analyses and explain why they did not.

Follow-up:

Please explain the document at Attachment 1. For example:

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1. *what does the percentage allocation column represent?*
2. *What does 100% allocation mean?*
3. *Why is there no info in the FTE's column?*
4. *What do the other columns represent?*
5. *Are the business groups shown in the first column all central support and administrative costs?*

Attachment 3: the response says Attachment 3 is a copy of the interview? This is just a spreadsheet showing the people interviewed for each business unit? Do you have the actual questions asked?

CORPORATE

14. Ref: **SEC IR#64 [L-14-64]**

Ref: Exhibit F3-3-1, table 2: Asset Service Fees – Nuclear

a. Please provide an explanation as to why the nuclear asset fees increase from $14.7M in 2005 to $30.8M in 2006.

Answer: refers to L-1-61 (Board Staff 61) [L-14-65 is also relevant for this question] That answer is reproduced below:

> OPG refined its methodology for computing asset service fees during 2006 to include certain Real Estate operating costs, such as the cost of utilities and facility maintenance, as a component of the fee. These costs were previously allocated to generation facilities through the cost allocation process.
>
> • OPG expanded the scope of the asset service fee concept in 2006 to all centrally held assets to achieve consistent treatment. Specifically, OPG included the Kipling Building Complex and Energy Markets assets in the scope of the asset service fee. Hence, costs related to these centrally held assets, such as depreciation, that were previously allocated to generation segments were essentially replaced by the service fee starting in 2006.

Follow-up questions:

- *What proportion of the increase is due to the change in methodology to include real estate operating costs and what proportion is due to the decision to expand the scope of the asset service fee concept?*
- *Where can we see the corresponding reduction in allocated costs in respect of real estate operating costs?*
- *Please explain the difference, from ratepayer point of view, of costs being allocated versus being included in the asset service fee.*

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15. Ref: **SEC IR#68 [L-14-68]**
Ref: Exhibit F3-4-1, pg. 9: Power Workers Union

Follow-up:

In OPG's response to part (b), it states that "skill broadening became part of the standard operating practice of the company because it was demonstrated to be a cost-saving initiative to OPG." Please explain how it was demonstrated to be a cost-saving initiative and specify what the cost-savings were.

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16. Ref: **SEC IR #69 [L-14-69]**
Ref: Exhibit F3-4-1, pg. 12: Management Group

a. Please provide a copy of the most recent report of the Compensation and Human Resources Committee's management group compensation review.

Follow-up:

Attachment 1: report to Compensation and Human Resources Committee

- *Who prepared this report?*
- *What was the reason for the report?*
- *Pg. 2: recommendation to increase base pay for managers. Was this done?*
- *Had OPG been experiencing any difficulties attracting or retaining management personnel?*

CORPORATE

17. Ref: SEC IR #76 [L-14-76]
Ref: Exhibit C1-2-2, pg. 2: Existing Long-Term Debt Issues

The evidence states that OPG reached an agreement with the OEFC to provide financing of up to $1B for the Niagara Tunnel project. Please provide a copy of this agreement, together with the interest rate analysis by OPG to support the rate provisions.

Follow-up:

The interest rate under the Credit Facility is defined as the Base Rate plus the Applicable Spread. The Base Rate is the Benchmark Government of Canada bonds, and the Applicable Spread is defined as the "additional spread in basis points …that will apply to an Advance, as determined by the OEFC based on a survey of market rates."

- *What conditions or parameters, other than those stated, are placed on OEFC in determining the Applicable Spread?*

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- *Please provide the Base Rate and Applicable Spread on all Advances under the Credit Facility since 2005.*

CORPORATE

18. Ref: **SEC IR #81 [L-14-81]**

Ref: Exhibit G1-1-1, table 1: Other Revenues – Regulated Hydroelectric

b. The chart indicates that the "actual" revenues have been much higher than the "budget" revenues in 2005, 2006, and 2007. Please explain why this is the case.

Follow-up:

Response says that evidence indicates- at G1-1-1, pg. 7 – that segregated mode of operations and water transactions are not forecasted. The reason stated in the evidence is as follows:

> *For purposes of the regulated payment amount calculation, SMO revenues are not used as an offset to the hydroelectric revenue requirement. The volume and revenue associated with SMO transactions are difficult to forecast as they are a response to hourly market-based signals (specifically demand and excess generation) and prices.*

The evidence then states that OPG will share the net revenues it earned from SMO transactions for the interim period.

- *Why are segregated mode of operations and water transactions difficult to forecast?*
- *What exactly is OPG's proposal re sharing the net revenues from SMO transactions for the interim period?*
- *How does OPG intend to deal with 2008 and 2009?*
- *Is it OPG's position that these revenues not be included (or deducted) from the revenue requirement simply because they're difficult to forecast?*

HYDROELECTRIC

b. The actual revenue in 2006 ($57.9M) is significantly higher than revenues in other years. Please explain why this is the case.

Follow-up:

- *Explain what the "automatic generation control contract" with IESO was?*
- *Was it for one-term (2005-2007) only?*
- *Why wasn't it renewed?*

HYDROELECTRIC

- *Second reason given: different accounting period for 2005: how would this explain the lower revenues for 2007 and 2008?*

HYDROELECTRIC

19. Ref: **SEC IR #83 [L-14-83]**
Ref: Exhibit I1-1-1, pg. 15 – Chart 1

a. Please provide a copy of the full analysis through which the values presented in "Chart 1, Estimated Benefits of Sir Adam Beck Complex Operations to Consumers" were obtained.

Response: see Board Staff #91 [L-1-91]

Follow-up:

- *What are the costs to ratepayers from this proposal?*
- *In Board Staff 91 [L-1-91], OPG says its economic simulations showing the benefit to consumers starts with the baseline of none of the PGS units running? Why is that?*
- *I1/1/1, pg. 11: formula for OPG's proposed hydroelectric payment amount: what is the difference between MWavg (defined as hourly volume or the actual average hourly net energy production over the month) and MW(t) (defined as net energy production supplied into the IESO market for each hour of the month)*

HYDROELECTRIC

Production Forecast

20. Ref: **SEC # 84 [L-14-84]**

Ref: Exhibit E1-1-1, pg. 3: Hydroelectric Production Forecast

The evidence states that potential water transactions with New York Production Authority are computed in the forecasting application, however water transactions with respect to the use of OPG's share of water by New York Power Authority are not included. Please explain why the New York Power Authority's share of water is not included in the production forecast.

Follow-up:

The pre-filed evidence states as follows:

Potential water transactions with New York Power Authority are also computed in the forecasting application, with adjustments applied based on assessment of historical performance with respect to transactions (see

Ex. G1-T1-S1 for a discussion of water transactions). However, water transactions with respect to the use of OPG's share of water by New York Power Authority are not included in the production forecast for the regulated hydroelectric facilities.

- *Please explain the difference between water transactions with NYPA, which are computed in the forecasting application, and water transactions with respect to the use of OPG's share of water by NYPA, which are not included in the production forecast?*

HYDROELECTRIC

22. Ref: **SEC IR#91 [L-14-91]**

Follow-up:

The reply states that the current lease with St. Lawrence Seaway Management Corporation expires in June 2008 and "expectations are that rental payments will be determined by alternative means for the next term."

- *Does OPG have any more information on what alternative means will be used to determine the lease payments for the next term?*
- *Why was it necessary to change the means by which lease payments were determined? Did OPG ask for this change or did St. Lawrence Seaway Management Corporation?*

HYDROELECTRIC

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May 9, 2008

VIA MAIL and E-MAIL

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

Dear Ms. Walli:

Re: Vulnerable Energy Consumers Coalition (VECC)
EB-2007-0905
Ontario Power Generation Inc.

Please find enclosed the Technical Conference Questions from VECC in the above noted matter.

Yours truly,

Michael Buonaguro
Counsel for VECC
Encl.

EB-2007-0905

Ontario Power Generation Inc.

Payment Amounts for Prescribed Generating Facilities

2008 and 2009 Revenue Requirement

Technical Conference

VECC Follow-up Questions to OPG on Interrogatory Responses

1. Reference: L-16-2 (VECC IR No. 2)

Preamble

This IR requested information on capital expenditures included in the application which may provide benefits to the unregulated business. In response, OPG stated that "none of the projects, for which capital spending is forecast in this application in respect of prescribed assets, will benefit OPG's unregulated assets, with the exception of certain capital expenditures by OPG's corporate groups that are included in Ex. D3-T1-S1, Table 1. Please refer to the response to L-16-5 for the discussion of capital expenditures by OPG's corporate groups."

The Table 1 referenced is subtitled "Capital Expenditures in Corporate Groups impacting Prescribed Facility Rate Base or Asset Service Fee."

a) Can OPG provide a breakdown of the capital expenditures in the referenced Table showing the amounts impacting the regulated rate base and the amounts impacting the service fee with a brief explanation?

b) Can OPG provide a breakdown with respect to the allocation of responsibility for recovery of these capital expenditures – from regulated and unregulated businesses – of the amounts shown in Table 1?

c) Can OPG confirm that no (i) fees or (ii) return of capital or (iii) return on capital in respect of capital spending on assets shown in Table 1 are being recovered in this application from ratepayers before the associated capital projects are used and useful (in service)?

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d) With respect to the OPG Clarington Energy Park Development Project described at Ex. D3-T1-S2 p.4, can OPG confirm that this project is entirely to the (expected) benefit of the regulated operations?

e) With respect to the OPG Clarington Energy Park Development Project, are all costs being capitalized?

f) With respect to the OPG Clarington Energy Park Development Project, please indicate what costs are being recovered over the test period from ratepayers under OPG's proposals and the rationale for such recoveries.

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2. Reference: L-16-4 (VECC IR No. 4)

Please indicate whether OPG would accept a capital expenditure variance account which would hold ratepayers harmless in the event that actual capital expenditures during the test period were significantly less than forecasted capital expenditures during the test period.

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3. Reference: L-16-7 (VECC IR No. 7)

This IR asked OPG to "provide a table showing past historical, current, and projected (i.e., for 2008 and 2009) rates of OM&A capitalization in respect of the prescribed facilities. OPG's response appears to be unresponsive. Can OPG provide such a table showing Gross OM&A, Net OM&A, and the percentage capitalized?

CORPORATE

4. Reference: L-16-15 (VECC IR No. 15)

Preamble

This IR noted that the data in Ex. F1-T2-S1 Table 1 indicated that compensation to labour in OPG's regulated hydroelectric business averaged $100.8K per FTE in 2005 and steadily increased over the period 2005-2009 to an average of $130.0K per FTE in 2009, representing an average annual increase of 6.6% per FTE per year over 2005-2009.

OPG confirmed that the VECC calculation was correct while noting the significant increases in pension and OPEB costs over this period, referencing Ex. F3-T4-S1 Chart 6.

Preliminary calculations by VECC using the information contained in Ex. F1-T2-S1 Table 1 and F3-T4-S1 Chart 6 appear to show an unusual pattern in direct labour costs per FTE for regulated hydroelectric operations, though "the allocation of costs related to corporate support functions" referred to in note 1 to Chart 6 may be responsible.

a) Please provide a table breaking out total labour compensation for the regulated hydroelectric business among (i) direct labour costs, (ii) direct pension and OPEB costs not including allocations of costs related to corporate support functions, and (iii) allocations related to corporate support functions. Also please show these categories on a per FTE basis in the table and provide explanations for any large proportional changes year-over-year in the "per FTE" figures.

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b) Please provide a similar table for the prescribed nuclear facilities.