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December 6, 2010

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-2010-0008: Ontario Power Generation Inc. – Payment Amounts

Please find enclosed the submissions of VECC in the above noted proceeding.

Yours truly,

Michael Buonaguro
Counsel for VECC
Encl.

EB-2010-0008

FINAL SUBMISSIONS OF THE VULNERABLE ENERGY CONSUMERS COALITION

Table of Contents

INTRODUCTION

1. These are the final submissions of the Vulnerable Energy Consumers Coalition (“VECC”) with respect to the application by Ontario Power Generation Inc. (“OPG”’) for rates effective March 1, 2011 covering a test period from January 1, 2011 to December 31, 2012.

2. VECC’s submissions are organized using the approved issues list, with the caveat that if VECC has no submissions under an issue in the issues list we have not included that issue in our submission.

3. VECC is in receipt of the comprehensive submissions distributed by the Board Staff team on November 30, 2010, and to a large extent VECC adopts and relies on those Board Staff submissions where Board Staff’s analysis and conclusions align with those of VECC. Accordingly, in these submissions, we have identified those issues wherein VECC specifically relies on the submissions of Board Staff in lieu of making duplicative submissions, and in some instances either added to Board Staff’s submissions or qualified VECC’s support for Board Staff’s position.

4. Additionally there are certain issues where VECC is aware that other intervenors are making specific submissions that are consistent with VECC’s analysis and conclusions; where possible VECC has previewed those submissions and has specifically adopted them.

5. For issues that VECC has not specifically made submissions or specifically adopted submissions from either Board Staff or other intervenors it should not be assumed that VECC accedes to the position of OPG as set out in OPG’s application and submissions.

RATE BASE

2.1 What is the appropriate amount for rate base?

6. VECC has reviewed the submissions of Board Staff on this issue[1] and adopts them as appropriate, specifically (i) the reduction of $12.0M in the hydroelectric rate base associated with the St. Lawrence Visitor Centre in 2011 and 2012 and (ii) the reduction in nuclear rate base of $128M and $161M in the 2011 and 2012 rate bases respectively, as summarized on page 22 of the Submission.

[1] Board Staff Submission, EB-2010-0008, dated November 30, 2010, pages 19-22

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

Summary

7. VECC respectfully submits that OPG's proposal to include CWIP in rate base for the Darlington Refurbishment Project be rejected. However, in the event that the Board decides to approve OPG's CWIP proposal, VECC supports Board Staff's proposal that the return on any such assets included in rate base be limited to interest costs only, i.e., excluding any ROE.

VECC Submission

8. VECC has reviewed Board Staff's Submission on this issue[2] and supports that submission, particularly in respect of (i) the fact that the DRP proposal does not fall within the scope of the Board's Report entitled *The Regulatory Treatment of Infrastructure Investment in connection with the Rate-regulated Activities of Distributors and Transmitters in Ontario,* (ii) the insignificant threat of rate shock should the request be denied, and (iii) the lack of evidentiary support for OPG's claim that failure to receive approval of the CWIP proposal would negatively impact OPG's credit rating.

9. VECC adds that OPG has stated that failure to receive approval of its CWIP proposal will have no effect on their decision to proceed with the DRP.[3]

10. VECC would also like to draw the Board's attention to the response given to VECC IR 14 c)[4] in which in both examples shown, the $6B project and the $10B project, the current regulatory treatment results in a lower NPV of costs recovered from ratepayers than does the proposed CWIP treatment.

11. Therefore, given VECC's views with respect to the inapplicability of the Board's Report to the current proposal under consideration and the lack of justification for the CWIP proposal through rate shock and credit risk arguments, VECC submits that there is no good reason, compelling or otherwise, provided on the record, to support saddling ratepayers with a higher cost recovery (in NPV terms) than is required.

12. Indeed, VECC submits that in a project appraisal exercise, where alternatives are being considered, the approach leading to the lowest cost in terms of NPV would be preferred, other things equal (i.e., the same project revenue profile, same discount rate, and the same life of the project and lifetime of the asset being considered).

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[2] Board Staff Submission, EB-2010-0008, dated November 30, 2010, pages 35-38
[3] VECC IR Exhibit L Tab 14 Schedule 004 a)
[4] Ibid part c)

13. Therefore VECC urges the Board to deny the proposed CWIP treatment of the DRP.

CAPITAL STRUCTURE AND COST OF CAPITAL

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

With respect to capital structure, VECC accepts OPG's proposals as filed. For the return on equity, VECC submits that the ROE for 2011 should be based on data three months in advance of the effective date and then updated for 2012.

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

14. VECC respectfully agrees with the Board Staff submission[5] that the rate used for the notional long term debt should, all things being equal, attract the same rate as OPG's actual long term debt, in accordance with the Board's May 28, 2009 decision in EB-2008-0272 at pages 54 and 55, rather than the Board's deemed long term debt as proposed by OPG:

> The Board agrees with intervenors that it is not appropriate to apply the Board's deemed long-term debt *rate* to the notional or deemed long-term debt. The two are quite separate concepts. The deemed long-term debt rate is clearly intended to apply in the absence of an appropriate market determined cost of debt, such as affiliate and variable rate debt situations. For companies with embedded debt, it is the cost of this embedded debt which should be applied to any additional notional (or deemed) debt that is required to match the capital structure to the Board's deemed capital structure. This is consistent with the treatment given to LDCs that have undergone rebasing in 2008 and 2009.
>
> Hydro One's cost of capital shall be adjusted to use its weighted average cost of embedded debt for purposes of determining the cost to be applied to the notional or deemed long-term debt.[6]

15. The total revenue requirement impact of applying OPG's weighted average cost of embedded debt for the purpose of determining the cost of OPG's notional or deemed long-term debt is a reduction of approximately $4.2M as set out in Exhibit L Tab 14 Schedule 5 a) relative to their proposal based on

[5] Board Staff Submission, pages 6-8.
[6] VECC notes that this principle was adopted by the Board several months after the OPG decision in EB-2007-0905 dated November 3, 2008, and that the principle was re-affirmed in the April 9, 2010 Decision in EB-2009-0096 with respect to HONI Tx at page 46, a decision made after and in contemplation of the release of the Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, EB-2009-0084, dated December 11, 2009.

the 2010 deemed debt rate, assuming the capital structure and rate base presumed by the application.

16. Board Staff, in its argument, points out that the OPG's proposal to use the Board's deemed rate for notional debt is marginally less costly then OPG's forecast long term debt as a result of the updating of the deemed debt rate for 2011 filings. VECC agrees with Board Staff's suggestion that the Board may consider accepting OPG's proposal given the circumstances, although VECC does support the consistent application of the Board's policy regarding the extension of the utility's weighted average cost of actual debt to notional debt amounts in the normal course.

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

17. VECC respectfully submits that the same capital structure and cost of capital should be used for both OPG's regulated hydroelectric and nuclear businesses, and defers to the argument of OPG in reply to the argument to be advanced by some intervenors supporting separate capital structures and/or cost of capital parameters.

CAPITAL PROJECTS

Nuclear

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

4.6 Are the proposed in-service additions for nuclear projects appropriate?

Darlington Refurbishment Project

18. VECC respectfully submits that the Board should explicitly reject any notion that its decision provides any level of approval for OPG's expenditures with respect to the Darlington Refurbishment Project ("the DRP"), as OPG has specifically said it is not seeking Board approval of the Project.[7]

19. VECC notes that Board Staff raises the concern that a rejection of the impacts of the Darlington Refurbishment Project on 2011-2012 rates has an associated impact of approximately $200M:

> Board staff notes that the revenue requirement impact of the DRP as proposed by OPG is a credit of $200 M; or put another way, were the

[7] OPG AIC page 40.

Board were [sic] to disallow the DRP costs and service life adjustments and other changes, OPG's test period revenue requirement would increase by about $200M.[8]

20. The approximately $200M in net impact of the DRP is itemized at Exhibit D2 Tab 2 Schedule 1 Table 2. Presumably the concern raised by Board Staff is that, as OPG is not actually seeking approval of the DRP, then it may be inappropriate to approve any of the impacts of the DRP, even though those impacts are, in the test period, to the credit of ratepayers.

21. VECC notes that the approximately $200M in net "credit" associated with the DRP can be disaggregated into 3 categories:

    a) The CWIP in rate base proposal impact of the DRP,
    b) The net impact of the DRP on test period Nuclear Liabilities expenses, and
    c) The net impact of the DRP on test period non-Nuclear Liability expenses.

The CWIP in rate base proposal impact of the DRP

22. As set out in Exhibit D2 Tab 2 Schedule 1 Table 2 the net revenue requirement of the CWIP in rate base proposal of the DRP is $37.9M, a debit to ratepayers.[9] As noted earlier in this argument VECC submits that the CWIP in rate base proposal should be rejected by the Board as submitted by Board Staff, an argument that operates independently of whether it approves or disapproves, to any degree, the DRP, and as such can be separately eliminated from consideration in terms of any concern about including the DRP impacts in the test period. In VECC's view rejecting the CWIP in rate base proposal essentially reconciles the dilemma of approving or not approving the DRP in this proceeding, as the capital costs of the project will not be entering rate base until the project is actually a) approved and b) used and useful. Eliminating consideration of the CWIP proposal as a separate item increases the net credit of the DRP in the test period to $235.2M.

The net impact of the DRP on test period Nuclear Liabilities expenses

23. Once one eliminates consideration of the CWIP in rate base proposal, the net credit of $235.2M in the test period associated with the DRP can be further split into Nuclear Liability and non-Nuclear Liability amounts. A review of the itemized DRP impacts shows that the Nuclear Liability associated impacts of the DRP are a credit of $188.8M, approximately 80% of the total net credit to ratepayers in the test period.[10]

[8] Board Staff Submission, page 39.
[9] Exhibit D2 Tab 2 Schedule 1 Table 2 line 2 + line 12.
[10] Exhibit D2 Tab 2 Schedule 1 Table 2 lines 1+5+9+11+14+15+20+21+22+24+25.

24. As discussed in more detail with respect to the issue of the recovery of 2010 related impacts of the DRP on Nuclear Liabilities, the revenue requirement related to Nuclear Liabilities is specifically governed by regulation 53/05, which creates the Nuclear Liability Deferral Account in connection with the obligations of OPG under the Ontario Nuclear Funds Agreement ("ONFA"), which in turn requires the drafting and approval of reference plans setting out OPG's Nuclear Liabilities.

25. The nature of the Nuclear Liabilities amount as it exists in the revenue requirement, in conjunction with the protection afforded OPG under the ONFA and the Nuclear Liability Deferral Account, is such that, VECC submits, OPG is protected from any underfunding in the test period in relation to Nuclear Liabilities if it turns out the DRP is rejected and the various changes in its Nuclear Liabilities for the test period do not, in fact, occur. Under such circumstances, VECC submits, the various components of the Nuclear Liabilities, through the updating of the reference plan, will simply be updated to account for the current state of OPG's Nuclear Liabilities and captured in the Nuclear Liability Deferral Account. It is in part because of this protection afforded OPG, VECC submits in later argument, that ratepayers should be protected from overpaying towards Nuclear Liabilities when, as appears to have happened in 2010, the amount recovered for Nuclear Liabilities exceeded OPG's actual Nuclear Liabilities for the year as a result of an accounting change.

26. In this way, VECC submits, the Board can approve the impacts of the DRP on OPG's Nuclear Liabilities related revenue requirement, knowing that if it turns out those impacts are based on an incorrect assumption that the DRP will go ahead the updating of the reference plan and the operation of the Nuclear Liability Deferral Account will "true up" the impacts in the future through, as Board Staff puts it, the "unwinding" of the depreciation assumptions.[11]

The net impact of the DRP on test period non-Nuclear Liability expenses

27. After accounting for the CWIP proposal and the Nuclear Liability expenses there remains a net impact of $46.4M, related almost entirely to the decrease in depreciation expense of $65.3M, offset to some extent by an increase in the return on the existing Darlington Assets of $8.5M and an increase in OM&A expense of $10.4M.

28. Again, a future disallowance of the DRP will be captured by an unwinding of the depreciation rate change. However the OM&A expense would not be recoverable, it appears to VECC, unless the Board specifically required a

[11] It appears to VECC, for example, that the current effort to update the existing reference plan, including the underlying cost assumptions, could have a material effect on the test period Nuclear Liabilities quite apart from the impact of the DRP.

variance account to track the OM&A expense of $10.4M in the event the Board ultimately disallows all the costs associated with the DRP, per the scenario posed by Board Staff at page 39 of its submissions.[12]

29. Accordingly, VECC submits, the Board can and should

a) explicitly reject the notion that it is approving the DRP in this proceeding,
b) nevertheless, allow the net credit impact of the DRP over the test period (exclusive of the CWIP in rate base proposal) to be realized, and
c) establish a DRP variance account to allow the Board to track the DRP related OM&A expenses for future prudence review as proposed by Board Staff.

PRODUCTION FORECASTS

Regulated Hydroelectric

5.1 Is the proposed regulated hydroelectric production forecast appropriate?

30. VECC respectfully agrees with Board Staff's proposal that the variance from the production forecast associated with surplus baseload generation should be tracked in a variance account in the manner described by Board Staff in its submission at pages 83 and 84. VECC presumes that the proposal by Board Staff at page 84 that:

> OPG corroborate the specific SBG loss claims through reference to IESO orders (if applicable), general market conditions (total demand, total baseload supply) and audited production reports from the SBG-affected generation units that demonstrate deviations from near-time trend production that is contemporaneous with SBG market conditions.

is intended to ensure that claimed instances of surplus baseload generation causing lost production relative to the test period production forecast are:

a) caused by external factors (IESO order, market conditions causing lost production beyond the control of OPG) and
b) coincide with the actual production capacity of the relevant OPG units.

[12] It appears to VECC that Board Staff, in asserting that test period expenditures related to the DRP, in the event the DRP is ultimately rejected, could be disallowed, contemplated that those expenses would be captured in a deferral account for the prudence review of those expenditures in the next rate case that Board Staff seems to envisage.

Nuclear

5.2 Is the proposed nuclear production forecast appropriate?

31. VECC agrees with Board Staff's submission that the nuclear production forecast should be adjusted by eliminating the 2.0TWh per year allowance for major unforeseen events, with a corresponding reduction in revenue requirement of approximately $200M.[13]

OPERATING COSTS

Nuclear

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

32. VECC has reviewed a draft of SEC's submissions on this issue and adopts these submissions.

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

33. VECC has reviewed a draft of SEC's submissions on this issue and adopts these submissions.

6.6 Is the forecast of nuclear fuel costs appropriate?

Summary

34. VECC respectfully submits that there is a good probability that the forecasted nuclear fuel costs are too high.[14] Further, all of the impacts on ratepayers of such an over-forecast are not recorded in the existing Nuclear Fuel Cost Variance Account.

35. VECC submits that the current variance account treatment rewards over-forecasting fuel costs through the impact of these cost estimates on working capital and hence rate base. VECC proposes that a separate variance account or sub-account be established to track the revenue requirement impacts of any variances of forecast fuel costs over actual fuel costs, through inflating the forecasted working capital component of rate base over the actual required working capital component.

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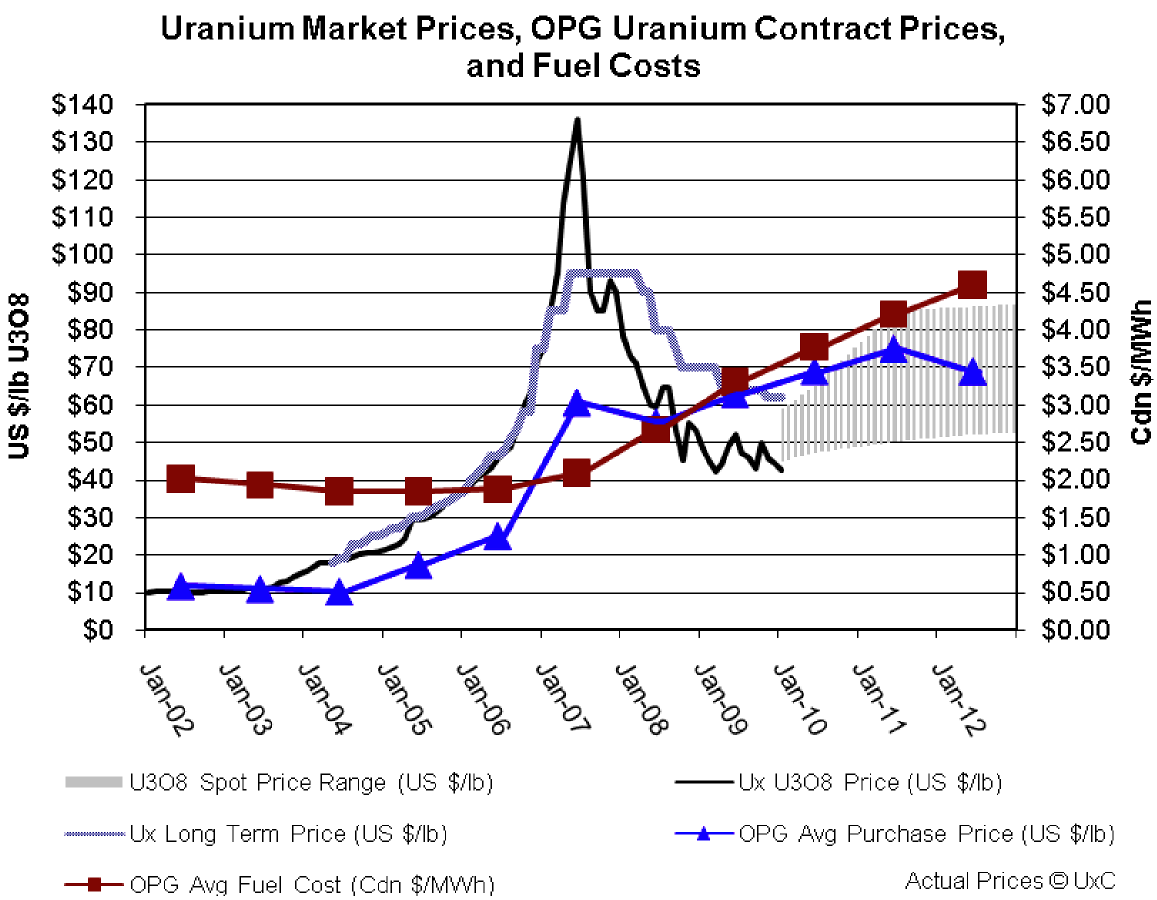
[13] Board Staff Submission pages 85-87.
[14] The response to SEC IR L-14-033 indicates that these costs have been consistently over-forecast.

36. Finally, VECC respectfully submits that an external review of OPG's nuclear fuel procurement strategy, with the objective of minimizing nuclear fuel costs subject to not exceeding some appropriate target level(s) of volatility, is warranted. VECC submits that such a report be finalized in time to file at OPG's next payment amounts proceeding.

VECC Submission

37. VECC has reviewed Staff's submissions on this issue[15] and supports their submissions on this issue, with two minor caveats.[16] Below, VECC provides some brief additional comments on the evidence and then outlines the two caveats aforementioned.

38. The chart shown below is reproduced from the pre-filed evidence.[17]



[15] Board Staff Submission, November 30, 2010, pages 53-59
[16] As discussed below, these relate to VECC's proposal for an independent review of OPG's nuclear fuel procurement strategy and to Board Staff's proposed variance account incentive proposal.
[17] Exhibit F2 Tab 5 Schedule 1 page 12

39. Board Staff has already ably noted the disconnect between uranium price and fuel cost as evidenced in this graph and also noted that while volatility is reduced in fuel costs, the fuel costs steadily increase, independent apparently of succeeding spot price decreases.[18]

40. VECC notes that this graph also shows that when the “spot price” (Ux U308 Price as shown by the black line) is low and stable, as between January 02 to Mid 03, OPG’s strategy appears to be successful at maintaining a low cost and low cost variance. However, under these conditions VECC submits that virtually any procurement strategy would achieve such performance. After the spot price begins to rapidly increase, OPG’s procurement approach does not appear to be as successful.

41. Regarding the current strategy, it appears from the testimony that there is considerable discretion practiced with respect to short-term purchase decisions as evidenced by the following exchange:

> MR. BUONAGURO: Right. So if a spot market opportunity, I will call it, came up right now, to buy substantially cheaper than what you have on hand, uranium, it doesn't sound like it would be very easy for you to take advantage of it. Is that what I am hearing?
>
> MR. MAUTI: We always consider whatever opportunities may be there. We also get unsolicited offers to sell uranium to us. We would have to assess whether we felt it was appropriate to maybe buy and hold that uranium for a period of time.
>
> Foregoing any additional need at some point in the future, there is always a cost associated to that, such as the holding cost and working capital cost of carrying additional amounts. It is not something that is impossible to do, but if it is outside of the ranges, it gets evaluated and brought to a more senior level in the company for that decision.[19]

42. VECC accepts that current fuel prices include the lagged effects of prior purchases and also of the average inventory accounting procedures used to calculate current costs as evidenced in the following exchange:

> MR. BUONAGURO: Okay. Then just going back to this red line, my understanding is that that red line, which is what forms the revenue requirement for the test period, doesn't anticipate any what I would call spot market opportunities in the two years. It is based entirely on your existing index price contracts and your market-priced contracts?
>
> MR. MAUTI: I guess, bear in mind as you buy uranium it goes in as the first part of our inventory cycle, it gets averaged out, and as that

[18] Board Staff Submission, November 30, 2010, pages 55
[19] Transcript Volume 4 page 164

happens and gets converted into dioxide and converted into a fuel bundle, it has an impact on the averaging of that process.

So while it is lagged, it is not invisible over the next couple of years

So if you make a uranium purchase today, there is -- at today's lower average price than currently is in your inventory, you will see an impact of it is. Is it not direct and not immediate, but you do start to see impacts from that.

MR. BUONAGURO: So for example, when did you say the last spot market price was?

MR. MAUTI: There were purchases in 2009.

MR. BUONAGURO: So presumably, the impact of that on revenue requirement would be starting to be felt now, or in the next year?

MR. MAUTI: Well, those purchases were factored into the value of our inventory that we used as part of our planning purposes to set these amounts.[20]

43. As such, VECC cannot conclude conclusively that there are significant defects in the current procurement strategy. However, as it is VECC's understanding that there has not recently been an independent review of OPG's nuclear fuel procurement strategy, VECC submits that the Board should order an independent review of OPG's nuclear fuels procurement strategy to be completed in time for OPG's next Payment Amounts proceeding.

44. With respect to the Nuclear Fuel Cost Variance Account, VECC accepts Board Staff's submissions regarding the current incentive for OPG to over-forecast fuel costs thereby increasing rate base and return, undeservedly, through the associated increase in forecasted working capital.[21]

45. Board Staff has proposed asymmetrical sharing of variances of actual fuel costs to forecast: 50:50 sharing if actual costs are above forecast but 100% credit to ratepayers for any variances below forecast. Further, Staff has proposed that the variance account be restructured to capture the impacts of such variances on rate base through the fuel inventory costs included in working capital allowance.[22]

46. With respect to the first proposal, it appears to VECC that under-forecasts will be punitive for OPG while OPG will be held whole in the case of over-forecasts.

47. For example, in the case of actual costs being $1M, in the event of forecasted costs being $500K, OPG would only recover $750K if VECC understands

[20] Transcript Volume 4 pages 165-166
[21] Board Staff Submission, November 30, 2010, page 58
[22] Ibid pages 58-59

Staff's proposal correctly. But had the forecast been for $1M or any higher amount, OPG would recover the actual cost of $1M.

48. Therefore, the ultimate effect of implementing Board Staff's proposal might be to (i) disincent under-forecasting due to the punitive results and thereby incent over-forecasting to avoid these punitive consequences or (ii) incent holding costs to the forecast level. While VECC believes there is merit in Board staff's proposal, VECC urges further analysis be given to this imaginative proposal prior to approval in order to avoid unintended consequences.

49. Finally, VECC submits that rather than restructuring the existing variance to capture rate base-related revenue requirement impacts of variances from forecasted fuel costs, it would be preferable to establish a new account or sub-account to track these impacts on transparency grounds.

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

Corporate Costs

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

50. VECC has reviewed Board Staff's submissions with respect to compensation levels and test period increases[23]and adopts Staff's position on these issues. VECC notes that in previous decisions, the Board has reduced the revenue requirement of an applicant when the applicant's compensation costs were significantly above the market median or 50th percentile.[24]

51. Regarding nuclear FTEs approved and actual 2008-2009, VECC supports Staff's submission that "OPG appears to have collected $106M on account of its last proceeding that it did not spend on employee compensation and … this should be taken into account in determining the appropriate compensation amount to be included in OPG's revenue requirement."[25]

[23] Board Staff Submission, November 30, 2010, pages 64-69
[24] Decision with Reasons in EB-2008-0272 and EB-2009-0096
[25] Board Staff Submission, November 30, 2010, page 70

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

52. VECC has reviewed Board Staff's submissions on matters relevant to this issue and adopts these submissions as they appear on pages 70-75 of the Submission dated November 30, 2010.

OTHER REVENUES

Regulated Hydroelectric

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

53. VECC respectfully submits that the forecasted revenue from the segregated mode of operation and water transactions should be based on the methodology approved in EB-2007-0905, with a resulting total increase in the revenue from those two sources over the test period of $13M.[26]

54. The methodology approved by the Board for the 2008-2009 test period was as follows:

> The Board concludes that an appropriate approach will be to include the average net revenues over the last three years into the forecast as a revenue offset in each year of the test period. In the case of SMO, the offset will be $6.6 million; for WT, the offset will be $6.9 million. (These amounts are for 2009; the amount for test period portion of 2008 will be 75% of that amount.) Any incremental revenues will accrue to OPG. This also simplifies the regulatory structure by eliminating the need for deferral accounts.[27]

55. In this way the Board approved methodology embeds, over time, the actual performance of the company with respect to segregated mode of operation and water transactions[28], while at the same time providing the company with an incentive, within the test period, to increase the revenue from these two sources by allowing the company to keep any revenue in excess of the forecast amount.

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[26] Exhibit L Tab 14 Schedule 26 illustrates the difference in other revenue between the as filed Plan and the previously approved Forecast Methodology for 2011 and 2012. VECC has no submissions with respect to the Ancillary Services revenue forecast.
[27] EB-2007-0905 Decision dated November 3, 2008 page 48.
[28] Transcript Volume 1 page 40-41.

56. VECC notes, for example, that in 2008 OPG earned $12.8M in excess of the embedded forecast amounts for Segregated Mode of Operations and Water Transactions combined, retained as a benefit to it resulting from the Board's approved methodology. Failing to subsequently incorporate the actual overearning in 2008 into the following year forecasts is inappropriate, as it is an essential nature of the forecasting methodology that actual overearning in any particular year be captured in subsequent test year forecasts to the benefit of ratepayers.

57. The flip side to earning that benefit under such a methodology, VECC submits, is that in subsequent periods the overearning by the company in previous periods increases the threshold OPG has to meet before achieving incentives, and increases the risk of losses as the threshold increases and affects the forecast. That is the nature of the methodology, which will, over time, reflect any under-earning that OPG experiences to lower the threshold in the future.

58. Accordingly VECC submits that the methodology for forecasting revenue for segregated mode of operations and water transactions should remain unchanged, such that the forecast amounts as set out in response to Exhibit L Tab 14 Schedule 26, which produce a revenue requirement increase relative to the application of $13M, should be used.

Nuclear

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

59. VECC has reviewed a draft of SEC's argument and supports SEC's position that revenue from heavy water sales should be treated as an offset to OPG's revenue requirement.

NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING LIABILITIES

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

Summary

60. VECC respectfully submits that OPG's treatment of the impact of the Darlington Refurbishment Project (the "DRP") on its 2010 Nuclear Liabilities was inappropriate such that ratepayers should receive full value for the ratepayer contribution towards Nuclear Liabilities that was embedded in 2010 rates.

61. VECC's primary position is that the full (net) impact of the DRP on Nuclear Liabilities in 2010 should be used as an offset to the test period revenue requirement by virtue of OPG's circumvention of the Nuclear Liabilities Deferral Account which should have captured the reduction in Nuclear Liabilities in 2010. VECC calculates the full (net) impact to be $64.2M exclusive of related tax impacts.

62. VECC's alternative position is that ratepayers should receive full credit for their contribution towards Nuclear Liabilities in 2010 through a reduction in the rate base associated with the Asset Retirement Cost (ARC). Under this alternative position the ARC related opening rate base would be further depreciated by the additional $64.2M paid in 2010, with an associated reduction in the revenue requirement for the test period.

VECC Submission

63. Effective January 1, 2010 the DRP entered into the "definition phase", prompting accounting changes in relation to, amongst other things, the 2010 Nuclear Liabilities of OPG. In summary, the 2010 Nuclear Liabilities of OPG were reduced by approximately $81.8M inclusive of related tax impacts.[29]

64. In Undertaking J11.05 OPG clarifies that the impact of $81.8M it describes is relative to its 2010 budget, rather than the revenue requirement that actually underpins 2010 rates, since OPG did not apply for a 2010 rate order. Accordingly, VECC concedes, it is more appropriate, for the purpose of recording the variance between the Nuclear Liabilities embedded in the rate order underpinning 2010 rates and the Nuclear Liabilities that arise as a result of the DRP, to determine the cost of Nuclear Liabilities that are actually embedded in the rate order in EB-2007-0905 as applied to 2010. In order to do so one has to account for the fact that the 21 month revenue requirement underpinning the prevailing 2008-2009 rate order is being applied to the 12 months in 2010.[30]

65. Such can be done by reviewing Exhibit L Tab 14 Schedule 34 Attachment A, wherein VECC asked for the Board approved Nuclear Liabilities for, *inter alia*, the 2008-2009 21 month test period. The attachment shows the EB-2007-0905 Board approved 21 month Revenue Requirement related to Nuclear Liabilities to be $364.7M exclusive of related tax impacts. Converting that 21 month Revenue Requirement into a 12 month Revenue Requirement for 2010

[29] Undertaking J11.05 sets out the 2010 impact of the Darlington Refurbishment entering into the Definition phase effective January 1, 2010. Of that total impact, lines 1, 5, 9, 11, 14, and 15 relate to the change in OPG's Nuclear Liabilities for the prescribed facilities. The rest of the document set out non-Nuclear Liability impacts on the prescribed facilities, which are not relevant to this portion of VECC's argument, or to the impact on costs associated with the Bruce Facilities, which, according to the response in Exhibit L Tab 14 Schedule 35, are captured in the Bruce Lease Variance Account.

[30] This is similar to the exercise OPG undertakes in Exhibit H Tab 1 Schedule 1 page 8 to calculate the 12 month equivalent value for 2010 which they then claim in the Tax Loss Variance Account.

equals a 2010 Revenue Requirement in rates for Nuclear Liabilities exclusive of related tax impacts of $208.4M.[31]

66. To determine, then, the impact of the DRP on the 2010 Revenue Requirement for Nuclear Liabilities exclusive of related tax impacts, one calculates the difference between the $208.4M in the prevailing rate order to the "With Darlington Refurbishment 2010" column in Exhibit L, Tab 15, Schedule 35, Attachment 1, which shows a 2010 Revenue Requirement for Nuclear Liabilities exclusive of tax impacts of $144.2M. The difference between the two numbers is $64.2M.

67. Accordingly, VECC asserts, the 2010 Revenue Requirement Impact of the DRP (as opposed to the 2010 Budget Impact of the DRP) is a net reduction of $64.2M, exclusive of related tax impacts.

68. When asked to describe if and in what manner the 2010 revenue requirement impact of the DRP is credited to ratepayers, OPG stated, in part, that:

> There is no variance account in place that would provide for the return of these amounts to ratepayers. Returning these amounts to ratepayers without a variance account in place would amount to retroactive ratemaking. On this basis, OPG believes it is appropriate that it retain these amounts.[32]

69. VECC notes that the obligation on the Board to provide for the recovery of Nuclear Liabilities in rates arises specifically from Ontario Regulation 53/05, s. 6 (2) 8., which states as follows:

> The Board shall ensure that Ontario Power Generation Inc. recovers the revenue requirement impact of its nuclear decommissioning liability arising from the current approved reference plan.[33]

70. VECC further notes that Ontario Regulation 53/05, at section 5.2, establishes the Nuclear Liability Deferral Account in order to, under certain circumstances, record variances in Nuclear Liabilities:

> **Nuclear liability deferral account**
>
> **5.2** (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records, on and after the effective date of the Board's first order under 78.1 of the

[31] The number is exclusive of tax impacts because there was no provision for tax in the 2008-09 test period rate order.
[32] Exhibit L Tab 14 Schedule 35
[33] Ontario Regulation 53/05, Payments Under Section 78.1 of the Act, s. 6 (2) 8., made under the Ontario Energy Board Act, 1998.

Act, the revenue requirement impact of changes in its total nuclear decommissioning liability between,

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

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

71. Accordingly, VECC submits, there is a variance account that records the difference between the liability incorporated into the Board's most recent order, in this case the order in EB-2007-0905 dated November 3, 2008, and changes in that liability, so long as that change results from a new approved reference plan.

72. VECC acknowledges, as does OPG, that the Nuclear Liabilities embedded in 2010 rates arise from the 2006 Approved Reference Plan,[34] and there has been no new reference plan approved. Accordingly, *prima facie*, there is no change in liability to record in the deferral account created by s. 5.2 of Ontario Regulation 53/05.

73. However, during the course of the hearing, OPG disclosed that its decision to move the DRP into the "Definition Phase" effective January 1, 2010 qualified as a material change under s. 5.1.2 of the Ontario Nuclear Funds Agreement (the "ONFA"),[35] which in turn triggered OPG's obligation under the ONFA to:

> immediately notify the Province in writing to that effect and to prepare or cause to be prepared a new or amended Reference Plan for the Management of Nuclear Waste and/or Decommissioning of Stations and Other Facilities (whichever is affected by the material change) as soon as practically possible. . .

74. Pursuant to this obligation OPG did notify the Province in writing of the material change, but did not prepare or cause to be prepared a new or amended reference plan, having sought in its written notification to the Province (and having received in response) relief from that obligation.[36]

75. In seeking relief from the obligation to provide an updated or amended reference plan, OPG did not advise the Province of the immediate changes in its Nuclear Liabilities for 2010 as a result of the triggering material change,[37] namely the decrease in its 2010 Nuclear Liabilities of approximately $64.2M

[34] Exhibit C2 Tab 1 Schedule 1 page 5.
[35] Transcript Volume 11, pages 158-160
[36] Undertaking J11.04.
[37] Transcript Volume 11 page 160, and Undertaking J11.04

exclusive of tax impacts. Nor did OPG advise the Province that by excusing the obligation to prepare an updated or amended reference plan OPG and the province would circumvent the operation of the Nuclear Liability Variance Account which would have otherwise served to protect ratepayers from the change in Nuclear Liabilities as a result of the accounting effect of the DRP.

76. Likewise OPG did not advise the Board, to VECC's knowledge, at any time prior to the 2010 rate year, that:

a) it planned to enter the "definition phase" of the DRP effective January 1, 2010 and that, in accordance with its application of its accounting rules, its 2010 Nuclear Liabilities would materially decrease,

b) entering the "definition phase" of the DRP would trigger the material change provision of the ONFA,

c) triggering the material change provision of the ONFA, under normal circumstances, would have required a new or amended reference plan, which in turn would have attracted the operation of the Nuclear Liabilities Deferral Account to record the material decrease in OPG's Nuclear Liabilities, and

d) despite the material decrease in OPG's Nuclear Liabilities for 2010 and the triggering of the ONFA provisions and related deferral account protection, OPG was going to seek approval from the province to forego providing an updated or amended reference plan, circumventing the protection afforded by the Nuclear Liability Deferral Account.

77. OPG failed to notify the Board of these particulars, despite the fact that as early as December 12, 2008 OPG was recommending to its Board of Directors that the DRP enter the "definition phase", and therefore trigger its accounting policies to reduce its Nuclear Liabilities in addition to triggering its obligations under the ONFA, as early as 2009.[38] VECC notes in particular that OPG applied for an accounting order with respect to all of its outstanding deferral and variance accounts (except the Tax Loss Variance Account, to be discussed later on) on June 9, 2009 (EB-2009-0174) without mentioning, to VECC's knowledge, at any time up until the accounting order was granted on October 6, 2009, the fact that OPG was in the midst of preparing to enter the

[38] Undertaking J10.10 shows that OPG presented a preliminary timeline to its Board of Directors wherein the project entered the Definition Phase in early 2009; that same response suggests that the timing was moved back somewhat soon after the presentation, but VECC notes further that prior to the end of 2009 OPG made a further presentation to its Board of Directors (Exhibit D2, Tab 2, Schedule 1, Attachment 1, page 5) showing that it continued to plan to enter the Definition Phase at the start of 2010.

"definition phase" of the DRP effective January 1, 2010, nor the implications of doing so on its 2010 Nuclear Liabilities.[39]

78. In VECC's respectful submission, at a minimum, full disclosure of these facts to the Board in a timely manner would have allowed the Board to consider mechanisms to appropriately capture the impact of the reduced 2010 Nuclear Liabilities in view of the fact that OPG had obviated the operation of the Nuclear Liability Deferral Account by obtaining relief from the Province from the obligation to prepare an amended reference plan that would have captured the relevant impacts. Accordingly VECC respectfully submits that, under these circumstances, it would be appropriate for the Board to provide for a refund of the $64.2M (exclusive of related tax impacts) in ratepayer over-contributions to OPG's Nuclear Liabilities in 2010.

79. It is clear, VECC respectfully submits, that the combination of the ONFA and Ontario Regulation 53/05 create a regime wherein OPG is fully protected from material changes to its Nuclear Liabilities. Under such circumstances VECC submits that it is inappropriate to allow OPG to collect funds through rates for Nuclear Liabilities and then, through an accounting change, fail to apply those funds against its total Nuclear Liability.

80. The inappropriateness of OPG's proposal to retain the 2010 reduction in its Nuclear Liabilities is highlighted by the distinct possibility that the Darlington Refurbishment may not be ultimately approved. Under such circumstances the 2010 impacts that produced a surplus of $64.2M for OPG will have to be accounted for in the recalculation of OPG's Nuclear Liabilities in order to continue to ensure it recovers its full revenue requirement related to Nuclear Liabilities, but there will be, under OPG's proposed treatment, no accounting for the fact that in 2010 ratepayers had contributed $64.2M towards those higher Nuclear Liabilities.

81. Accordingly, VECC submits, it would be just and reasonable under the circumstances for the Board to credit to ratepayers the $64.2M in overpayments towards Nuclear Liabilities relative to the amount embedded in rates for 2010, either as a credit against the new test period rates or against existing deferral account accounts.

82. Alternatively, VECC submits, the Board could credit ratepayers for the contributions towards Nuclear Liabilities embedded in 2010 rates against Nuclear Liabilities by requiring OPG to account, for regulatory purposes, for the full value of the ratepayer contribution against the rate base associated with Nuclear Liabilities. To do so, VECC submits, would require an additional reduction in the ARC amounts for 2010 and forward of $64.2M; in doing so the Board would be crediting ratepayers for their full contribution towards

[39] VECC notes that at Transcript Volume 10, page 137 OPG confirms that the Board Meeting approving the Timetable for the Darlington Refurbishment Project, including entering the Definition Phase on January 1, 2010, was on November 19, 2009.

2010 Nuclear Liabilities, while still allowing OPG to recover the full amount for the adjusted 2010 Nuclear Liabilities, including those amounts (i.e. accretion amounts) that went up.

Related Tax Impacts

83. As noted above the 2010 impact on Nuclear Liabilities of $64.2M is exclusive of tax impacts. Undertaking J11.05 sets out the tax related impacts of the $58.1M reduction in Nuclear Liabilities (relative to the 2010 OPG Budget), a total further reduction of $23.7M in taxes; assuming a similar ratio between the base reduction and related tax reduction, and noting the similarity in the two base reduction amounts, VECC asserts that the related tax reductions for the $64.2M in Nuclear Liabilities is approximately $26.2M.

84. VECC's position with respect to the Tax Loss Variance Account, insofar as OPG claims an amount in that Account of $195M for 2010, is that OPG should be denied recovery of the entire amount; that position and argument is set out under issue 10.1. If successful VECC concedes that the tax related reductions of approximately $26.2M related to the change in Nuclear Liabilities will have already been subsumed in the $195M disallowance.

85. However, in the event the board rejects VECC's submission that OPG should be denied recovery of the entire $195M claimed in the account for 2010, VECC notes that the $195M claimed effectively represents, in part, the addition of tax amounts back into rates for 2010, including the addition of Nuclear Liability related tax amounts. As the 2010 tax amounts related to Nuclear Liabilities, relative to the tax amounts that are included in the $195M variance amount, have been reduced by approximately $26.2M, VECC submits that, at a minimum and in addition to any other reductions[40], the $195M amount for 2010 should be reduced by $26.2M for the same reasons the Board should return the base amount of $64.2M to ratepayers.

DESIGN OF PAYMENT AMOUNTS

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

9.2 Is the hydroelectric incentive mechanism appropriate?

Summary

86. VECC respectfully submits that the hydroelectric incentive mechanism is inappropriate and should be discontinued in its entirety. In the alternative

[40] With respect to additional amounts, VECC notes for example SEC's argument that there are tax benefits owing to ratepayers which will eliminate the taxes payable for 2010; the within argument would mean that an additional $26.2M of benefits would be carried forward beyond 2010.

VECC submits that the incentive produced by the mechanism should be shared 75/25 as between ratepayers and the shareholder, to the benefit of ratepayers.

The Hydroelectric Incentive Mechanism

87. The hydroelectric incentive mechanism ("HIM") is described by OPG as follows:

> Under the hydroelectric incentive mechanism approved in EB-2007-0905, OPG is financially obligated to supply a given quantity of energy ("hourly volume") in all hours and receives the regulated rate for the hourly volume in all hours regardless of the actual output from its regulated hydroelectric facilities. If OPG produces more actual energy than the hourly volume in a given hour, it receives regulated payment amounts up to the hourly volume, and market prices for the incremental amount of energy above this hourly volume. If OPG's actual energy production from its regulated hydroelectric facilities is less than the hourly volume in a given hour, the amount payable to OPG at the regulated rate is reduced by the production shortfall multiplied by the market price.
>
> The hydroelectric incentive mechanism improves OPG's operational drivers by tying operational decisions, regardless of hourly output, to market prices instead of the regulated rate.[41]

88. Energy production is moved from off-peak to on-peak mainly by "[t]he deployment of the Pump Generation Station ("PGS") in conjunction with the Sir Adam Beck Generating Stations 1 and 2 ("SAB 1 and SAB *2") .... ."*[42]

89. Decisions with respect to shifting production from off-peak to on-peak are made as follows:

90. In the off-peak periods, OPG compares:

> the cost of pumping in the off-peak periods ... with the forecast value of the additional generation in the next on-peak period(s). Similarly, during on peak periods, the value of generation is continually compared with the net cost of re-filling the PGS reservoir during the next off-peak period(s). ... In both instances, if the expected value of generation exceeds the expected cost of pumping, then the PGS is bid/offered into the market to operate. This economic assessment

[41] Exhibit E1 Tab 2 Schedule 1 page 1
[42] Ibid and also page 2 where it is stated "While there is some peaking capability at R.H. Saunders and the DeCew Falls Generating Stations, the great majority of peaking activity occurs at the Sir Adam Beck complex."

does not incorporate any consideration of either the regulated price or the hourly volume.[43]

91. In its pre-filed evidence, OPG estimated that "between December 2008 and December 2009, usage of the PGS lowered demand-weighted market prices by approximately $1.14/MWh. ... This figure is an estimate because some information – such as the offer prices of other market participants' generation – is not available to OPG and must be estimated."[44]

92. While OPG estimated in EB-2007-0905 that the HIM would provide it with $12M in incremental revenues in 2009, actual 2009 HIM incremental revenues were $23.2M.[45]

93. For 2010, the year-to-date incremental HIM revenues were $11M as at the end of August.[46] Per Undertaking J1.2, the forecast for 2010 was $8.0M.

94. For the test period, OPG forecasts incremental HIM revenues of $13.3M in 2011 and $16.3M in 2012.[47]

VECC Submission

95. VECC agrees that rational use of the PGS/SAB complex, by decreasing production in the off-peak period to allow for increasing production in the on-peak period, should generally be expected to result in an increase in off-peak prices and a decrease in on-peak prices, thereby lowering the inter-period price spread.

96. However, VECC maintains that the current HIM structure in not appropriate going forward for the 2011 and 2012 Test Years for the reasons as set out below.

97. The PGS in combination with the SAB facilities is designed <u>solely</u> for the purpose of pumping water during the off-peak in order to provide extra energy during the on-peak in VECC's view.

> MR. BUONAGURO: Thank you. Now, would you agree generally that peak or on-peak prices are greater than off-peak prices?
> MR. PETERSON: Normally speaking, yes, on-peak prices would be greater than off-peak prices.

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[43] Ibid page 2
[44] Ibid
[45] Exhibit E1 Tab 2 Schedule 1 page 3. OPG attributes the variance over forecast in 2009 to more energy shifting than forecast and higher op-peak – off-peak spreads than were forecast.
[46] Transcript Volume 1, page 25
[47] Exhibit E1 Tab 2 Schedule 1 page 3

MR. BUONAGURO: And would you then agree that the on-peak periods are higher-value periods than off-peak periods, generally speaking, with respect to...?

MR. PETERSON: The on-peak periods are generally higher-value, in that the prices are higher, yes.[48]

…

MR. BUONAGURO: Okay. Now, turning to the PGS, I guess the pump generation systems that you've mentioned before, my understanding of the operation is that they are designed to pump water during the off-peak period and then, when the opportunity cost for generation was lower, and flow the pumped water back down during periods when the price is higher. Is that generally how it works?

MR. PETERSON: Yes. You said that it's for off-peak periods. It generates low-value periods, would be a better way to state it, to pump during low-value periods and to generate during high-value periods.

MR. BUONAGURO: Right. And that's their raison d'être, if I could put it...

MR. PETERSON: Yes.[49]

98. At the March 29, 2010 Consultative ("Day 1"), OPG indicated that absent the HIM, there would not be a significant difference in operation of the PGS and that OPG would still try to manage the benefits:

5.8 QUESTIONS

Peterson elaborated on the following points in response to stakeholder questions—

1. In reference to Ontario customer benefits on Slide 8, Peterson agreed that since consumers are exposed only to regulated rates they may not see the full and immediate impact of a change in the Market Clearing Price.
2. The SMO is not an incentive mechanism, it's more of a market mechanism, allowing OPG to disconnect up to eight units at Saunders and physically connect them to Hydro Quebec's system. Revenues from SMO are treated like ancillary revenues or non-energy related revenues to offset any costs of the segregated service to Quebec, and are included in the application as "Other Revenue Source".
3. Previously connections with Quebec were virtually impossible because of difficulty with synchronization, the only suitable source of Ontario power was through SMO.

[48] Transcript Volume 1 page 26
[49] Transcript Volume 1 page 28

The new DC intertie allows electricity to be provided from various sources as long as it enters Quebec through the DC intertie. Quebec is buying from the market now, not specifically OPG.

4. The new HIM resulted from the last hearing. **In response to a question about whether it has caused a significant change in the way that OPG manages these on peak, off peak adjustments, Peterson admitted that the operational changes are more incremental, but that it does provide clearer drivers to influence OPG actions. Peterson felt that OPG would still try to manage those benefits if there was no incentive.** (Emphasis added.)[50]

99. Furthermore, if the PGS/SAB facilities were owned and operated by a competitive third-party rather than by OPG, VECC submits that the facilities would be operated in the same manner as OPG describes in its pre-filed evidence and this operation would act to decrease the on-peak off-peak spreads.

100. VECC submits that all of the resources required to operate the PGS/SAB facilities are compensated fully and fairly – absent the HIM – through inclusion of the associated OM&A costs and capital costs in the test period revenue requirements. In particular, the OM&A costs associated with the forecasting required to operate the PGS are already paid for by ratepayers in the revenue requirement and the facilities involved are already paid for by ratepayers in the form of return and depreciation charges included in the revenue requirement.[51]

101. In addition, VECC submits that OPG <u>could</u> operate the HIM exactly as it does now in the absence of an HIM, as evidenced by this exchange during the oral phase of the proceeding:

> MR. BUONAGURO: Let me put a hypothetical to you. Let's say that the Board were to tell you, as part of this hearing, that you're no longer going to receive an incentive payment but that you should operate as though you were, using this formula, to the extent that this formula drives your operations. That's something that OPG could do; correct?
> MR. PETERSON: Correct.[52]

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[50] This excerpt was originally extracted from notes from Day 1 as posted by OPG. It was then assigned as Exhibit K1.1 at the oral proceeding.
[51] In VECC's view both of these factors of production are generously compensated.
[52] Transcript Volume 1 pages 35-36

102. VECC notes that OPG has asserted that there are risks to it under the HIM:

> MR. PETERSON: I think you have to recognize that the incentive mechanism provides us with a good, clear driver on which to base our decisions, our economic pump and generate decisions.
> Absent that type of a driver, you would likely operate incrementally less because of the risk associated with it.
> The incentive mechanism has -- allows you to take somewhat more risk and be somewhat more aggressive.
> MR. BUONAGURO: And can you describe to me what you mean by the risk that you would be taking on and therefore not willing to take on if you didn't receive an incentive?
> MR. PETERSON: Certainly. When you forecast the difference between a low period and off-peak period and on-peak period, there's always a risk that you get it wrong. And if you get it wrong, you actually lose money. And that does occur under the operation of the incentive mechanism. There are <u>time periods</u> when OPG actually loses. (Emphasis added.)[53]

103. However, VECC also notes that there seems to be little or no risk financially to OPG under the HIM on a longer term basis such as an annual basis (or two-year test period basis):

> MR. BUONAGURO: Over the course of the year, you would agree with me that so far, on the yearly basis, there's been no loss. In fact there have been revenues in excess of forecast; is that correct?
> MR. PETERSON: That's correct. But there are, in more isolated time periods, as you -- there are times when you lose, or make minimal amounts of money.
> MR. BUONAGURO: True, but so far they've netted out to a profit?
> MR. PETERSON: To date they have.[54]

104. VECC notes that in response to a question by the Presiding Member during the oral hearing, OPG's witness stated that a decision to pump involved incremental costs that would not be incurred without the pumping. Hence, OPG's witness asserted that OPG would be in a loss position if it could not "receive an incentive or recover those costs."[55]

105. VECC maintains that there is no risk to OPG operating the PGS without an HIM in exactly the way it has operated the facility in the past if incremental revenues <u>net of costs</u> are to the benefit of ratepayers.

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[53] Ibid page 35
[54] Ibid pages 35-36
[55] Ibid page 36

106. In fact this issue was brought up in cross-examination:

> MR. BUONAGURO: But if the Board were to put the ratepayer in the position of bearing the risk of those costs, would you agree that there would be no disincentive to OPG to operate as it has over the last two years or three years without an incentive?
> MR. PETERSON: If you were to expose the ratepayer to the risk associated?
> MR. BUONAGURO: Well, I mean, so far, and I don't mean to be glib, but so far the risk is of earning up to $23 million a year in incentive. That is the risk that I've seen manifest itself over the last few years, at least in 2009.
> MR. PETERSON: I think when you look at the risks and the payment or the incentive that we get from the incentive mechanism, there's a residual ratepayer benefit that's incurred from a cycling of it on a proper basis. And I think that at that benefit is -- the benefit to the ratepayer outweighs the incentive to OPG.
> MR. BUONAGURO: All right. I'll leave it at that. Thank you.[56]

107. Therefore, given that:

- The PGS is solely designed for the operational purpose for which it is currently being used,
- A third party would operate the PGS/SAB facilities in the same way as OPG currently operates these facilities with or without an HIM,
- OPG has stated that it could operate the PGS the same as it currently operates the facility absent the HIM,
- OPG has stated[57] that it would manage the benefits of the PGS absent the HIM,
- The full resource costs of operating the PGS/SAB facilities, including the costs of forecasting, operational decisions, incremental pumping and associated costs, [58] and capital costs, are included in the revenue requirement, and
- There is no risk of loss on an annual or longer basis to OPG by operating the PGS exactly the same way that it currently operates it without the HIM,

108. VECC submits that it is inappropriate to approve the HIM in its current form for the 2011-2012 Test Period.

[56] Ibid pages 36-37
[57] See above excerpt from Day 1 Consultative notes, question 4 response under section 5.8. VECC is aware that during the hearing, OPG stated there would be incremental changes absent an HIM.
[58] These costs already include the forecasted costs of pumping since OPG has estimated the 2011-2012 test period incremental (net) HIM revenues

109. In VECC's view, the full amount of the incentive portion of the net revenues associated with the HIM that are currently enjoyed by OPG, should be to the credit of ratepayers.

110. This could be accomplished by a number of means including (i) establishment of a deferral account to track the full amount of the net incremental revenues for later credit to ratepayers, and (ii) treating the estimated annual HIM net revenues as an offset to the revenue requirement and tracking any variances from forecast in a variance account. VECC submits that while the second approach is preferred, either approach would be acceptable.

111. However, should the Board not find it appropriate to credit ratepayers with the full amount, finding instead that OPG requires some incentive, VECC submits that possible approaches – not preferred to its position as stated as immediately above, yet acceptable in the event some incentive is found to be necessary – would be to (i) credit e.g., 90% of the forecasted net revenues as an offset to the revenue requirement with any variances tracked in a variance account to be shared 50:50 between ratepayers and the shareholder or (ii) tracking all of the net revenues in a deferral account for later sharing 75:25 in ratepayers' favour.[59]

112. In respect of VECC's variance account proposals on this issue and any concern the Board might have about the impact the use of such an account may have on OPG's operation of the PGS, VECC notes the following exchange at the oral proceeding in respect of managing nuclear fuel costs which suggests that it would not have an impact:

> MR. MILLER: What we were asking, I think, if you have any incentive to attempt to lower these costs. We have seen they have been going up. I have heard your explanation for that. But doesn't the existence of the variance account at least reduce any incentive to reduce nuclear fuel costs?
>
> MR. MAUTI: I don't necessarily believe so, no. We have dedicated people and a professional group.[60]

[59] VECC notes that this approach has been adopted by the Board for transactional services provided by gas distributors.
[60] Transcript Volume 4 page 104

DEFERRAL AND VARIANCE ACCOUNTS

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

Summary

113. VECC is aware that the School Energy Coalition ("SEC") is submitting a comprehensive argument with respect to the issue of what amounts should be included in the Tax Loss Variance Account, with a particular focus on the failure of OPG to properly account for the impact of timing differences related to OPG's transition from an unregulated to a regulated entity. SEC has shared drafts of that argument with VECC which VECC supports and adopts as part of its submissions to the Board on this topic.

114. In addition to SEC's argument regarding the actual calculation of credits to ratepayers that should be accounted for in the Tax Loss Variance Account, VECC respectfully submits that the amounts recorded in the Tax Loss Variance Account for 2010 of $195M (which are described as including both tax amounts and mitigation amounts) are inappropriate and should be rejected by the Board. More specifically, it is VECC's position that OPG did not establish a deferral account to track 2010 related variances related to Tax Losses, such that the recovery of any such amounts is unjustified retroactive rate making that the board should not allow.

VECC Submission

115. The Board's decision in EB-2009-0038 dated May 11, 2009 determined as follows:

> The Board varies the [EB-2007-0905] Payments Decision in a manner that links the revenue requirement reduction and regulatory tax losses, and orders the establishment of a tax loss variance account to record any variance between the tax loss mitigation amount which underpins the rate order <u>for the test period</u> and the tax loss amount resulting from the re-analysis of the prior period tax returns based on the Board's directions in the Payments Decision as to the re-calculation of those tax losses. (emphasis added)

116. At Exhibit H1 Tab 1 Schedule 1 page 8, OPG asserts the following:

> Since the 2008 - 2009 payment amounts continue in 2010, OPG is forecasting to record an addition of $195.0M in 2010, which is equal to the annualized value (i.e., 12/21) of the $341.2M revenue requirement reduction incorporated in the payment amounts for the 21-month test period from April 1, 2008 – December 31, 2009.

117. VECC notes that as part of the application (EB-2009-0174) by OPG with respect to the operation of its deferral and variance accounts related to the 2008 and 2009 test period into 2010 no approval was sought or provided specific to the Tax Loss Variance Account established in EB-2009-0038; this despite the fact that every other deferral and variance account established for the 2008-2009 test period was brought forward for the Board's review in that application, whether or not OPG was forecasting amounts to be recorded in the accounts in the period beyond 2010.

118. When asked whether OPG had simply forgotten to include the Tax Loss Variance Account in its EB-2009-0174 application OPG confirmed that it deliberately excluded that single account from the application, [61] on the basis that no relief from the Board was required to track amounts beyond the 2008/09 test period. [62] Accordingly it is OPG's position that they were at liberty to track $195M in the Tax Loss Variance Account in perpetuity, until they applied for a new rate order or, presumably, until the Board intervened.

119. In VECC's respectful submission it is clear on the face of the decision establishing the Tax Loss Variance Account that the variance that was to be tracked was limited to the test period (9 months of 2008 plus 2009), and in particular the variance between the $341.2M in tax loss mitigation amount in that period and the actual amount of tax loss available against the test period rates. The decision establishing the test period Tax Loss Variance Account never contemplates, either explicitly or implicitly, the operation of a similar account beyond 2009.

120. Put another way, in VECC's submission, the approved 2008/09 Tax Loss Variance Account is simply a different account than the 2010 Tax Loss Variance Account that OPG never brought before the Board.

121. It may well be, VECC concedes, that had OPG brought their proposal to track a calculated amount of $195M as an amount that should be partially or fully credited to OPG through a variance account that the Board may have considered the proposal and granted relief on the basis of OPG's prorating the mitigation in the prevailing rate order to a 12 month period. However OPG did not make that proposal to the Board, nor did they provide any information in the EB-2009-0174 proceeding with respect to OPG's position and intentions with respect to the Tax Loss Variance Account.[63]

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[61] Transcript Volume 14 page 106.
[62] Transcript Volume 14 page 105; OPG's initial answer is that all variance accounts established by Board order continue until changed by a subsequent board order, but soon after OPG amended that answer to suggest that was the case unless the order establishing the variance account had a fixed end date.
[63] Transcript Volume 14 page 109.

122. VECC respectfully submits that had OPG proposed, in the context of the accounting order proceeding, that it track an additional $195M in the Tax Loss Deferral Account for 2010, the intervenors may have made submissions and the Board may have considered very different relief and treatment in relation to 2010 and subsequent years in the absence of an application for new base rates.

123. Accordingly, VECC submits, OPG, in the context of the $195M it seeks to recover for 2010 in the Tax Loss Variance Account, is in a position analogous to their response to VECC in Exhibit L Tab 14 Schedule 35. To paraphrase that response in relation to the proposed recovery within the Tax Loss Variance Account:

> There is no variance account in place that would provide for the return of these amounts to [OPG]. Returning these amounts to [OPG] without a variance account in place would amount to retroactive ratemaking. On this basis, [ratepayers] [believe] it is appropriate that [they] retain these amounts.[64]

124. The difference between the relief sought by OPG with respect to the 2010 amount of $195M and the relief sought by VECC with respect to $64.2M related to Nuclear Liabilities ($90.4M inclusive of tax impacts) is that in the first case OPG should bear the consequences of failing to bring forward its proposal for variance account treatment of the requested $195M, whereas in the second case OPG should not benefit from its failure to notify the Board of its actions that ultimately circumvented the operation of the Nuclear Liability Deferral Account and caused ratepayers to overpay towards Nuclear Liabilities.

Impact of DRP on 2010 Nuclear Liability-Tax Impacts

125. As noted above VECC asserts that, in the event the board rejects VECC's submission that OPG should be denied recovery of the entire $195M claimed in the Tax Loss Variance Account for 2010, VECC notes that the $195M claimed effectively represents, in part, the addition of tax amounts back into rates for 2010, including the addition of Nuclear Liability related tax amounts. As the 2010 tax amounts related to Nuclear Liabilities, relative to the tax amounts that are included in the $195M variance amount, have been reduced by approximately $26.2M (as set out above under issue 8.2), VECC submits that, at a minimum and in addition to any other reductions, the $195M amount for 2010 should be reduced by $26.2M for the same reasons the Board should return the base amount of $64.2M to ratepayers.

[64] Exhibit L Tab 14 Schedule 35

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

10.4 Is the proposed continuation of deferral and variance accounts appropriate?

10.6 What other deferral and variance accounts, if any, should be established for the test period?

DRP Deferral Account

126. As noted earlier a Darlington Refurbishment Project Deferral Account should be established to track expenses related to the DRP in the test period that could be the subject of disallowance in the event the DRP is not approved.

Surplus Baseload Generation Deferral Account

127. As discussed earlier VECC supports the Board Staff proposal that SBG be tracked in a deferral account rather than forecast and embedded in rates.

Pension/OPEB Variance Account

128. VECC has reviewed and concurs with Board Staff's analysis with respect to the request for a Pension/OPEB Variance account and the reasons why the Board should reject the request.

129. In particular VECC notes that historically the precedent relied upon by OPG, the existence of a similar account to the benefit of Hydro One Networks Inc. ("HONI"), was established under very specific and unique circumstances.

130. HONI Distribution applied for and received Board approval for a deferral account for its pension costs in RP-2004-0180/EB-2004-0270, an application that was granted by the Board by a decision dated July 14, 2004. The decision noted that the Board dispensed with a hearing and notice of the proceeding on the basis that no party would be materially affected by the issuance of the requested accounting order.[65] Furthermore the Board noted, in denying the actual recovery of the deferred pension costs at that time, that:

> The Board is currently undertaking a process to establish approved rates for electricity distributors, based on updated revenue requirements, with the intent that these new distribution rates will be effective on May 1, 2006. Post-retirement benefits and pensions is one issue that will be under consideration as part of this process,

[65] RP-2004-0180/EB-2004-0270 decision dated July 14, 2004, page 2.

> which the Board believes is the most appropriate forum for dealing with issues of the kind raised by this application.[66]

131. Subsequent to that decision HONI Transmission applied for a similar account in EB-2006-0501, which was included in a settlement agreement and approved by the Board on August 16, 2007, but only on the understanding that:

> Hydro One and the other parties to the settlement should be aware that the Board is providing no assurance that any amounts in those accounts in the future will be included in rates, nor does the approval of the establishment of these accounts indicate any acceptance by the Board of the types of expenditures being recorded in the accounts.[67]

132. In HONI's next rate filing, a Distribution application, HONI requested a pension deferral account again; the Board noted that:

> Some intervenors objected to the establishment of this account on the grounds that there is no regulatory precedent, that there is no such account for Hydro One's transmission business, and that the risk will be shifted from the shareholder to the ratepayer.[68]

133. Despite these objections, the Board approved the account, asserting in part that:

> In this case, given that a pension cost differential account has already been authorized by the Board for Hydro One Networks Transmission and these costs relate to personnel in the same corporate structure, it is reasonable to extend this regulatory treatment to Hydro One Networks. This account shall accrue interest at the Board's prescribed rate.[69]

134. Accordingly VECC, submits, the fact that HONI has pension deferral accounts is not the result of decisions wherein the Board actually turns its mind to the appropriateness of allowing HONI to be fully protected from the risk associated with its pension cost forecasts. Rather the existing Distribution pension deferral account is based on a finding that the Transmission pension deferral account already existed, failing to recognize that the Transmission pension deferral account was granted without recognizing any acceptance that the amounts tracked were recoverable by the utility.

[66] RP-2004-0180/EB-2004-0270 decision dated July 14, 2004, page 2.
[67] EB-2006-0501, Decision dated August 16, 2007 Appendix 3 page 6.
[68] EB-2007-0681, Decision dated December 18, 2008, page 48.
[69] EB-2007-0681, Decision dated December 18, 2008, page 48.

135. Accordingly, in VECC's view, the Board should not accept that there is an influential precedent for such an account in Ontario, and for the reasons set out by Board Staff reject OPG's proposal for the test years.

Recovery of Reasonably Incurred Costs

136. VECC submits that its participation in this proceeding has been focused and responsible. Accordingly, VECC requests an award of costs in the amount of 100% of its reasonably-incurred fees and disbursements.

Respectfully Submitted on the 6th Day of December, 2010