VINCENT J. DEROSE
T 613.787.3589
vderose@blg.com

Borden Ladner Gervais LLP
World Exchange Plaza
100 Queen St, Suite 1100
Ottawa, ON, Canada K1P 1J9
T 613.237.5160
F 613.230.8842
blg.com

Borden Ladner Gervais

File No. 339583/000168

By Electronic Filing

August 26, 2014

Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
27th floor
Toronto, ON M4P 1E4

Dear Ms Walli,

Ontario Power Generation Inc. ("OPG")	
2014-2015 Payment Amounts Application	
Board File No.:	**EB-2013-0321**

Please find enclosed the Argument of Canadian Manufacturers & Exporters ("CME"), in this proceeding.

Yours very truly,

Vincent J. DeRose
VJD/kt
Encl.
c. Colin Anderson (OPG)
Crawford Smith (Torys LLP)
Charles Keizer (Torys LLP)
All Interested Parties
Paul Clipsham (CME)
Peter C.P. Thompson, Q.C. (BLG)
Emma Blanchard (BLG)

OTT01: 6504401: v1

EB-2013-0321

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

AND IN THE MATTER OF an application filed by Ontario Power Generation Inc. pursuant to section 78.1 of the *Ontario Energy Board Act, 1998* for an order or orders determining payment amounts for the output of certain of its generating facilities.

ARGUMENT OF CANADIAN MANUFACTURERS & EXPORTERS ("CME")

August 26, 2014

Peter C.P. Thompson, Q.C.
Vincent J. DeRose
Emma Blanchard
Borden Ladner Gervais LLP
World Exchange Plaza
100 Queen Street
Suite 1300
Ottawa, ON K1P 1J9

Counsel for CME

INDEX

1. INTRODUCTION & OVERVIEW

1. These submissions are made on behalf of Canadian Manufacturers & Exporters ("**CME**") whose members are being increasingly challenged by the continuing escalation of their electricity costs.

2. In preparing these Submissions, we have benefitted from Board Staff's comprehensive submissions. We have also benefitted by Intervenor groups circulating draft Argument, which we reference throughout this Argument. Finally, we also wish to reiterate that we have worked closely with Consumers Council of Canada ("**CCC**") throughout the entire proceeding.

3. Ontario Power Generation Inc. ("**OPG**") has a mandate from its owner to operate as a commercial enterprise. OPG expressly committed to operate its commercial enterprise as efficiently and cost-effectively as possible. It agreed that its performance should be benchmarked against the top quartile of electricity generating companies in North America.[1]

4. OPG's operation of its commercial enterprise falls well below this performance benchmark. The excessiveness of its spending has been analyzed and criticized by its regulator, the Ontario Energy Board ("**OEB**" or the "**Board**"), by the Auditor General and now by the author of the Report on the Sustainability of Electricity Sector Pension Plans dated March 18, 2014, and posted by the Government of Ontario on August 1, 2014.

5. OPG contends that it is focused on cost control.[2] The phrase "cost control" implies that reasonable cost levels are being held within reasonable limits. The level of OPG's historic spending has not, however, been reasonable. Rather, it has been excessive and extravagant. The business transformation exercise in which OPG is currently engaged cannot reasonably be characterized as one of cost control. Rather, as a consequence of the criticisms of its excessive spending and its failure to perform to the level of the benchmarks to which it is contractually committed, OPG is now engaged in reducing its excessive spending in order to bring it within the ambit of what is just and reasonable. OPG is not engaged in an exercise of holding reasonable cost levels within reasonable limits.

6. Ratepayers are obliged to shoulder the burden of rates which are just and reasonable. OPG's perception that it is entitled to recover from ratepayers the consequences of any historic cost commitments it made that affect future spending levels is a misperception. An important component of the Board's statutory obligation to set just and reasonable rates is to protect

---

1 Memorandum of Agreement ("MOA"), Exhibit A1-4-1, Attachment 2.

2 OPG Argument-in-Chief ("OPG AIC"), p. 1.

ratepayers with respect to the prices of electricity service. Cost commitments made by OPG which produce future spending levels that are materially incompatible with the benchmarks to which OPG has contractually committed are not recoverable under the auspices of just and reasonable rates. Historic cost commitments which produce such future spending levels are the responsibility of the utility shareholder. Moreover, excessive or careless spending falls well outside the ambit of ratepayer responsibility.

7. Overall, OPG's performance does not meet or exceed the benchmarks to which it is contractually committed. In many respects, it does not benchmark well and it shies away from having its performance evaluated against the appropriate benchmarks.[3]

8. New initiatives to ensure that the prescribed facilities continue to supply reliable power are laudable[4] provided that the costs of such initiatives are reasonable. It is questionable whether OPG's management of the Niagara Tunnel Project ("**NTP**") was careful and cost-effective. A significant portion of the $491.4M budget overrun falls outside the ambit of ratepayer responsibility.

9. The same can be said for the Darlington Refurbishment Project ("**DRP**") where third party evaluators have been less than complimentary of OPG's management of certain aspects of that project.

10. The fact that the current cost of electricity generated by the prescribed facilities may be among the lowest cost generation sources serving Ontario consumers[5] and that the cost of generation from the prescribed facilities provides a moderating effect on Ontario electricity prices[6] is not the result of OPG's cost-effective operation as a commercial enterprise. Rather, it is the direct result of its owner's political decisions to heavily subsidize other forms of electricity generation.

11. Relying on the consequences of its owner's actions in forcing electricity consumers to subsidize other forms of electricity generation to support a contention that the outcome of OPG's operations are efficient and cost-effective is tantamount to OPG and its owner pulling themselves up by their own boot straps.

12. Similarly, the political decision of OPG's owner to add previously unregulated hydro facilities to OPG's prescribed assets does not operate to moderate electricity prices for

3 For our detailed submissions on benchmarking see Sections 6 B, D and G.
4 OPG AIC, p. 1.
5 OPG AIC, p. 1.
6 OPG AIC, p. 3.

consumers as OPG argues.[7] Rather, it materially increases those prices. The fact that OPG operated its prescribed facilities at an actual loss in 2013 is more a testament to the combined effect of the unreasonable spending and its owner's political decisions to subsidize other sources of electricity generation than it is evidence supporting a conclusion that the current burden on ratepayers of OPG's payment amounts is too low.

13. Moreover, when the retroactivity component of OPG's claims is brought into account, the overall increase in payment amounts which OPG asks the Board to approve is not 23.4% over the level of OPG's existing payment amounts. That percentage impact is substantially greater and will produce about a 43% rate increase if the payment amounts OPG seeks effective January 1, 2014 and July 1, 2014 were to be implemented on September 1, 2014.[8] The percentage increase in the payment amounts OPG seeks with effective dates of January 1 and July 1, 2014, increases significantly above the 43% level with an implementation date beyond September 1, 2014.

14. The retroactivity component of the payment amounts to which OPG claims to be entitled is the staggering sum of about $649M as of September 1, 2014.[9] We estimate that this amount increases by about $92M by month as the implementation date extends beyond September 1, 2014. We estimate that for a December 1, 2014 implementation date, the retroactivity component of OPG's proposed payment amounts increases to the colossal sum of $925M. This component of OPG's claim is staggering and must be rejected.

15. Moreover, the December 31, 2013 deferral account balances which remain uncleared under OPG's proposal of $177.2M in hydroelectric and $1,265.5M in nuclear accounts, which OPG is proposing to address in a subsequent 2014 proceeding[10] operate to mask the total overall payment amount increases OPG is and will be asking the Board to approve in 2014. We submit that, separately and in combination, the increases in costs which OPG is seeking and will be seeking to recover in the test period are overwhelming and are neither just nor reasonable.

16. OPG's challenge in the Courts of the Board's Decision disallowing amounts claimed from ratepayers on the grounds of its failure to perform in accordance with the benchmarks to which it is contractually committed is difficult to comprehend when OPG acknowledges that it

7 OPG AIC, p. 3.
8 Exhibit J3.10.
9 Exhibit J3.10, and Transcript, Vol. 3, pp. 85-87.
10 Transcript, Vol. 13, pp. 89-97.

anticipated that Decision and was already planning to reduce its excessive spending when the Decision issued.[11]

17. Similarly, OPG's resistance to considering alternatives for reducing the pension costs being recovered from ratepayers on the grounds that the Board has no jurisdiction to consider such alternatives[12] is telling, as is its position that the Board lacks power to reject its retroactivity claim.[13] These positions not only lack merit, they also convey an attitude of entitlement which is troubling to electricity consumers.

18. The submissions which follow reflect CME's views on the components of OPG's claims which require adjustment in order to confine the relief granted within the ambit of just and reasonable rates.

19. Throughout these submissions, we refer to the facts and evidence pertaining to OPG's claims contained in the submissions of Board Staff to whom we are indebted for their provision of such a thorough and detailed factual analysis.

2. GENERAL

Issue 1.1 (Primary) – Has OPG responded appropriately to all relevant Board directions from previous proceedings?

20. As noted by Board Staff in their submissions, in response to the $145M cut which the Board made to OPG's revenue requirement in EB-2010-0008 as a result of OPG's poor performance relative to its peers in terms of key performance and value for money metrics, OPG appealed the Board's EB-2010-0008 Decision first to the Divisional Court (where the Board's decision was upheld) and subsequently to the Ontario Court of Appeal (where the decision was overturned). The Board has now obtained leave to appeal the Court of Appeal's decision to the Supreme Court of Canada.[14]

21. As noted in the Introduction and Overview, we question whether OPG's Court challenge of the Board's EB-2010-0008 Decision with Reasons dated March 10, 2011, was an appropriate response to the explicit and implicit directives therein to reduce compensation costs. OPG acknowledged that the Decision to this effect came as no surprise. In fact, OPG anticipated the Decision before it was rendered and had commenced its planning to reduce such costs before the Decision issued.

---

11 Transcript, Vol. 1, pp. 125-129 and 132-134.
12 OPG AIC, pp. 99-100.
13 OPG AIC, pp. 145-148.
14 Board Staff Submissions, p. 66.

22. What OPG expects to gain from its Court challenges is unclear, even if the Supreme Court of Canada upholds the Court of Appeal Decision.[15] We question the appropriateness of a utility pursuing Court challenges of its regulator in such circumstances.

Issue 1.2 (Primary) – Are OPG's economic and business planning assumptions for 2014-2015 appropriate?

23. OPG argues that cost control features prominently in its business planning. As already noted, cost control implies holding just and reasonable cost levels within those parameters. We do not regard the exercise of eliminating an excessive level of spending as an exercise of cost control.

24. What OPG's business planning appears to lack is a determined and dedicated effort to perform to the level of the benchmarks to which it is contractually committed. Our detailed submissions with respect to benchmarking are contained in Sections 6 B, D and G of this Argument.

Issue 1.3 (Secondary) – Has OPG appropriately applied USGAAP accounting requirements, including identification of all accounting treatment differences from its last payment order proceeding?

25. Like Board Staff, we do not have any specific submissions related to USGAAP. We support Board Staff's request for a Board direction requiring OPG to obtain prior Board approval for accounting changes resulting in a revenue requirement impact of more than \$20M.[16]

Issue 1.4 (Oral Hearing) – Is the overall increase in 2014 and 2015 revenue requirement reasonable given the overall bill impact on customers?

26. The overall impact on consumers of OPG's proposals needs to be considered in the context of the retroactivity component of the relief OPG seeks and the pending deferral account clearances which OPG is proposing to implement on January 1, 2015, some of which are currently unknown.

27. We estimate that there will be an increase in payment amounts of about 61%[17] if the relief OPG seeks is granted with an implementation date of December 1, 2014. This percentage estimate does not reflect any further increases related to December 31, 2013 deferral account balance clearances that will become effective on either January 1, 2015, or on some later date in the test period ending December 31, 2015 under OPG's proposals.

15 Transcript, Vol. 1, p. 134, lines 19-28, indicating that OPG has not yet decided what relief to seek from the Board if the Court of Appeal's Decision is sustained by the Supreme Court of Canada.

16 Board Staff's Submissions, pp. 3-5.

17 Exhibit J3.10, and Transcript, Vol. 3, pp. 85-87 (\$925M ÷ by \$649M x 43% = 61%).

28. We submit that the overall impact of the relief OPG proposes is clearly unreasonable.

3. CAPITAL STRUCTURE AND COST OF CAPITAL

Issue 3.1 (Primary) – What is the appropriate capital structure and rate of return on equity for the currently regulated facilities and newly regulated facilities?

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

A. Capital Supporting Newly Regulated Hydro Assets and its Cost

29. OPG, Board Staff and others submit that it is appropriate for the Board, when determining OPG's 2014 and 2015 Payment Amounts, to cost the capital supporting the newly regulated hydro assets having a value of $2,524.9M as of December 31, 2013, at an overall weighted cost of OPG utility debt and equity. Counsel for the School Energy Coalition ("**SEC**") and the Vulnerable Energy Consumers Coalition ("**VECC**") advocate such an approach provided that the equity ratio for all utility assets, including the newly regulated hydro assets, is reduced from 47% to about 43%.

30. For reasons which follow, we submit that the better way to approach the costing of the capital supporting newly regulated hydro assets at December 31, 2013 is by considering the actual source and cost of the capital supporting those assets just prior to the effective date of their re-characterization or re-classification as prescribed or regulated OPG assets.

31. The principle on which we rely is that the Board can always have regard for the actual sources and costs of capital which are used to support utility assets when determining matters pertaining to capital structure and the cost of capital. For example, we submit that it would be entirely appropriate for the Board to determine a capital structure of 75% debt and 25% equity for a utility that actually uses debt capital to finance 75% of its utility assets. Similarly, it would be entirely appropriate for the Board to determine a cost of debt for a particular utility at a rate which differs from the deemed cost of debt where the utility actually incurs debt costs which materially differ from the costs of capital which the utility asks the Board to approve.

32. We submit that this principle was endorsed and applied by the Board in OPG's initial Payment Amounts Case, EB-2007-0905, when it rejected OPG's proposal to have the nuclear liabilities component of its Rate Base earn a return equivalent to its overall weighted utility return.[18] Instead, the Board adopted an approach to the costing of the capital supporting nuclear

18 See EB-2007-0905 Decision with Reasons at pp. 88 and 89, found at Exhibit K3.6, Tab 5.

liabilities which operated to keep OPG's owner whole until such time as it has to raise capital in the capital markets to support that utility asset.

33. The Board has also approved and applied the principle on which we rely in those cases where it has determined that utility assets funded by deferred taxes should not attract any cost of capital charges recoverable from ratepayers.

34. The facts to which this principle should be applied include the following:

(a) The Government of Ontario is the source of capital which supports assets of the old Ontario Hydro which have become "stranded";

(b) The capital supporting such assets is "stranded debt" which is defined as that portion of the total debt of the old Ontario Hydro that cannot be serviced in a competitive market environment after re-structuring of the electricity sector in 1999;[19]

(c) Although the capital supporting the newly regulated hydro assets was initially able to be serviced to its owners' satisfaction in the competitive market environment that existed after utility sector restructuring in 1999, that situation has now materially deteriorated;[20]

(d) As of December 31, 2013, there was an actual loss incurred as a result of the operation of these assets in a scenario which assumes their operation on a stand-alone basis;

(e) As of December 31, 2013, OPG was earning NOTHING to cover the costs of the capital supporting the newly regulated hydro assets. None of the capital supporting those assets could be serviced in the competitive market environment. Accordingly, that capital became "stranded debt" in its entirety as of December 31, 2013;

(f) As a consequence, the Government of Ontario, decided to re-characterize the assets as prescribed assets so as to bring them into the ambit of the Board's regulation of OPG's utility activities;

(g) While this action was undoubtedly taken by the Government of Ontario to enable OPG to recover the costs of capital supporting those assets prior to their re-characterization as prescribed assets, there is nothing in the Government's

19 See excerpt from 2012 Auditor General's Report, Exhibit K3.6, Tab 15, para. 1.
20 Transcript, Vol. 1, p. 120, Exhibit J11.15, and Transcript, Vol. 13, pp. 113-115.

proposal to prescribe OPG's unregulated non-contractual hydroelectric assets as utility assets which evidences an intent to enable OPG to recover more than the costs of the capital actually supporting those assets at the time of their re-characterization;

(h) Rather, the rationale for the proposed re-characterization of the assets as regulated OPG assets was as follows:

> ***Prescribing OPG's unregulated, non-contracted hydroelectric assets would improve OPG's ability to properly plan for and maintain these important hydroelectric assets. These facilities are critical to the operation of Ontario's electricity market, as they represent about 3,000 megawatts of reliable, clean generation that are able to respond to changing load demands in the province.***
>
> ***The proposed amendment would improve regulatory efficiency by providing the OEB with the authority to regulate nearly all of OPG's assets. This new process would leverage the OEB's existing, open and transparent rate setting process that it uses to establish rates for OPG's currently prescribed hydroelectric and nuclear assets. Providing for the amendments now makes sense since the OEB is in the midst of updating its processes for regulating OPG's existing regulated assets.***[21]

(i) No new capital was required by OPG to support the re-characterization of these assets. OPG's regulated utility incurred no costs to "acquire" $2.5B of newly regulated hydro assets. The re-characterization transaction involved a few accounting entries equivalent to journal entries;

(j) Upon the re-characterization of the previously unregulated assets as newly regulated hydro assets, the $2.5B of "stranded debt" capital previously supporting those assets was effectively eliminated and that capital now resides inside the utility; and

(k) We agree that section 11 of Ontario Regulation 53/05 ("O. Reg. 53/05") requires the Board to accept the $2.5M value of the assets and liabilities set out in OPG's most recently audited Financial Statements for payment setting purposes. However, the regulation does not say that, when setting the payment amount for newly regulated hydro assets, a Board must cost the capital supporting those assets at a weighted cost of debt and equity. There is nothing in section 11 of the regulation which constrains the Board's ability to consider the actual source of

[21] See Exhibit A1-6-1, found at Exhibit K3.6, Tab 10.

capital when fixing the just and reasonable payment amount for the newly regulated hydro assets. The Board has already determined in the EB-2007-0905 proceeding that it has this flexibility.[22]

35. Having regard to these facts and the principle that actual costs of the capital supporting utility assets should be considered, we submit that, to keep OPG's owner whole, the capital related to the entire portion of the $2.5B of newly regulated hydro assets should reflect the reality that, as of December 31, 2013, it was "stranded debt" capital which was effectively removed from the unregulated stranded debt bucket, and placed within the OPG regulated utility bucket. As of December 31, 2013, the capital supporting newly regulated hydro assets was "stranded debt" and not a combination of debt and equity capital.

36. We submit that the costing of that capital supporting newly regulated hydro assets for regulated payment setting purposes should be at the interest rate which applies to "stranded debt". In an exercise of its expertise, the Board and its staff can determine the prevailing interest rate which is charged on "stranded debt". Based on the information contained in the record in this proceeding, we estimate that the rate is about 5.9%.[23] It needs to be emphasized that this rate is higher than the 4.85% and 4.86% forecasted rates for 2014 and 2015 that are used by OPG for costing incremental debt required to support its previously regulated hydroelectric and nuclear assets.

37. OPG argues that the circumstances pertaining to the re-characterization of newly regulated hydro assets as regulated OPG assets and the circumstances pertaining to the initial prescription of certain of OPG's hydroelectric assets and its nuclear assets as prescribed assets are identical. We disagree.

38. When the Board first determined OPG's Payment Amounts in EB-2007-0905, OPG was operating under the auspices of Payment Amounts which the Government had established by Regulation. Unlike the newly regulated hydro assets, at December 31, 2013, the prescribed assets were not being operated at an actual loss. The capital supporting those assets was not "stranded debt".

39. That situation is distinguishable from the situation prevailing as of December 31, 2013, with respect to the newly regulated hydro assets. On a stand-alone basis, those assets were

---

22 See EB-2007-0905 Decision with Reasons, November 3, 2008, at pp. 77-79.

23 See Exhibit K3.6, Tab 19, for the Ontario Electricity Financial Corp. 2012 Financial Statements, at p. 18 citing the effective rate of interest on its debt portfolio of 5.86%.

producing an actual loss from operations. As a consequence, the capital supporting those assets was entirely "stranded debt".

40. For these reasons, we submit that all of the capital supporting the $2.5M of newly regulated hydro assets should be costed at a debt rate of about 5.9% for the purposes of determining OPG's 2014 and 2015 Payment Amounts.

41. It is also important to appreciate that we accept the value of the newly regulated hydro assets at $2.5B for the purposes of setting the newly regulated hydro payment amount. We are arguing for the use of the "stranded debt" rate to cost the capital supporting those assets to prevent OPG from receiving "windfall profits".

42. Our argument for that rate is based on principles which the Board has applied in prior cases. Until such time as OPG actually raises capital in the capital markets to support newly regulated hydro assets, the actual cost of that capital at the time that the assets were characterized as utility assets, being the "stranded debt" rate should be applied to determine the newly regulated hydro payment amount. Our approach is a principled approach which produces a result which is more favourable to ratepayers than the result proposed by others.

43. The issue we raise is a costing issue pertaining to the capital supporting the newly regulated hydro assets. When determining the question of whether or not to apply our proposed newly regulated hydro costing approach, we urge the Board to bear in mind that its traditional role as an economic regulator is to act as a surrogate for competition. Under section 29(1) of the *Ontario Energy Board Act*, the Board is required to forebear from regulating where a competitive market exists.

44. It is worthy of note that the recent amendments to O. Reg. 53/05 effectively eliminate a competitive market for electricity in Ontario. As a result of O. Reg. 53/05, the Board is being required to set the payment amount for OPG newly regulated hydro generation, which will be substantially above competitive and market prices. The amendments to O. Reg. 53/05 effectively require the Board to insulate OPG from competition.

45. Another way for the Board to consider the appropriateness of our proposal is to consider the question of whether O. Reg. 53/05 would likely have been amended had the newly regulated assets earned 5.9% on the capital supporting those assets. We submit the answer to that question is "no". This is but another reason that the 5.9% we have suggested, for the purposes of determining OPG's 2014 and 2015 payment amounts, is reasonable.

46. One might argue that the recent amendments are of questionable validity in that they appear to be incompatible with the mandatory forbearance provisions of the Board's enabling legislation. While we are not making that argument, we do suggest that the Board should be mindful of the anti-competitive exercise in which it is engaged in this proceeding. We submit that such a perspective should prompt the Board to prefer the principled approach to costing the capital supporting newly regulated hydro assets at December 31, 2013, which produces for consumers the lowest price increase above competitive electricity price levels.

B. <u>Capital Supporting Previously Regulated Hydro and Nuclear Assets</u>

47. Under the costing approach we are proposing the current Board deemed capital structure for OPG of 47% equity and 53% debt should continue to be applied to the previously regulated hydroelectric and nuclear assets.

48. We accept OPG's Long-Term and Short-Term Debt Cost estimates which we understand to be 4.85% and 4.86% for Long-Term Debt for 2014 and 2015 respectively, and 1.87% and 2.89% for Short-Term Debt for each of those years. These are the rates which should be applied to the debt capital supporting previously regulated hydroelectric and nuclear assets.

49. We have been provided with drafts of the capital structure submissions of SEC and VECC. Those submissions propose an equity ratio of no more than 43% for the purpose of delivering OPG's Payment Amounts for 2014 and 2015. If the Board rejects our proposed approach to the costing of the capital supporting the newly regulated hydro assets, then an equity ratio of no more than 43% should be approved for determining the 2014 and 2015 Payment Amounts.

C. <u>Deferred Taxes Component of Newly Regulated Hydro Assets</u>

50. OPG's Financial Statements at December 31, 2013, had recorded therein an amount of $281M for deferred taxes related to the newly regulated hydro assets. This amount was charged against amounts electricity consumers paid to OPG prior to December 31, 2013.

51. While we accept that the last part of section 11(ii) of O.Reg.53/05 requires the Board to treat the $281M of deferred taxes recorded in the Balance Sheet as of December 31, 2013, as a capital gain, that requirement does not detract from the reality that all of the capital supporting the newly regulated hydro assets at December 31, 2013, was "stranded debt" capital. This outcome is a consequence of the operation of those assets on a stand-alone basis at an actual loss as of December 31, 2013. Accordingly, the deferred tax amount recorded in OPG's

December 31, 2013 Balance Sheet as deferred taxes related to the newly regulated hydro assets is wholly supported by "stranded debt" and should be costed at 5.5% for the purposes of determining OPG's 2013 and 2014 Payment Amounts.

52. It needs to be noted that costing the "stranded debt" capital supporting the deferred tax component of the December 31, 2013 Balance Sheet pertaining to the newly regulated hydro assets is an issue which is unrelated to the question of whether electricity consumers have already paid the amount of those deferred taxes. On that question, there can be no doubt that consumers have paid these amounts. We agree with counsel for SEC that it is unreasonable to require consumers to pay those amounts twice and that whatever relief the Board grants to OPG should prevent such an outcome.

4. CAPITAL EXPENDITURES AND RATE BASE

Issue 2.1 (Primary) – Are the amounts proposed for rate base appropriate?

53. Our submissions on the inappropriateness of the amount OPG proposes for Rate Base are described below.

A. Regulated Hydroelectric Capital Expenditures

Issue 4.2 (Secondary) – Are the proposed regulated hydroelectric capital expenditures and/or financial commitments reasonable?

54. We support and adopt the submissions of Board Staff with respect to this issue and urge the Board to reduce the hydroelectric capital expenditures budgets by $19M in each of the years 2014 and 2015.[24]

55. We understand that counsel for other ratepayer representatives will be pointing to the evidence which demonstrates that OPG's actual capital expenditures have historically been less than forecast. We expect this evidence to be relied upon to support a submission that OPG's 2014 and 2015 capital expenditure budget should be set at a range of about 90% of the values presented in the application. This approach produces a budget reduction outcome similar to that proposed by Board Staff. If the Board does not accept Board Staff's approach, then we support the submissions that we understand other ratepayer representatives will be making to reach a similar result.

[24] Board Staff Submissions, pp. 11-12.

B. Regulated Hydroelectric Rate Base

Issue 2.1 (Primary) – Are the amounts proposed for rate base appropriate?

Issue 4.1 (Secondary) – Do the costs associated with the regulated hydroelectric projects that are subject to section 6(2)4 of O.Reg. 53/05 and proposed for recovery (excluding the Niagara Tunnel Project), meet the requirements of that section?

Issue 4.3 (Secondary) – Are the proposed test period in-service additions for regulated hydroelectric projects (excluding the Niagara Tunnel Project) appropriate?

56. Once again, we have nothing to add to the thorough analysis and presentation of the facts contained in Board Staff's submissions to find that Rate Base in-service amounts for each of the years 2014 and 2015 are excessive by $13M as Board Staff has submitted.[25]

C. Niagara Tunnel Project

Issue 4.4 (Primary) – Do the costs associated with the Niagara Tunnel Project that are subject to section 6(2)4 of O.Reg.53/05 and proposed for recovery, meet the requirements of that section?

Issue 4.5 (Primary) – Are the proposed test period in-service additions for the Niagara Tunnel Project reasonable?

57. In addition to reviewing Board Staff's submissions on the NTP, we have also had the benefit of reviewing Association of Major Power Consumers in Ontario's ("**AMPCO**") and SEC draft submissions. Board Staff, AMPCO and SEC all provide a comprehensive review of the background facts pertinent to the NTP. We wish to specifically compliment AMPCO on the extensive submissions it has presented. We rely upon the facts as summarized by these parties. For this reason, we only highlight the facts that we deem to be most essential for the Board to understand the reductions we recommend.

58. An underlying suggestion in OPG's argument on the NTP is that the Board should somehow take into consideration, in assessing cost overruns, whether those cost overruns would have nevertheless occurred had OPG undertaken the project correctly from the beginning. In our submission, the question for the Board is not what the NTP forecast should have been initially if it had been properly handled by OPG. As a general principle applicable to all rate regulation, ratepayers should not be responsible for the cost consequences of imprudent or careless actions by a regulated utility such as OPG. To the extent that the Board agrees that OPG has acted imprudently, carelessly, or otherwise mismanaged the NTP, the cost

[25] Board Staff Submissions, pp. 12-15.

consequences that flow from that imprudent, careless or improper management must be borne by the shareholder and not the ratepayer.

59. In July, 2005 the OPG Board of Directors approved a budget of $985.2M for the NTP. At that time, the NTP business case was based on an in-service date of June 2010 with an assumed annual output of 1.6TWh.

60. As compared to the original budget and plan approved by OPG's Board of Directors, the Niagara Tunnel was put into service almost three years late, in March, 2013, with a cost over-run of $491.4M (which is more than 50% of the original budget). Moreover, the annual output is 1.5TWh (which is about 6% less than originally forecast).[26]

61. The budget of $985.2M was increased in 2009 to $1.6B. The total estimated final project costs are $1,476.6M, which represents an increase over the original budget of $491.4M.

62. While the original budget for the NTP was approved by OPG's Board of Directors prior to April 1, 2008, and as a result does not require any approval from the Board, the whole of the additional $491.4M is subject to a complete prudence review. To this end, OPG confirmed in cross examination that it is within the Board's jurisdiction to reduce all or some of the $491.4M budget.[27]

63. In 2005, OPG entered into a "Design-Build Agreement" for the NTP with the contractor, Strabag AG ("**Strabag**"). The Design-Build Agreement provided for non-binding dispute resolution before a Dispute Resolution Board ("**DRB**") which was intended, among other things, to address disputes relating to unforeseen subsurface conditions.

64. Pursuant to the Design-Build Agreement, OPG and Strabag also jointly developed and agreed upon a Geotechnical Baseline Report ("**GBR**"). The GBR was intended to describe with precision the rock conditions that Strabag could expect to encounter when building the tunnel and thereby create a baseline for the allocation of risk associated with geotechnical conditions as between Strabag and OPG.

65. OPG's independent expert, Mr. Ilsely, confirmed during cross-examination that it is "absolutely essential" in a project of NTP's magnitude to ensure that the GBR is not defective. According to Mr. Ilsely, the whole objective of the GBR is to provide simple parameters for rock conditions or "visible parameters" which will provide a basis for a DRB to make a decision in the event of a dispute relating to subsurface conditions. If the GBR is inadequate in some way, then

---

26 ExhibitE1-1-1, p. 3.
27 Transcript, Vol. 1, p. 53.

it makes it more difficult for a DRB to make a decision as to whether there is or is not a "differing site condition".[28]

66. Mr. Ilsley confirmed that, in terms of allocations of geotechnical risk, ground conditions are normally the owner's responsibility, and means and methodology are normally the contractor's responsibility. As such, a GBR will establish, so long as it is not defective, what is a ground condition event (the owner's responsibility), and what is a means and a methods issue (the contractor's responsibility).[29]

67. In this context, we submit that it was incumbent on OPG to ensure that the GBR was not deficient. Any costs incurred as a result of the GBR being deficient cannot be considered prudent.

68. One of the roles of a DRB is to interpret the GBR in the context of disputes involving geotechnical matters. Mr. Ilsley confirmed that when a GBR is defective or otherwise ambiguous, DRBs will first look at the contract requirements in order to determine the basic responsibility for the various activities. Mr. Ilsley went on to say that "If it's all ambiguous, then it's tough. And often in those cases, you know, there is a tendency to split the baby".[30]

69. In April 2007, after tunnelling approximately 3 km, Strabag claimed that it was encountering Queenston shale formation subsurface conditions that were not consistent with the GBR, and that this constituted a "Differing Subsurface Condition" within the meaning of the Design-Build Agreement. On this basis, Strabag claimed $90M in cost over-runs incurred in completing the first 3 km.[31] Because OPG did not accept Strabag's claim, the non-binding dispute resolution provisions of the Design-Build Agreement were triggered and the matter was submitted to a DRB.

70. The DRB issued its Report on August 30, 2008. That report made a number of findings with respect to the GBR being "defective" or simply misleading. Specifically, at page 16 of 19, the Board made the following finding with respect to the GBR:

> ***Therefore, the Board concludes that the language used in the GBR may have been misleading to one or both parties. More importantly, the provisions "closest match" and "all other conditions" used in the GBR would make the [Differing Subsurface Condition] clause in the contract essentially meaningless, contrary to the intent of both parties, and contrary to case law disallowing exculpatory language.***

---

28 Transcript, Vol. 1, pp. 58-59.
29 Transcript, Vol. 1, pp. 60-61.
30 Transcript, Vol. 1, p. 62.
31 Transcript, Vol. 1, p. 65.

> ***Since both parties jointly developed the GBR, any misunderstanding or inappropriate wording should, in the Board's opinion, be the shared responsibility of both parties. [emphasis added]***

71. The DRB went on to make a number of findings with respect to specific claims made by Strabag. With respect to the "excessive outbreak" claim, at page 17 of 19, the DRB made the following comments:

> ***Based on the GBR provisions "closest match" and "all other conditions requiring greater support" that would invalidate the concept of a [Differing Subsurface Condition], as discussed previously, the DRB would conclude that the GBR is defective. <u>In addition to being defective, the DRB concludes that the GBR was misleading</u> based on imprecise terms used in the document and the exclusion of "rock pressure generally exceeding rock mass strength" in the rock characteristics for rock condition 4Q in the QF. In combination, these led the Contractor to a reasonable but incorrect interpretation of anticipated subsurface conditions within the QF at the time the DBA was signed. Thus the DRB concludes that, were it not for the defective GBR, a [Differing Subsurface Condition] with respect to excessive overbreak would exist.***
>
> ***Whether the GBR was defective or simply misleading, both Parties developed the GBR jointly and therefore both Parties must share in the consequences in resolving the issue. [emphasis added]***

72. With respect to Strabag's claim arising out of "inadequate table of rock conditions and rock characteristics", at page 18 of 19, the DRB made the following comments:

> ***The DRB agrees that the Table of Rock Conditions and Rock Characteristics is inadequate to be used for the identification of [Differing Subsurface Conditions] and, further, <u>that the inclusion of such terms as the "closest match" and "all other conditions" essentially renders the concept of [Differing Subsurface Conditions] meaningless and makes the GBR defective</u>. Other contract language has been used in the U.S. in Design-Bid-Build contracts in an effort to avoid [Differing Subsurface Condition] claims. <u>Such disclaimer language is contrary to case law and has consistently been thrown out by the U.S. courts</u>. In this DB contract, <u>both Parties jointly developed the GBR document and both Parties should share the shortcomings of the resulting documents.</u> [emphasis added]***

73. The DRB concluded that the GBR was defective. Consequently, the DRB could not assign responsibility based on the definition set out in the GBR to either OPG or Strabag. In the words of OPG's independent expert, because the GBR was defective or misleading, and because it was jointly developed by Strabag and OPG, the DRB "split the baby".[32]

---

32 DRB, p. 72.

74. While the DRB concluded that certain elements of the dispute were entirely the responsibility of Strabag, it concluded that others should be shared equally between Strabag and OPG. The DRB did not attribute specific values to the various issues. While we believe that this information would have been of significant assistance to OPG in ensuing negotiations with Strabag regarding contract cost increases, in cross-examination, OPG confirmed that it made no attempt to quantify any of the individual issues that were in dispute before the DRB or to assess the potential value of any of the various aspects of the dispute before the DRB.[33]

75. After receiving the report of the DRB, OPG and Strabag went on to negotiate a settlement of Strabag's $90M claim for historic cost over-runs together with an Amended Design-Build Agreement. These negotiations resulted in a revised agreement which did not include a fixed price and which ultimately produced a cost overrun of $491.4M over the original budget for the NTP. According to OPG, the $491.4M was caused by adverse subsurface conditions.[34]

76. The $90M claim was for work done on 3 km of the tunnel. The entire NTP, however, was 10 km.[35]

77. Of the $491.4M increase, $282.5M represented incremental costs of the Diversion Tunnel.[36] This increase of $282.5 includes $40M paid for Strabag's over-run costs for the first 3 km and an incremental $243M to complete the final 7 km.

78. On a per km basis, this means that OPG agreed to pay Strabag an extra $13.3M per km for the first 3 kms of tunnelling. We submit that it is reasonable to draw an inference from this portion of the agreement that, consistent with the DRB's decision, both Strabag and OPG agreed that an allocation of responsibility for costs associated with geotechnical conditions not appropriately described in the joint GBR was appropriate.

79. In this context, we have difficulty accepting the subsequent decision to conclude an Amended Design-Build Agreement which provided for an extra $34.7M (totalling $243M) per km for the last 7 kms, particularly in the absence of any evidence as to the potential cost of other alternatives open to OPG at the time.

80. We submit that it is not prudent for OPG to negotiate an incremental amount to be paid to Strabag for subsurface conditions for the last 7 km that is materially in excess of the

33 DRB, pp. 65-66.
34 Transcript, Vol. 1, p. 54.
35 Transcript, Vol. 1, p. 77.
36 Exhibit D, Tab 2, Schedule 1, p. 128 of 145, and Transcript, Vol. 1, p. 77.

incremental amount paid for the first 3 km. OPG should not have paid Strabag more than $13.3M per km, or $133M, in extra costs for the tunneling work of the entire 10 km. For this reason, we urge the Board to disallow, at the very least, $149.5M for this work ($282.5M - $133M = $149.5M).

81. CME has further reviewed the submissions of Board Staff on OPG's defective Design-Build Agreement and inadequate risk mitigation strategy. We agree with the recommendations of Board Staff that address items other than the $282.5M increase for the Diversion Tunnel. On the basis of Board Staff's submissions, we support the additional reductions:

(a) $6M for incremental design work;

(b) $26M for the profit provided to Strabag on the basis that OPG did not adequately mitigate the possibility that Strabag could in practice withdraw from the project;

(c) $15M in carrying costs on the expectation that that with an amended Design-Build Agreement the project would have been completed earlier;

(d) $10M in Office and General Costs and Overhead Recovery costs; and

(e) $2M related to the fall of ground due to improperly closed borehole.

82. These costs represent an additional $59M reduction, for a total reduction of $208.5M. This is, in our submission, the minimum reduction that the Board should approve. This amount is also generally consistent with the overall reduction advocated by SEC.

83. As indicated at the commencement of this section, we have also had the opportunity to review the detailed and persuasive submissions prepared by AMPCO. AMPCO's submissions support a reduction of about $375M. On this basis, we submit that the appropriate range for an appropriate reduction to be imposed by the Board is a low end of $208.5M and an upper end of $375M.

D. <u>Nuclear Capital Expenditures</u>

(i) <u>Applicability of Section 6(2)4 of O. Reg. 53/05</u>

Issue 4.6 (Secondary) – Do the costs associated with the nuclear projects that are subject to section 6(2)4 of O. Reg. 53/05 and proposed for recovery, meet the requirements of that section?

84. We agree with Board Staff's submission that Pickering Continued Operations, including the Fuel Channel Life Cycle Management Project and the DRP are subject to section 6(2)(4) of O. Reg. 53/05 because they served to increase output or refurbish a prescribed generating

station. Our agreement with Board Staff on this issue is, however, without prejudice to the submissions that follow on the DRP.

E. Capital Expenditures

Issue 4.7 (Oral Hearing) – Are the proposed nuclear capital expenditures and/or financial commitments reasonable?

85. In responding to this issue, we have benefitted from Board Staff's comparison of actual capital expenditures compared to budget or budget approved capital expenditures. In particular, we wish to reiterate that as compared to budget or Board approved amounts over the 2010 to 2013 period, actual capital spending was about 9% less. Furthermore, when compared to Board approved amounts, OPG's actual capital expenditures were 20% less. On this basis, we support Board Staff's proposal to reduce the proposed capital expenditures by 10%. We believe this would result in a more reasonable level of forecasted expenditures. We agree with Board Staff that OPG has a history of over-stating its nuclear capital expenditures.

86. In agreeing to this proposal by Board Staff, we expressly confirm that the proposed reduction is on a without prejudice basis to our submissions on the DRP which follow.

F. Nuclear Rate Base

Issue 2.1 (Primary) – Are the amounts proposed for rate base appropriate?

Issue 4.8 (Secondary) – Are the proposed test period in-service additions for nuclear projects (excluding those for the Darlington Refurbishment Project) appropriate?

87. We have nothing to add to the analysis of the facts presented by Board Staff in its submissions and urge the Board to reduce 2014 and 2015 Rate in-service amounts by $18M and $17M respectively as Staff proposes.[37]

G. Darlington Refurbishment Project

88. In its submissions to the Board in EB-2010-0008, CME supported the DRP on the basis that OPG's early estimates could justify a tentative finding that the DRP would have positive economic feasibility. In other words, CME was satisfied that OPG had demonstrated, on the basis of the information available at the time, that the economic benefits of proceeding with the DRP appeared likely to outweigh the costs of the DRP.

89. CME nevertheless urged the Board to temper any such preliminary finding by expressly reinforcing OPG's obligation to objectively establish and confirm the continued economic

[37] Board Staff Submissions, pp. 29-30.

feasibility of the DRP, throughout the evolution of the project. In CME's submission, sound regulatory principles dictate that a failure to discharge this obligation should result in a write down of the value of Darlington assets, in subsequent proceedings, for the regulatory purpose of determining OPG's just and reasonable nuclear payments.

90. In its Decision in EB-2010-0008, the Board recognized the need to reassess the DRP in the event that the results of the definition phase demonstrate that the cost of the DRP will rise above the $6B to $10B range forecast in 2010 particularly in light of the cost overruns of refurbishments at Point Lepreau and Bruce and given the particular risk that ratepayers bear in relation to large nuclear refurbishment projects.[38]

91. In the four years since EB-2010-0008, OPG has narrowed its "medium to high confidence estimate range" from between $6B to $10B in 2009 dollars to between $8B to $10B in 2013 dollars excluding interest and escalation"[39] (or $12.9B in 2013 dollars including interest and escalation); however, external consultants retained by OPG to undertake external oversight assessment continue to raise concerns about the potential for cost overruns in the DRP. For example, in a report prepared in advance of OPG's 2013 Business Case, Burns & McDonnell/Modus Strategic Solutions("**BMcD/Modus**") noted that:

> ***"Between the years 2009 and 2012, the DR Project's overall budget has grown by [ ] (2012 dollars) which is equivalent to [ ] of initial budget. The current point-estimate of [ ] (2012 dollars) in the 2013 Business Plan [ ] latest approved by the [Board of Directors]. This total increase represents in large part scope growth of the DR Project ..... [If] scope is not effectively managed .... OPG's management will be hard-pressed to deliver the DR Project at an acceptable cost."***[40]

92. CME continues to support the DRP on the conditional basis described above; however, notwithstanding OPG's suggestion that the DRP is project "unlike any other considered by the OEB,"[41] we submit that fundamental regulatory principles must guide the Board in considering the DRP. We therefore urge the Board to continue to reinforce its jurisdiction to write down the value of Darlington assets for regulatory purposes in future proceedings should the economic feasibility of the DRP be called into question.

---

38 Decision EB 2010-0008 at pp.72-73.

39 OPG AIC, p. 41 and Exhibit J15.2.

40 Exhibit D2-02-02, Attachment 1, p. 17 of 76, BMcD/Modus August 13, 2013 report. We have redacted those portions of this citation marked confidential in OPG's Exhibit. We would direct the Board's attention to the unredacted version of this citation as we believe it sheds additional light on the issue of potential cost overruns.

41 OPG AIC, p. 41.

H. Approvals Sought by OPG

93. We are concerned that, if granted, some of the approvals and findings which OPG seeks from the Board[42] in this proceeding, specifically OPG's request for:

(a) a finding that "the proposed capital expenditures of $839.9M in 2014 and $842.5M in 2015 are reasonable (Issue 4.10);

(b) approval of certain in-service additions (Issue 4.9); and

(c) a finding that "OPG's commercial and contracting strategies for the DRP are reasonable" (Issue 4.11)

could hamper the Board in future proceedings in undertaking the reassessment of the DRP which is necessary to properly establish OPG's just and reasonable nuclear payments.

94. Our submissions with respect to each of the three requested approvals and findings highlighted above follow.

I. Test Period Capital Expenditures – Darlington (Issue 4.10)

95. OPG is seeking a finding that proposed capital expenditures of $839.9M in 2014 and $842.5M in 2015 are reasonable.

96. We adopt Board Staff's position[43] that the Board should not make a finding on the reasonableness of the proposed test period capital expenditures associated with the DRP and that capital expenditures should remain subject to the Board's future finding of reasonableness or prudence prior to their closing to rate base.

97. In its decision in EB-2010-0008, the Board noted that "the Board does not normally give approval to capital expenditures for projects which come into service after the test period"[44] and then went on to determine that "once the DRP reaches the stage of having a release quality cost estimate, the Board expects to examine the reasonableness of proceeding with the project. At that time, the Board may consider establishing a framework within which prudence could be examined should the project proceed forward."[45]

98. OPG currently expects the release quality estimate to be available at the end of 2015.[46]

---

42 OPG AIC, p. 40.
43 Board Staff Submissions, p. 31.
44 Decision EB-2010-0008, p. 72.
45 Decision EB-2010-0008, p. 72.
46 Transcript Vol. 16, p. 8, line 4.

99. A significant amount of time was devoted during the oral hearing to developing an understanding of the degree of certainty which the release quality estimate is expected to provide with respect to forecast overall costs for the DRP. One of the external consultants retained by OPG, BMcD/Modus advised that OPG is now using guidelines produced by the Association for the Advancement of Cost Engineering ("**AACE Guidelines**") for the classification of cost estimates[47] which establish engineering and scope definition as the key underlying metric for developing certain "classes" of cost estimates from Class 5 (most conceptual with the largest range of potential variability) to Class 1 (most mature with the narrowest range of potential variability) as follows:

	Primary Characteristic	*Secondary Characteristic*		
ESTIMATE CLASS	MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES Expressed as % of complete definition	END USAGE Typical purpose of estimate	METHODOLOGY Typical estimating method	EXPECTED ACCURACY RANGE Typical variation in low and high ranges [a]
Class 5	0% to 2%	Concept screening	Capacity factored, parametric models, judgment, or analogy	L: -20% to -50% H: +30% to +100%
Class 4	1% to 15%	Study or feasibility	Equipment factored or parametric models	L: -15% to -30% H: +20% to +50%
Class 3	10% to 40%	Budget authorization or control	Semi-detailed unit costs with assembly level line items	L: -10% to -20% H: +10% to +30%
Class 2	30% to 75%	Control or bid/tender	Detailed unit cost with forced detailed take-off	L: -5% to -15% H: +5% to +20%
Class 1	65% to 100%	Check estimate or bid/tender	Detailed unit cost with detailed take-off	L: -3% to -10% H: +3% to +15%

Notes: [a] The state of process technology, availability of applicable reference cost data, and many other risks affect the range markedly. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope.

100. While OPG was careful to point out that the expected accuracy ranges produced by the AACE Guidelines may vary between different aspects of the DRP because there will be more certainty around some forecast costs (e.g. waste and fuel related costs) than others[48], OPG's evidence was that the release quality estimate for the DRP will be somewhere between a Class 2 and a Class 3 Estimate.[49]

101. In the last quarter of 2013, OPG provided an overall cost estimate of $10B (2013 dollars) to its Board of Directors[50] or $12.9B (2013 Dollars including interest and escalation). It was

47 Exhibit D2-02-02, Attachment 1, June 26, 2014 BMcD/Modus Report, at pp. 4-5.
48 Transcript Vol. 16, p. 16, lines 9-15.
49 Transcript Vol.16, p. 12, lines 25-28.
50 Exhibit D2-02-02, Attachment 1, June 26, 2014 BMcD/Modus Report at p. 7 of 26.

OPG's evidence that on average OPG's overall cost estimate for the DRP is a Class 4 estimate which is progressing to Class 3 estimate.[51] Estimates classified as Class 4 are described in the AACE guidelines as having a maturity level of project definition deliverables expressed as a percentage of complete definition of between 1% and 15% and are expected to typical variations up to 50% over high ranges.

102. This context, it is not surprising that, notwithstanding the "uncertainty bands" which OPG has built around its current point estimate[52], when asked by SEC whether it would be reasonable for the Board to assume that the all-in cost at the end of the day will not be more than $12.9B, OPG's senior vice president of nuclear projects was not prepared to agree that this is a reasonable assumption and responded instead:

> ***Mr. Reiner: I would not say [it] will not be [more than $12.9 Billion], because, there is also the potential for unknown things to arise, and then we would have to evaluate what the impact of those unknowns.***[53]

103. We submit that the reasonableness of capital expenditures for the DRP which are not coming into service during the test period should not be assessed in the absence of estimates which will provide the certainty required to permit the Board to make assumptions about the maximum reasonable capital cost of the DRP.

J. Test Period In-Service Additions (Issue 4.9)

104. A significant portion of the test period in-service additions for Darlington relate to two projects forming part of the "Campus Plan" component of the DRP, namely the construction of a heavy water storage facility (the "**D_2O Project**") and the auxiliary heating system (the "**AHS**").

105. In May of 2014, BMcD/Modus issued a report to OPG's Nuclear Oversight Committee (the "**May 2014 Report**") which described the D_2O Project and the AHS as "two projects that may cause external stakeholders to question OPG's management prudence"[54] and which identified significant variances between the forecast costs approved by OPG's Board of Directors for these two projects.[55] By way of summary, BMcD/Modus states:

> ***Many of the Campus Plan Projects are forecasted to complete significantly beyond the approved budgets and schedules. In fact, schedule adherence is so poor that the Campus Plan work poses***

[51] Transcript, Vol. 16, p. 14, line 14.

[52] Transcript, Vol. 16, p. 69, lines 9-16.

[53] Transcript Vol. 16, p. 9, lines 9-12.

[54] BMcD/Modus Report, May 13, 2014, p. 10.

[55] BMcD/Modus Report, May 13, 2014 Attachment C "Summary of Cost Variances to Date for Campus Plan Projects", p. 1 [Confidential/Redacted].

> ***multiple threats to the start of the Refurbishment. Over the last quarter, BMcD/Modus has engaged in a thorough review of several key Campus Plan projects in an attempt to identify trends and understand the causes of these cost and schedule overruns. Our findings show that the predominant cause was [that the management team responsible for] ... managing this work for the [DRP] incorrectly applied an "oversight" project management approach for its EPC contracting strategy, leading to <u>a series of cascading management failures</u> and contractor performance issues, <u>including misunderstandings of scope, uncontrolled scope creep, poor quality cost estimates, unrealistic and incorrect schedules and an inability to manage known risks, additional costs and delays</u>. For multiple reasons....[the management team] was completely overwhelmed in trying to management Campus Plan Projects – in particular, the two largest of these projects the D2O Storage Facility and the Auxiliary Heat Steam Plant ("AHS") which were <u>the "pilot" projects for this new contracting model</u>.***[56]
> [Emphasis added]

106. OPG has assessed the impact of the additional costs now forecast for the Campus Plan Projects, including D_2O Storage and AHS at \$260M[57]; however, it has not sought to amend its revenue-requirement calculation because, as a result of schedule delays which must be attributed, at least in part to the above described mismanagement, the majority of the D_2O Storage project will not come into service during the test period.

107. We adopt Board Staff's submission that any approval of amounts that OPG seeks to close to rate base in this application should not be considered a finding of prudence for the D_2O Project.[58]

108. Notwithstanding OPG's suggestion that all of the additional costs now forecast for the Campus Plan Project represent "value-added work", the \$260M currently forecast by OPG will necessarily include some costs associated with implementing the recovery process currently required to put the Campus Plan Projects back "on-track". For, example, OPG admits that the forecast cost increase will include costs associated with accelerating the construction schedule for the D_2O Storage project in order to protect the critical path for the overall DRP and that OPG is currently in the process of isolating costs associated with this type of measure.[59]

109. In the context of the foregoing, we submit that would be inappropriate from OPG to recover the whole of the increased campus plan costs from ratepayers as these amounts close to rate base as it suggests that it is entitled to do.[60] OPG should be held to account for failing to

---

56 Exhibit D2-2-2, Attachment 1, May 13, 2014, BMcD/Modus, p. 1.
57 Transcript, Technical Conference, July 8, 2014, p. 44, lines 1-3.
58 Board Staff Submissions, p. 34.
59 Transcript, Technical Conference, July 9, 2014, p.41, lines 7-25.
60 Transcript, Technical Conference, July 8, 2014, pp.121 and 122.

prudently manage significant projects which are critical to the overall success of the DRP and the amount added to rate base should be written down to reflect any amount expended to redress management failures of the type described by BMcD/Modus in their May 13, 2014.

110. In this regard, and because OPG has been unable or unwilling to provide an estimate of these amounts, we recommend a reduction of between 10% and 20% of all in service additions proposed for the test period with respect to the D_2O Storage Facility and the AHS.

K. Reasonableness of OPG's Commercial and Contracting Strategy (Issue 4.11)

111. OPG seeks a finding of reasonableness in respect of certain "guiding principles" forming the commercial strategy selected by OPG for the DRP including:[61]

- The use of a "multi prime" contractor model where OPG retains responsibility for overall project management and design authority and the division of the DRP into 5 separate work packages; and,
- The use of target pricing where projects are less defined and require more oversight.

112. In their submissions to the Board, Board Staff note that the Board has never made a finding on commercial and contracting strategies such as these before and indicate that it "remains unclear … why OPG needs the Board to made a determination on this issue." Board Staff goes on to reiterate their concern that "it is unclear what a determination on the commercial and contracting strategies in the current proceeding would mean in future applications when more significant amount [sic] would be proposed for addition to rate base." As a result, Board Staff submits that no specific approval should be provided under this issue.[62]

113. We adopt Board Staff's submission as described above. In our view OPG's request for a finding of reasonableness regarding its selected commercial and contracting strategy amounts to an attempt to insulate OPG from commercial and contractual risks which would normally exist in the marketplace and from the full extent of the review which sound regulatory principles would dictate should occur in future proceedings.

114. The significant commercial and contractual risks associated with undertaking the DRP are highlighted in reports prepared by OPG's external consultants, Concentric Energy Advisors Inc. ("**Concentric**")[63] and include the following:

---

61 OPG AIC, p. 44.
62 Board Staff Submissions, pp. 36-37.
63 Exhibit D2-2-1 Attachment 7-1, pp. 4-5.

- the Canadian marketplace for the procurement of qualified nuclear engineering fabrication and construction services is very limited … Of the pool of vendors, only one vendor [SNC-Lavalin Nuclear, Inc.] recently provided a full turn-key refurbishment of a CANDU reactor…With regard to certain work packages [forming part of the DRP] only a single supplier has ownership or access to the original design basis documentation necessary to complete the work. Thus, creating competitive tension to produce optimal contractual terms can be difficult.

- no Canadian CANDU refurbishment or return to service project to date represents a model of a successful commercial strategy. …. [Pickering, Bruce and Point Lepreau] represent the most recent attempts to successfully plan, design and execute significant refurbishment or repair work on Canadian CANDU reactors… each project utilized a different commercial strategy [and each] project encountered challenges to the successful completion of the refurbishment work.

115. While Concentric ultimately concludes that the multi-prime model is reasonable and prudent under the current market circumstances, Concentric also makes a number of observations[64] highlighting the significant management challenges which OPG will face as result of the selection of this model including:

- OPG's "selection of the multi-prime strategy was based on the recognition that alternative models have not been successful." As a result, OPG has elected to retain responsibility for "coordinating the interfaces between each of the prime vendors selected to complete the work packages, and overseeing the Project's multiple prime contractors" and for "vendor claims for scope changes, owner-caused delays and vendor-caused delays that affect other vendors."

- "Given the complexity of the [DRP] and the limited working space within the Darlington site, Ontario Power Generation's coordination of the various work tasks will require extensive planning to prevent claims of delay or increased costs caused by Ontario Power Generation's failure to adequately plan and coordinate the work or interference from another vendor …. While Concentric is in agreement with the selected commercial strategy, we do note that this model does not mirror Ontario Power Generation's previous experience with significant projects and that the Project team has limited experience in managing vendors under this model. …."

[64] Exhibit D2-2-1, Attachment 7-1, p. 6.

116. Concentric also provides an assessment of the use of a "target pricing strategy" for significant work packages forming part of the DRP including the Retube and Feeder Replacement project which represents approximately 60% of the total forecast cost for the DRP.[65]

117. Concentric notes that while the target pricing model will give OPG flexibility to adapt to the DRP's evolving scope and create incentives intended to limit cost increase and schedule delays it will also create significant oversight responsibilities because once the cost for each unit exceeds the target price and caps for each unit, the contract is essentially a cost reimbursable (excluding vendor overhead and profit) agreement with a more limited risk transfer relative to a fixed price agreement.[66]

118. In endorsing the multi prime contracting model and the target pricing strategy respectively, Concentic cites "current market circumstances"[67] or the existence of "a market that lacks sufficient depth to create adequate competition to support a fixed price agreement that meaningfully transfer the risk of price increases and schedule over-runs to a vendor."[68]

119. In our submission, seeking approval of riskier commercial and contracting strategies on the basis that they are the only strategies available in a limited market is 'putting the cart before the horse.' OPG's obligation to demonstrate the continued economic feasibility of the DRP includes satisfying the Board that the DRP can be delivered within approved budgets and schedules notwithstanding the existence of a sub-par market for nuclear services in Canada.

120. The reasonableness of the above-described contracting strategies will in large part depend on OPG's ability to meet the significant management challenges created by these strategies. OPG's abilities in this regard are, at best, unproven particularly in light of recent management breakdowns which occurred in connection with the D_2O Storage Facility and the Auxiliary Heat Steam Plant ("**AHS**") which were the "pilot projects"[69] for the target pricing contracting strategy.

121. As a result, the reasonableness of OPG's commercial and contracting strategies should not be assessed prospectively as requested by OPG but rather should be considered as part of the larger review of the DRP at a time when OPG can objectively demonstrate a proven ability to successfully manage multiple prime contractors operating under target price arrangements.

---

65 OPG AIC, p. 41.
66 Exhibit D2-2-1, Attachment 7-1, p. 9.
67 Exhibit D2-2-1, Attachment 7-1, p. 8.
68 Exhibit D2-2-1, Attachment 7-1, p. 10.
69 Exhibit D2-2-2, Attachment 1, May 13, 2014, BMcD/Modus, p.1.

L. Ontario's Long Term Energy Plan (Issue 4.12)

122. For the same reasons that we submit that the Board should not make a finding regarding the reasonableness of the OPG's commercial and contracting strategies for the DRP, we submit that it would be premature for the Board to make a finding as to the whether the DRP aligns with Ontario's Long Term Energy Plan issued on December 2, 2013.

5. PRODUCTION FORECASTS

A. Regulated Hydro-Electric Production Forecast

Issue 5.1 (Secondary) – Is the proposed regulated hydroelectric production forecast appropriate?

123. OPG's proposed hydroelectric production forecast is appropriate.

B. Surplus Baseload Generation ("SBG")

Issue 5.2 (Primary) (reprioritized) – Is the estimate of surplus baseload generation appropriate?

124. Board Staff has recommended that the current approach to Surplus Baseload Generation ("**SBG**") be maintained. The basis for this recommendation is that SBG forecasting is clearly difficult.

125. We agree with Board Staff that SBG forecasting is difficult. Subject to the caveat, set out below, this is the central reason that we support the continuation of the SBG variance account.

126. Our concern relates to the large debit amounts that have accumulated in the SBG variance account, coupled with the fact that actual SBG for 2011, 2012 and 2013 are all well below the amounts forecast by OPG for 2014 and 2015. These amounts are set out in Table 15 of Board Staff's submissions.[70]

127. Table 15 demonstrates that the actual SBG for 2011 and 2012 was 0.1 TWh, and for 2013 was 0.2 TWh. OPG has forecast substantially higher SBG, 0.6 TWh, for each of the years 2014 and 2015.

128. Similarly, for the newly regulated hydroelectric facilities, actual SBG for 2011 and 2012 was 0.2 and 0.3 TWh, respectively. Again, the forecast for 2014 and 2015 of 0.4 and 0.5 TWh are well in excess of recent years.

70 Board Staff Submissions, p. 39.

129. In these circumstances, we believe that it would be appropriate for the Board to embed some SBG in the Payments Amount by appropriately adjusting the production forecast.

C. Hydroelectric Incentive Mechanism ("HIM")

Issue 5.3 (Secondary) – Has the incentive mechanism encouraged appropriate use of the regulated hydroelectric facilities to supply energy in response to market prices?

Issue 5.4 (Primary) – Is the proposed new incentive mechanism appropriate?

Issue 9.7 (Primary) (reprioritized) – Is OPG's proposal to make existing hydroelectric variance accounts applicable to the newly regulated hydroelectric generation facilities appropriate?

Issue 9.8 (Secondary) – Is the proposal to discontinue the Hydroelectric Incentive Mechanism Variance Account appropriate?

130. We have little to add to Board Staff's thorough analysis of these issues. For all of the reasons Staff has articulated, OPG's proposed new incentive mechanism, the eHIM proposal should be rejected. The existing HIM mechanism should be maintained, along with the HIM variance account.[71]

131. The HIM and SBG variance accounts should be managed in a way which eliminates the unintended benefit to OPG of the interaction between SBG conditions and the HIM. As Staff notes in its submission, this unintended benefit is the result of SBG reducing the average monthly hourly production threshold for HIM, thus increasing the potential revenues from HIM, while also collecting the regulated payment from reduced energy production that is the result of SBG conditions.

132. We submit that this unintended consequence of the interaction between the HIM and SBG variance accounts should be managed either through periodic credit postings to the SBG deferral account or by an appropriate year-end adjustment when the SBG variance account balance is cleared.

133. We support Board Staff's graduated percentage sharing mechanism which would allocate the first $50M of revenues between OPG and consumers on a 50/50 basis, with the next $20M of revenues shared on a 60/40 basis in favour of consumers, the next $20M of revenues shared on a 80/20 ratio and any additional revenues to be shared on a 90/10 ratio in favour of consumers.[72]

[71] Board Staff Submissions, pp. 40-50.
[72] Board Staff Submissions, p. 50.

D. Storage

Issue 5.1(a) (Primary) – Could the storage of energy improve the efficiency of hydroelectric generating stations?

134. While the Board and others should give serious consideration to the storage initiative which Mr. Tolmie is promoting, the breadth of his presentation is far greater than the scope of the issue which the Board has framed for determination in this proceeding.

135. That issue is confined to a consideration of whether the storage of energy could improve the efficiency of hydroelectric generating stations. Mr. Tolmie obviously believes that the answer to the question which the Board has posed is YES. However, there is no sworn evidence before the Board which has been tested in cross-examination upon which the Board could make any findings in this particular proceeding with respect to this issue.

E. Nuclear Production Forecasts

Issue 5.5 (Primary) – Is the proposed nuclear production forecast appropriate?

136. For all of the reasons articulated by Board Staff in their submission, OPG's nuclear production forecasts should be reduced by 1.32tWh.[73]

6. OPERATING COSTS

A. Regulated Hydroelectric OM&A

Issue 6.1 (Oral Hearing) – Is the test period Operations, Maintenance and Administration budget for the regulated hydroelectric facilities appropriate?

137. We have reviewed both Board Staff's submissions and SEC's submissions on this issue and we agree with their shared conclusion that the evidence in this proceeding demonstrates a consistent under-spending for Hydroelectric OM&A relative to budgeted and approved operating costs and that there was no evidence of any impact of this under-spending on OPG's operations.[74]

138. We support the submissions of both Board Staff and SEC that a reduction in OPG's hydroelectric OM&A is warranted in these proceedings. While we see merit in the alternative methodologies for calculating such a reduction described by each of Board Staff and SEC, we prefer the approach recommended by SEC which would reduce the requested amount budgeted for hydroelectric OM&A by 4.3% a year, resulting in a reduction of $9.7M in 2014 and

---

73 Board Staff Submissions, pp. 51-56.

74 Board Staff Submissions, pp. 57-58 and SEC draft Submissions.

$10M in 2015, in order to reflect OPG's historical percentage of actual versus planned hydroelectric OM&A spending. We believe that this approach is most likely to incent OPG to maintain any efficiencies realized over the past years.

B. Regulated Hydroelectric Benchmarking

Issue 6.2 (Oral Hearing) – Is the benchmarking methodology reasonable? Are the benchmarking results and targets flowing from those results for the regulated hydroelectric facilities reasonable?

139. We share the concerns expressed by both Board Staff and SEC with respect to the benchmarking exercise which OPG has undertaken with respect to its hydroelectric operations. More specifically, we agree with Board Staff that "selectively benchmarking only 50% of total OM&A costs and completely excluding regulatory costs, which are a significant component of operating cost, is not representative of the operations of the hydroelectric facilities."[75]

140. In addition, in our submission, only limited weight can be ascribed to a benchmarking exercise undertaken internally as opposed to by an objective third party, a weakness which, as discussed by Board Staff, appears to have been recognized by OPG's own consultant, KPMG, which did not use the OPG hydroelectric "benchmarking" results in its overall review of benchmarking at OPG.[76]

141. Given the above, in our submission, the results of the benchmarking exercise undertaken by OPG with respect to its hydroelectric facilities are, at best, of limited assistance to the Board in assessing the reasonableness of OPG's costs or productivity. At worst, they may obscure inefficiencies in hydroelectric OM&A. For example, and as pointed out by SEC, with respect to the significant labour and pension costs that OPG has elected to exclude as corporate and centrally held costs.

142. As argued by both Board Staff and SEC, we believe that OPG should be required to produce a complete and independent benchmarking exercise for its hydroelectric facilities in anticipation of IRM.

C. Nuclear Operations, Maintenance and Administration ("OM&A") Budget

Issue 6.3 (Oral Hearing) – Is the test period Operations, Maintenance and Administration budget for the nuclear facilities appropriate?

143. We believe that ratepayers are justified in demanding significant reductions to the proposed nuclear OM&A for the test period given OPG's continued poor performance relative to

---

75 Board Staff Submissions, p. 60.
76 Board Staff Submissions, pp. 59-60.

its peers in terms of both productivity and value for money, and its apparent renunciation of the core objective established by its shareholder to target "top quartile of private and publicly-owned nuclear electricity generators in North America". Our detailed submissions in this regard are found in the sections which follow.

D. Nuclear Benchmarking

Issue 6.4 (Oral Hearing) – Is the benchmarking methodology reasonable? Are the benchmarking results and targets flowing from those results for the nuclear facilities reasonable?

144. In preparing our submissions on nuclear benchmarking, we have had the benefit of reviewing the submissions of Board Staff. We share many of the concerns expressed by Board Staff with respect to OPG's markedly poor performance in all three key benchmarking metrics[77] and OPG management's failure to assume any measure of responsibility for these unsatisfactory outcomes.

145. Only nine years after the establishment of OPG pursuant to terms outlined in the Memorandum of Agreement ("**MOA**") with the Province of Ontario dated August 17, 2005, we are also troubled by OPG's apparent refusal to establish targets intended to propel OPG into "the top quartile of private and publicly owned nuclear electricity generators in North America."[78] We submit that this objective is fundamental to OPG's mandate and that ratepayers have a reasonable expectation of "continued improvement" which is directed towards achieving this goal within a reasonable time frame.

146. OPG's most recent benchmarking exercise was the subject of significant questioning during the oral hearing in this proceeding. CME would draw the Board's attention to a number of conclusions arising from this benchmarking exercise with reference to Board Staff's submissions as well as to the summary of nuclear benchmarking reports contained in the chart filed as Exhibit J5.2 which was prepared by Board Staff and subsequently reviewed and accepted by OPG. Specifically:

77 Three "key metrics" were identified Phase 1 and 2 reports prepared by ScottMadden Inc. which were filed in the second payments case (EB-2010-0008) and which have also been filed in this proceeding. OPG conducts ongoing benchmarking using the methodology established in these reports. See Board Staff Submissions, pp. 65-67.

78 Memorandum of Agreement with OPG's Shareholder, dated August 17, 2005.

- **Performance Measures (WANO NPI[79] & UCF[80])**: On both key performance measures, OPG's overall nuclear operations are benchmarking in the bottom quartile. OPG's overall ranking on the two key performance metrics deteriorated slightly between 2008 and 2011, going from the bottom 15% of its peers (17th of 20) in 2008 to the bottom 11% of its peers (24th out of 27) in 2011 on the WANO NPI metric and from the bottom 10% (18th out of 20) in 2008 to the bottom 9% (25th out of 28) in 2011 on the UCP metric;

- **Total Generating Cost ("TGC")**: Although there is a slight improvement in OPG's overall standing on the TGC metric between 2008 and 2011, going from 16th out of 16 in 2008 and 12th out of 14 in 2011, OPG is still solidly in the bottom quartile on this value for money metric. Pickering "A" and "B" have never been other than in the bottom quartile; however, historically, Darlington has benchmarked in the top quartile. As a result, it should be of great concern to all ratepayers that the 2013-2015 business plan filed by OPG in connection with this application projects a TGC for Darlington which deteriorates to second quartile in 2014 and third quartile in 2015.

- **Benchmarking Targets:** In 2009, ScottMadden, the consultant retained by OPG in response to direction from the Board in the first payments case, recommended targets for 2014 for all three key metrics which were supported by OPG executives and which ScottMadden concluded would "not achieve "best quartile" performance ... [but] would represent a significant improvement over current performance."[81] Board staff have undertaken a review of these targets relative to 2013 rolling actuals and OPG's 2013-2014 business plan[82] and have reached the following conclusions which we support:

    - It is highly unlikely that OPG will achieve the ScottMadden 2014 WANO NPI and UCF performance targets for either Darlington or Pickering;

79 WANO NPI standards for World Association of Nuclear Operator Nuclear Performance Index and is a "roll-up of ten indicators, all of which are focused on operational excellence in what the industry is doing" (Transcript Vol. 5, June 18, 2014, at p. 70).

80 UCP stands for "Unit Capability Factor".

81 Exhibit K5.5, ScottMadden Phase 2, p. 31.

82 Board Staff Submissions, pp. 69-70.

- The ScottMadden 2014 TGC target for Darlington of $36.75/MWh appears to significantly exceed the value for money results which OPG was already achieving in 2008, being the year preceding the release of the ScottMadden targets, suggesting that for some reason, which is not readily apparent, ScottMadden found it necessary to project total generating cost increases between 2009 and 2014 as opposed to reductions as might have been expected in such an aspirational exercise; and,

- In its 2013-2015 business plan, OPG is setting targets for 2015 which are inferior to the 2014 target for Darlington and stagnant at Pickering, as opposed to driving towards top quartile as required under the MOA.

147. We submit that the results of OPG's most recent benchmarking exercise, particularly as described above, show that OPG's performance falls far short of what ratepayers should reasonably expect.

148. Importantly, the Board reached this same conclusion in OPG's last payment case (EB-2010-0008) and determined that it was necessary to send a "strong signal that OPG must take responsibility for improving its performance"[83] by reducing the payment amount by $145M and by reminding OPG that "if costs are in excess of a reasonable level of performance, then those excess costs are appropriately borne by the shareholder."[84]

149. It is clear from the evidence that OPG failed to accept the Board's direction.[85] As indicated by Board's Staff, "It would appear that the OPG nuclear business no longer considers closing the gap and achieving top quartile to be an objective."[86]

150. In this context, we submit that, in addition to specific disallowances relating to compensation and to corporate costs which we advocate further in this submission, and in recognition of the fact that OPG's poor nuclear performance directly impacts the costs imposed on ratepayers, it would be appropriate for the Board to order a further reduction in OPG revenue requirement.

151. In their submissions, Board Staff offer a rough calculation[87] of the reductions in the OPG's revenue requirement if OPG had a TGC closer to the benchmarking midpoint of

83 Decision EB-2010-0008, p. 86.
84 Decision EB-2010-0008, p. 87.
85 In fact, OPG appealed the Board's decision as described in more detail in footnote 113 to Board Staff's Submissions. Notably, the Court of Appeal confirmed that benchmarking could be used by the Board and this issue has not been carried further in the Board's subsequent appeal to the Supreme Court of Canada.
86 Board Staff Submissions, p. 70.

$40.50/MWh as opposed to the $46.92/MWh identified as OPG's overall nuclear TGC in the 2012 Benchmarking Report.[88] The resulting savings to the ratepayer would be $300M per year (TGC Differential x production forecast). If OPG were actually to achieve top quartile, the savings would be $725M per year.

152. While we recognize that using the above-referenced calculations to determine a reduction in the revenue requirement represents something of a blunt instrument, given the limited impact that the Board's previous rulings have had in terms of incenting OPG to take additional responsibility for improving its benchmarking performance, we submit that a stronger message is warranted. As a result, and recognizing that TCG includes OM&A, fuel and some capital costs, we submit that a reduction in the revenue requirement of $150M, being half of the amount by which the revenue requirement would be reduced if OPG was achieving the benchmarking midpoint would be appropriate. This proposed reduction would be incremental to the specific disallowances described below.

E. <u>Nuclear Fuel</u>

Issue 6.5 (Secondary) – Is the forecast of nuclear fuel costs appropriate? Has OPG responded appropriately to the suggestions and recommendations in the Uranium Procurement Program Assessment report?

153. OPG is requesting Board approval of a budget of $266.5M for 2014 and 260.5M for 2015 for nuclear fuel.[89] These costs include the cost of fuel bundles, used fuel storage costs and fuel oil for standby generators.

154. In EB-2010-0008, the Board provided the following directive to OPG: "In the next proceeding, the Board will examine OPG's procurement program to determine whether the company is optimizing its contracting in order to minimize costs to ratepayers. The Board will therefore direct OPG to file an external review as part of its next application."[90]

155. In response to that direction, OPG filed the Uranium Procurement Program assessment Study prepared by Longenecker and Associates (the "**Longenecker**").[91] That Study compared OPG's nuclear fuel policies and practices to a number of nuclear power generators in both Canada and the United States. On the basis of that survey, Longenecker made a number of recommendations.

---

87 Board Staff Submissions, p.70.
88 Exhibit F2-1-1, Attachment 1, p. 80.
89 Exhibit N2-1-1.
90 EB-2010-0008, p. 55.
91 Exhibit F5-2-1.

156. The Longenecker Study noted that OPG's annual uranium requirements are about 2 million pounds/year and OPG's policy is to maintain a minimum inventory of 1 million pounds or 50% of annual requirements as strategic inventory. Moreover, additional inventory is also held in the form of finished fuel which contains about 2 million pounds. As a result, OPG is carrying about 1.5 years of inventory or 150% of annual requirements. According to Longenecker, the value of the uranium contained in inventories carried by OPG is approximately $170M.

157. Longenecker goes on to confirm that no US utility carries finished fuel as inventory and, in comparison, a large number of US nuclear generators only require an inventory of between 30% and 35% of annual requirements. Longenecker also notes that, in general, nuclear utilities plan for a maximum of one-year interruption of deliveries. On this basis, Longenecker concluded that OPG's multiple inventories provide a significant potential to "optimize" the existing multiple inventories, thereby allowing for reduced investment and lower annual inventory carrying costs.

158. In CME interrogatory number 8, OPG confirmed that, in accordance with the Longenecker Study, it reduced its inventory to 30% of its annual requirement, the carrying costs savings would be $4.7M over the test period ($2.3M in 2014 and $2.4M in 2015). We submit that these reductions are appropriate.[92]

159. Moreover, OPG's forecasted fuel costs for 2014 and 2015 are significantly greater than OPG's historical spending. We suggest that the forecast cost of nuclear fuel for 2014 and 2015 should be no more than $244.7M, which was the actual cost of fuel for 2013.[93]

160. Finally, we support the request by Board Staff that OPG be required, as part of the next payments application, to provide a further study that addresses how its nuclear fuel requirements and cost estimates are appropriate and meet "good utility practice".

F. <u>Pickering Continued Operations</u>

Issue 6.6 (Primary) – Are the test period expenditures related to continued operations for Pickering Units 5 to 8 appropriate?

161. We have no submissions with respect to this issue other than to reiterate our comments in the context of the DRP that OPG bears the onus of demonstrating, on a continuous basis, that projects continue to be economically feasible. In the course of Pickering, this is particularly

---

[92] Exhibit L-6.5-3.
[93] Exhibit L-6.5-17, SEC 101.

true in light of the diminishing cost advantage of Pickering continued operations identified by OPA and highlighted in Board Staff's submissions.[94]

G. Compensation

Issue 6.8 (Oral Hearing) – Are the 2014 and 2015 human resource related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate?

162. In response to the Board's direction in the last payments case, OPG has undertaken two significant benchmarking exercises. One addresses staffing levels and the other addresses overall compensation. The deficiencies in these two reports as well as OPG's poor performance relative to its peers, particularly with respect to compensation, support the conclusion that the 2014 & 2015 human resources related costs submitted for approval by OPG are far from reasonable and must be reduced. Our detailed submissions in this regard follow.

(i) Staffing Levels

163. In both of the previous payment amounts proceedings, the evidence has been that OPG's nuclear operations are overstaffed relative to industry benchmarks or medians.[95]

164. In light of the poor performance of the nuclear business overall relative to comparable nuclear electricity generators, and the significant component of OPG's total operating costs attributed to labour costs (it was OPG's evidence that currently 72% of OPG's costs are labour costs[96]), the Board directed OPG to conduct a staff level analysis as part of its benchmarking studies for the next proceeding.

165. Subsequently, OPG retained Goodnight Consulting Inc. ("**Goodnight**") which completed an initial report in July of 2011 and an updated report in February of 2013.

166. As indicated in Board Staff's submissions, the July 2011 Goodnight report concluded that OPG's nuclear staffing was 17% (or 866 full time equivalent employees ("**FTEs**")) above the comparable benchmark. This gap dropped to 8% (430 FTEs) in February 2013 and to 4.7% (244 FTEs) as of March 1st of 2014. While we agree that these results do reflect a reduction in benchmarked staffing levels, we support Board Staff's conclusion that "nuclear remains overstaffed and will likely remain overstaffed until at least the very end of the test period."[97]

94 Board Staff Submissions, p. 75.
95 EB-2010-0008, p. 44 (Reference to Navigant report filed in the previous proceeding which found OPG's 2006 staffing levels to be 12% higher than benchmark as well as p. 26 of the Phase 2 Scott Madden report also filed in this proceeding which concluded that "staff levels per unit exceed both the industry median and Bruce Power levels).
96 Transcript, Vol. 6, p. 120, line 24.
97 Board Staff Submissions, p. 87.

167. In addition, in our submission, the nuclear staffing benchmarking exercise undertaken by Goodnight is deficient in a number of significant respects. While OPG's nuclear staffing number for 2011 was 8,700[98] FTEs, only 5,574 OPG FTEs were included in the 2011 Goodnight study. As a result, approximately 3100 FTEs, representing 36% of the FTEs dedicated to OPG's nuclear operations were not subject to any external benchmarking.[99] With respect to the exclusion of three of the larger groups of FTEs from the staffing level benchmarking, our submissions are as follows:

- **1031 "CANDU specific" FTEs**: The group of comparables assembled by Goodnight did not include any CANDU reactors and much was made in both the Goodnight reports[100] and in OPG's evidence[101] of the uniqueness of the CANDU technology and the broad range of functions exclusive to the CANDU design; however, the difficulties associated with benchmarking CANDU reactors are not new to OPG[102] and there are a number of available options for addressing them. For example, the ScottMadden benchmarking report considered staffing level data from Bruce Power. When asked why reference was not made to Bruce Power or why ScottMadden was not retained to assist in order to supplement the Goodnight reports, OPG's witness simply stated that they did not have data from Bruce Power[103] and did not know whether ScottMadden was ever contacted in this regard.[104]

- **1400 "Non-Dedicated" FTEs:** OPG's evidence was that approximately 1400 FTEs allocated to OPG's nuclear operations are people who are not entirely "dedicated" to nuclear operations and the example that was given was "finance people who maybe spend half their time on nuclear, half nuclear, half hydro" which Goodnight "could not benchmark."[105] It remains unclear to us why benchmarking of functions such as corporate finance which would likely be common to most utility companies could not have occurred, even if a different group of comparators had to be used.

98 Exhibit F4-3-1, and Transcript, Vol. 6, p. 105, line 27.
99 Transcript, Vol. 6, June 19, 2014, p. 107.
100 Exhibit F5-1-1 Part (a) (Goodnight Report, July 2011), p. 14.
101 See for example, Transcript Vol. 6, June 19, 2014, p. 107.
102 For example, in EB-2010-0008, the Board noted that "OPG may want to consider whether a study of the major cost differences between CANDU and PWR/BWR would facilitate the review of its application on the issue of cost differences between the various technologies.
103 Transcript Vol. 6, June 19, 2014, p. 108.
104 Transcript Vol. 6, June 19, 2014, p. 110.
105 Transcript Vol. 6, June 19, 2014, pp. 103- 104.

- **732 FTEs – "Generic Exclusions":** These exclusions relate to functions such as addressing nuclear waste and used fuel, outage execution activities and water treatment.[106] While these functions would appear to be common to all nuclear electricity generators, it appears that Goodnight excluded them from benchmarking because they lacked data on them. When asked whether any thought was given to undertaking a specific study on staffing levels for outages, OPG's witness again expressed that their outages are "longer and very complicated" and therefore difficult to benchmark.[107]

168. OPG submits that "while it is not appropriate to extrapolate the staffing results established by Goodnight to those functional areas which Goodnight could not benchmark" the Board should accept, on the basis of oral testimony from OPG's witnesses and in the absence of any objective market comparison, that OPG has "found efficiencies" and has "achieved staff reductions in those non-benchmarked groups."[108] We submit that OPG has not provided a sufficient basis for this conclusion.

169. In our submission, given the magnitude of the costs at stake and OPG's poor benchmarking performance on the total generating cost metric, OPG's failure to undertake staff level benchmarking for such a large percentage (36%) of its nuclear dedicated workforce constitutes a failure to adequately respond to the Board's direction regarding staffing level benchmarks in EB-2010-0008.

170. In addition to the staffing numbers themselves, as discussed in detail in Board Staff's submissions with reference to the Auditor General's report dated December 10, 2013, when broken into functional groups, 23 functional areas are staffed above benchmark with only 14 functional areas below benchmark. When benchmarked staffing levels between 2011 and 2013 were compared, it became apparent that one of the most overstaffed areas, facilities....improved only slightly from 173% to 170% over benchmark.[109]

171. Even more troubling from a costs control perspective is the Auditor General's observation that while unionized staffing levels are going down, there is "a significant increase in the management staffing levels"[110] at OPG. As indicated in Board Staff's submission, the

[106] Exhibit F5-1-1 Part (a) Goodnight July 2011 Report, p. 15.
[107] Transcript, Vol. 6, pp. 114-115.
[108] OPG AIC, p. 77.
[109] Board Staff Submissions, p. 84.
[110] Exhibit KT2.4, Report of the Auditor General, p. 163.

"Auditor General noted that in 2012, 17 employees were promoted to VPs and 50 to directors."[111]

(ii) Compensation

172. OPG has applied for regulated compensation costs of $1,604.2M for 2014 and $1,618.1M for 2015[112] which are in excess of its compensation costs for 2010,[113] notwithstanding an overall reduction in FTE's. This trend demonstrates OPG's inability to successfully manage compensation costs.

173. In its Decision in the last payments case, EB-2010-0008, the Board directed OPG to prepare a full compensation benchmarking study. In response to that direction, OPG filed the Aon Hewitt Report ("**Aon Report**") in this proceeding.[114]

174. OPG's forecast total average compensation per employee for 2015 is $205,914 for management, $176,508 for SEP employees, and $163,458 for PWU employees.[115] The Aon Report concludes that OPG's compensation for these three identified categories of OPG employees are all, in varying degrees, much greater than the 50th percentile of market. PWU, which represents 53% of OPG's overall compensation costs, was the worst with ranges between 19.1 and 29.4 over the 50th percentile.

175. We submit that the findings contained in the Aon Report indicate that OPG has not made any significant improvements in its compensation costs since EB-2010-0008. Of even more concern is the fact that OPG was not surprised by the findings of the Aon Report.[116]

176. OPG has attempted to diminish the impact of the conclusions drawn in the AON Report in the context of this proceeding by suggesting that the comparisons drawn in the AON report are of limited value given the constraints which Ontario's collective bargaining regime places on OPG. OPG also argues that in assessing the reasonableness of OPG's unionized labour costs the Board must look at the final result, and that the Board is not in a position to offer a critique on any specific negotiating strategies.[117]

177. We would urge the Board to reject these arguments and submit that it is entirely appropriate for the Board to assess the reasonableness of the total compensation paid by OPG

111 Exhibit KT2.4 Report of the Auditor General, p. 159.
112 Exhibit J9.7, Attachment 1.
113 In 2010, its overall compensation costs were $1,581M compared to $1,618.1M in 2015.
114 Exhibit F1-4-1.
115 Exhibit J9.7, Attachment 1.
116 Transcript, Vol. 8, pp. 74-75.
117 Transcript, Vol. 8, pp. 64-66.

as compared to other similar utilities. This is a significant rationale for the benchmarking study that the Board in the last payment's case directed OPG to undertake.

178. We note that the Auditor General's Report references the Aon Report in support of its conclusion that OPG should measure its salary levels against similar organizations to ensure that they are reasonable.[118] As Board Staff rightly points out at page 182 of its Argument, the Auditor General also compared the total average earnings for selected OPG positions with the total maximum earnings for the same positions in the Ontario Public Service generally. In this additional comparison, OPG's general compensation was, in many cases, greatly in excess of the average compensation for comparable positions in the Ontario Public Service. This contributed to the Auditor General recommendation that OPG should be comparing its compensation levels to the broader public sector to ensure that its own salaries are reasonable.[119]

179. In addition to our concerns about the conclusions of the Aon Report, we also wish to highlight the deficiencies report itself in terms of providing useful information to guide the Board in assessing the reasonableness of OPG's compensation costs.

180. The Aon Report does not contain any data which would allow the Board to identify how much, on a financial basis, OPG is over or under on costs at either the 75th percentile or 50th percentile (and in our submission the 25th percentile). Under cross-examination, OPG was unable to say how much money would have to be removed from payroll to bring all of the PWU society and management positions to the 50th percentile.[120] We submit that this is unacceptable.

181. In the last payments case, OPG used data from a Towers Perrin survey to prepare a chart comparing OPG's salary levels with those of other organizations in the survey. In that case, OPG advised the Board of the amount of money that would have to be removed from payroll to bring their positions to either the 75th percentile or 50th percentile. When asked to explain to the Board why OPG was able to quantify bringing the positions from the Towers Perrin survey to the 50th percentile in the previous case, but was unable to do so with the Aon Hewitt survey in this case, OPG's only explanation was that the Towers Perrin information actually showed job rates for a position whereas the Aon data, as presented, did not provide individual salary rates.[121]

118 K2.4 Report of the Auditor General, pp. 165 and 170.
119 Exhibit K2.4, Report of the Auditor General, pp. 165-170.
120 Transcript, Vol. 9, pp. 169-170.
121 Transcript, Vol. 9, p. 172.

182. The use of the Towers Perrin report in the last proceeding demonstrates that such data is available and that it is relevant to the Board's determination. Such data could have been presented in this case in the same form that it was presented in the previous case. OPG, however, elected not to do so. In this regard, Chairperson Hare made the following observation:

> ***The decision last time made it very clear that the Board finds that the compensation benchmark should be generally set at the 50th percentile, so I find it rather outstanding that you wouldn't have figured out what the different in compensation would be, if it is at the 50th percentile. That is what the decision said last time.***

183. In J9.11, OPG was directed by the Board to "provide evidence that would allow the Board to know or quantify moving OPG from where it currently stands to the 50th percentile". In response, OPG estimated that moving PWU compensation to the median would result in a reduction in base salaries and wages paid in the regulated business of $96M in 2014 and $94M in 2015.[122]

184. J9.11 does not, however, provide any estimates of the costs required to also move the Society and Management to the 50th percentile. We submit that in the face of OPG's election to not provide such information, the Board is entitled to make an adverse finding that there would be significant additional reductions in base salaries and wages.

(c) Proposed Reduction in 2014 & 2015 Human Resources Related Costs

185. In determining the appropriate amount of such a reduction, we urge the Board consider that the MOA with the Province of Ontario requires OPG to establish targets to propel OPG "into the top quartile of private and publicly owned nuclear generators in North America"[123]

186. We submit that the ongoing overstaffing identified in Goodnight together with OPG's poor benchmarking performance with respect to compensation levels identified in the Aon Report confirm that OPG has failed to bring its human resources related costs within reasonable limits for regulatory purposes and justify significant reductions in OPG's 2014 and 2015 human resource s related costs.

187. We also note that, as discussed in more detail in our submissions above, both the Goodnight and the Aon Report fail to provide significant information that would have been of assistance to the Board in making its determination.

188. Given that it is the only estimate which OPG has provided to the Board, we would suggest that, as a starting point, the minimum reduction that the Board should consider is $96M

122 J9.11
123 Memorandum of Agreement with OPG's Shareholder, dated August 17, 2005.

in 2014 and $94M in 2015 as identified in J9.11. This would, however, only address excessive compensation paid to the PWU, and not adjust compensation levels for Society or Management. We appreciate that because OPG failed to quantify the reductions to Society and Management needed to meet the 50th percentile, the Board is placed in a difficult position. Nevertheless, with the assistance of Board Staff, we believe that the Board can estimate such an additional reduction. To this end, we suggest that an additional amount of $50M per year would be appropriate. If accepted, this would then result in reductions of $146M in 2014 and $144 in 2015.

189. Moreover, to move OPG compensation levels to the 25th percentile, which would be consistent with the MOA, these reductions would need to be, at the very least, doubled. This would result in reductions of $292M in 2014 and $288M in 2015.

H. <u>Pension and Other Post-Employment Benefits</u>

Issue 6.8 (Oral Hearing) - Are the 2014 and 2015 human resource related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate?

Issue 6.10 (Oral Hearing) – Are the centrally held costs allocated to the regulated hydroelectric business and nuclear business appropriate?

190. We have had the benefit of discussing this topic with SEC, and also reviewing analysis prepared by them. To this end, we support the recommendations and calculations of SEC that result in a $609.4M reduction. The following submissions support this proposed reduction.

191. We believe that the Board should in this case apply the cash methodology rather than the accrual methodology for determining the amount of pension and benefit costs which OPG can recover in its payment amounts.

192. In the EB-2010-0008 Decision with Reasons issued, almost 3½ years ago on March 10, 2011, the Board observed at page 91 that, "The Board in this case sees no compelling reason to change OPG's existing approach of using the accrual method".

193. In our view, the question for the Board to determine in this case is whether there are now compelling reasons to require that the pension and benefits costs recovered from ratepayers in 2014 and 2015 be determined by applying the cash rather than the accrual method of accounting.

194. Much has changed for ratepayers since March 10, 2011. First, total electricity prices have continued to significantly escalate. Manufacturers and other consumers are finding it very difficult to cope with these frequent price increases.

195. Second, the enormous payment amount increases OPG seeks in this case are, in and of themselves, an overwhelmingly compelling reason to adopt the cash method for determining the pension and benefit costs recoverable in the regulated payment amounts.

196. Third, OPG's pension and benefits plans are considered by experts to be unsustainable. Having regard to the Towers Perrin 2011 Report and the Report on the Sustainability of Electricity Sector Pension Plans, to which Board Staff refers in their argument, the Board should not hesitate to find that OPG's pension and benefit plans are unsustainable. The Board should no longer be burdening ratepayers with the future costs of unsustainable pension and benefit plans.

197. Fourth, as Board Staff notes in their arguments, the vast amounts which OPG has already collected, but not yet paid out for pensions and benefits, totalling some $752M as of December 31, 2013, has already been used for general corporate purposes. OPG's position that the Board has no jurisdiction to require it to refrain from using these monies for general corporate purposes lacks merit. Board Staff has persuasively addressed this issue in their submissions.

198. Fifth, we agree with Board Staff that U.S. GAAP accounting rules should not deter the Board from adopting the cash method when determining pension and benefits amounts which OPG can collect from ratepayers. Hydro One recovers pensions on a cash basis without encountering any auditing qualifications of the type speculated by OPG.

199. Finally, we feel it is important to note that this reduction in the amount of pension and benefit costs collected from ratepayers is not a disallowance but is only a change in the method of recovering such costs.

200. For these reasons, we urge the Board to direct OPG submissions to apply the cash methodology rather than the accrual methodology for determining the amount of pension and benefit costs to be recovered in its payment amounts. It appears to us that the correct reduction resulting from such a change has been calculated by SEC. If the Board does not accept SEC's calculation, then Board Staff's suggested amount should be adopted.

I. Corporate Costs

Issue 6.9 (Oral Hearing) – Are the corporate costs allocated to the regulated hydroelectric and nuclear businesses appropriate?

201. We support the submissions of Board Staff at pp. 112-115 of their argument including the recommended disallowance to the nuclear test period OM&A of $25M per year related to corporate costs in light of benchmarking results and historical spending.

J. Depreciation

Issue 6.11 (Secondary) – Is the proposed test period depreciation expense appropriate?

202. We have reviewed the submissions of both Board Staff and SEC on this issue.

203. We agree that the economic life for the Niagara Tunnel must be greater than 90 years, as proposed by OPG. We support the Board imposing an economic life in the range of 135 years, as proposed by Board Staff, to 150 years, as proposed by SEC.

K. Income and Property Taxes

Issue 6.13 (Primary) (reprioritized) – Are the amounts proposed to be included in the test period revenue requirement for income and property taxes appropriate?

204. We adopt the submissions of Board Staff and SEC with respect to this issue. More specifically:

(i) Tax Loss Carry - Forward

205. OPG has declined a regulatory tax loss of $211.6M[124] for 2013 which it states was caused by a shortfall in nuclear production. We agree with SEC that to allow OPG to retain the benefit of this tax loss would be tantamount to rewarding OPG for poor performance in its nuclear facilities, given that OPG has already collected payments in lieu ("**PILs**") from ratepayers as part of their 2013 payment amount.[125]

206. We also agree with both the Board and SEC that OPG's argument reflects a misreading of the Board's Decision in EB-2007-0905. The "benefits follow costs" principle was developed to address issues associated with allocating costs to benefits as between regulated and unregulated periods and not to allow utility companies to retain the benefit of income tax losses when they have already collected PIL amounts for the same period.

124 Exhibit J13.4.
125 SEC Submissions, pp. 52-23.

207. We agree that the regulatory tax loss in 2013 should be carried forward to 2014 to reduce taxable income and therefore payment amounts. This is consistent with the Board's long established policy with respect to tax loss carry-forwards as described in Board Staff submissions.[126]

(ii) Deferred Taxes on Newly Regulated Hydroelectric Assets

208. We have had the benefit of reviewing SEC's in depth analysis of OPG's request that ratepayers pay, in the future, for tax costs incurred prior to the regulation of the Newly Regulated facilities and we adopt SEC's submission that this would be both unfair to ratepayers and would constitute retroactive ratemaking. Our more detailed submissions with respect to this issue are contained in Section 3C of our argument.

7. OTHER REVENUES

A. Regulated Hydroelectric

Issue 7.1 (Secondary) – Are the proposed test period revenues from ancillary services, segregated mode of operation and water transactions appropriate?

209. As noted by Board Staff, a comparison between the historical and forecast of other revenues for the test period suggests that variances between the forecast revenue and actual revenues for the test period are likely.[127] As a result, we recommend the following:

(i) Previously Regulated Hydroelectric:

- **Ancillary Services Revenue:** Adjust the forecast amount for 2014, by the average of 2011, 2012 and 2013 actual amounts[128] escalated by 2% per year. Adjust the forecast for 2015 by the 2014 value, escalated by 2%. This results in forecast values of $27.2M in 2014 and $27.8M in 2015;

- **Segregated Mode of Operation (SMO):** Calculate the forecast for both 2014 and 2015 in a manner consistent with the methodology accepted by the OEB in EB-2010-0008, using 2011, 2012 and 2013 actual amounts. This results in forecast values of $1.7M in each of 2014 and 2015; and

126 Board Staff Submissions, p. 120.
127 Board Staff Submissions, p. 121.
128 See chart contained at p. 120 of Board Staff Submissions.

- **<u>Water Transactions (WT):</u>** Calculate the forecast for both 2014 and 2015 in a manner consistent with the methodology OPG's pre-filed evidence[129], using 2011, 2012 and 2013 actual amounts. This results in forecast values of $1.2M in each of 2014 and 2015.

- This will result in new total other revenues for Previously Regulated Hydroelectric of $30.1M for 2014 and $30.6M for 2015.

(ii) <u>Newly Regulated Hydroelectric:</u>

Using the approach set out above[130]:

- **<u>Ancillary Services Revenue:</u>** Forecast values of $29.8M in 2014 and $30.4M in 2015; and,

- **<u>Segregated Mode of Operation (SMO):</u>** Forecast values of $0.00 in 2014 and $0.00 in 2015.

- This will result in new total for Newly Regulated Hydroelectric of $29.8M for 2014 and $30.4M for 2015.

B. <u>Nuclear</u>

Issue 7.2 (Secondary) – Are the forecasts of nuclear business non-energy revenues appropriate?

210. We believe that OPG has under-forecast nuclear business non-energy revenues given that, as indicated by Board Staff, the 2013 actual total was $37.6M when the forecasted amount was only $24.8M. As a result, we support Board Staff's submission that the Board should consider the 2013 actual nuclear other revenue as the normal level for the test period, being $37.6M for both 2014 and 2015.[131]

129 Exhibit G1-1-1.
130 Actual values contained chart contained at p. 121 of Board Staff Submissions.
131 Board Staff Submissions, p. 122.

C. Bruce Nuclear Generating Station

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

211. We have no submissions with respect to this issue other than to support SEC's request that OPG be required to file information regarding Bruce NGS' cost of generation as part of any future payment amount application.[132]

8. NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING LIABILITIES

Issue 8.1 (Primary) (reprioritized) – Is the revenue requirement methodology for recovering nuclear liabilities in relation to nuclear waste management and decommissioning costs appropriate? If not, what alternative methodology should be considered?

Issue 8.2 (Primary) (reprioritized) – Is the revenue requirement impact of the nuclear liabilities appropriately determined?

212. We have nothing to add to the submissions made by Board Staff and others with respect to this issue.

9. DEFERRAL AND VARIANCE ACCOUNTS

Issue 9.1 (Secondary) – Is the nature or type of costs recorded in the deferral and variance accounts appropriate?

213. We have no submissions with respect to this issue other than to support Board Staff's reservation of the right to re-examine any accounts that are not being disposed of in this proceeding in greater detail in the future application that will dispose of them.[133]

Issue 9.2 (Secondary) – Are the balances for recovery in each of the deferral and variance accounts appropriate?

Issue 9.3 (Secondary) – Are the proposed disposition amounts appropriate?

Issue 9.4 (Secondary) – Is the disposition methodology appropriate?

214. Our submissions with respect to the balances for recovering each of the deferral and variance accounts are limited to the SBG variance account.

215. If the Board accepts our submissions on how the eHIM should operate, and in particular, that double counting that arises out of a consequence of the interaction of the SBG and HIM variance accounts should be eliminated, then the SBG variance account must be adjusted.

---

132 SEC Submissions, p. 62.
133 Board Staff Submissions, p. 124.

216. Currently, there is $19.2M recorded in the SBG variance account. In cross-examination, CME requested that OPG identify the SBG related incentive revenue that would need to be deducted from the $19.2M to accomplish such an adjustment. OPG confirmed that the proper deduction is $6.8M.[134] Therefore, we urge the Board to reduce the SBG account by $6.8M for an account balance of $12.4M.

Issue 9.5 (Secondary) – Is the proposed continuation of deferral and variance accounts appropriate?

Issue 9.8 (Secondary) – Is the proposal to discontinue the Hydroelectric Incentive Mechanism Variance Account appropriate?

217. If the Board accepts the submissions of CME and Board Staff with respect to the continuation of the HIM adjusted for SBG, then we agree with Board Staff that the account should be continued and should continue to operate as it now does. Moreover, the account should also function for the incentive mechanism revenue related to the newly regulated facilities.

A. <u>Clearance of Only Four Accounts</u>

Issue 9.6 Oral Hearing) – Is OPG's proposal to not clear deferral and variance account balances in this proceeding (other than the four accounts directed for clearance in EB-2012-0002) appropriate?

218. We have reviewed Board Staff's submissions with respect to this issue and we agree that "the most effective and efficient means of assessing deferral and variance account balances is to do so at the time of also assessing a utility's cost of service, given the links between certain of the accounts and the revenue requirement."[135] In this case, the impact of clearing all variance accounts as opposed to only the four which OPG's has proposed to clear in the application before the Board would be significant payment riders: $8.42/MWh for previously regulated hydroelectric facilities and $27.47/MWh for the nuclear facilities.

219. The very large December 31, 2013 balances in deferral accounts which OPG proposes to refrain from clearing in this proceeding must be borne in mind when considering the impacts of the relief OPG seeks for the 2014 and 2015 test period. As already noted, these impacts are enormously unreasonable.

134 Exhibit J4.7, and Transcript, Vol. 13, p. 125.

135 Board Staff Submissions, p. 127.

B. Accounts for Newly Regulated Hydroelectric Facilities

Issue 9.7 (Primary) (reprioritized) – Is OPG's proposal to make existing hydroelectric variance accounts applicable to the newly regulated hydroelectric generation facilities appropriate?

220. We support Board Staff's submissions with respect to this issue.[136]

C. Other Deferral Accounts

Issue 9.9 (Primary) (reprioritized) – What other deferral accounts, if any, should be established by OPG?

221. We have had the benefit of reviewing Board Staff's submissions with respect to this issue and we adopt Board Staff's recommendations as follows:

(a) **Pension & OPEB Cash Variance:** We agree that, to the extent that the Board approves a cash basis for pension and OPEB, it would be reasonable for the Board to approve a variance account for the difference in forecast cash payments included in the revenue requirement and actual cash payments and that carrying charges should apply to the cash variance; and,

(b) **GRC Variance:** We agree that a variance account should be established to capture, for return to the ratepayers, the costs savings associated with a 10 year GRC payment holiday likely to be granted to OPG by the Ministry of Natural Resources with respect to the NTP.[137]

10. METHODOLOGIES FOR SETTING PAYMENT AMOUNTS

A. Incentive Regulation

Issue 11.1 (Oral Hearing) – Has OPG responded appropriately to Board direction on establishing incentive regulation?

222. We agree with Board Staff's description of the timing issues surrounding the consideration of the incentive regulation and support the proposal that OPG be directed to file publicly with the Board the independent hydroelectric productivity study requested by the Board in EB-2010-0008 before the end of 2014 so that this information can be taken into account in establishing working groups.

---

136 Board Staff Submission, p. 128.
137 Board Staff Submission, pp. 128-129.

B. Mitigation

Issue 11.3 (Oral Hearing) – To what extent, if any, should OPG implement mitigation of any rate increases determined by the Board? It mitigation should be implemented, what is the appropriate mechanism that should be used?

223. The need for mitigation will depend upon the Board's response to the many difficult issues which this case raises.

224. In their submissions, Board Staff invites the Board to consider requiring OPG to forego collecting some $52.7M of revenue requirement in the newly regulated hydro payment amount which OPG is proposing for the 18 months between July 1, 2014 and December 31, 2015.

225. For reasons already articulated, we submit that a principled approach to the costing of the capital supporting newly regulated hydro assets at December 31, 2013, should produce an outcome which is as favourable, if not more favourable, to ratepayers than the outcome which Board Staff is inviting the Board to determine as mitigation. Staff's mitigation proposal is based on an assumption that the payment amount for the newly regulated hydroelectric assets will be in the amount OPG proposes and thereby produce a payment amount increase of some 59%. For reasons which we have already articulated, we do not expect that assumption to materialize.

226. We have no particular mitigation proposals for the Board to consider. Rather, we submit that the time has now come to limit OPG's recoveries to cost levels which are compatible with the benchmarks to which it is contractually committed. Setting payment amounts to achieve that outcome, and denying OPG's retroactivity claims, should eliminate the need for any further mitigation measures.

11. IMPLEMENTATION

A. Effective Date and Retroactivity

Issue 12.1 (Oral Hearing) – Are the effective dates for new payment amounts and riders appropriate?

227. OPG's retroactivity claims for previously regulated hydro and nuclear payment amounts, and the newly regulated hydro payment amount are considered below.

B. Previously Regulated Hydroelectric and Payment Amounts

228. The submission of Board Staff clearly demonstrates that the Board has the power to reject OPG's request to have the payment amounts for previously regulated hydro and nuclear assets made effective January 1, 2014. OPG's argument that the Board is required to set the

effective date of these payment amounts on January 1, 2014 because the existing payment amounts were declared interim as of that date, is an argument which lacks merit for all of the reasons described by Board Staff.

229. Matters which the Board should consider in addition to the failure of OPG to file its Application with sufficient lead time to allow a hearing of the Application to be completed before the proposed effective date include the magnitude of the retroactivity increase being requested and its impact. If we assume that December 1, 2014 is now the earliest feasible implementation date, then, as already noted, the retroactivity claim is in the amount of $925M which, if granted, would increase the percentage payment amount increase from 23% to 61%.

230. This percentage increase does not reflect either the deferral account which OPG seeks in this case to have effect on January 1, 2015, or the amounts of the deferral account balances which OPG is proposing to address in a subsequent 2014 proceeding.

231. We submit that none of the retroactive amounts pertaining to previously regulated hydroelectric and nuclear assets should be recoverable from ratepayers. OPG should be held responsible for the delays in this proceeding. The hearing of evidence could not possibly have been concluded earlier because of OPG's filing of updated DRP evidence in July 2014.

232. The effective date of the payment order should be the first day of the month following the issuance of the Board's Decision in accordance with the Board's prior decisions to that effect to which Staff refers at page 137 of their submissions.

C. <u>Newly Regulated Hydro Assets</u>

233. OPG argues and Board Staff agrees that section 11 of O. Reg. 53/05 requires the Board to make the payment amount with respect to newly regulated hydro assets effective July 1, 2014.

234. We accept that this is what section 11(i) of the Regulation states. However, the Government of Ontario cannot by regulation override the provisions of the powers conferred on the Board by its enabling legislation to set just and reasonable rates, including the power to condition rate orders in the manner determined by the Board to be appropriate. The Regulation mandating the Board to adopt an effective date of July 1, 2014 for the newly regulated hydro payment amount is invalid and ultra vires.

235. Under its enabling legislation, the Board is fully empowered to reject OPG's retroactivity claim with respect to the newly regulated hydro payment amount and it should do so for the

same reasons that it should reject the retroactivity claim pertaining to the previously prescribed hydroelectric and nuclear assets payment amounts.

12. COSTS

236. CME requests that it be awarded 100% of its reasonably incurred costs in connection with this matter.

ALL OF WHICH IS RESPECTFULLY SUBMITTED this 26th day of August, 2014.

Peter C.P. Thompson, Q.C.
Vincent J. DeRose
Emma Blanchard
Counsel for CME

OTT01: 6478944: v1