AMPCO

August 26, 2014

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319, 27th Floor
2300 Yonge Street
Toronto, ON M4P 1E4

Re: Ontario Power Generation Inc. 2014/2015 Payments Amount Application
AMPCO Final Submissions
Board File No. EB-2013-0321

Dear Ms. Walli:

Attached please find AMPCO's final submissions in the above proceeding.

Please do not hesitate to contact me if you have any questions or require further information.

Sincerely yours,

Adam White
President
Association of Major Power Consumers in Ontario

Copy to: Ontario Power Generation Inc.

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Ontario Power Generation Inc. (OPG)
2014 -2015 Payment Amounts Application
for Prescribed Generating Facilities

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.

Final Submissions of AMPCO

August 26, 2014

Introduction & Background

1. OPG filed an application September 9, 2013 seeking approval of payment amounts ($/MWh) for its nuclear generating facilities, previously regulated hydroelectric facilities and newly regulated hydroelectric facilities based on a forecast revenue requirement and production forecast as well as payment riders reflecting recovery of four deferral and variance account balances. The application was based on OPG's 2013-2015 Business Plan. On December 6 2013, OPG filed an Impact Statement (N1) based on OPG's updated 2014-2016 Business Plan that increased revenue requirement and payment amounts.[1]. In May 2014, OPG filed a second update (N2) that reflected five material changes that reduced the payment amounts.[2] N1 also included an additional $33M increase in revenue requirement over 2014-2015 that OPG is not seeking to recover in this application in order to minimize the impact on the proceeding schedule.[3]

2. The regulated facilities in this application include two generating stations with a capacity of 6,606 MW and 54 hydroelectric generating stations (5 existing and 48 new) with a capacity of 6,422 MW for a combined regulating capacity of 13,028 MW.[4]

3. OPG has an obligation to operate the prescribed assets safely, reliably and efficiently for the benefit of the people of Ontario.[5] In accordance with the Memorandum of Agreement with its shareholder (the Province), OPG is also required to operate as a financially sustainable and commercial enterprise.[6] In addition, OPG's states its mission is to be Ontario's low cost generator of choice.[7] AMPCO submits the balancing of these three objectives and consideration of ratepayer interests, customer impacts and value for money provide the context in which this application should be viewed.

4. The Table below prepared by AMPCO summarizes the Payment Amounts requested in OPG's application.

5. OPG calculates the weighted average of previously regulated hydroelectric and nuclear payment amounts and payment amount riders, weighted by forecast production for the test period, to be $62.84/MWh. Using the same test period production forecast, the weighted average of currently approved payment amounts and riders for 2013 is $52.35/MWh. The resulting increase is $10.80/MWh or 20.6%.[8] The overall increase is 23.4% when the newly regulated facilities are included.[9]

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[1]changes to forecast pension & OPEB costs, forecast production changes for nuclear and previously regulated hydroelectric & a change in ancillary service revenues for previously regulated hydroelectric assets

[2]changes to forecast pension & OPEB, audited 2013 deferral & variance acct balances, forecast production changes for nuclear (related impacts on nuclear fuel costs), reduction in2014 forecast Darlington OM&A &update to ROE for 2014 & 2015

[3] N1-1-1 Page 2

[4] A1-3-1 Page 1

[5] A1-3-1 Page 8

[6] A1-3-1 Page 7

[7] A1-3-1 Page 8

[8] N2-1-1 Table 5

[9] Transcript Vol 3 Page 137 Line 21

6. The combined effect of the new payment amounts and riders inclusive of the newly regulated hydroelectric facilities[10] is an average increase of $5.31/month on a typical consumer's monthly bill.[11]

Approvals Requested[12 13]	**2011 Board Approved ($M)**	**2014 Plan ($M)**	**2015 Plan ($M)**	**Total ($M)**	**Change vs EB-2010-0008**
Nuclear January 1, 2014					
Revenue Requirement	5,251.5	3,228.5	3,166.9	6,395.4	1,143.9
Production TWh		48.5	46.1	94.6	
Deficiency				1,521.0	
Payment Amounts $ MWh	51.52			**67.6**	
Payment Riders[14] $ MWh	4.33			**1.35**	
Previously Regulated Hydroelectric January 1, 2014					
Revenue Requirement	1,419.2	866.6	891.2	1,757.8	338.6
Production TWh		20.1	21.0	41.1	
Deficiency				286.8	
Payment Amounts $MWh	35.78			**42.75**	
Payment Riders[15]	(1.65)			**3.36**	
Newly Regulated Hydroelectric Effective July 1, 2014 (18 mos)					
Revenue Requirement		554.6[16]	575.9	1,130.5	N/A
Production TWh		12.4	12.5	24.9 TWh	
Payment Amounts $MWh				**47.57**	

7. The higher payment amounts arise from total test period deficiencies of $1,521.0M for nuclear and $286.8M for previously regulated hydroelectric.[17] The revenue deficiency is driven by changes in revenue requirement and forecast production.

8. The forecast nuclear production declines by 7.3 TWh relative to the 2011-2012 production approved by the Ontario Energy Board (the "Board" or "OEB"). The forecast hydroelectric production for previously regulated facilities increases by 3.1 TWh relative to the 2011-2012 production approved by the OEB.

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[10] OPG assumed newly regulated hydroelectric earned $30 per MWh in market revenues
[11] N2-1-1 Page
[12] J7.1
[13] Unless otherwise noted
[14] 2015 deferral & variance account $62.2M (N2)
[15] 2015 deferral & variance account $70.6M (N2)
[16] One half of $552.6M in 2014
[17] J3.3

9. OPG has included the $145.5M compensation disallowance in the EB-2010-0008 Decision as part of the nuclear deficiency. AMPCO submits it is not appropriate that OPG seeks, in this proceeding to recover a Board directed disallowance from a previous proceeding.

10. The increases in revenue requirement are largely driven by three elements: the inclusion of the Niagara Tunnel in rate base, higher costs relating to nuclear liabilities as a result of the Ontario Nuclear Funds ("ONFA") Reference Plan approved in 2012; and an increase in pension and OPEB [NTD: Shelley define OPEB] costs.

11. AMPCO has prepared detailed submissions on the first two elements. AMPCO has not provide detailed submissions on every issue. AMPCO has reviewed the thorough and beneficial Board Staff submissions filed August 19, 2014 and draft submissions and positions of others. Where AMPCO agrees with the positions of others as a result of its own review and analysis of the evidence, or where AMPCO supports the submissions of others, AMPCO has adopted those submissions to avoid duplication of the same supporting points.

Issue	**Proposed AMPCO Adjustments**	**$M**
4.1	Reduction in Hydroelectric Capital	43.2
4.3	Reduction in Hydroelectric In-Service Capital Additions	39.3
4.4, 4.5	Disallowance for Niagara Tunnel	407.4
4.5	Reduction in Nuclear In-Service Additions	35
6.1	Reduction in Hydroelectric OM&A	19.7
7.1	Increase in Hydroelectric Other Revenues	43.1
7.2	Increase in Nuclear Other Revenues	59.5
8.1, 8.2	Reduction in Revenue Requirement impact of nuclear liabilities	28.5
Other		
5.4	Increase in nuclear production forecast	1.6 TWh

1. GENERAL

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

12. OPG indicates it has made progress in managing its controllable costs over the past few years. OPG refers to its Business Transformation (BT) initiative as the primary tool to control costs. OPG also states that through the use of benchmarking OPG has initiated activities to control cost and improve performance.[18]

13. OPG introduced BT in 2011 to develop approaches to reduce staff levels and modify cost structures to be more consistent with expected decreases in capacity and energy production. BT includes transforming OPG into an integrated centre-led organizational model and creating a scalable organization that is efficient and flexible. To meet its BT objectives, OPG is using attrition to reduce staff year-end 2015 head count by 2000 employees (1,300 regulated staff) with the potential for further reduction in later years. OPG expects to reduce OM&A by $700M between 2011 and 2015, of which $550M is attributable to regulated operations.[19] AMPCO provides further discussion on OPG's BT under Issue 6.8.

14. OPG calculates the weighted average of previously regulated hydroelectric and nuclear payment amounts and payment amount riders, weighted by forecast production for the test period, to be $62.84/MWh. Using the same test period production forecast, the weighted average of currently approved payment amounts and riders for 2013 is $52.35/MWh. The resulting increase is $10.80/MWh.

15. OPG has applied this increase to the typical consumer's usage of OPG generation, after adjusting for line losses and accounting for OPG's share of the province's generation to calculate customer impacts.

16. Based on as filed evidence, the combined effect of the new payment amounts and riders inclusive of the newly regulated hydroelectric facilities[20] an average increase of $5.36/month on a typical consumer's monthly bill. Impact Statement N1 revised the total customer impact to $5.94. This amount was further revised to $5.31 in N2.

17. The first payment amount application (EB-2007-0905) sought an increase of 14.8%. In the second application (EB-2010-0008), the payment amount increase sought was 9.6% but was changed to 6.2% prior to filing. In the current application, OPG is seeking a 23.4% increase including new regulated hydroelectric facilities.[21]

18. At the technical conference AMPCO asked OPG if it set customer rate impact targets when developing its application payment amounts and OPG responded that they do not.[22]

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[18] A1-3-1 Page 2
[19] A1-3-1 Page 2 & A1-4-1
[20] OPG assumed newly regulated hydroelectric earned $30 per MWh in market revenues
[21] Board Staff Submissions Page 132
[22] Tech Conf Transcript Vol 2, Page 150

19. AMPCO submits OPG needs to demonstrate its commitment to controlling costs beyond business transformation initiatives.

3. CAPITAL STRUCTURE AND COST OF CAPITAL

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

20. OPG seeks approval of a deemed capital structure of 53 percent debt and 47 per cent equity which reflects its existing Board-Approved capital structure. In this application, OPG is adding newly regulated hydroelectric facilities to its regulated assets and proposes to maintain the deemed capital structure. The newly regulated hydroelectric assets add approximately 3,100 MW in net in service capacity.[23]

21. AMPCO agrees with the submissions of Board Staff and other intervenors that there has been a significant change to the regulated business with the regulation of the newly regulated hydroelectric facilities effective July 1, 2014. AMPCO agrees the newly regulated facilities have the same risk as the previously regulated facilities and a decrease is thickness is appropriate.

4. CAPITAL PROJECTS

Regulated Hydroelectric

4.2 Secondary - Are the proposed regulated hydroelectric capital expenditures and/or financial commitments reasonable?

22. OPG forecasts hydroelectric capital expenditures of $127.5M in 2014 and $138.2M in 2015, and in addition $2M in 2014 related to the Niagara Tunnel Project (NTP). Capital expenditures of $2M related to the NTP are addressed separately by AMPCO under Issue 4.4. Therefore, these submissions relate to hydroelectric capital expenditures of $125.5M in 2014.

23. AMPCO submits that in order to gauge reasonability with respect to OPG's forecast hydroelectric expenditures it is important to look at past spending.

24. With respect to hydroelectric capital spending (excluding the NTP), AMPCO submits that historically, OPG's expenditures have been less than forecast. AMPCO has prepared a Table in AMPCO Appendix A to show the variance between budget and actuals for the years 2010 to 2013 for Previously Regulated Hydroelectric and Newly Regulated Hydroelectric.

25. The Table shows that for Previously Regulated Hydroelectric, OPG has spent 81% of budget and for Newly Regulated Hydroelectric OPG has spent 85% of budget. On this basis AMPCPO submits that the Board should adjust OPG's 2014 and 2015 forecast on this basis, thereby reducing OPG's hydroelectric capital amounts for the test period by $43.4M.

[23] A1-4-2 page 4

Issue 4.2

AMPCO Appendix A

Issue 4.2 Hydroelectric Capital

Capital Expenditures Summary - Previously Regulated Hydroelectric and Newly Regulated Hydroelectric ($M)

	2010			2011			2012			2013			Total Budget	Total Actual	2010-2013 Average	2014	2015	Total
	Bud.	Act.	Var.	Bud.	Act.	Var	Bud.	Act.	Var.	Bud.	Act.	Var.				Plan	Plan	
Previously Redgulated Hydroelectric	53.5	40.4	-13.1	39.9	35.3	-4.6	36.8	29.8	-7.0	33.8	26.7	-7.1	164.0	132.2	0.81	34.5	38.2	
Newly Regulated Hydroelectric	80.2	68.6	-11.6	76.7	61.4	-15.3	91.4	80.1	-11.3	71.4	60.5	-10.9	319.7	270.6	0.85	91.0	100.0	
	133.7	109.0	-24.7	116.6	96.7	-19.9	128.2	109.9	-18.3	105.2	87.2	-18.0	483.7	402.8		125.5	138.2	263.7

AMPCO Proposal	**2014**	**2015**	
	Plan	**Plan**	
Previously Redgulated Hydroelectric	27.8	30.8	
Newly Regulated Hydroelectric	77.0	84.6	
	104.8	**115.4**	220.3
Proposed Reduction			**43.4**

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

26. AMPCO supports the submissions of SEC that the Board should approve 83.3% of OPG's planned hydroelectric capital additions (excluding the Niagara Tunnel Project) for the Test Period based on average historical in-service additions (actual vs. budget). This results in approved amounts of $70.1 million for 2014 and $126.2 million for 2015, reductions of $14.0 million and $25.3 million respectively.

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?

27. OPG's Niagara Tunnel Project (NTP) consists of one 10.2 km long tunnel with a 14.4 m excavated diameter (interior diameter of 12.7 metres) to convey water from the Niagara River upstream to the Sir Adam Beck hydroelectric plants. The purpose of the NTP is to increase diversion capacity of the Sir Adam Beck Niagara Generating Station complex by 500 m3/s and to facilitate a 1.6 TWh increase in average annual hydroelectric output.

28. In July 2005, OPG's Board of Directors approved a $985.2M budget and in-service date of June 2010 for the project. In May 2009, OPG's Board of Directors approved an increase in funding for the project to $1.6 billion and a revised in-service date of December 2013, resulting in a budget cost variance of $615M and a schedule variance of 42 months.

29. OPG indicates the variance is due to delays in the NTP primarily due to difficulties encountered by Strabag (Contractor) in excavating the tunnel through the Queenston shale formation, and unsuccessful attempts to resolve Strabag's claims for cost and schedule relief, which resulted in OPG and Strabag negotiating a new contract.

30. The tunnel began operation on March 9, 2013. The estimated total costs to completion are $1,476.6M ($1,472M capital + $4.6M removal expense in 2014).[24]

31. O. Reg. 53/05, section 6(2)4 requires the Ontario Energy Board (Board) to ensure that OPG recovers the capital and non -capital costs of the NTP approved by OPG's Board of Directors prior to the first payment amounts order and to determine the prudence of any expenditures beyond the OPG Board approved amount.

32. The table below shows that the $491.4M is subject to O. Reg. 53/05, section 6(2)4 and thus OPG seeks a finding from the Board that the $491.4M in cost above the $985.2M originally approved its Board of Directors was prudently incurred.

	OPG BOD Approved Budget	**Total Estimated Final Project Costs**	**Amount Subject to OEB Approval**
Original Business Case March 2005	$985.2M	$1,476.6M	$491.4M

[24] Ex L -4.5-1 Staff-025

33. In the body of our submission, we argue that in a number of different areas, OPG was imprudent in the way that they addressed aspects of this project and as a result, costs associated with their imprudence should be disallowed. The following subject areas reflect our areas of concern:

- the design-build contract proposed by OPG as opposed to a design-bid-build contract did not allow for sufficient analysis of and compensation for risk;

- the Geotechnical Baseline Report (the GBR) originally proposed by OPG contained many significant mistakes and mischaracterizations which persisted through the second and third versions and which were primarily responsible for the huge overridges in money and time for the part of the project for which OPG is seeking approval of this Board and in particular the GBR,

  - misled the contractor to inaccurately interpret the subsurface conditions in the Queenston formation,

  - caused Strabag to propose inappropriately a design for tunnel construction which included an open Tunnel Boring Machine (TBM)

- the dispute over responsibility for the overridges which will be described in the body of this report were taken to a dispute review board (the DRB), as provided for in the contract between Strabag and OPG where ultimately responsibility was apportioned, but in renegotiating its contract with Strabag, OPG chose “the easy way out” and did not hold Strabag responsible for its share of the overages as determined by the DRB but still seeks the approval of this Board to have rate payers pay for OPG’s unnecessary largess.

34. OPG indicates that the amount spent on the NTP represents the true cost of completing the project given the subsurface conditions actually encountered. OPG further submits the costs above the original budget arose entirely from the fact that the rock conditions encountered were substantially worse than OPG reasonably anticipated given the geotechnical investigations that it conducted prior to beginning the project.[25]

35. OPG estimates the costs associated with adverse subsurface conditions to be $486.8M[26] making the tunnel approximately 50% over budget. AMPCO has prepared a table (Appendix B) that compares the original contract elements to the estimated cost to complete the tunnel. Key cost variances include:

- Increase in tunnel diversion construction costs = $280.3M
- Increase in Design, Scope, Project Management and Owner’s Representative costs = $17.8M
- Increase in infrastructure costs at inlet & outlet= $18.6M
- Increase in interest = $97.7M

36. In addition, there are costs above the original contract budget including incentives paid under the new negotiated Amended Design Build Agreement (the ADBA) ($60M) and

[25] OPG Argument-In-Chief
[26] L-4.4-2-AMPCO-016 (g)

overhead and office and general costs totalling $114.2M. In the original contract budget, overhead was included in all budget elements.

37. The Board has a well-established set of principles regarding the conduct of a prudence review:

- Decisions made by the utility's management should generally be presumed to be prudent unless challenged on reasonable grounds.

- To be prudent, a decision must have been reasonable under the circumstances that were known or ought to have been known to the utility at the time the decision was made.

- Hindsight should not be used in determining prudence, although consideration of the outcome of the decision may legitimately be used to overcome the presumption of prudence.

- Prudence must be determined in a retrospective factual inquiry, in that the evidence must be concerned with the time the decision was made and must be based on facts about the elements that could or did enter into the decision at the time.[27]

38. AMPCO has reviewed and analyzed the evidence on the NTP in detail and concludes that not all elements of the $486.8M in cost overrun above the original budget were prudently incurred.

39. For the reasons discussed below, AMPCO concludes that a total of $407.4M in cost overruns directly related to the diversion tunnel should be disallowed by the Board:

- Tunnel construction = $240.3M[28]
- Settlement re: DRB Decision = $40M
- Contract incentives = $15M
- Owner's Representative= $10.8M
- Scope Changes = $0.7
- Project Management = $0.6M
- Dispute Review Board Costs = $0.3M
- Interest = $97.7M
- Other infrastructure costs =$2M

Background

40. A study of the possible expansion of OPG's hydroelectric facilities began in 1982 resulting in Ontario Hydro (OPG's predecessor) proposal for the then planned project design which consisted of two tunnels (500 m3/s each), a three-unit underground generating station and new transmission facilities between Niagara Falls and Hamilton; the Niagara River Hydroelectric Development (NRHD) project.

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[27] Enbridge Gas Distribution, RP-2001-0032, Decisions with Reasons, December 31, 2002, P.63
[28] $280M-$40M settlement paid to Strabag for disputes

41. An Environmental Assessment (EA) for the NRHD project was submitted in March 1991 and approval was obtained on October 14, 1998. The EA required that the tunnels be excavated using a tunnel boring machine (TBM) starting from the outlet end, proceeding under the buried St. David's Gorge (determined lowest tunnel point) and following the route of the existing Sir Adam Beck 2 tunnels. In addition the EA stipulated that it would terminate if construction had not commenced within 10 years. Thus the EA would terminate in 2008, but could be extended a further 5 years subject to approval of an environmental review status report.[29]

42. In 1998, Ontario Hydro made a decision to proceed with phase one of the HRHD and a Request for Proposal was issued for the construction of a single 500 m3/s tunnel using a Design-Build approach. A recommended bidder was identified, but the contract was never awarded due to the imminent reorganization of Ontario Hydro.[30] AMPCO notes all of the qualified contractors in the 1998 bidding process proposed a closed TBM with a precast segmental concrete liner.[31] Shortly after OPG was formed, in 1999, OPG announced its decision to defer construction of the tunnel indefinitely.

43. In June 2004, OPG announced and the Government of Ontario endorsed the decision to proceed with a new water diversion tunnel and OPG conducted an RFP process in July 2004 for one tunnel.[32]

44. Three proponents bid on OPG's RFP that was based on the conceptual design used in the 1998 bidding process. The conceptual design referenced the use of a closed (fully shielded) TBM. Chapter 9.1 of the Owner's Mandatory Requirements in the RFP specifically called for a Shielded TBM suitable for safely excavating the ground conditions as described in the GBR.[33] Two unsuccessful proponents proposed a closed (fully-shielded) TBM. The third bidder, Strabag AG[34] (Strabag), considered both an open and closed TBM[35]and in the end proposed an open TBM design that was accepted by OPG. A Design-Build Agreement using an open TBM was signed by Strabag on August 18, 2005.

45. It was recognized from the beginning that the tunnel design and construction presented several design challenges beyond the tunnel size including high horizontal stress, the presence of the St. David's Gorge, and time dependant deformation of the rock mass.[36]

46. The RFP process included GBR-A which was based on OPG's data from over 10 years of geotechnical investigation. Respondents were asked to include modifications to the GBR as part of their proposals (GBR-B) and the final GBR (GBR-C) was negotiated as part of the contract.

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[29] D1-2-1 Page 9
[30] D1-2-1 Page 10
[31] D1-2-1 Page 67, Footnote 23
[32] D1-2-1 Page 23
[33] L-4.4-2-AMPCO-016 (d)
[34] Strabag AG is made up of Strabag (100%), Dufferin as subcontractor, Engineering by ILF and Morrison Hershfield
[35] D1-2-1 Page 67
[36] F5-6-1 Page 5

47. AMPCO submits there were many serious problems early on with the Contract approach used by OPG, the interpretation of the geotechnical investigations and the development of the GBR that in combination led to a serious misunderstanding between OPG and Strabag on the subsurface conditions resulting in a Differing Subsurface Conditions dispute totalling $90M as well as a significant profile restoration project over 3 years totalling $92M that was not originally contemplated. The dispute was reviewed by theDRB. The settlement of the DRB conclusions and recommendations regarding the dispute is discussed below.

48. The DRB characterized the contract as having a lot of problems.[37] The DRB considered the negotiations to be a monumental effort, characterized by the Owner's Representative as "fast-tracked and extensive" that along with other factors including a lining method that had never been used in North America, contributed to a contract with a lot of problems, particularly in the GBR and resulting disputes.[38]

Contract Approach

49. OPG selected a Design-Build approach over a Design-Bid-Build approach for the NTP. Design-Build is the same approach used by Ontario Hydro in the 1998-1999 RFP process.[39]

50. Tunnels in North America have traditionally been constructed using Design-Bid-Build contracts, in which the Contractor has no involvement in preparing the contract documents, including the GBR. All bidders tender to the identical contract provisions, including the GBR conditions and design.[40]

51. Design-Build contracts require parties to jointly negotiate and prepare the contract according to the owner's requirements and the proposer's design, means and methods.[41] Design-Build Contracts are becoming more frequent on large challenging construction projects primarily to reduce the pre-bid time spent on design efforts and equipment procurement, thereby facilitating earlier completion.[42] A Design-Build contract reduces the delivery schedule by overlapping the design phase and construction phase of a project.

52. OPG indicates it selected the Design-Build approach as the preferred risk management strategy to:

- minimize project duration;
- capture tunnel contractor experience and innovations;
- fully integrate construction methods and constructability into the design;
- appropriately allocate project risks; and
- obtain as much upfront price certainty as possible.

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[37] D1-2-1 Attach 7 DRB Report Page 7
[38] D1-2-1 Attach 7 DRB Report Page 7
[39] D1-2-1 Page 23
[40] D1-2-1 Attach 7 DRB Report Page 6
[41] D1-2-1 Attach 7 DRB Report Page 7
[42] D1-2-1 Attach 7 DRB Report Page 6

53. The issue of minimizing project duration is further emphasized in the Project Charter in the Design-Build Agreement between OPG and Strabag, in OPG's July 28, 2005 Business Case Summary for the project and in the DRB's report.

54. AMPCO submits that there are issues with a Design-Build contract regarding attention to details and resulting negotiations that can lead to disputes. The DRB states that "Typically during Design Build negotiations the parties concentrate on getting the work started, often without adequate attention to the details of the design, specifications and payment provisions. It is not uncommon therefore, that after award of Design-Build contracts, problems arise from provisions in the negotiated contract that were either not clearly written, were overlooked, or reflect misunderstandings during the final drafting of the contract." This is precisely what occurred on the NTP. OPG's multi-step process to develop the GBR led to confusion and deficiencies in the negotiations and understanding of the GBR baseline that had a negative ripple effect on the means and methods of the contractor.

55. OPG provided its data, analysis and interpretation of over 10 years of geotechnical data to each proponent in GRB-A. The NTP Design Build contracting strategy allowed the proponents bidding on the work to modify the geotechnical baseline, design efforts and equipment procurement based on their own understanding of the geotechnical baseline. If the proponent's initial understanding of the geotechnical baseline is inaccurate and their selection of means and methods is not appropriate for the baseline subsurface conditions, the project can be off course from the beginning. With a Design-Bid-Build approach the design and construction phases do not overlap and adequate time is allotted to prepare detailed designs, specifications including a GBR, thereby reducing the risk of misunderstandings and hasty negotiations.

Bid Evaluation Process

56. AMPCO has concerns regarding OPG's Evaluation Process for the project related to the scoring.

57. Three contractors and their designers prepared preliminary designs, design basis and methods statements, specifications, drawings and payment provisions in accordance with OPG bidding requirements, mandatory requirements and conceptual design.[43]

58. A summary of the evaluation categories and their relative scoring is shown in table below

Summary Evaluation Categories Score	Score (#)	Percent (%)
Compliance with Owner's Mandatory Requirements	Yes/No	Yes/No
Price/Schedule/Flow Guarantee	150	30%
Design & Construction Approach	80	16%
Risk Management Approach/Impact on OPG Risk Profile	65	13%
Response to GBR	45	9%
Adherence to Invitation and Agreement	45	9%
Project Team & Key Personnel	45	9%

[43] D1-2-1 Attach 7 DRB Report Page 6

Preliminary Project-Specific Safety/Security/Emergency Plans	35	7%
Environmental Compliance Plan and QA/QC Program	35	7%
Total	500	100%

59. Out of a maximum of 500 points, a maximum score of 45 points is possible (9%) for "Response to the GBR" compared to 80 points (16%) for "Design and Construction". Given that OPG was responsible for Differing Subsurface Conditions under the Contract, and GBR-A, prepared by OPG and its experts, formed the initial baseline for the understanding of geotechnical conditions, AMPCO submits a weighting at least equal to Design and Construction (16%) should have been assigned to "Response to GBR" in the evaluation. OPG needed to put more emphasis on the proponents' response to the GBR especially given that the site conditions are a significant input to selecting the construction method given that the top two risks to project cost and schedule were determined to be Dispute Review Board interpretation of agreement unfavourable and Differing Subsurface Conditions claim due to rock strength.[44]

60. AMPCO submits OPG knew the subsurface conditions better than any other Party and had a responsibility to ensure Strabag fully understood the subsurface conditions early on so that further negotiations of GBR-A (GBR-B & GBR-C) were not based on inaccurate and misleading information. Leaving misunderstandings to be addressed at the construction stage is not a prudent approach.

Contract Details

61. Budget details regarding the project are shown below.[45]

NTP Design Build Agreement	**Contract Price**
Tunnel Work	$622.6M
Cost Contingency - Tunnel	$96M[46]
Sub-total Tunnel Contract	*$723.6M*
Guaranteed Flow Amount Incentive	$5M
Cost Contingency for Other Project Elements	$11M
Other project costs	$245.4
Total Contract Price	**$985M**
In-service date	June 2010
Schedule Contingency	36 weeks
Max Incentives/Liquidated Damages (20% of $622.6M)	$125M[47]

62. Under the Design-Build contract arrangement with Strabag, ratepayers were to be protected from

[44] D1-2-1 Attach 5 July Business Case Summary Appendix C
[45] D1-2-1 Attach 5 July 2005 Business Case Summary
[46] $112 M Contingency = $96M for Tunnel, $5M for Guaranteed Flow Amount Incentive & $11M for other project elements
[47] 20% of Contract Price (20% of $622.6M = $125M)

cost overruns because Strabag agreed to build the tunnel for a fixed price. The contract included a significant bonus for early completion and significant damages for late completion limited to 20% of the contract price or $125M.

63. The contract also included a $96M cost contingency and 36 week schedule contingency based on an update of the project risk assessment. AMPCO has concerns regarding the outcome of this risk assessment.

Risk Assessment

64. OPG retained URS Corporation (URS) in 2004 to perform both qualitative and quantitative risk assessments of the NTP. The quantitative risk assessment was undertaken in two stages. An initial risk assessment was performed concurrently with the RFP process based on the reference tunnel concept and once Strabag was identified as the preferred proponent, OPG updated the quantitative risk evaluation through an expert panel of the NTP team consisting of OPG, Hatch and Torys LLP.

65. Based on the updated risk assessment, the July 2005 Business Case Summary (Appendix C – Project Risk Profile)[48] for the project included 20 risks and identified the top two contributors to potential cost increases as:

1) DRB interpretation of agreement unfavourable and;

2) DSC (Differing Subsurface Conditions) claim due to rock strength.

66. These same two factors in reverse order were also identified as the top two contributors to potential schedule delay for which OPG, rather than the contractor, would be responsible.[49]

Appendix C – Project Risk Profile

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigation Activity	Risk After Mitigation
Cost				
The contractor may encounter subsurface conditions that are more adverse than described in the Geotechnical Baseline Report (GBR)	Unexpected, adverse subsurface conditions could slow tunnel construction and require the contractor to undertake remedial / extra work resulting in legitimate claims for extra costs and / or schedule extension for differing subsurface conditions (DSC).	High	• The GBR is based on extensive field investigations carried out over a 10-year period and knowledge gained through construction of the existing SAB2 tunnels. • The 3-stage GBR process used facilitates contractor input and concurrence before construction begins. • Residual tunnel construction risk to OPG is addressed by a contingency allowance of $96 M in the project release estimate and a contingency allowance of 8 months in the scheduled in-service date, both based on a 90% confidence level.	Medium

67. The above risk is the only high risk in OPG's risk profile that is mitigated to medium after mitigation; the rest are mitigated to low. OPG's mitigation activities include knowledge gained through construction of the Sir Adam Beck 2 tunnels and a 3-stage GBR process.

[48] D1-2-1 Attach 5 July 2005 BCS Appendix C
[49] D1-2-1 Pages 27-28

68. The Sir Adam Beck 2 tunnels were not constructed in the Queenston Formation where the majority of the problems occurred which limits the mitigation value in the Queenston Formation. As discussed in more detail below, the 3 stage mitigation process was flawed from the beginning in that the initial geotechnical document GBR-A, prepared by OPG as the starting point for the negotiations between OPG and Strabag, contained imprecise and misleading information that ended up being addressed at the construction stage.

69. Based on the risk assessment, a $96M cost and 8 month schedule contingency was established based on a 90% confidence level, i.e. there was a 10% chance that the GBR would be wrong.[50]

70. To conduct the assessment URS and OPG defined the following terms.[51]

Hazard – A situation that, if it occurs, brings about a negative impact on achieving Project objectives.

Cause – The circumstances that allow a hazard to manifest itself.

Likelihood – an event's probability of occurrence over the lifetime of the hazard, expressed in this report in qualitative terms such as likely or unlikely.

Consequence – impact of hazard occurrence measured for several aspects of the Project, such as financial, schedule or environmental impacts.

Risk - expressed as the combination of the likelihood of an event occurring over a specified time frame, and the consequence if the event occurs.

Risk Assessment – the formalized process of identifying hazards and associated risks, of evaluating their consequence and probability of occurrence, and of preparing strategies as appropriate for preventative and contingent actions.

Risk Management – the overall systematic process of Risk Assessment, risk mitigation and control

Risk Factor – a unique combination of hazard, cause and outcome. In this analysis, each risk factor is assigned a unique number for analysis purposes

71. Upon reviewing the specific details of the first URS Report (D-2-1_Att 3_URS Quantitative Risk Assessment) and the update (D1-2-1_Att 4_URS Update of Risk Assessment Report), AMPCO has significant concerns regarding the outcome of the risk assessment undertaken for the NTP and believes that OPG and its experts missed a critical risk consideration in the construction of the NTP in the Queenston Formation and overlooked an important cost contingency for the contract to mitigate this risk.

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[50] Transcript Vol 2, Page 131

[51] D-2-1_Att 3_URS Quantitative Risk Assessment

72. AMPCO acknowledges that differing site conditions are never completely mitigated. In reviewing the Risk Assessment Matrix that identified these risks, AMPCO submits it appears that a risk of lower rock strength or weaker rock strength was not identified by the expert panel as a hazard cause; it was not included in the risk matrix. Only the risk of higher rock strength was identified as a hazard and included in the top two contingency risks for the project.

73. Specifically, Hazard ID #61801 is identified as DSC claim due to rock strength. The hazard is described as "Encountering Ground Conditions more adverse than advertised in Contract." The cause of the hazard is Rock Strength higher than anticipated. The potential consequences are Submittal of DSC claim – legal proceedings against owner. Appendix C in the July 2005 Business Case Summary describes the risk as subsurface conditions that are more adverse than described in the Geotechnical Baseline Report. AMPCO submits this adverse risk is based on Hazard ID#61801 and is specifically referring to rock strength higher than anticipated.

74. The distinction between a contingency for rock strength higher versus lower than anticipated is important because OPG used this information to develop the contingencies for the project and the confidence level. Consideration of rock strength lower than anticipated would have resulted in a higher contingency amount and further mitigation activities. Also early identification of this risk would have influenced the lining design and means and methods proposed by the contractor.

75. 81.25% of the total bored tunnel length was expected to be in the Queenston Formation. The Queenston Formation is characterized by alternating layers of stronger and weaker rock which are, in turn, characterized by a wide range of strength and anisotropic (material properties are different in different directions) stiffness and time dependent deformation behaviour. The rock mass behaviour along the tunnel is highly influenced by high horizontal stresses. Stress induced failure focused along the bedding planes in the crown resulted in extensive overbreak during the tunnel excavation. The contractors TBM design and support methods further exacerbated the overbreak. Cleary less competent rock was encountered; a risk not identified in OPG's risk register.

76. On this basis, AMPCO submits that OPG's risk assessment process was flawed and inadequate.

77. AMPCO has concerns regarding OPG's characterization of the rock and rock strength.

Rock Characterization

78. Mr. Ilsley, an expert testifying on behalf of OPG states in his report "The primary aim of site investigations for a rock tunnel project is to characterize the rock mass conditions sufficiently so that the design approach and selected construction methods can address the indicated ground conditions.[52] AMPCO submits OPG didn't adequately characterize the rock mass conditions.

[52] F5-6-1 Page 5

79. In GBR-A, under the rock characterization section[53], OPG indicated that the detailed lithology (nature of the rock material such as siltstone, mudstone, shale, sandstone)[54] was derived from logging in the test audit near the tunnel outlet and it was noted that borehole logs completed prior to excavation of the test adit do not describe the individual Queenston lithological types. Due to the many rock classification types in the Queenston Formation, OPG described the Queenston Formation as non-uniform. OPG further stated that the majority of the upper six subdivisions in the Queenston Formation were comprised of muddy siltstone (Type IIIB); however in the upper Q10 of division of the Queenston Formation, a significant percentage of Type V (mudstones) occurs. Mudstone is characterized by compaction features, often associated with shears and/or weak zones, whereas muddy siltstone has a higher grain size (stronger).

80. AMPCO was unable to discern from the evidence if the tunnel excavation encountered more mudstone in the alternating layers of rock and therefore weaker conditions than anticipated which in turn contributed to the overbreak issue. Given the non-uniform nature of the Queenston Formation and the lack of knowledge of the nature of the rock beyond the test adit area, AMPCO submits OPG should have done further lithology testing along the tunnel route.

<u>Rock Strength</u>

81. OPG's assessment of rock strength parameters contributed to the development of the Table of Rock Condition and Rock Characteristics[55]. (AMPCO Appendix B)

82. The Table represented the baseline for % of total bored tunnel length in each rock condition and the $/m paid to the contractor in each rock condition. The $/m estimate for each rock type was used to arrive at the fixed price amount.[56] For rock condition 1 (stable rock) the unit rate was $9,383/m whereas for the most difficult rock in the Queenston Formation (rock condition 6) the contract unit rate was $25,272/m.[57] The Table was also used by the contractor to design rock support for the tunnel to accommodate the rock conditions.[58]

83. Geological and geotechnical input data derived from OPG's investigations and engineering judgment, was used to define the Rock Mass Types and Rock Mass Behaviour Types in the GBR. The DBR concluded that the Rock Condition and Rack Characteristics Table included several unworkable rock characteristics and was inadequate to be used for the identification of Differing Subsurface Conditions which rendered the concept of DSC meaningless and the GBR defective. [59]

Rock Mass Strength Parameters in Queenston Formation Optimistic

84. AMPCO has concerns with the development of the Table of Rock Conditions and Rock Characteristics that go beyond what the DRB identified. AMPCO submits the underlying

[53] L-4.4-Schedule 2-AMPCO 016 Attachment 1 Page 15 (GBR-B: Strabag response to GBR-A)
[54] F5-6-1 Page 31
[55] D1-2-1 Attach 7 DBR Report Page 37
[56] D1-2-1 Attach 6 Appendix 5.4 GBR, Appendix 1.1 (j)
[57] D1-2-1 Attach 6 Appendix 5.4 GBR Page 38
[58] D1-2-1 Attach Appendix 5.4 GBR Page 36
[59] D1-2-1 Attach 7 DRB Report Page 17

data, interpretation and engineering judgment applied to developing the inputs to the Table were inadequate at the GBR-A stage. As part of GBR-B, Strabag was required to respond to questions posed in GBR-A. In response to questions regarding rock strength, Strabag indicated it found OPG's Geological Strength Index (GSI) values in Tables 6.9 and 6.10 to be optimistic compared to the joint spacing data.[60] Strabag also noted that the stated Rock Mass Rating and GBR values cannot be carried out due to lack of information concerning the Rock Mass Rating input parameters. AMPCO submits this should have been a concern to OPG and any gaps in data should have been addressed. Based on engineering judgement the Rock Mass Rating values were then combined with the 'mi' and compressive strength evaluation to estimate the strength of the in-situ rock mass as provided in Table 6.10. AMPCO notes Table 6.10 shows all of the strength testing in the area of the trial enlargement. It is unclear to AMPCO if further testing was done along the tunnel route.

85. AMPCO submits it appears there were issues with the estimated data provided in Tables 6.9 and 6.10 related to the rock strength parameters estimated at the RFP stage as the data was subsequently removed in the updated Geotechnical Report in the Amended Design Build Agreement. AMPCO submits OPG's characterization of rock mass strength was imprecise and optimistic which misled the contractor into assuming the rock conditions were stronger. (See AMPCO Appendix C)

86. OPG did not take the necessary care to ensure the GBR was as accurate as possible and that the contractor understood the information. OPG's GBR was imprecise with respect to anticipated rock strength which misled the contractor to reasonably but inaccurately interpret the rock conditions as being stronger. As discussed below AMPCO believes that Strabag's lining design, choice of TBM and tunnel support design shows Strabag anticipated stronger rock conditions.

87. AMPCO submits further mitigation measures such as filling in data gaps re: rock lithology and rock strength could have been undertaken.

88. The DRB provides several other examples where the GBR was imprecise and therefore misleading to the Contractor. Specifically, the DBR states the GBR was misleading 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 Queenston Formation. In simple terms, if rock strength is greater than the induced stress the rock will not fail. However, if the induced stress in the rock exceeds the rock strength, the rock will fail.

89. This is significant because it in combination with other factors led the Contractor to a reasonable but incorrect interpretation of anticipated subsurface conditions within the Queenston Formation at the time the DBA was signed. The GBR erroneously contains clauses intended for a closed (shielded) TBM.

90. The issue of how other imprecise, ambiguous and misleading statements in the GBR misled the contractor is discussed in more detail below.

[60] L-4.4 -AMPCO-016 Page 25

Queenston Formation

91. The GBR contained key clauses regarding anticipated rock conditions in the Queenston Formation. These clauses in particular describe the conditions that were known and what was to be expected regarding the rock conditions in the Queenston Formation.[61]

- The Queenston Formation is generally massive. However, construction of the tunnel in the Queenston Formation will have to allow for high in situ stresses and variations in rock mass strength. In addition, the presence of major sheared bedding planes at specific elevations must be accounted for. The weathered zone below the contact with the Whirlpool Formation and below the St. David's Gorge represents a weaker zone. Sheared bedding planes have developed within the Queenston Formation along Type IV (reddish-brown silty mudstone) and Type V (mudstone) rocks. These sheared planes are of low strength, are planar on a large scale and observed to be continuous throughout the test adit. There is potential for these sheared bedding planes to be continuous throughout the tunnel alignment. The performance of the trial enlargement has shown that significant slabbing can occur in the crown, in areas where sheared bedding planes exist some 2 m or less above the crown elevation, and on the sidewalls, particularly in areas immediately below such planes. These planes will be intersected by the tunnel at a low angle for a substantial portion of the tunnel length.

- Slabbing and plucking of rock blocks around and above the TBM shield and cutterhead can be expected to occur throughout the tunnel due to the occurrence of weak bedding planes in combination or not in combination with joints.

- Stability in the Queenston Formation will be further influenced by stress-induced failure. Over stressing will occur at the crown and at the invert. Stress induced spalling will occur at the sidewalls and will be exacerbated by the presence of sheared bedding planes. A maximum of 3-m thick crown slabbing and 1 m thick sidewall spalling will occur. Crown slabbing can occur immediately upon excavation, while sidewall spalling of 0.1 - to 0.2 -m depth due to overstressing will occur within ½ hr of excavation. Invert heave is expected.

- Total rock overbreak will be 30 000 m^3 where overbreak refers to rock beyond the maximum tunnel excavation diameter.

92. With respect to excessive overbreak, Strabag and OPG proposed differing quantities in the negotiation of the contract that the DRB concluded was the result of a serious misunderstanding between the parties with respect to overbreak.[62]

93. Strabag anticipated only 15,000m^3 based on its proposed means and methods in the Queenston Formation. OPG estimated 45,000 m^3 of total overbreak (3 times as much as the contractor). The GBR set the total overbreak quantity at 30000m^3, the average of the two estimates. In the end, the total overbreak quantity was vastly exceeded; 60,000m3, 50,000 m^3 of which was in the crown. The final amount was two times the 30,000m^3 baseline in the

[61] D1-2-1 Attach 6 Appendix 5.4 GBR Pages 35-36
[62] D1-2-1 Attach 7 DBR Report Page 16

GBR[63] and four times what Strabag expected, but closer to what OPG expected. OPG anticipated a higher level of overbreak but in the end negotiated a lower amount. Given that OPG was responsible for the differing subsurface conditions and OPG's knowledge of the high horizontal stresses in the Queenston Formation and the potential for incompetent rock in the St. David's Gorge area, AMPCO submits it was imprudent for OPG to negotiate a lower quantity, thereby increasing OPG's risk.

GBR is Defective

94. AMPCO supports the DRB conclusions, arrived at by the three tunnelling experts on the DRB, that the GBR was defective in that it contained imprecise, ambiguous and misleading statements about the Queenston Formation. AMPCO submits this led to an inaccurate but reasonable interpretation by the contractor about the subsurface conditions of the Queenston Formation at the time the GBR was signed. OPG was responsible for the GBR.

95. AMPCO has reviewed OPG's evidence in detail and has included numerous examples of how the GBR was imprecise, defective and ambiguous as follows based on the DRB's assessment and AMPCO's assessment as follows:

Defective GBR as identified by the DRB

- Statements in GBR led contractor to inaccurately interpret the Queenston Formation as generally massive.

- At time GBR-A was prepared, OPG anticipated a fully shielded TBM would be used. Greater emphasis in GBR-A may have been placed on anticipated issues with a fully shielded TBM instead of immediate support problems associated with an open main beam TBM excavation in the Queenston Formation under high horizontal stress.

- Statements in GBR written for a fully shielded TBM may have influenced contractor.

- GBR contained potentially misleading statements related to Observed Performance of Trial Enlargement (Adit)[64]

    - Adit referenced numerous incidences of sidewall spalling . Sidewall spalling would not be expected in a circular tunnel excavated with a TBM in rock expected to fail due to high horizontal overstress. This opinion is supported as sidewall spalling has not occurred in the Queenston Formation.

    - Adit referenced invert heave. Circular invert of a TBM might show only minor invert cracking under same subsurface conditions as adit. This opinion is supported as only minor slabbing of rock in invert has occurred in the Queenston Formation.

[63] Transcript Vol 2, Page 111
[64] D1-2-1 Attach 6 Appendix 5.4 GBR 7.4.1.2

96. The misleading statements that sidewall spalling and invert heave would occur contributed to improper tunnel supports proposed by contractor for 73% of tunnel length.

97. Type 4Q is different than Rock Type 5 and 6 in that it omits "continuous overbreaking due to slabbing". Continuous overbreak due to slabbing occurs throughout the Queenston Formation and this was anticipated . Therefore Type 4Q description was imprecise. This resulted in contractor classifying all of the Queenston Formation as Rock Type 5.

AMPCO Assessment of GBR

98. During the oral hearing AMPCO provided examples to the witnesses where statements in GBR-A that continued in GBR-C had imprecise statements that in AMPCO's view are significant and further mislead the contractor in its interpretation of the subsurface conditions. A few of the examples are provided below:

- **Slickenslided:** GBR-A prepared solely by OPG did not describe rock joint surfaces as being "slickensided in some instances". Slickenslided reflects surfaces of discontinuities with evidence of former movement and therefore of very low shear strength.[65] This omission is substantial as it reflects a weaker condition OPG was aware of at the time (as per Ilsley Report) reflecting low strength in some areas, particularly the St. David's Gorge area. This information if included may have given Strabag a better understanding of the weaker conditions that exist.[66]
- **Massive**: GBR-A prepared solely by OPG described Queenston Formation as being Massive to Blocky. Massive refers to competent rock, stronger rock, and this was removed in the update. OPG's inaccurate characterization of Queenston Formation as massive misled the contractor and the outcome was the original support using steel sets could not be installed and modified tunnel supports had to be designed and implemented.[67]
- **Rock of fresh and of excellent quality**: GBR-A prepared soley by OPG describes bedrock at the St. David's Gorge below a certain depth as "generally fresh and of excellent quality".[68] Contractor was mislead by this statement; the joint surfaces were more slickensided in some instances.[69]
- **Incorrect Stress Regimes for Design Purposes:** GBR-A incorrectly described the tunnel at Station 0+000 to 1+700 in Queenston Formation (subunits Q2 to Q 10) as "tunnel is nearly parallel to minimum stress when it should have been "tunnel is nearly parallel to maximum stresses". The distinction between minimum and maximum is important and misleading to contractor because the direction of the in situ stresses aligned with the tunnel can cause failure to propagate.[70]
- **GBR is Ambiguous** Mr. Ilsley stated at the hearing that he considered OPG's GBR to be ambiguous.[71] Ambiguous is an understatement. The DRB concluded that the Contractor and Designer could have been mislead by statements within the GBR that were incorrectly or imprecisely drafted according to guidelines in "Geotechnical Baseline Reports for

[65] F5-6-1 Page 12
[66] KT1.1 Pages 69-70
[67] KT1.1 Pages 72-73
[68] D1-2-1 Attach 7 DRB Report, Page 12
[69] KT1.1 Pages 77-78
[70] Kt1.1 Pages 91-92
[71] Transcript Vol 2

Construction", ASCE, Section 6.4, Page 27.[72] On Page 27, the guidelines indicate that the goal of a well-written GBR is to avoid contractual ambiguity. Whenever possible, baseline statements should be in terms of measurable properties or parameters that can be objectively observed and recorded during construction. Ambiguous terminology such as "may," "can", "might", "up to", "could", "should," "some", "few", "ranges from…to.." and "would" etc. should not be used in baseline statements. Rather, definitive terms, such as "is," "are," "will," etc. should be used to clearly establish the baseline. The guidelines further state that adverbs should be avoided and the use of general adjectives, such as "generally", "large," "significant," "minor," "local", "Many" etc. should also be avoided unless these terms are defined and quantified.

99. There are several examples in the document where ambiguous terminology is used and this ambiguous terminology became an issue in the dispute process related to differing subsurface conditions. The DRB quoted several sections from the GBR to illustrate this point as follows:[73]

• 8.1.2.2: "...As a result, there is a *potential* for thin rock wedges to develop at any bedding plane." To the optimistic contractor bidding for the work, *potential* is likely to be interpreted as seldom likely to occur.

• 8.1.2.3 "The Queenston Formation is *generally* massive." Without defining the extent more quantitatively, this could, in the Board's opinion, lead to a reasonable interpretation of massive rock. Other descriptions in the GBR warn of less massive conditions that "must be accounted for", but these could be interpreted as local conditions.

• 8.1.2.3: "significant slabbing *can* occur in the crown" which could also be interpreted that slabbing might not occur; when in actuality it occurred throughout the QF.

• 8.1.3.2: "initial support must be installed within or *immediately behind* the shield". This can be interpreted that installation of initial support could be delayed to immediately behind the shield.

100. The DBR states that consideration of the above statements may have led the Contractor to propose Rock Condition 4Q in the Queenston Formation[74] that does not include slabbing as one of the rock characteristics, while actual conditions show slabbing should have been expected throughout the horizontally overstressed Queenston Formation.

101. The DRB also references other statements shown below that may have influenced the contractor but never developed or were more severe than expected. The statements include references to a closed (shielded) TBM.

[72] D1-2-1 Attach 7 DBR Report, Page 14
[73] D1-2-1 Attach 7 DBR Report, Page 14
[74] D1-2-1 Attach 6 Appendix 5.4 GBR Rock Characteristics Table, Page 37

• 8.1.2.5 *"Slabbing* and plucking of rock blocks *around* and above the TBM shield ..." was apparently written for a TBM using a full circle shield and erecting precast concrete segments. A main beam TBM roof shield does not have an *"around"* portion and no substantial *slabbing* of rock blocks *around* the TBM shield can occur.

• 8.1.2.6 "Stress induced spalling will occur at the sidewalls ...within *Yz* hour of excavation", when in actuality it has not occurred in the sidewalls within the QF to any measurable degree, even after days of the sidewalls standing unsupported.

• 8.1.2.6 "Invert heave is *expected.",* when actually invert heave does not appear to have been a problem, although some fracturing of the invert has been reported.

• 8.1.3.2 "... initial support must be installed ... immediately ... and must provide full coverage to the rock surface." Initial support cannot be installed immediately when using a main beam TBM. This apparently is also written for a TBM with a full circle shield.

102. As a simple test, the guideline states (Page 27) that the question "If I encountered a site condition pertaining to this baseline would I know if it differed from the indicated conditions? If an affirmative answer is not given, the baseline statement is not sufficiently clear. In AMPCO's view it appears this simple test was not applied given the misunderstandings that occurred between OPG and Strabag.

103. AMPCO notes other examples of ambiguous language in the GBR as follows:

- 4.4.1.1 Bedrock Characteristics, Bedding Planes: "Bedrock in the Project area has <u>generally</u> well-defined bedding with a southerly dip of about 6 m/km and an east-west strike. Sheared, weak bedding planes exist between many of the rock formations and within the Queenston Formation."

- 4.4.2.4 Faulting and Discontinuities: "The joint sets vary in spacing, frequency and continuity depending on location and lithology. Vertical joints are <u>generally</u> widely spaced. The joint surfaces are <u>generally rough</u> and fresh to slightly weathered."

- 4.4.3 Bedrock Characteristics, Bedding Planes "The primary bedding planes will affect the excavation of the tunnel as many are clay rich and form weak discontinuity surfaces that, because of the shallow dip of the tunnels, <u>may</u> follow the excavation for considerable distances. Their locations can be estimated from Figure 4.1. However, because only two boreholes are available with geophysical trace information, detailed correlation of all the bedding planes within the Queenston Formation across the complete length of the tunnel alignment has not proved possible."

104. AMPCO submits if information was lacking and additional testing was required to achieve clearer language on specific issues, OPG should have undertaken any additional testing as required.

- 4.4.4.4 Bedrock at St. David's Gorge "The bedrock (Queenston Formation) over the width of the St. David's Gorge is slightly weathered and relatively more fractured to a depth of between 15 to 25 m below the bottom of the gorge. Below this depth, the rock is <u>generally</u> fresh and of excellent quality. No evidence of a major fault or other major discontinuities underlying the St. David's Gorge has been found to date either by drilling or from geophysical surveys."
- Rock Condition 5 & 6 (Queenston Formation): rock pressure <u>generally</u> exceeding rock mass strength.

105. Lessons learned in the guideline (Pages 51-58) conclude that a poorly written GBR can be a lightning rod for claims and disputes. The guideline also suggests having an independent review of the GBR at different stages of completion in order to identify possible ambiguity and inconsistencies, and to verify that all relevant issues are appropriately addressed. OPG's evidence does not indicate that an independent review was done.

AMPCO's Position

106. Given that responsibility for the risk of differing subsurface conditions from the baseline as established in the GBR was allocated to OPG, and given what OPG knew about the challenging rock characteristics in the Queenston Formation, AMPCO submits OPG should have taken extra care to ensure GBR-A was as definitive as possible and ambiguous language was avoided. There is no evidence the GBR process included sufficient scrutiny or assessment from either internal or external resources to ensure the GBR was as precise as reasonable possible.

107. In consideration of the number of examples of ambiguous language as noted above, some of which led to significant disputes between OPG and Strabag, AMPCO submits OPG was negligent in its preparation of GBR-A and any disallowance should reflect the extent to which it was negligent and the impact of the outcome. In its review AMPCO concludes that the modifications between GBR-A and GBR-C were minimal.

108. AMPCO's position is that OPG's GBR was deficient from the beginning with GBR-A and the numerous ambiguous, imprecise and misleading statements made the GBR sufficiently defective that Strabag's reliance on it caused Strabag to reasonably but inaccurately interpret the subsurface conditions as being stronger. The consequences of OPG's defective GBR influenced the method and means of the contractor such that the support methods employed exacerbated the excessive overbreak issue.

Consequences of Defective GBR

109. AMPCO submits that the contractor's misunderstanding of the subsurface conditions had significant consequences that directly contributed to the significant cost overruns i.e. improper selection and design of the TBM including support methods resulting in slower tunnel advances.

Improper Selection of TBM

110. There are two types of TBMs: open and closed. The TBM used in the NTP was the largest open gripper main beam TBM in the world. Strabag worked with The Robbins Company and

its designer[75] to design an open TBM for the tunnel to meet the specific criteria for the project that included a 90-year service life for the tunnel.

111. OPG indicates the TBM was selected based on the rock conditions anticipated as a result of the geotechnical research and investigation prior to the project.[76] In hard rock nothing bores faster than an open main beam TBM. In fractured rock, a shielded TBM is preferred over an open TBM as it protects against rock collapse. With a shielded TBM, workers are protected from broken rock and the cutterhead minimizes disturbance of the rock face it bores, preventing large blocks from collapsing and causing excessive boring stresses. By contrast, an open main beam TBM transfers a high thrust through the cutterhead and disc cutters that create fractures in the rock causing chips to break away from the tunnel face.[77] It appears the soft to moderate strength of the rock in the Queenston Formation (10MPa-12MPA) was no match for the thrust of Strabag's open TBM.

112. The DRB noted that at the time GBR-A was prepared by OPG it anticipated that a precast, gasketed segmental lining would be used, erected with a fully shielded TBM. Under such conditions the rock surrounding the excavation is never exposed; the rock is allowed to slab, loose rock is not removed, and continuous support is provided by the shield, segments and annular backfill.[78] AMPCO's compendium includes drawings of an open main beam TBM compared to a closed fully-shielded TBM.[79] In AMPCO's view, it is clear from the drawings and design features of each type of TBM that a fully shielded TBM design is better suited to the rock conditions and characteristics in the Queenston Formation as described in detail in sections 6.2.2, 6.4.3, 6.6.2, 6.6.3, 6.8 and 8.1.2 in the GBR.

113. AMPCO acknowledges that the 90-year service life design was a unique criterion for the tunnel project. Strabag's successful proposal featured a prestressed a cast-in-place concrete lining method with an impermeable waterproof membrane that was judged by OPG's RFP Evaluation Team (OPG, Hatch & Torys[80]) to be significantly superior to the methods proposed by the other two tenderers, each of which involved a fully shielded TBM with a single pass, pre-cast segmental lining.[81] To the DRB's knowledge, the tunnel design had not been used in North America.[82] Strabag was not the low bidder and acknowledged in their proposal that using a shielded TBM with a pre-cast segmental liner would make construction easier.[83] Nowhere in the evidence does it state that the fully shielded TBM designs of the other unsuccessful proponents were incapable of meeting the 90-year service life requirement.

114. Notwithstanding the 90-year service life requirement, the fact that Strabag proposed an open TBM given that Queenston Formation is not characterized as competent rock further supports the DRB finding that the contractor misinterpreted the subsurface conditions in the Queenston Formation. AMPCO submits OPG's decision to accept Strabag's open TBM was

[75] ILF Consulting
[76] L-4.4-1-Staff-022 (b)
[77] The Robbins Company website
[78] D1-2-1 Attach 7 DRB Report Page 14
[79] KT1.1 Pages 53-54
[80] D1-2-1 Page 29
[81] D1-2-1 Attach 7 DRB Page 6
[82] D1-2-1 Attach 7 DRB Report Page
[83] D1-2-1 Attach 7 DRB Report Page 6

inappropriate given OPG's knowledge of the subsurface conditions. AMPCO submits OPG took an unnecessary risk by doing so.

Project Modifications Needed

115. Substantial overbreak was encountered as soon as the TBM reached the Queenston Shale. Strabag modified the TBM itself and the support methods to limit the amount of overbreak. The original configuration of Strabag's TBM on this project had an unsupported distance of 1.2 m over the cutterhead and thus could not prevent loss of rock from outside the excavated surface in the crown over the cutter head, at the grille bars/buckets. Rock in this area can relax, relax, fracture, break apart and fall past these grille bars into the buckets before it can be supported by the TBM roof shied.[84]

116. Tunnel support is chosen and designed to match the deformation characteristics of the rock mass surrounding the tunnel. Strabag had originally proposed that 73% of the tunnel length be supported by steel sets (support 4) which was primarily chosen to address sidewall spiling an invert heaving, 2 conditions that occur with a closed TBM, and To address the substantial overbreak issue, Strabag developed two new rock support types (4R and 4S).

117. Clearly, Strabag's original TBM design and tunnel supports selected demonstrates that Strabag anticipated stronger more competent conditions and was misled by the GBR.

Profile Restoration Project

118. The excessive overbreak resulted in profile damage and a three year restoration project totalling $92M[85] that included the development of specialized equipment. AMPCO submits this work was a direct consequence of OPG's defective GBR.

AMPCO Position

119. The DRB ruled that that the excessive overbreak encountered during tunnel construction constituted a Differing Subsurface Condition. AMPCO submits the numerous examples provided by the DRB and AMPCO adequately demonstrate that OPG's GBR was inadequate, imprecise, ambiguous and defective at the GBR-A stage. OPG's defective GBR misled the contractor to inaccurately interpret the condition of the rock conditions resulting in an overbreak quantity that vastly exceeded the amount in the contract. Since GBR-A was prepared solely by OPG and formed the basis of the continued misunderstanding in GBR-C, AMPCO submits OPG is responsible for any cost overrun resulting from the excessive overbreak. OPG indicates 100% of the cost overruns are a direct result of the excessive overbreak issue. On this basis, AMPCO has determined that the Board should disallow $352.4M related to consequences directly associated with OPG's defective GBR and inadequate risk assessment as follows:

- Tunnel construction = $240.3M[86]

[84] D1-2-1 Attach 7 DRB Report Page
[85] JT2.1
[86] Less $40M dispute settlement

- Owner's Representative= $10.8M
- Scope Changes = $0.70
- Project Management = $0.6M
- Dispute Review Board Costs = $0.3M
- Interest = $97.7M
- Other infrastructure = $2M

Outcome of Dispute: Differing Subsurface Conditions

120. Excessive overbreak along with four other issues represented the dispute put forward by Strabag: Large Block Failures; Ground Conditions beneath St. David's Gorge; Insufficient Stand-up Time; Excessive Overbreak; and Inadequate Table of Rock Conditions and Characteristics.

121. For the first and third issue the DRB determined there was no differing subsurface condition. The DRB found that with respect to the last two issues, the GBR was defective. AMPCO submits future contract negotiations should have taken into account the DRB's conclusions on a differing subsurface condition for each issue.

Imprudent Decision

122. With respect to the second issue, St. David's Gorge, Strabag's proposal included raising the OPG's conceptual design low-point of the tunnel's vertical alignment by approximately 50 m. In doing so, OPG negotiated a clause in the contract (5.5e of the DBA) that "No request by the Contractor for relief for differing subsurface conditions will be allowed in respect of Work under the St. David's Gorge to the extent that the width of the gorge is within the width defined in the GBR". OPG added the clause to reduce its risk exposure if rock conditions worsened as a direct result of the Contractor raising the vertical alignment.[87]

123. Firstly, AMPCO submits that OPG's decision to accept Strabag's proposal to raise the tunnel alignment was imprudent given what OPG knew about the change in rock conditions. OPG was clearly concerned about the added risk of intersecting the buried channel itself and had adequate knowledge of the risks. This risky realignment was discussed as an example of when an EA amendment would be required in the Qualitative Risk Assessment Report dated February 24, 2005 which states "A shallower alignment through the St. David's gorge, technically risky at the time of the EA, may be proposed by one or more contractors as a cost and time saving measure.[88] OPG realized that the change in alignment moved the tunnel from more competent rock to less competent rock at this higher elevation and OPG wanted no part of the risk.[89] Strabag agreed that OPG would have no part of this risk. The DRB notes that although the tunnel did not intersect St. David's Gorge, boring explorations are not reliable in defining the exact depth of the buried channel and it is uncertain how close the tunnel may have come to the bottom of the Gorge.[90] The DRB determined that Strabag

[87] D1-02-1 Attach 7 DRB Report Page 2
[88] D1-2-1 Attach 7 DBA Attach Page 1-1
[89] D1-2-1 Attach 7 DRB Report Page 2
[90] D1-2-1 Atach 7 DRB Report Page 10

cannot claim for a Differing Subsurface Condition in this section of the tunnel (800 m) as such claims were expressly prohibited by the Design Build Agreement.

124. AMPCO submits that no claimed losses with respect to this issue should be considered between OPG and Strabag under any proposed settlement agreement and that none of these costs should be passed on to ratepayers.

125. OPG confirmed that the total cost of the five issues is approximately $90M, however, OPG was unable to provide a breakdown of the dispute costs by issue. The cost implications of these five issues is discussed below under OPG's response to the DRB conclusions where OPG reached a settlement with Strabag on its claimed losses and negotiated a new contract in the form of an Amended Design Build Agreement.

Contract Renegotiation

126. OPG indicates that around the time of the dispute decision, $463M had been spent on the tunnel to date.[91] Had the project been abandoned an additional $100M in close-out costs would have been incurred for a total of $563M.

127. In response to the DBR report, OPG in consultation with the Owner's Representative (OR) determined that four options were available moving forward.

- Seek to replace Strabag with a new contractor to complete the tunnel.
    - OPG considered this should only be considered as a last resort due to the cost and schedule consequences of locating, hiring and mobilizing a replacement contractor. During the hearing Mr. Ilsley provided a project example that illustrated this option could result in a significant increase in project costs.
    - OPG did not provide a cost estimate for this alternative. It is unclear if the costs would have been greater than the final NTP cost, but given that a TBM was over 140 m underground at the time of the DRB's decision in August 2009, it seems logical that it would be complicated, time consuming and costly to switch contractors which would not in the best interests of ratepayers.
- Reject the DRB recommendations and pursue arbitration under the Rules of Arbitration of the International Chamber of Commerce as provided in the agreement (Section 11.5 as amended).
    - OPG concluded there was no advantage to pursuing arbitration unless attempts at negotiation failed given the additional time needed for arbitration and a greater risk of a less certain outcome than negotiation.
- Settle all outstanding disputes with Strabag and negotiate a new target cost contract for completion including incentives and disincentives based on cost and schedule to completion.

[91] D1-2-1 Page 115

- OPG concluded that a negotiated settlement and contract with Strabag was the best path forward to reach the best result in terms of cost and schedule.

- In reaching this conclusion it appears as if OPG was held hostage by its concern that Strabag would abandon the project if it was held to the terms of the existing agreement it had with OPG. In so doing AMPCO suggests that OPG ignored certain issues such as the fact that Strabag was an International contractor in the field of tunnelling whose reputation would be significantly hurt by abandoning its agreement with OPG. In addition, there is no evidence that OPG sought to determine the seriousness of its concern that Strabag would abandon the current agreement but rather accepted it as a given and renegotiated its agreement with Strabag.

- The agreement which was renegotiated, the ADBA, favours Strabag over OPG in that it does not reflect the allocation of responsibility for previous cost and time overridges determined by the DRB. This was done, allegedly, as a further inducement to have Strabag remain engaged in the project. Once again, there does not appear to have been any serious inquiry undertaken as to whether that was in fact a concern. All-in-all, it appears to AMPCO that OPG took the, "easy way out" in negotiating its second agreement with Strabag at the expense of rate payers.

- In AMPCO's view OPG did not adequately consider the option negotiating changes to the existing DBA based on cost sharing.

Contract Renegotiation

128. As AMPCO understands it OPG and Strabag negotiated a hybrid solution that included resolution of Strabag's claim for differing subsurface conditions in the Queenston Formation and negotiated ADBA using the original DBA as the basis for the ADBA except that the contract was converted from a fixed price contract to a target price contract.

129. Under the ADBA, OPG and Strabag agreed on a target cost of $985M, a contract schedule completion date by June 2013 and changes to the allocation of risk.[92] The ADBA also incorporates changes in the tunnel route (vertical and horizontal) to excavation with the tunnel crown in the Queenston Formation which shortened the tunnel length by 200 m.

130. OPG resolved Strabag's claimed losses of $90M to November 2008 by agreeing to pay Strabag $40M provided Strabag provided OPG with a $40M letter of credit to cover the possibility that a final agreement could not be reached. This left Strabag with a loss of approximately $50M. Under the ADBA Strabag could earn a $20M completion fee plus maximum schedule and incentive fees of $40M which were achieved leaving Strabag with a profit of $10M as shown in the Table below prepared by AMPCO. In AMPCO's view, OPG's negotiated ADBA with Strabag does not reflect and equitable sharing of the losses as referenced in the DRB ruling.

[92] D1-2-1 Page 109

ADBA		Negotiated Settlement/ Incentives Paid	Audited Losses
Strabag's Claimed Losses	A	($90M)	($77M)
Claim Settlement	**B**	**$40M**	**$40M**
Claim Balance[93]	C=A-B	($50M)	($37M)
Completion Fees: Interim completion Fee Substantial Completion Fee	D	$20M $10M $10M	$20M $10M $10M
Schedule Incentive	E	$40M	$40M
Total Paid	B+D+F	**$100M**	**$100M**
Total ADBA incentives	F=D+E	**$60M**	**$60M**
Strabag Profit	**C-F**	**$10M**	**$23M**

131. OPG had the right to audit Strabag's losses and to the extent that the full $90M was not substantiated in the audit, the $40M payment could be reduced proportionately. The result of the OPG audit was that only $77.44M of the $90M was substantiated[94] so the $40M paid to Strabag should have been reduced by $5.6M to $34.4M on a ratio basis. Instead OPG chose to pay Strabag the full $40M and did not reduce the amount as provided for under the terms of the settlement. AMPCO submits OPG's decision to forego the $5.6M under the negotiated contract was imprudent. The above table shows Strabag was paid $100M.

132. AMPCO agrees with Board Staff that it is clear that although OPG assumed responsibility for hundreds of millions in extra costs, it is not evident what additional costs were borne by Strabag. The chief cost to Strabag appears to be a lower profit margin than had previously been expected. AMPCO supports Board Staff's analysis that if Strabag were to have walked away from the project it would have resulted in significant costs to Strabag, more than the reduced profit it wound up with so it is reasonable to expect that OPG could have negotiated a greater "sharing " of the costs resulting from the overbreak.[95] In AMPCO's view there was no adequate sharing of costs. AMPCO submits OPG's decision to pay Strabag $40M was imprudent.

133. Strabag achieved the incentives provided for in the contract because of OPG's largesse. Under the ADBA the target price and completion date can be extended. As a result of events, the contract target price was increased under Amendments No.1 and No.2 and the schedule was extended by 94 days due to two events. As a result, Strabag received $40M in incentives instead of $25M that it would have received under the original target substantial completion date.[96] As noted below AMPCO submits that the 17 day extension due to an ungrouted borehole event is not justified. The tunnel was in-service March 9, 2013, ahead of

[93] If Target Cost & Schedule Met $50M reduced from $50M to $30M
[94] Transcript Vol 2 Page 66
[95] Board Staff Submission Page 25
[96] Transcript Vol

the June 2013 target date. AMPCO submits the terms OPG negotiated with Strabag were imprudent. AMPCO submits ratepayers should not have to pay the extra $15M.

Other Infrastructure Costs

134. The realigned tunnel intersected a historical borehole that wasn't properly grouted. [97] OPG's witness confirmed this was not the appropriate approach. AMPCO submits the $2M final cost should not have been an allowed cost to be borne by ratepayers and a further disallowance of $2M is appropriate. AMPCO submits that the 17 days increase to the target schedule was not appropriate and should be treated as a disallowance with respect to the incentive paid as indicated above.

OPG's Owner Representative

135. Beginning in 1998, Ontario Hydro (now OPG) engaged Acres (now Hatch Mott Macdonald) to provide engineering services that included geotechnical investigations and analysis as OPG did not have the expertise in-house. Based on these investigations and analysis, Hatch prepared the GBR included in the Design Build Agreement.[98] It is not clear to AMPCO why OPG did not investigate the possibility of seeking financial recovery from Hatch given that the GBR was imprecise, ambiguous, misleading and determined by the DRB to be defective. In the end Hatch made an additional $10.8M (See Appendix C). In AMPCO's view, OPG should have taken legal action against Hatch.

AMPCO Position

136. OPG failed to negotiate a fair and equitable contract for rate payers based on the DRB conclusions and recommendations. AMPCO submits that a reduction of $40M paid to Strabag related to claimed losses is appropriate.

AMPCO Position

137. AMPCO has demonstrated that there were deficiencies in the GBR (beginning with GBR-A) which misled the contractor to reasonably but inaccurately interpret the subsurface rock conditions resulting in a tunnel lining design and means and methods that did not adequately address the conditions encountered. This led to significant consequences on the tunnel project including TBM modifications, new tunnel supports, and a costly restoration project that accounted for approximately <u>89%</u> of the cost overruns. Further imprudent decisions on the part of OPG with respect to contract negotiations with Strabag account for the remaining amount.

138. OPG has stated that if the original GBR had been accurate with respect to the amount of overbreak, then Strbag would have charged more to perform the work from the outset. AMPCO submits that if the original GBR had been accurate, it is highly probable that the contractor would have proposed a different design using a fully closed (shielded) TBM as contemplated in the design concept for the project, and a route that minimized tunnel length in the Queenston Formation.

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[97] Transcript Vol 1 Page 9

[98] L-4.4-2-AMPCO-016 (f)

Disallowance

139. AMPCO submits not all costs and resulting proposed additions to rate base were reasonable & prudently incurred for the reasons discussed above. On this basis, AMPCO has calculated a disallowance that it considers to be appropriately representative of the cost overruns associated with the excessive overbreak issue.

Proposed Disallowance	**$M**
Tunnel Diversion	$240.3M
Settlement re: DRB Decision	$40M
Contract Incentives	$15M
Owner's Representative costs	$10.8M
Scope Changes	$0.7M
Project Management	$0.6M
Dispute Review Board Costs	$0.3M
Interest	$97.7M
Other infrastructure costs	$2M
TOTAL	$407.4M

Issue 4.4
Issue 4.5

AMPCO Appendix B

NIAGARA TUNNEL PROJECT - BREAKDOWN OF CONTRACT PRICE

DESCRIPTION OF WORK	CONTRACT PRICE TOTAL	TARGET COST TOTAL	ESTIMATED CAPITAL COST TO COMPLETE	Variance $	Variance %
Insurance Premium	$2,724,181	$4,293,380.33	$2,600,000	-$124,181	-4.6%
Mobilization/Demobilization	$31,729,969	$30,977,603.51	$31,000,000	-$729,969	-2.3%
Maintenance Bond in the form of Appendix 4.1 (f)	$610,749	$700,000.00		-$610,749	-100.0%
Performance Letter of Credit (LC)	$2,544,789	$5,427,291.33	$7,600,000	$5,055,211	198.6%
Design	**$5,870,313**	**$9,702,340.78**	**$11,600,000**	**$5,729,687**	**97.6%**
Accelerating Wall, Intake Channel and Approach Wall	$54,862,211	$64,759,581.32	$64,400,000	$9,537,789	17.4%
Diversion Outlet Canal	$12,730,052	$12,906,781.88	$15,400,000	$2,669,948	21.0%
Dewatering System Shafts	$3,787,251	$3,649,132.60	$3,800,000	$12,749	0.3%
Intake Structure	$5,334,935	$8,635,794.00	$6,100,000	$765,065	14.3%
Intake Gates	$2,325,461	$2,478,138.00	$4,700,000	$2,374,539	102.1%
Outlet Structure	$7,222,558	$12,819,894.28	$11,700,000	$4,477,442	62.0%
Outlet Structure Gate and Hoist	$5,957,260	$3,603,112.00	$4,800,000	-$1,157,260	-19.4%
Diversion Tunnel	**$406,881,138**	**$689,016,578.99**	**$687,200,000**	**$280,318,862**	**68.9%**
Tunnel Boring Machine	$78,242,470	$78,242,470.00	$78,200,000	-$42,470	-0.1%
Flow Verification Test	**$94,682**	**$569,097.00**	**$300,000**	**$205,318**	**216.9%**
Demolition and Disposal of Dewatering Structure (optional)	$1,495,595	$0.00	$100,000	-$1,395,595	-93.3%
Proponent's Estimate of its DRB Cost (50% of overall cost)	$221,557	$366,671.11		-$221,557	-100.0%
Dewatering Structure		$1,452,034.00			
Item not used		$0.00			
Scope Changes		$739,235.99	$700,000	$700,000	
Provisional Sum		$206,152.03	$200,000	$200,000	
Changes in Applicable Law		$235,000.00	$100,000	$100,000	
Warranty Administration Fee		$100,000.00	$100,000	$100,000	
Office and General Cost		$54,119,710.85	$78,400,000	$78,400,000	
Dispute Review Board Cost			$300,000	$300,000	
TOTAL (excluding contingency)	**$ 622,635,171**	**$985,000,000**	**$1,009,300,000**	$386,664,829	62.1%
Overhead Recovery		$32,700,000.00	$36,200,000	$36,200,000	
Interim Completion Fee			**$10,000,000**		
Substantial Completion Fee			**$10,000,000**		
Schedule Incentive			**$40,000,000**		
One-time Settlement Interest			$1,400,000		
Tunnel Contingency*	$ 101,000,000	$164,000,000	$5,800,000	-$95,200,000	-94.3%
TOTAL Tunnel Contract Costs	723,635,171	1,181,700,000	$1,112,700,000	$389,064,829	53.8%
OPG Project Management	$ 4,400,000	$6,000,000	$5,000,000	$600,000	13.6%
Owner's Representative	$ 25,400,000	$40,400,000	$36,200,000	$10,800,000	42.5%
Other Consultants	$ 4,000,000	$5,900,000	$6,500,000	$2,500,000	62.5%
Environmental / Compensation	$ 12,000,000	$9,600,000	$8,700,000	-$3,300,000	-27.5%
Other Contracts / Costs	78,900,000	$69,800,000	$68,400,000	-$10,500,000	-13.3%
Interest	136,800,000	$286,600,000	$234,500,000	$97,700,000	71.4%
TOTAL	**$985,135,171**	**$1,600,000,000**	**$1,472,000,000**	**$486,864,829**	49.4%
2014 Expenses			**$4,600,000**		
TOTAL			**$1,476,600,000**		
Schedule contingency	36 weeks	28 weeks			

* $101M=$96M contingency for tunnel (15.4%) + $5M GFA; $11M contingency for othe project elements; Total contingency =$112M (13%)

	Rock Condition	Rock Characteristics	% of Total Bored Tunnel Length
Formations above Queenston Formation	1	• stable rock	0.16
	2	• loosening of rock in crown or localized area	2.73
	3	• unstable or closely broken rock • frequent overbreak due to discontinuities	10.59

	4	• unstable or closely broken rock
		• continuous overbreak due to any of:
		    o discontinuities
		    o sidewall spalling
		    o invert heave
			5.28

Queenston Formation	4Q	• continuous overbreak due any of:
		    o sidewall spalling
		    o invert heave
		• crown is more than 3m from bedding plane
			23.69

	5	• continuous overbreak due to any of:
		    o sidewall spalling
		    o invert heave
		    o slabbing
		• squeezing rock conditions
		• rock pressure generally exceeding rock mass strength
		• crown is within 3m of bedding plane
			46.90

	6	• continuous overbreak due to any of:
		    o sidewall spalling
		    o invert heave
		    o slabbing
		• squeezing rock conditions
		• rock pressure generally exceeding rock mass strength
		• closely broken shear and thrust zones
		• crown is within 3m of bedding plane
		• all other conditions requiring greater support than under Conditions 4Q and 5
			10.65

6.4 Assessment of Rock Mass Strength

pressure and structural orientation terms. The modified value is denoted the Geological Strength Index (GSI). A set of empirical relationships are then used relating GSI values and the constants 'm' and 's'.

(c) Mohr-Coulomb parameters will be estimated from the constants 'm' and 's' following the instantaneous approach suggested by Hoek (1997), at the applicable actual effective horizontal stresses, in consideration of pore water pressures.

6.4.2 Rock Formations Above Queenston Formation

1 The rock mass strengths were estimated on the basis of the average uniaxial compressive strength of the rock and m_i values recommended by Hoek (1988) for the various rock types. The resulting 'm' and 's' values given in Table 6.9 were based on RMR values that were adjusted for the purpose of rock mass strength estimates as per Hoek (1988).

6.4.3 Rock Mass Strength of Queenston Formation

The Queenston rock mass strength has been evaluated in the Definition Engineering Phase 2 investigations, based on the 'm_i' (intact) values from triaxial testing and RMR values. Results of laboratory triaxial strength testing were used to estimate the intact rock strength as previously discussed. Rock mass strengths are given in Table 6.10.

1 The RMR values noted in Table 6.8 were similarly grouped into simplified 'generic' classes to provide approximate values for specific areas. These RMR values were then combined with the 'm_i' and compressive strength evaluations to estimate the strength of the in situ rock mass as given in Table 6.10.

2 The subdivision of the Queenston rock mass strengths into particular depths in Table 6.10 does not take into account any weaker or close jointed zones such as those under the St. Davids Gorge.

6.5 Groundwater and Gas

6.5.1 Hydrogeology

1 The rock strata form an interlayered succession of relatively pervious and relatively impervious rocks. The impervious formations impede flow, whereas the more permeable formations serve either as recharge or discharge horizons for adjacent formations. Within the more permeable formations, the hydraulic conductivity is principally related to the presence of a few open fractures which are predominantly horizontal. Vertical connectivity of these fractures is low, except in the upper rock units. Thus, formations which exhibit high hydraulic conductivity from packer testing may have a low vertical hydraulic connectivity.

(c) Mohr-Coulomb parameters can be estimated from the constants 'm' and 's' following the instantaneous approach suggested by Hoek (1997), at the applicable actual effective horizontal stresses, in consideration of pore water pressures.

6.4.2 Rock Formations Above Queenston Formation

1 The uniaxial compressive strength (UCS) and m_i values of the rock and estimated RMR of the rock mass are given in Table 6.9. RMR values were adjusted for the purpose of rock mass strength estimates as per Hoek (1988) and m_i values. were estimated on the basis of the average values recommended by Hoek (1988) for the various rock types.

6.4.3 Rock Mass Strength of Queenston Formation

The uniaxial compressive strength (UCS) and m_i values of the rock and estimated RMR of the rock mass are given in Table 6.10. RMR values were adjusted for the purpose of rock mass strength estimates as per Hoek (1988) with m_i from triaxial testing and RMR values. Results of laboratory triaxial strength testing were used to estimate the intact rock strength (UCS) as previously discussed

1 The RMR and m_i values noted in Table 6.8 were similarly grouped into simplified 'generic' classes in Tables 6.9 and 6.10 to provide approximate values for specific areas. .

6.5 Groundwater and Gas

6.5.1 Hydrogeology

1 The rock strata form an interlayered succession of relatively pervious and relatively impervious rocks. The impervious formations impede flow, whereas the more permeable formations serve either as recharge or discharge horizons for adjacent formations. Within the more permeable formations, the hydraulic conductivity is principally related to the presence of a few open fractures which are predominantly horizontal. Vertical connectivity of these fractures is low, except in the upper rock units. Thus, formations which exhibit high hydraulic conductivity from packer testing may have a low vertical hydraulic connectivity.

2 In addition to areas of increased weathering and discontinuities as given in Section 4, zones of increased jointing and higher hydraulic conductivity in the area will potentially occur where the tunnel alignment crosses the trend line of the crest of Horseshoe Falls (the east-west trending jointing at the Canadian Falls area is parallel to this trend line).

3 Piezometric levels in the Guelph and Upper Lockport formations are controlled by recharge from nearby bodies of water such as the Niagara River, the PGS reservoir, and the existing power canals into which these strata daylight. High hydraulic conductivity was measured for some of these rocks and the flow is largely confined to

Table 6.9
Rock Mass Strength Parameters for Rock Formation Above Queenston Shale

Formation	RMR	Adjusted RMR*	Compressive Strength (MPa)	m_i	m	s
Lockport Dolostone						
- Eramosa	69	79	151	7.0	3.3	0.0970
- Goat Island	69	79		7.0	3.3	0.0970
- Gasport	72	82		7.0	3.7	0.1353
DeCew Dolostone	69	79	128	7.0	3.3	0.0970
Rochester Shale	64	77	42	10.0	4.4	0.0777
Irondequoit Limestone	72	82	106	7.0	3.7	0.1353
Reynales Dolostone	67	77	95	7.0	3.1	0.0777
Neahga Shale	56	66	14	10.0	3.0	0.0229
Thorold Sandstone	78	83	163	15.0	8.2	0.1524
Grimsby Sandstone Shale	70	75	155 33	10.0	4.1	0.0622
Power Glen						
• Sandstone/Shale	61	66	172	10.0	3.0	0.0229
• Shale	65	70	24	10.0	3.4	0.0357
Whirlpool Sandstone	85	87	216	15.0	9.4	0.2359

* Adjusted RMR values are equivalent to GSI.

Table 6.10
Rock Mass Strength of Queenston Formation

Area	RMR	σ_c (MPa)	m_i	m	s
Inlet area	66	33	6.5	1.93	.0229
Tunnel alignment (general)					
Q10	55	33	6.5	1.30	.0067
Q8,9	65	33	6.5	1.86	.0205
Q6,7	71	33	6.5	2.31	.0399
Q4,5	67	46	14.5	4.46	.0256
Q1,2,3	82	46	14.5	7.62	.1353
Tunnel Alignment in area of St. Davids Gorge					
Q6	67	33	6.5	2.00	.0256
Q5	67	46	14.5	4.46	.0256
Q3,4	73	46	14.5	5.53	.0498
Q1,2	76	46	14.5	6.15	.0695
Outlet Area					
Q7-10	57	33	6.5	1.40	.0084
Q5-6	77	46	14.5	6.38	.0776

σ_c = uniaxial compressive strength
m,s = Hoek-Brown constants for rock mass
m_i = Hoek-Brown constants for intact rock

Notes:
1. Above values based on Definition Engineering Phase 2 investigation results for intact core. Phase 1 results of $m_i = 10$ and $\sigma_c = 45$ MPa were superseded by this work.
2. RMR values have been adjusted and are equivalent to GSI.

Table 6.9
Rock Mass Strength Parameters for Rock Formation above Queenston Shale

*

Formation	RMR	Adjusted RMR*	Unconfined Compressive Strength (MPa)	m_i
Lockport Dolostone - Eramosa - Goat Island - Gasport	 69 69 72	 79 79 82	151	7.0 7.0 7.0
DeCew Dolostone	69	79	128	7.0
Rochester Shale	64	77	42	10.0
Irondequoit Limestone	72	82	106	7.0
Reynales Dolostone	67	77	95	7.0
Neahga Shale	56	66	14	10.0
Thorold Sandstone	78	83	163	15.0
Grimsby Sandstone Shale	70	75	155 33	10.0
Power Glen • Sandstone/Shale • Shale	 61 65	 66 70	 172 24	 10.0 10.0
Whirlpool Sandstone	85	87	216	15.0

* Adjusted RMR values are equivalent to GSI.

Table 6.10
Rock Mass Strength Parameters of Queenston Formation

Area	RMR	Unconfined Compressive Strength (MPa)	m_i
Inlet area	66	33	6.5
Tunnel alignment (general)			
Q10	55	33	6.5
Q8,9	65	33	6.5
Q6,7	71	33	6.5
Q4,5	67	46	14.5
Q1,2,3	82	46	14.5
Tunnel Alignment in area of St. Davids Gorge			
Q6	67	33	6.5
Q5	67	46	14.5
Q3,4	73	46	14.5
Q1,2	76	46	14.5
Outlet Area			
Q7-10	57	33	6.5
Q5-6	77	46	14.5

σ_c = uniaxial compressive strength
m,s = Hoek-Brown constants for rock mass
m_i = Hoek-Brown constants for intact rock

Notes:

1 Above values based on Definition Engineering Phase 2 investigation results for intact core. Phase 1 results of $m_i = 10$ and $\sigma_c = 45$ MPa were superseded by this work.

2 RMR values have been adjusted and are equivalent to GSI.

DBA

GBR-C

Table 4.1
Major Stratigraphic Units

Formation Name	Thickness (m)	Petrographic Description
Thorold	2 - 3.5	Sandstone, light grey to greenish-grey; medium-bedded to massive; irregular green shale partings occur throughout. The sandstone is orthoquartzitic. The texture of the formation is very fine-grained. Silt-size to fine-grained quartz particles are cemented with secondary silica.
Grimsby	12.5 - 12	Sandstone, to reddish-brown; thin- to thick-bedded, often calcareous with interbedded shale. The sandstone texture varies from fine to medium grained. A weathered zone frequently occurs at the top of the formation.
Power Glen	10 – 13	Shale with siltstone beds and stringers; dark grey to greyish-green shale and siltstone, and light grey limestone and dolomite. Quartz is the most abundant non-clay mineral. Clay minerals consist of illite, chlorite and small amounts of montmorillonite and mixed layered clays.
Whirlpool	4.9 - 8.5	Sandstone, light grey to white; medium-bedded and cross-bedded; fine- to medium-grained. The quartz grains are well rounded, and are well cemented by secondary silica. Feldspar grains altered to kaolinite are abundant. Occasional green shale inclusions and chloritic shale partings occur throughout.
Queenston	>300	Shale (technically classified as a silty mudstone or siltstone), reddish-brown with interbeds and nodules of green. The shale is silty and is cemented in many situations by dolomite and calcite. In many places it is massive to blocky, however some fissile sections occur. Scattered gypsum nodules occur throughout lower sections of the unit; quartz is a common constituent. Clay minerals are illite, chlorite, kaolinite, montmorillonite and other clays. Numerous small, high angle slickensides occur, often stained with iron oxide.
Subdivisions of the Queenston Formation		
Q10 Q9 Q8 Q7	45 - 50	Generally upwards fining sequence of reddish brown mudstones and silty mudstones with about 30% green muddy siltstone interbeds and blebs. Division Q10 commonly shows weathered surfaces within which numerous slickensided partings occur.
Q6 Q5	30 - 35	Reddish brown muddy siltstones with distinct bedding partings and marked bands of green siltstone and occasional bands and areas of distinctive gypsum nodules. Some zones contain slickensided compaction features. A zone of phosphate nodules occurs at base.
Q4	15 - 20	Reddish brown muddy siltstone with frequent green siltstone.

AOBA

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→ Queenston	>300	Shale (technically classified as a silty mudstone or siltstone), reddish-brown with interbeds and nodules of green. The shale is silty and is cemented in many situations by dolomite and calcite and is blocky in many places, however. some fissile sections occur. Scattered gypsum nodules occur throughout lower sections of the unit; quartz is a common constituent. Clay minerals are illite, chlorite, kaolinite, montmorillonite and other clays. Numerous small, high angle slickensides occur, often stained with iron oxide.
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Q4	15 - 20	Reddish brown muddy siltstone with frequent green siltstone.

3 The primary bedding planes will affect the excavation of the tunnel as many are clay rich and form weak discontinuity surfaces that, because of the shallow dip of the tunnels, may follow the excavation for considerable distances. Their locations can be estimated from Figure 4.1. However, because only two boreholes are available with geophysical trace information, detailed correlation of all the bedding planes within the Queenston Formation across the complete length of the tunnel alignment has not proved possible.

4.4.2 Faulting and Discontinuities

1 There are no known occurrences or reports of any major faulting within the Project area. Some near-surface, low angle thrusts with minor vertical displacement are known to occur and are probably related to stress relief associated with the gorge formation and the high horizontal residual stresses in the area. Some shearing of this type can be expected in the area of the St. Davids Gorge.

2 Regional joint measurements indicate the jointing to be high angle or vertical with the dominance of three major joint directions and a subordinate fourth set. In addition to these high angle sets, there is another set parallel to bedding. Based on strike directions the most prominent subvertical joint sets are

(a) a 005deg joint set which parallels the general trend of the Niagara River, particularly in the area of the tunnel outlet

(b) a 045deg joint set which approximately parallels the Niagara River, downstream from the Whirlpool

(c) a 085deg joint set which approximately parallels the Niagara Escarpment

(d) a 135deg joint set which approximately parallels the buried St. Davids Gorge.

3 Gypsum and calcite, and dolomite mineralization occur along joint sets of 085deg and 135deg orientations.

4 The joint sets vary in spacing, frequency and continuity depending on location and lithology. Vertical joints are generally widely spaced. The joint surfaces are generally rough and fresh to slightly weathered.

4.4.3 In Situ Stresses

1 High in situ stresses exist in the Project area bedrock. Measurements show that maximum horizontal stress in the Queenston Formation range from 10 to 24 MPA, with a maximum horizontal/vertical stress ratio varying from 3 to 5. Higher stress ratios are measured in the overlying rock units. In general, the orientations of the maximum horizontal stresses along the alignment of the diversion tunnel lie within the NE-SW quadrant. The orientations of the local stresses are influenced by the

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presence of major physiographic features, namely the buried St. Davids Gorge and the Niagara River Gorge.

4.4.4 Bedrock at St. Davids Gorge

1 The geological profile of and below the buried St. Davids Gorge, interpreted from boreholes and geophysical investigations, is shown in Figure 4.2.

2 For the purposes of this GBR, the width of the St. Davids Gorge is 800 m.

3 Figure 4.3 represents the baseline for the bottom of the St. Davids Gorge. This figure is based on available seismic (Niagara River Hydroelectric Development, Seismic Reflection Survey, Niagara Falls, Ontario, multiVIEW Geoservices Inc., January 1991) and borehole data from the St. Davids Gorge area. Elevations shown are equal to the interpreted seismic elevations minus an amount equal to a 20% error in depth calculations (as compared to 15% that was recommended in the seismic report). Elevations are given as ellipses consistent with the original seismic report. Borehole information is given as top of rock minus 5 m. The baseline represents spot elevations of the bottom of the gorge, defined as the top of bedrock (fractured or otherwise). Contouring of this data does not represent a baseline.

4 The bedrock (Queenston Formation) over the width of the St. Davids Gorge is slightly weathered and relatively more fractured to a depth of between 15 to 25 m below the bottom of the gorge. Below this depth, the rock is generally fresh and of excellent quality. No evidence of a major fault or other major discontinuities underlying the St. Davids Gorge has been found to date either by drilling or from geophysical surveys.

4.4.5 Geological Profile

1 The geological profile and the lithology as shown in Figures 4.1 and 4.2 of the GBR has been projected horizontally and is applicable to the alignment selected by the Contractor.

4.5 Hydrogeologic Setting

1 Groundwater conditions in the Project area are influenced by depth and lithology, and vary between the rock formations above the Queenston Formation, but are relatively consistent in the Queenston formation. The only known aquifers are the Lockport and DeCew (dolostone) Formations, whereas the remaining strata below the DeCew are generally considered to be aquitards. The groundwater below the DeCew Formation is highly corrosive.

presence of major physiographic features, namely the buried St. Davids Gorge and the Niagara River Gorge.

4.4.4 Bedrock at St. Davids Gorge

1 The geological profile of and below the buried St. Davids Gorge, interpreted from boreholes and geophysical investigations, is shown in Figure 4.2.

2 Figure 4.3 indicates the interpreted top of bedrock at the St. Davids gorge and is based on available seismic (Niagara River Hydroelectric Development, Seismic Reflection Survey, Niagara Falls, Ontario, multiVIEW Geoservices Inc., January 1991) and borehole data from the St. Davids Gorge area. Elevations shown are equal to the interpreted seismic elevations minus an amount equal to a 20% error in depth calculations (as compared to 15% that was recommended in the seismic report). Elevations are given as ellipses consistent with the original seismic report. Borehole information is given as top of rock minus 5 m.

3 The bedrock (Queenston Formation) over the width of the St. Davids Gorge is slightly weathered and relatively more fractured to a depth of between 15 to 25 m below the bottom of the gorge shown in Figure 4.3. * No evidence of a major fault or other major discontinuities underlying the St. Davids Gorge has been found to date either by drilling or from geophysical surveys.

4.4.5 Geological Profile

1 The geological profile and the lithology as shown in Figures 4.1 and 4.2 of the GR has been projected horizontally and is applicable to the alignment selected by the Contractor.

4.5 Hydrogeologic Setting

1 Groundwater conditions in the Project area are influenced by depth and lithology, and vary between the rock formations above the Queenston Formation, but are relatively consistent in the Queenston formation. The only known aquifers are the Lockport and DeCew (dolostone) Formations, whereas the remaining strata below the DeCew are generally considered to be aquitards. The groundwater below the DeCew Formation is highly corrosive.

4.6 Natural Gas

1 Natural gas has been encountered in some of the formations, particularly in the Rochester and Grimsby Formations, with some minor amounts of gas being encountered in other formations, including the Queenston.

Table 6.14
Stress Regimes for Design Purposes

Approxi-mate Station	Queenston Subunits	Horizontal Stress (respect to tunnel) (MPa)		Remarks
		Radial	Axial	
0+000 to 1+700	Q2 to Q10	15	23	tunnel is nearly parallel to minimum stress, transformed stresses quoted
1+700 to 3+800	Q2 to Q3	22	16	orientation of stress field uncertain and tunnel curves in this section; maximum values quoted
3+800 to 7+800	Q4 to Q5	19	17	stress orientation is known and consistent with regional stress field; transformed values quoted
7+600 to 10+000	Q6 to Q10	17	11	stress orientation uncertain and tunnel curves, maximum values quoted

(b) The modeling shall include

(i) analyses for both the deepest and shallowest tunnel sections in the Queenston formation

(ii) both unwatered and operational tunnel conditions.

(c) The following parameters shall be included in the analyses:

(i) appropriate rockmass and bedding plane strength and deformability values as given in the GR

(ii) The horizontal effective stress values given in Section 6.6 of the GR shall be used as input into an analysis that considers the relative stiffnesses of the various rock formations. The input in situ stresses shall then be reduced appropriately until no overall plastification of the rock mass occurs. These modified values for horizontal stress will be used in subsequent analyses.

For the Queenston Formation the following horizontal effective stresses are to be considered as input into the design.

Approxi-mate Station	**Queenston Subunits**	**Horizontal Effective Stress (respect to tunnel) (MPa)**		**Remarks**
		Radial	**Axial**	
0+000 to 1+700	Q2 to Q10	15	23	tunnel is nearly parallel to maximum stress, transformed stresses quoted
1+700 to 3+800	Q2 to Q3	22	16	orientation of stress field uncertain and tunnel curves in this section; maximum values quoted
3+800 to 7+800	Q4 to Q5	19	17	stress orientation is known and consistent with regional stress field; transformed values quoted
7+600 to 10+000	Q6 to Q10	17	11	stress orientation uncertain and tunnel curves, maximum values quoted

(iii) Hoek-Brown residual rock mass strength parameters: $m_r = 1.0$, $s_r = 0.001$ (or equivalent)

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

140. OPG has applied for approval of total in-service additions for the Niagara Tunnel Project of \$1,439.2M in 2013 plus an additional \$13.4M during the test period for a total of \$1,452.6M.[99]

141. As discussed under Issue 4.4 the proposed in-service additions included in rate base should be reduced by \$407.4M.

Nuclear

4.7 Oral Hearing: Are the proposed nuclear capital expenditures and/or financial commitments reasonable?

142. AMPCO supports Board Staff's submissions that given a history of overstating its capital expenditure requirements, the proposed amounts less 10% would be a more realistic level of forecasted expenditure.

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

143. AMPCO supports Board Staff's submissions that nuclear rate base should be adjusted to reflect a reduction of \$18M and \$17M in in-service amounts for 2014 and 2015, respectively, which is roughly 12% of proposed additions.

5. PRODUCTION FORECASTS

Regulated Hydroelectric

5.1 Secondary - Is the proposed regulated hydroelectric production forecast appropriate?

144. OPG is seeking approval of a test period hydroelectric forecast of 32.4 TWh in 2014 and 33.5 TWh in 2015 for a total test period forecast of 65.9 TWh.

145. AMPCO accepts OPG's proposed hydroelectric production forecast over the test period.

Hydroelectric Production Forecast	**2014**	**2015**
Previous Regulated Facilities	20.1	21.0
Newly Regulated Facilities	12.4	12.5
TOTAL	**32.4**	**33.5**

Nuclear

5.5 Primary - Is the proposed nuclear production forecast appropriate?

[99] Ex. L-4.5-1 Staff-025

146. AMPCO supports board staff analysis and conclusions regarding Darlington's production forecast and the proposed increase in outage days for the VBO/SCO and critical path work. Specifically, no evidence regarding the emergency service water piping and emergency coolant injection valve replacement "lifecycle management" critical path work was submitted in the application, although OPG witnesses described the work as significant. AMPCO supports Board Staff's position to disallow the 1.32 TWh reduction regarding the increase in outage days for VBO/SCO and critical work since no supporting evidence was provided.

147. AMPCO has further submissions on the 0.28 TWh proposed reduction relating to lake water temperatures. AMPCO believes this reduction should not be included in the nuclear production forecast for the prescribed facilities. This was discussed at the hearing when an OPG witness stated, "…we don't necessarily have the end-of-the-year results for 2013. So the 2014 to 2016 business plan is already -- and the generation plan is being worked on based on 2012 actual."[100] Given that the actual reduction due to water temperature of 0.26 TWh in 2013 is now available, rather than using the reduction of 0.4 TWh based on 2012 actual, AMPCO submits based on 2013 actual an increase of 0.14 TWh in 2014 and 0.14 TWh in 2015 should be applied. Furthermore the OPG witness also stated losses may increase because, "we may see very warm temperature this summer".[101] AMPCO notes this was not the case this summer.

148. AMPCO therefore submits that the Board should increase the production forecast by 1.6 TWh (1.32 TWh supporting board staff and 0.23 TWh for water temperature) over the test period to a total of 96.2 TWh.

6. OPERATING COSTS

Regulated Hydroelectric

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

149. AMPCO supports SEC's submissions that OPG's proposed hydroelectric amounts for the test period are not appropriate given that OPG has historically underspent over the 2010 to 2013 period (by 4.3%) based on actuals compared to budget and OPG is on track to underspend in 2014.

150. Accordingly, AMPCO support's SEC's proposed 4.3% reduction to hydroelectric Base & Project OM&A costs in the test period which is a reduction of $9.7M in 2014 and $10M in 2015.[102]

[100] Ex-2013-0321 Oral Hearing Volume 6 Transcript Page 81 Line 27
[101] EB. 2013-0321 Oral Hearing Volume 6 Transcript Page 82 Line 14
[102] SEC Submissions, Issue 6.1

Nuclear

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?

151. OPG proposes Fuel Oil costs of $4.1M in 2014 and $4.2M in 2015. The 2010-2012 historical average (actual) is $2.5M. The 2013 actual was $2.4M. AMPCO submits based on the historical average and 2013 actual, setting 2014 and 2015 to 2013 actual is more reasonable. This results in a decrease in nuclear fuel costs of $3.5M over the test period.[103]

Table 1

Nuclear Fuel Costs ($M)

Line No.	Description	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2013 Budget	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(F)	(g)
	Uranium:							
1	Darlington NGS	100.6	117.8	119.9	86.0	119.7	124.8	111.8
2	Pickering NGS	71.5	82.5	90.3	107.3	96.2	95.5	95.2
3	Total Fuel Bundle Cost	172.1	200.3	210.2	193.3	215.9	220.3	207.1
4	Total Fuel Bundle Cost[1] ($/MWh)	3.76	4.12	4.29	4.33	4.50	4.43	4.31
5	Used Fuel Storage & Disposal[2]	23.5	26.0	51.9	49.0	52.7	56.1	56.7
6	Fuel Oil	2.2	2.5	2.9	2.4	4.0	4.1	4.2
7	Total Nuclear Fuel Costs	197.8	228.9	265.1	244.7	272.6	280.5	267.9

Notes:
1 Line 3 divided by Nuclear production forecast/actual from Ex. E2-1-1 Table 1. 2013 Actual is 44.7 TWh
2 Used Fuel Storage & Disposal is discussed in Ex. C2-1-1.

6.6 Primary - Are the test period expenditures related to continued operations for Pickering Units 5 to 8 appropriate?

152. OPG has filed an updated business case for the Pickering Continued Operation 2012. OPG reports that the system benefit of Pickering Continued Operation is $520M. AMPCO believes this Net Present Value (NPV) to be highly optimistic.

[103] Ex L 6.5 SEC-101

153. AMPCO notes that the economic analysis performed as part of the updated business plan did not consider the sunk costs between 2009 to 2012. The 2012 Present Value$ of the removed continued operation costs and production impact in 2009 to 2012 was a $140M NPV ($2012)[104]. Therefore, Pickering Continued Operation NPV is $380M.

154. Furthermore, AMPCO notes OPG used a higher demand forecast scenario compared to the Long Term Energy Plan, (LTEP) therefore enhancing the NPV benefits.

Ontario Demand Forecast (TWh) Underlying OPG's Pickering Continued Ops Evaluation Provided in Ex. F2-2-3, Attachment 1									
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Base	141.9	142.2	142.6	143.0	144.0	144.2	145.6	147.2	148.4
Low	141.2	140.8	140.4	140.1	140.4	139.8	140.5	141.2	141.7
High	143.4	145.1	147.0	149.0	151.6	153.4	156.5	159.8	162.9

2013 LTEP: Annual Forecast Demand, Net of Conservation (TWh)

Year	2013 LTEP Annual Demand Forecast (TWh)
2014	140.8
2015	140.2
2016	140.4
2017	139.6
2018	139.9
2019	141.1
2020	141.5

Ex. 2013-0321 Exhibit L GEC Interrogatory #007

155. The LTEP demand forecast is almost equal to OPG's Pickering Continued Operations Evaluation under "Low" Ontario demand forecast scenario.

156. Based on OPG's sensitivity analysis, the NPV is most sensitive to the expected value of electricity on the system. According to OPG, "In a low value regime, the Continued Operation of the Pickering units could result in an <u>increased system **cost** of $410 PV</u> over the Continued Operation period. A low value regime could result if there is such a <u>low demand for electricity</u> that much of the generation currently on the system (not just Pickering) would be surplus to needs."[105]

157. Therefore under a low Ontario demand scenario, and in accordance with the LTEP forecast, the Pickering Continued Operations NPV proves to be much lower than $380M[106]. Based on

[104] Ex. 2013-0321 Exhibit L Tab 6.6 AMPCO Interrogatory #055
[105] Ex. 2013-0321 F2-2-3 Attachment 1 Page 10
[106] $520M minus sunk costs of $140; therefore AMPCO considers an NPV of only $380M.

OPG's sensitivity analysis, AMPCO estimates the NPV to decrease to -$85M under a low demand forecast.[107]

158. Lastly, the expected value is also sensitive to the Continued Operations life achieved. AMPCO notes one of the highest risks regarding the success of Pickering Continued Operations is the pressure tube to Calandria tube contact.[108] This contact leads to the formation of a potential defect; impacting continued operations by additional planned outage day are required to inspect and disposition such defects. According to OPG "appropriate activities were built into the Continued Operations planning scenario to mitigate those risks".[109]

159. However, "In the 2013 Unit 5 outage, unexpected reductions in pressure tube to calandria tube gaps were noted. …Monitoring and maintaining the gap between calandria and pressure tubes is critical since there is the potential for blistering if the pressure tube and calandria tube touch which can result in failure of the pressure tube".[110]

160. It is clear to AMPCO that one of OPG's highest risks regarding the success of the Continued Operation of Pickering has been impacted in 2013. OPG has already taken action by additional planned outage days in the generation plan, impacting the continued operation. OPG states, "The 2014 mid-cycle planned outage is therefore required to measure the gap and to perform maintenance as required."[111]

161. It is important also to note, OPG predicted a high probability of success of achieving 2 years without encountering the Pressure tube to calandria tube contact. However, during the unit 5 outage in 2013, this estimate proved too optimistic.

162. Given the unexpected reduction in pressure tube to calandria tube gap discovered in 2013, AMPCO believes the probability of achieving 247,000 EFPH for unit 5 is unlikely. OPG states, "if 2 fewer years of continued operation life were achieved, there would be a reduction in the expected value of approximately $435M."[112] Based on OPG's sensitivity analysis, AMPCO estimates under the unit 5 pressure tube to calandria tube issue, the NPV is expected to decrease by 72.5M.[113]

163. AMPCO believes that the NPV of Pickering continued Operations is not a benefit but rather a cost. Therefore, AMPCO does not support any Pickering Continued Operations expenditures in the test period.

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[107] Under low value scenario (low demand and low gas prices) the NPV may decrease by $930M (a benefit of +$520M to a cost of -$410). AMPCO assumes a reduction of $465M for a low demand scenario only.
[108] Ex. 2013-0321 F2-2-3 Attachment 1 Page 14
[109] Ex. 2013-0321 F2-2-3 Attachment 1 Page 4
[110] Ex. 2013-0321 N1 Page 14 Line 2 and line 5
[111] Ex. 2013-0321 N1 Page 14 Line 3
[112] Ex. 2013-0321 F2-2-3 Attachment 1 Page 10
[113] AMPCO assumes given the pressure to calandria gap issue discovered, unit 5 is assumed to achieve 2 fewer years. Given a $435M NPV reduction if all six united achieve 2 fewer years of continued Operations, AMPCO assumes a sixth of $435M NPV reduction would be expected is one unit achieves 2 fewer years than expected.

6.12 Secondary - Are the depreciation studies and associated proposed changes to depreciation expense appropriate?

164. AMPCO supports Board Staff's and SEC's submissions that the useful life of the Niagara Tunnel should be more than the 90 year useful life proposed by OPG.

165. AMPCO supports SEC's submission that 150 years is a more appropriate useful life given that the original two tunnels completed in 1955 are expected to be in-service until 2074, i.e. for 120 years and the Niagara Tunnel was be constructed with superior materials and more modern technology.

7. OTHER REVENUES

Regulated Hydroelectric

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

166. Other revenues earned by OPG's regulated and newly regulated hydroelectric facilities are revenues associated with ancillary services, segregated mode of operation ("SMO") and water transactions ("WT"). Revenues less costs are applied as an offset to OPG's revenue requirement.

167. The table below reflects OPG's forecast Other Revenues for regulated hydroelectric for the test period of $56.7M in 2014 and $57.6 for 2015, for a total test period amount of $114.3M.

Other Revenues Regulated Hydroelectric $M	**2010 Actual**	**2011 Actual**	**2012 Actual**	**2013 Budget**	**2013 Actual**	**2014**	**2015**
Previously Regulated Hydroelectric	30.8	31.5	21.6	31.8	48.7	19.9	20.2
N1 Impact Statement[114]						14.2	14.3
Sub-total						34.1	34.5
Newly Regulated Hydroelectric	26.4	26.1	25.9	22.2	35.7	22.7	23.1
TOTAL	**57.2**	**57.6**	**47.5**	**54.0**	**84.4**	**56.8**	**57.6**

168. AMPCO has reviewed the methodology used by OPG to forecast revenues related to Ancillary SMO and WT for the test period and makes the following submissions:

Ancillary Services

[114] N1-1-1 Page 17 Table 1

169. In EB-2007-0905, to forecast Ancillary Services, OPG based its forecast on actual or forecast contract revenues achieved depending on the type contract, for a representative period (one year), and then an escalation factor representing inflation was added. [115] For subsequent years, a factor representing inflation per year was applied.

170. In the current application OPG has applied an escalation factor representing inflation (2%) to the 2013 budget amount ($17.8M) to determine the forecast for 2014 ($18.2M). For 2015 an escalation factor representing inflation is added to the 2014 forecast, consistent with the methodology in EB-2007-0905 resulting in a forecast of $18.5M for 2015. Ancillary Services revenues for the test period equal $36.7M

171. As part of the interrogatory process, 2013 actuals for Ancillary Services revenues was provided, i.e. $37.1M.[116] AMPCO submits an inflation factor added to 2013 actuals to forecast 2014 revenues would be more representative of expected revenues in 2014. On this basis AMPCO submits the Board should approve a revised forecast of $37.8M for 2014[117] based on 2013 actuals. For 2015, an inflation factor added to the 2014 forecast would result in a 2015 forecast of $38.6M.[118] The total for the test period is $76.4M, an increase of $11.3M for the test period.

172. AMPCO notes differences between forecast and actual revenues associated with ancillary services are recorded in the Ancillary Service Net Revenue Variance Account-Hydroelectric Sub-Account.

Segregated Mode of Operation (SMO)

173. OPG proposes to use the original revenue offset mechanism established by the Board in EB-2009-0905 based on the average net revenues of the last three years for the 2014 and 2015 test period. OPG has based its calculation on the three historical years 2010, 2011 and 2012.

174. As part of the interrogatory process, 2013 actuals were provided. AMPCO submits the net revenues from the last three years 2011, 2012 and 2013 should be used to calculate the forecast for 2014 and 2015. The Table below in Appendix C prepared by AMPCO shows that this would result in an increase in SMO revenues of $3.3M over the test period.

Water Transactions

175. The OEB's decisions in EB-2007-0905 and EB-2010-0008 specified that the average of the previous three historical years of actual net water revenues be applied as an offset against OPG's revenue requirement.

176. OPG proposes to change how it calculates the revenue offset to account for the significant decrease in water transactions between the New York Power Authority and OPG due to the Niagara Tunnel coming into service. The start of operations for the Niagara Tunnel represents a structural change to the WT market. WT revenues in the test period are

[115] EB-2007-0905 G1-1-1 Pages 3-5
[116] L-1.0-1 Staff 002
[117]2014 forecast = 2013 actual 2% inflation= $37.1 x 2%=$37.8M
[118] 2015 forecast = 2014 forecast 2% inflation = $38.6M

forecast to decrease by approximately 65 percent. Therefore, OPG proposes to reduce the average revenue forecast by 65 per cent for 2014 and 2015 to $1.7M per year, based on 2010-2012 actuals. AMPCO takes no issue with OPG's structural change in how it calculates WT revenues and accepts OPG's 2014 and 2015 forecast.

177. Applying the same methodology to calculate other revenues for newly regulated hydroelectric facilities associated with Ancillary Services and SMO, the increase over the test period is $27.8M as shown in the Table in Appendix C.

Issue 7.1

AMPCO Appendix C

Issue 7.1 **Other Revenues Hydroelectric: Test Period Revenues Ancillary Services, Segregated Mode of Operation & Water Transactions**

Ref: LPMA #15

(Note: Ancillary Services net Revenue Variance Account, HE & Nuclear subaccounts)

	OPG Test Period Methodology	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2014 Plan	2015 Plan	Test Period Methodology Updated	2013 Actual	2014 Plan	2015 Plan	Test Period Variance
HE Previous												
Ancillary Services	2013 Budget + inflation; 2014 Plan + 2 % inflation	26.2	22.2	20.8	17.8	18.2	18.5	2013 Actual + inflation; 2014 Plan + 2% inflation	37.1	**37.8**	**38.6**	11.3
Impact N1						14.2	14.3					
Sub-total						*32.4*	*32.8*					
SMO (RH Saunders)	average 3 prior years specific to each facility, 2010-2012 Actuals; 2015=2014	-0.9	1.7	-0.8	1.6	0.0	0.0	average 3 prior years, 2011-2013 Actuals; 2015=2014	4.1	**1.7**	**1.7**	3.3
WT	65% reduction of average net revenues 2010-2012 Actuals; 2015=2014	5.5	7.5	1.6	6.0	1.7	1.7	65% reduction of average net revenues, 2011-2013 Actuals; 2015=2014	1.0	**1.2**	**1.2**	-1.0
HIM Rev Adjustment					6.5				6.5			
Sub-Total		30.8	31.4	21.6	31.9	34.1	34.5		48.7	**40.7**	**41.4**	13.6
HE New												
Ancillary Services	2013 Budget + inflation; 2014 Plan + 2% inflation	26.4	26.1	25.9	22.2	22.7	23.1	2013 Actual + inflation; 2014 Plan + 2% inflation	35.7	**36.4**	**37.1**	27.8
SMO (Chats Falls)		0.0	0.0	0.0	0.0	0.0	0.0		0.0	**0.0**	**0.0**	0.0
Sub-Total		26.4	26.1	25.9	22.2	22.7	23.1		35.7	**36.4**	**37.1**	27.8
TOTAL		57.2	57.5	47.5	54.1	**56.8**	**57.6**		84.4	**77.1**	**78.6**	**41.3**

Nuclear

7.2 Secondary - Are the forecasts of nuclear business non-energy revenues appropriate?

178. OPG's forecast of nuclear non-energy revenues (net of related costs) for the test period is $33.1M and $30.5M in 2014 and 2015, respectively.[119] Nuclear- non- energy revenues (less costs) are treated as an offset to OPG's revenue requirement.

Table 33

$million	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2013 Actual	2014 Plan	2015 Plan
Heavy Water Sales	26.7	80.9	55.1	18.9	34.8	26.3	20.4
Isotope Sales	10.1	4.8	11.5	11.1	7.0	11.6	11.9
Inspection & Maintenance Services	36.0	7.1	4.1	0.0	0.0	0.0	0.0
Helium 3 Sales	0.0	0.0	0.0	0.0	0.0	0.0	4.0
Costs	-31.5	-10.7	-8.7	-7.2	-5.9	-6.8	-7.8
Net NGD Contribution	41.3	82.1	62.0	22.8	35.9	31.1	28.5
Ancillary Services	2.6	2.4	1.8	1.9	1.7	1.9	1.9
Third Party Training	0.8	0.6	0.1	0.1	0.0	0.1	0.1
Total	**44.7**	**85.1**	**63.9**	**24.8**	**37.6**	**33.1**	**30.5**

Source: Exh G2-1-1 Table 1, Exh L-1-Staff-2 Table 35

179. Nuclear-non-energy revenues are related to Heavy Water Sales, Heavy Water Services, Isotope Sales, Inspection & Maintenance Services, Helium 3 Sales, Ancillary Services and Third Party Training.

180. OPG states that the amounts proposed are a decrease from the previous test period and reflect a return to a more normal level of revenues for heavy water and sales and processing. OPG submits these forecasts are appropriate and should be accepted by the Board.[120]

181. AMPCO notes OPG's actual historical average Heavy Water Sales & Processing revenue for the period 2010-2013 is 227.5% higher than budget. In 2013, the actual for Heavy Water Sales & Processing revenue was 184% more than budget (i.e. $34.8M vs. $18.9M). The other revenue amounts for Isotope Sales, Inspection & Maintenance Services, Helium 3 Sales, Ancillary Services and Third Party Training have been relatively stable over the 2010 to 2013 period and any variances have been adequately explained, whereas Heavy Water Sales & Processing revenue actuals have been consistently higher than budget for the years 2010 to 2013 as shown in the Table below.[121]

Nuclear Non-Energy Revenues $M

Line No.	Description	Note or Reference	2010 BA	2010 Actual	2010 Variance	2011 BA	2011 Actual	2011 Variance	2012 BA	2012 Actual	2012 Variance	2013 BA	2013 Actual	2013 Variance	4-year Average	2014 Plan	2015 Plan
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	**Heavy Water Sales**		23.1	26.7	115.6%	22.9	80.9	253.3%	21.9	55.1	151.6%	18.9	34.8	84.1%	127.5%	26.3	20.4
2	**AMPCO Proposed Heavy Water Sales**	**Note 1**														59.8	46.4

Notes
1 The four year average was applied to OPG's Proposed Heavy Water Sales

[119] G2-1-1 Table 1
[120] OPG AIC Page 122
[121] G2-1-2 Table 1 & L-7.2-17-SEC-124

182. AMPCO submits OPG's 2014 and 2015 forecasts for Heavy Water Sales and processing are too low based on historical actuals.

183. AMPCO submits the Board should consider the 4 year historical average as normal for the test period for Heavy Water Sales and asks that the forecast for 2014 and 2015 be increased to $59.8 and $46.4M, respectively. This represents a total test period amount of $106.2M, an increase of $59.5M over the $46.7M in Heavy Water Sales revenues proposed by OPG.

184. The Table below shows the resulting impact on Total Nuclear Non-Energy Revenues for the Test Period.

Total Nuclear Non-Energy Revenues $M	**2014**	**2015**	**Total**
OPG Proposed	$33.1	$30.5	$63.6
AMPCO Proposed Adjustment to Heavy Water Sales	$33.5	$26.0	$59.5
TOTAL	**$66.6**	**$56.5**	**$123.1**

Bruce Nuclear Generating Station

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?

185. AMPCO submits that if the Board accepts AMPCO's proposal under Issues 8.1 and 8.2, the Bruce Lease revenues should be adjusted accordingly.

8**. NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING LIABILITIES**

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?

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

Introduction

186. OPG is seeking recovery of $422.6M in 2014 and $424.9M in 2015 ($847.4M over the Test Period) related to liabilities for nuclear waste management and decommissioning for both the Prescribed and Bruce Facilities.[122]

187. OPG has two segregated funds related to nuclear liabilities: the Decommissioning Fund and the Used Fuel Fund.

188. After reviewing OPG's 2013 financial statement, AMPCO determined that the Decommissioning Fund has excess earnings (Over-funded) as of December 31, 2013 of

[122] Ex. C2-1-1, Table 1

$624M ($64M in 2012 & $560M in 2013). OPG does not note the excess earnings in their pre-filed evidence. OPG's revenue requirement for its nuclear liabilities does not take into account these excess funds.

189. In OPG's financial statement the excess funding is shown as "Due to Province". The Decommissioning Fund had excess earnings for the first time in 2012 and, therefore, this is the first time that the Board has had before it the issue of how these excess funds are to be treated.

190. "Over-funded" means the value of the Decommissioning Fund is higher than the balance needed to complete all future obligations.[123]

191. OPG indicated both at the Technical Conference and in Cross-Examination during the hearing itself that the overfunding was due to market performance. OPG took the position that it is <u>required</u> to limit the earnings recognized from the decommissioning segregated fund to 5.15 percent (the "Target Amount").[124]

192. The Target Amount for the Decommissioning Fund in 2013 was $294M[125]. This is the amount OPG reports that this fund earned rather than the $854M it actually earned.

193. At the Technical Conference OPG indicated that it treated earnings from the Decommissioning Fund in this way because of its accounting policy. During the hearing itself OPG indicated that it was required to treat the fund's earnings in this way by the Ontario Nuclear Funds Agreement ("ONFA").[126]

194. In answer to Interrogatory J11.8 OPG indicated that sections 2.2, 4.7.3 and 8.2 of ONFA are the sections which require OPG to account for these funds in this way. AMPCO disagrees that these sections of ONFA require OPG to treat these funds in this way.

195. AMPCO submits that if the full amount earned or budgeted to be earned by these accounts were reported and accounted for fully that OPG's revenue requirement for the test period would be approximately $28.5M less than requested. OPG disagrees with AMPCO on both presumptions; the requirements of ONFA and the amount of the revenue requirement.

Background

196. On April 1, 1999, the obligation for nuclear waste management and decommissioning was transferred from the former Ontario Hydro to OPG. The responsibility for funding these liabilities is described in ONFA between the Province of Ontario and OPG.

197. ONFA requires OPG to establish two segregated funds; the Decommissioning Fund, and the Used Fuel Fund. The Decommissioning Fund was established to fund the future costs of nuclear fixed asset removal, long-term Low & intermediate Level Waste (L&ILW)

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[123] Technical Conference, April 23, Cross-Examination by AMPCO, Page 157, lines 2-4
[124] Technical Conference, April 23, Cross-Examination by AMPCO, Page 156, lines 12-25
[125] In 2013 the Decommissioning Fund earned a return on investment of $854M (APPENDIX D Table 4a Line 2 Column i). OPG recorded $294M as earning and the remaining $560M as Due to Province upon termination (AMPCO Appendix D Table 4a Line 4 Column i). In 2012, an amount of $64M Due to Province upon termination was recorded.
[126] Transcript, Volume 11, Cross-Examination by counsel for AMPCO, Pages 103-104, lines 14-7

management and a portion of used fuel storage costs after station End-of-Life. The Used Fuel Fund was established to fund future costs of long-term nuclear used fuel waste management.[127]

Decommissioning Fund

198. For the decommissioning fund, the rate of return target is 5.15 per cent per annum as indicated above. As defined in ONFA, this consists of a 3.25 per cent real rate of return plus an inflation adjustment. As per the 2012 Reference Plan, this inflation adjustment is 1.9 per cent per annum.[128] This target rate of return is NOT guaranteed by the Province. OPG and Ratepayers are required to fund any shortfall between the achieved and target rate of return through additional contributions as part of a renewed reference plan assessment.[129]

199. When the Decommissioning Fund is underfunded, the earnings on the Decommissioning Fund reflect actual fund returns based on market performance.[130]

200. AMPCO understands upon termination of the ONFA, the Province has a right to any excess in the Decommissioning Fund; the excess between the fair market value (asset) of the Decommissioning Fund and the estimated completion cost (liability), as per the most recent approved ONFA Reference Plan.[131]

201. AMPCO understands when the Decommissioning Fund is overfunded OPG's practice and "Accounting Policy"[132] limit the earnings it recognizes in its consolidated financial statement by recording the excess as payable to the province. As the province is entitled to the excess upon termination of ONFA, the Due to Province represents the amount the fund would pay to the province if the ONFA were to be terminated based on the consolidated balance sheet date. Consequently, the balance of the Decommissioning Fund is equal to the cost estimate of the liability based on the most recent approved ONFA reference plan.[133]

202. The Decommissioning Fund balance as of December 31, 2013 was $6,591.0 million and the liability was $5,967 million. The Decommissioning Fund balance was overfunded by $624 million. This amount was recorded as payable to the province or "Due to Province".[134]

203. As ONFA is in effect and presently not terminated, AMPCO understands the overfunded amount is treated as a Credit with the Province. This Credit may be used in the event the Decommissioning Fund earns less than its target rate of return, as had occurred in 2007 and 2008 during low market performance (see paragraphs 209 & 210). The Credit may also be used when the ONFA Reference Plan decommissioning liability estimate increases, as had

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[127] OPG Consolidated Financial Statements December 31, 2013, Page 35
[128] Technical Conference Volume 2, page 161
[129] Ex-2010-0008 C2-T1-S1, Page 7 Line 18
[130] OPG Consolidated Financial Statements December 31, 2013, Page 36
[131] ONFA section 8.2
[132] Technical Conference Volume 2, page 157, line 7
[133] OPG Consolidated Financial Statements December 31, 2013, Page 36 (attached in Appendix D)
[134] Appendix D Table 4 line 1 line 2 line 3 column i

also occurred previously when the 2006 ONFA Reference Plan was implemented[135] (see paragraphs 207 & 208).

204. AMPCO believes the amount of $624M should be accounted for in the Board's Approved 2007 Nuclear Liability methodology.

205. AMPCO submits that the $624M be accounted for and treated in accordance with the Board's EB-2007-0905 Nuclear Liability Approved Methodology. AMPCO notes that OPG has the right and access to the amounts due to the Province when needed; in the event that the Decommissioning Fund earns less than its target rate of return or in the event that a new ONFA Reference Plan is approved with a higher estimated decommissioning liability.[136] Historically OPG encountered these two events.

206. AMPCO prepared Appendix C Table 4, to illustrate this situation. A version of this table was also included in AMPCO Compendium Panel 7.[137] Information was compiled from OPG's publicly available consolidated financial statements.

207. On December 31, 2005, the Decommissioning Fund was in an overfunded position; the Decommissioning Fund Balance was greater than the cost estimate of the liability based on the most recent approved ONFA Reference Plan, the 1999 Reference Plan[138]. Therefore, OPG limited the earnings it recognized in its financial statements by recording a payable to the Province of any excess. This represented the amount the fund would pay to the Province if ONFA were to be terminated as of the consolidated balance sheet date. The Decommissioning Funds asset value was $4,583.0 million as at December 31, 2005 (Table 4 Line 1 Column a), with an excess of $484.0M which was recorded as Due to Province (Table 4 Line 2 Column a).

208. In 2006 the Province approved a new ONFA 2006 Reference Plan. This increased the decommissioning liability to reflect a more accurate estimate. As of December 31, 2006, the Decommissioning Fund had earned $592M (Table 4a Line 2 Column b). With the new nuclear liability estimate, however, the Decommissioning Fund was now underfunded by $190M and so OPG recorded $190M (Table 4a Line 5 Column b) from the Due to Province Credits to balance the liability. By the end of December 31, 2006, the Decommissioning fund was still in an overfunded position by $294M. This amount was recorded as Due to Province (Table 4 line 2 Column b); the amount the fund would pay the Province upon termination as of that date.

209. In 2007, the Decommissioning Fund earned only $5M (Table 4a Line 2 Column C); a lower earning than the Target rate of return. OPG accessed and supplemented the earning by decreasing the Due to Province (Credit) by $291M (Table 4a Line 5 Column c), an amount to match the target rate of return. By the end of December 31, 2007, the Decommissioning fund was still in an overfunded position with $3M (Table 4 Line 2 Column c) recorded as Due to Province (Credit).

[135] OPG Consolidated Financial Statements December 31, 2013, Page 36 (attached in Appendix D)
[136] OPG Consolidated Financial Statements December 31, 2013, Page 36 (attached in Appendix D)
[137] KT11.3
[138] OPG 2005 financial results page 29 (attached in Appendix D)

210. In 2008, the weak performance of the global financial markets had negatively affected the market value of the investments held in the Decommissioning Fund. The fund had lost $681M (Table 4a Line 2 Column d). OPG accessed and recorded the remaining $3M (Table 4 Line 2 Column c) from available credit (Due to Province) to the Decommissioning Fund Balance (Table 4a Line 5 Column d). The Decommissioning fund was in an underfunded position as of March 31, 2008, with no Due to Province Credit available (Table 4 Line 2 Column d).[139]

211. To further support AMPCO position, in OPG's 2008 financial statement a negative expense amount of $3M in 2008 and $291M in 2007 was recorded. A negative expense in accounting is a credit; this shows OPG accessing these Due to Province credits.[140]

212. Lastly, according to an OPG witness, "It effectively forms a <u>cushion</u> against any future change".[141]

213. As can be seen, OPG has the right to and does access the Decommissioning Fund overfunded amount:

OPG argues

"Notwithstanding OPG's objection to the feasibility of eliminating the Due to Province amount from the segregated fund balances, doing so would increase OPG's revenue requirement because eliminating the Due to Province Amount would increase each segregated fund balance, which would reduce unfunded nuclear liabilities. As per the Board's nuclear liability cost recovery methodology for prescribed facilities this would have the effect of decreasing the rate base amount that attracts a lower rate of return … and increasing the rate base amount that attracts a higher rate of return…. A hypothetical illustrative calculation showing how the revenue requirement would increase by eliminating the Due to Province amount is reflected in Ex. J13.6." [142]

214. AMPCO disagrees with this statement. The hypothetical illustrative calculation is misleading. OPGs calculation reflects just a part of the Ex-2007-0905 approved methodology, the Prescribed facilities part, and fails to include the Bruce facilities.

In Undertaking J13.6 OPG states,

"For simplicity, the 2013 earnings at line 15 have been increased from $326.5M to $1,181.9M by applying an allocation ratio of 53% for the prescribed facilities (suggested by Board Staff at TR, Vol. 13, Page 78) to the Due to the Province for the combined Used

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[139] By March 31, 2008 the Decommissioning Fund was in an Underfunded Position for the first time as far back as to December 31, 2003 relating to the 1999 Reference Plan. (Attached in Appendix D)
[140] OPG 2008 Year End Report Page 57 (Attached in Appendix D)
[141] Technical Conference Volume 2 Page 157 Line 14. This "Cushion" was used in 2006, 2007, and 2008 as discussed.
[142] Ex 2013-0321 OPG AIC page 128 line 15

Fuel Fund and Decommissioning Fund amount of $1,614M reflected in OPG's audited consolidated financial statements as at December 31, 2013;[143]

215. OPG allocated 53 per cent of the Due to Province amount of $1,614M; however, OPG fails to consider the remaining 47 per cent for the Bruce facilities in the calculation. OPG is responsible for the decommissioning and waste management of the Bruce facilities. In J13.6 Hypothetical C2-T1-S1 Table 1 line 18, is the Total Revenue Requirement Impact including the Bruce facilities Line 18 cannot be calculated without the full calculation of the Bruce facilities. OPG only calculated lines 1 to 8, ignored line 9 to 17 and then updates line 18. This is an incomplete calculation and is not the full representation of the EB-2007-0905 board approved Nuclear Liabilities methodology. This calculation is misleading.

216. AMPCO has undertaken to complete the analysis to provide a full picture regarding the treatment of the Due to Province and its impact on OPG Nuclear Liabilities revenue requirement (Prescribed and Bruce Facilities). AMPCO has attached its revised calculation at Table 1, Table 1a, Table 2, and Table 3 by allocating the $624M overfunded amount to both the Prescribed and Bruce Facilities.[144]

217. For the test years, OPG proposes to maintain the revenue requirement treatment for nuclear liabilities approved by the Board in EB-2007-0905 for Pickering, Darlington and the Bruce facilities. The revenue requirement treatment approved for the Bruce facilities in EB-2007-0905 differs from that approved for Pickering and Darlington.

Under the methodology applicable to the prescribed nuclear facilities,

- The depreciation expense resulting from the amortization of the Asset Retirement Cost (ARC) (liability) over the life of the nuclear facilities.
- The variable incremental used fuel costs and variable incremental low and intermediate level waste ("L&ILW") costs are determined in accordance with GAAP.
- The return be limited to the average Accretion Rate on a portion of the rate base equal to the lesser of; i) the unfunded nuclear liabilities, or ii) the unamortized ARC. OPG is able to earn a return on the excess of the unamortized ARC over the unfunded nuclear liability at the Weighted Average Cost of Capital (WACC) for the Prescribed facilities.[145]

For the Bruce facilities,

- The depreciation expense resulting from the amortization of the ARC over the life of the nuclear facilities (similar to Prescribed facility).

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[143] AMPCO is only concerned about the amount of $624M Due to Province (Table 4 Line 2 Column i) in the overfunded Decommissioning Fund. AMPCO has no concern about the $990 Used Fuel Fund Due to Province (Table 4 Line 5 Column i) and understands the Used Fuel Fund has a Provincial Guarantee; therefore the Province is entailed to the excess earnings. The portion of the Used Fuel Fund not Provincially Guaranteed (excess of 2.23M Fuel Bundles) is not in an overfunded position and therefore OPG's accounting policy does not limit the earning recorded.

[144] 53 per cent Prescribed facilities and 47 per cent Bruce facilities allocation (Ex-2013-0321 J11.8)

[145] EB-2007-0905 Decision with Reasons, Page 89 to 90

- The variable incremental used fuel costs and variable incremental low and intermediate level waste ("L&ILW") costs are determined in accordance with GAAP (similar to Prescribed facility).
- The net income determinants of accretion expense and earnings on segregated funds.[146]

218. AMPCO believes OPG does have access to the $624M overfunded amount in the Decommissioning Fund. Therefore, AMPCO's calculation considers only the $624 in Due to Province as opposed to OPG's $1,614M calculation.

219. In AMPCO Revised Hypothetical Ex. C2-1-1 Table 2 (Appendix D Table 2) for simplicity, the 2013 earnings in line 15 have been increase by $330.7M, from $326.5M to $657.2M, by applying OPG's allocation ratio of 53 per cent for the prescribed facilities regarding the excess overfunded amount of $624M in the Decommissioning Fund recorded as a Due to Province (Credit).

220. OPG earns a WACC on the excess of the funded liabilities and the unamortized ARC. AMPCO revised hypothetical version of Ex C2-1-1 Table 1a Note 1 and Table 1 line 5 (Appendix D Table 1a and Table 1) show this. AMPCO understands this partial increase in revenue requirement for the prescribed facilities, this is in accordance with the approved methodology.

221. In AMPCO revised hypothetical Ex. C2-1-1 Table 3 (Appendix D Table 3), for simplicity, the 2013 earning in line 15 have been increase by $293.3M, from $330.8M to $624.1M by applying OPG's allocation ration of 47 per cent for the Bruce facilities regarding the excess overfunded amount of $624 in the Decommissioning Fund recorded as a Due to Province (Credit).

222. AMPCO revised Ex. C2-1-1 Table 1 (Appendix D Table 1) summarizes the total revenue requirement impact for 2013 to 2015. AMPCO notes that according to the EB-2007-0905 Approved Methodology, the Board required that the Bruce lease revenue be calculated in accordance with GAAP for non-regulated businesses.[147] Therefore, the accretion expense less earnings on segregated funds must be included. AMPCO Revised Ex. C2-1-1 Table 1, line 13 includes the Decommissioning Fund Due to Province (Credit) earning for the Bruce facilities.

223. The AMPCO revised hypothetical version of Ex C2-1-1 Table 1a Note 2 and Note 3 (Appendix D Table 1a) has updated the estimates of income tax impact for both the prescribed and Bruce Facilities which are also reflected in the revised Table 1.

224. As can be seen after applying the <u>full</u> Ex-2007-0905 approved methodology to the Prescribed and Bruce Facilities, revised Table 1 estimates the total revenue requirement impact for 2014 and 2015 at line 18 would be $408.4M and $410.5M respectively. This is $28.5M lower than

[146] Ex-2007-0905 Decision with Reason, Page 110
[147] The costs should include all items that would be recognized as expenses under GAAP, including accretion expense on the nuclear liabilities. Forecast earnings on the segregated funds related to the Bruce liabilities should be included as a reduction of costs. Ex-2007-0905 Decision Page 110

the requirement impact of $422.5M and $424.9M shown in OPG's pre-filed evidence (Ex C2-1-1 Table 1.[148]

225. AMPCO believes that J13.6 is misleading because it fails to include the impact of the overfunded Due to Province amount regarding the Bruce Facilities, the remaining 47 percent.

226. AMPCO submits the Board should adopt AMPCO's revised calculation.

Used Fuel Fund

227. OPG states in its AIC on page 128 line 19,

> "ONFA Section 3.7.1(b)(i) stipulates that "the Province may direct the Used Fuel Fund Custodian to make a Disbursement to the Province in any amount up to the amount, if any, by which the Actual Used Fuel Fund Value exceeds the Fixed Used Fuel Fund Value" in respect of the Used Fuel Fund. Under the ONFA, the Actual Used Fuel Fund Value exceeds the Fixed Used Fuel Fund Value when the actual market return related to the first 2.23 million of used fuel bundles is greater than the Committed Return. This results in the Province's claim on the Used Fuel Fund amount above the Committed Return. The Province may exercise this claim after receipt of an OPG report containing an estimate of the amount of the Actual Used Fuel Fund Value and the Fixed Used Fuel Fund Value. OPG shall submit such a report to the Province after a Triggering Event, as specified in ONFA section 3.6.1 (e.g., when a new or amended Reference Plan becomes an Approved Reference Plan)."

228. Under ONFA, the limit to OPG's financial exposure with respect to the cost of long-term management of Used Fuel Fund was capped at $5.94B (January 1, 1999 present value) for the first 2.23M fuel bundles. Under the ONFA, the Province guarantees_the rate of return earned in the Used Fuel Fund for the first 2.23M bundles at a target rate of return.[149] The same target rate as noted above.

229. Since the rate of return for the first 2.23M fuel bundles is Provincially Guaranteed, if the Used Fuel Fund for the first 2.23M bundles earns a rate of return less than the target rate of return, the Province is obligated to make additional contributions. If the fund earns a rate of return for the first 2.23M bundles greater than the target rate of return, the Province is entitled to the excess.[150]

230. The difference between the target rate of return and the actual market return is recorded as due to or due from the province. The due to or due from the Province represents the amount the fund would pay or receive from the Province if target return were to be settled as of the consolidated balance sheet date. [151]

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[148] AMPCO notes due to comparison reasons, the calculated 2014 and 2015 revenue requirement impacts are based on ROE rates from the pre-filed evidence and do not reflect the update to those Ex. N2-1-1.
[149] Technical Conference Volume 2, page 157, line 26
[150] EB-2010-0008 C2-T1-S1, page 7 line 1
[151] OPG Consolidated Financial Statements December 31, 2013, Page 36 (attached in Appendix D)

231. AMPCO understands, given the used fuel fund for the first 2.23M bundles is guaranteed by the province, OPG and ratepayers do not have the right or access any over earning.

232. For the portion in excess of 2.23M fuel bundles, the same rate of return is used as the target rate of return, although the rate of return is **not** guaranteed by the Province. If the used fuel fund in excess of 2.23M bundles earns a rate of return less than the target rate of return, the Province is **not** obligated to make additional contributions. If the used fuel fund in excess of 2.23M bundles earns a rate of return greater than the target rate of return, the Province is **not** entitled to the excess. AMPCO understands every 5 years, after the update to the ONFA reference plan, the contribution profile is recalculated to reflect the change in contributions necessary to reflect market performance; higher earnings lead to downward adjustment to the contribution profile, while lower earnings lead to higher adjustment to the contribution profile.[152]

233. AMPCO also understands since the Used Fuel Fund is not in an overfunded position, OPG does not limit the earnings it records but the earnings reflect the actual fund return based on the market.

234. As of the end of December 31, 2013, the Used Fuel Fund balance was $8,519M.[153] However, as discussed above, the difference between the guaranteed target rate of return and the actual return, is recorded as Due to or Due from the Province. As of the end of December 31, 2013, the guaranteed portion of the Used Fuel Fund earned $990M in excess of the target rate of return. Therefore, $990M is recorded due to the province and OPG and Ratepayers do not have the right or access to this amount.

235. AMPCO has no concerns regarded the $990M recorded due to the Province regarding the Used Fuel Fund.

Transfer of Funds

236. OPG further states on page 128 line 6,

> "ONFA Section 4.7.3 stipulates that, only in circumstances where the market value of the Decommissioning Fund is more than 120 per cent of the Decommissioning Balance to Complete Cost Estimate, OPG has the right to direct 50 per cent of the amount in excess of the 120 per cent of the Decommissioning Balance to Complete Cost Estimate to be transferred to the Used Fuel Fund. This was explained by the OPG witness at the Technical Conference (Tr. Vol. 2, p. 158)….The OPG witness also stated that the 120 per cent threshold is not expected to be reached during the test period (Tr. Vol. 11, p. 110)."

237. AMPCO understands and agrees with OPG that a transfer between the Decommissioning Fund and the Used Fuel Fund is only possible in circumstances where the Decommissioning Fund is more than 120 per cent of the Decommissioning Balance to Complete Cost Estimate. AMPCO therefore also agrees that the Used Fuel Fund has the right to 50 per cent of the

[152] EB-2010-0008 C2-T1-S1, page 7 line 9
[153] Appendix D Table 4

amount in excess of 120 per cent of the Decommissioning Balance to Complete Cost Estimate.

238. AMPCO notes based on OPG's publicly available Financial Statements

- As of December 31, 2012 the Decommissioning Fund was $5,771M and the Decommissioning Fund to Complete Cost Estimate was $5,707M; therefore, the Decommissioning Fund is at 101.1 per cent funded[154].
- As of December 31, 2013 the Decommissioning Fund was $6,591M and the Decommissioning Fund to Complete Cost Estimate was $5,967M; therefore, the Decommissioning Fund is at 110.5 per cent funded. [155]
- As of March 31, 2014 the Decommissioning Fund was $6,878M and the Decommissioning Fund to Complete Cost Estimate was $6,033M; therefore, the Decommissioning Fund is at 114.0 per cent funded.[156]
- As of June 31, 2014 the Decommissioning Fund was $7,072M and the Decommissioning Fund to Complete Cost Estimate was $6,100M; therefore, the Decommissioning Fund is at 115.9 per cent funded.[157]

239. As of June 31, 2014 the Decommissioning fund was 115.9 percent. AMPCO believes over the next 6 remaining quarters in the test period, the Decommissioning Fund is likely to exceed 120 per cent of the Decommissioning Balance to Complete Cost Estimate. 50 per cent of the amount in excess of 120 per cent should be recorded in the Used Fuel Fund.

240. Given short-term fluctuations in the market are likely to occur, AMPCO submits it is unable to accurately predict the Decommissioning Fund balance within the test period. AMPCO recommends that the Board establish a deferral account to record 50 percent of any excess of 120 per cent of the Decommissioning Fund balance.

241. This Deferral account will record the amount the Used Fuel Fund is entitled to, and be applied in accordance with the EB-2007-0905 board approved methodology for recovering nuclear liabilities in a future application.

Variable incremental used fuel costs

242. AMPCO has concerns regarding the variable incremental used fuel costs and variable incremental low and intermediate level waste ("L&ILW") costs (Ex C2-1-1 Table 1 line 2, 3, 10, 11).

243. These variable expenses have increased significantly over past applications. AMPCO is also concerned about OPGs lack of transparency regarding the calculation of the variable expenses cost rate (Staff interrogatory 181) and recommends that calculation be more fully explained in OPG's next Payment Amounts application. AMPCO notes that it costs more than

[154] OPG Consolidated Financial Statements December 31, 2012, Page 36 (attached in Appendix D)
[155] OPG Consolidated Financial Statements December 31, 2013, Page 37 (attached in Appendix D)
[156] OPG Interim Consolidated Financial Statements March 31, 2014, Page 10 (attached in Appendix D)
[157] OPG Interim Consolidated Financial Statements March 31, 2014, Page 11 (attached in Appendix D)

nine fold to store a used fuel bundle at the Pickering Waste Management facilities compared to the Darlington waste management facility.

244. Lastly, AMPCO notes these variable incremental costs are a function of the production forecast. The production forecast has decreased significantly compared to the prefilled evidence. According to the second impact statement, AMPCO has estimated the prescribed facilities variable expense for used fuel and L&ILW management should be reduced by $5.5M over the total of the test period. AMPCO understand this falls below OPG materiality threshold, but feels there is no reason for OPG to receive extra even though it is small. Just like OPG has updated the Nuclear Fuel expense to reflect lower production forecast, OPG should do the same for the nuclear waste management variable expenses.

Considerations

245. Section 6(2)8 of O. Reg. 53/05 requires the OEB to ensure that OPG "recovers the revenue requirement impact of its nuclear decommissioning liability using the current reference plan". In AMPCO's view the Board should direct OPG should review its current methodology and any potential alternatives as part of its next payment amounts application. Consideration should be given to the potential impacts of all provisions of ONFA including the Used Fuel Fund Provincial Guarantee, Decommissioning Fund overfunded position, contributions, disbursements, and expenditures. AMPCO raises concern regarding OPG's accuracy in forecasting nuclear expenditures and disbursements. Furthermore the consultation should consider OPG's estimates of such liabilities since significant assumptions underlie the calculations of the Nuclear Liabilities and any changes in programs or the technology employed may result in significant changes to the liability.

Issue 8.1
Issue 8.2

AMPCO Appendix D

Numbers may not add due to rounding.

Table 1
AMPCO Revised Ex J13.6 Attachment 1 Hypothetical
Revenue Requirement Impact of OPG's Nuclear Liabilities ($M)
Years Ending December 31, 2010 to 2015

Line No.	Description	Note or Reference	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2014 Plan	2015 Plan
			(a)	(b)	(c)	(d)	(e)	(f)
	PRESCRIBED FACILITIES							
1	**Depreciation of Asset Retirement Costs**	Ex. C2-1-1 Table 2 Line 27	26.3	29.0	127.2	80.7	80.7	80.7
2	**Used Fuel Storage and Disposal Variable Expenses**	Ex. C2-1-1 Table 2 Line 4	23.5	26.0	51.9	52.7	56.1	56.7
3	**Low & Intermediate Level Waste Management Variable Expenses**	Ex. C2-1-1 Table 2 Line 5	1.1	0.9	3.8	3.3	3.1	5.5
	Return on ARC in Rate Base:							
4	**Return on Rate Base at Weighted Average Accretion Rate**	Ex. C1-1-1 Table 1-6 *	84.7	83.1	100.5	78.9	71.5	66.2
5	**Return of Rate Base at Weighted Average Cost of Capital**	Note 1	0.0	0.0	0.0	0.0	3.9	5.2
6	**Pre-Tax Revenue Requirement Impact**		135.6	139.0	283.4	215.6	215.3	214.3
7	**Income Tax Impact**	Note 2	(6.0)	(2.1)	58.8	39.2	15.1	13.8
8	**Total Revenue Requirement Impact** (line 6 + line 7)		129.6	136.9	342.2	254.8	230.4	228.1
	BRUCE FACILITIES							
9	**Depreciation of Asset Retirement Costs**	Ex. C2-1-1 Table 3 Line 24	26.1	23.9	69.6	100.6	100.6	100.6
10	**Used Fuel Storage and Disposal Variable Expenses**	Ex. C2-1-1 Table 3 Line 4	17.8	27.0	44.5	51.6	54.3	56.4
11	**Low & Intermediate Level Waste Management Variable Expenses**	Ex. C2-1-1 Table 3 Line 5	0.9	1.0	1.8	2.8	2.4	3.8
12	**Accretion Expense**	Ex. C2-1-1 Table 3 Line 6	283.1	296.6	327.8	367.8	382.9	397.3
13	**Less: Segregated Fund Earning (Losses)**	Ex. C2-1-1 Table 3 Line 15	418.0	240.1	350.9	624.1	362.2	375.7
14	**Impact on Bruce Facilities' Income Taxes**	Note 3	21.5	(27.5)	(23.2)	25.3	(44.5)	(45.6)
15	**Pre-Tax revenue Requirement Impact (Impact on Bruce Lease Net Revenues)**		(68.6)	80.9	69.6	(76.0)	133.5	136.8
16	**Income Tax Impact on Revenue Requirement** (line 15 x tax rate / (1-tax rate))	Note 4	(28.0)	29.2	23.2	(25.3)	44.5	45.6
17	**Total Revenue Requirement Impact** (line 15 + line 16)		(96.6)	110.1	92.8	(101.3)	178.0	182.4
18	**Total Revenue Requirement Impact - Prescribed and Bruce Faciliites** (line 8 + line 17)		33.0	247.0	435.0	153.5	408.4	410.5

* AMPCO notes due to comparison reasons, the calculated 2014 and 2015 revenue requirement impacts are based on ROE rates from the pre-filed evidence and do not reflect the update to those Ex. N2-1-1

See Ex. AMPCO Revised Table 1a for notes

Numbers may not add due to rounding.

Table 1a
AMPCO Revised Ex J13.6 Attachment 1 Hypothetical
Revenue Requirement Impact of OPG's Nuclear Liabilities ($M)
Years Ending December 31, 2010 to 2015
Notes to Ex. C2-1-1, Table 1

Notes:

1 If average UNL is less than average ARC for the prescribed facilities, the funded portion of average ARC (i.e. the amount by which average ARC exceeds average UNL) earns WACC as follows:

Table to Note 1

Line No.	Year	(from Ex. C2-1-1 Table 2, line 31) Average ARC ($M)	(from Ex. C2-1-1 Table 2, line 22) Average UNL ($M)	(a)-(b) ARC-UNL ($M)	Annual WACC	(c) x (d) if >0 Return on Rate Base ($M)	WACC Reference
		(a)	(b)	(c)	(d)	(e)	
1a	2010	1,517.6	1,719.9	(202.3)	7.19%	0.0	EB-2007-0905 Payment Amounts Order, App. A, Table 5b
2a	2011	1,490.0	1,605.6	(115.6)	7.31%	0.0	EB-2010-0008 Payment Amounts Order, App. A, Table 4b
3a	2012	1,851.1	2,017.0	(165.9)	7.40%	0.0	EB-2010-0008 Payment Amounts Order, App. A, Table 5b
4a	2013	1,470.2	1,550.0	(79.8)	7.40%	0.0	EB-2010-0008 Payment Amounts Order, App. A, Table 5b
5a	2014	1,389.5	1,332.2	57.3	6.77%	3.9	Ex. C1-1-1 Table 2
6a	2015	1,308.8	1,232.5	76.3	6.79%	5.2	Ex. C1-1-1 Table 1

2 The income tax impact for prescribed facilities is calculated as follows:

Table to Note 2 ($M)

Line No.	Item	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual
		(a)	(b)	(c)	(d)	(e)	(f)
1b	Increase in Regulatory Taxable Income Before Impact of Segregated Fund Contributions (Ex. C2-1-1, Table 1, line 6)	135.6	139.0	283.4	215.6	215.3	214.3
2b	Contributions to Nuclear Segregated Funds for Prescribed Facilities (Ex. C2-1-1 Table 2, line 16)	150.2	145.0	107.1	98.1	170.1	172.8
3b	Net Increase in Regulatory Taxable Income (line 1b - line 2b)	(14.6)	(6.0)	176.3	117.5	45.2	41.5
4b	Income Tax Rate (Ex. F4-2-1 Table 4 line 33 and Ex. F4-2-1 Table 5 line 29)	29.00%	26.50%	25.00%	25.00%	25.00%	25.00%
5b	Income Tax Impact (line 3b x line 4b / (1 - line 4b))	(6.0)	(2.1)	58.8	39.2	15.1	13.8

3 The impact on Bruce facilities' income taxes relates to higher deductible temporary differences associated with the expenses at Ex. C2-1-1 Table 1, lines 9-13, which are not deductible for tax purposes. The impact is calculated as follows:

Table to Note 3 ($M)

Line No.	Item	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual
		(a)	(b)	(c)	(d)	(e)	(f)
	Short-Term Temporary Differences:						
1c	Increase in Short-Term Temporary Differences - Depreciation Expense (Ex. C2-1-1 Table 1, line 9)	26.1	23.9	69.6	100.6	100.6	100.6
2c	Income Tax Rate - Current (Ex. G2-2-1 Tables 7 and 8, line 50)	29.00%	26.50%	25.00%	25.00%	25.00%	25.00%
3c	Increase in Deferred Income Taxes - Short-Term (-line 1c x line 2c)	(7.6)	(6.3)	(17.4)	(25.2)	(25.2)	(25.2)
	Long-Term Temporary Diffewrences:						
4c	Increase in Long-Term Temporary Differences - All Other Expenses (Ex. C2-1-1 Table 1, lines 10 through 13)	(116.2)	84.5	23.2	(201.9)	77.4	81.8
5c	Income Tax Rate - Long-Term (Ex. G2-2-1 Tables 7 and 8, line 54)	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
6c	Increase in Deferred Income Taxes - Long-Term (- line 4c x line 5c)	29.1	(21.1)	(5.8)	50.5	(19.4)	(20.5)
7c	Impact on Bruce Facilities' Income Taxes (line 3c + line 6c)	21.5	(27.5)	(23.2)	25.3	(44.5)	(45.6)

4 Income tax rates are from Ex. F4-2-1 Table 4, line 33 and Ex. F4-2-1 Table 5, line 29

Table 2
AMPCO Revised Ex J13.6 Attachment 1 Hypothetical
Prescribed Facilities - Asset Retirement Obligation, Nuclear Segregated Funds, and Asset Retirement Costs ($M)
Years Ending December 31, 2010 to 2015

Line No.	Description	Note	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2014 Plan	2015 Plan
			(a)	(b)	(c)	(d)	(e)	(f)
	ASSET RETIREMENT OBLIGATION							
1	**Opening Balance**	1	6,391.2	7,174.5	7,935.9	8,034.1	8,400.6	8,772.2
2	**Darlington Refurbishment Adjustment**	2	497.4					
3	**Adjusted Opening Balance** (line 1 + line 2)		6,888.6	7,174.5	7,935.9	8,034.1	8,400.6	8,772.2
4	**Used Fuel Storage and Disposal Variable Expenses**		23.5	26.0	51.9	52.7	56.1	56.7
5	**Low & Intermediate Level Waste Management Variable Expenses**		1.1	0.9	3.8	3.3	3.1	5.5
6	**Accretion Expense**		382.2	399.0	432.6	442.1	461.3	479.8
7	**Expenditures for Used Fuel, Waste Management & Decommissioning**		(122.0)	(104.0)	(115.5)	(131.6)	(148.8)	(197.6)
8	**Consolidation and Other Adjustments**		1.2	0.3	0.9	0.0	0.0	0.0
9	**Closing Balance Before Year-End Adjustments** (lines 3 through 8)		7,174.6	7,496.7	8,309.6	8,400.6	8,772.3	9,116.6
10	**Current Approved ONFA Reference Plan Adjustment**	3	0.0	439.2	(276.9)	0.0	0.0	0.0
11	**New CNSC Requirements Adjustment**	4	0.0	0.0	1.3	0.0	0.0	0.0
12	**Closing Balance** (line 9 + line 10 + line 11)		7,174.6	7,935.9	8,034.0	8,400.6	8,772.3	9,116.6
13	**Average Asset Retirement Obligation** ((line 3 + line 9)/2)		7,031.6	7,335.6	8,122.8	8,217.4	8,586.5	8,944.4
	NUCLEAR SEGREGATED FUNDS BALANCE							
14	**Opening Balance**	1	5,058.7	5,564.8	5,895.2	6,316.4	7,018.4	7,490.1
15	**Earnings (Losses)** Increased for Dec. 31, 2013 Due to Province Amount	6	417.7	220.7	355.7	657.2	364.2	387.2
16	**Contributions**		150.2	145.0	107.1	98.1	170.1	172.8
17	**Disbursements**		(61.8)	(35.3)	(41.6)	(53.3)	(62.6)	(116.5)
18	**Closing Balance** (line 14 + line 15 + line 16 + line 17)		5,564.8	5,895.2	6,316.4	7,018.4	7,490.1	7,933.6
19	**Average Nuclear Segregated Funds Balance** ((line 14 + line 18)/2)		5,311.8	5,730.0	6,105.8	6,667.4	7,254.3	7,711.9
	UNFUNDED NUCLEAR LIABILITY BALANCE (UNL)							
20	**Opening Balance** (line 3 - line 14)		1,829.9	1,609.7	2,040.7	1,717.7	1,382.2	1,282.1
21	**Closing Balance** (line 9 - line 18)		1,609.8	1,601.5	1,993.2	1,382.2	1,282.2	1,183.0
22	**Average Unfunded Nuclear Liability Balance** ((line 20 + line 21)/2)		1,719.9	1,605.6	2,017.0	1,549.9	1,332.2	1,232.5
	ASSET RETIREMENT COSTS (ARC)							
23	**Opening Balance**	1	1,098.0	1,504.5	1,914.7	1,510.5	1,429.8	1,349.1
24	**Reconciliation Adjustment**	5	(42.7)	0.0	0.0			
25	**Darlington Refurbishment Adjustment**	2	475.5	0.0	0.0	0.0	0.0	0.0
26	**Adjusted Opening Balance** (line 23 + line 24 + line 25)		1,530.8	1,504.5	1,914.7	1,510.5	1,429.8	1,349.1
27	**Depreciation Expense**		(26.3)	(29.0)	(127.2)	(80.7)	(80.7)	(80.7)
28	**Closing Balance Before Year-End Adjustments** (line 26 + line 27)		1,504.5	1,475.4	1,787.5	1,429.8	1,349.1	1,268.4
29	**Current Approved ONFA Reference Plan Adjustment**	3	0.0	439.2	(276.9)	0.0	0.0	0.0
30	**Closing Balance** (line 28 + line 29)		1,504.5	1,914.7	1,510.5	1,429.8	1,349.1	1,268.4
31	**Average Asset Retirement Costs** ((line 26 + line 28)/2)		1,517.6	1,490.0	1,851.1	1,470.2	1,389.5	1,308.8
32	**LESSER OF AVERAGE UNL OR ARC** (lesser of line 22 or line 31)		1,517.6	1,490.0	1,851.1	1,470.2	1,332.2	1,232.5

Notes:

1 Opening balances in col. (a) from EB-2010-0008, Ex. C2-1-1 Table 1.

2 Adjustment recorded on January 1, 2010 associated with the changes to the end-of-life date assumptions underlying the ARO calculation, as a result of the approval of the definition phase of the Darlington Refurbishment project.

3 Adjustments recorded on December 31, 2011 and December 31, 2012, as per Ex. C2-1-1 Table 4, associated with the current approved ONFA Reference Plan effective January 1, 2012.

4 Represents implementation, in accordance with GAAP, of new CNSC requirements in 2012 to include certain facilities with Waste Nuclear Substance Licenses not included in the 2012 ONFA Reference Plan due to timing of notification by the CNSC. As a result, ARO increased by $2.4M to include a legacy facility not used to support OPG's current operations, of which $1.3M is attributed to prescribed facilities and $1.1M is attributed to Bruce facilities. In accordance with GAAP, this amount was expensed (i.e., not included in ARC) in 2012.

5 Adjustment to remove from the ARC continuity amounts reflected in the non-ARC portion of PP&E in rate base. Total rate base is not impacted.

6 As of December 31, 2013 the Decommissioning fund was in an over funded position, the excess $624M was recorded as Due to Province. An allocation factor of 53 per cent to the Prescribed Facilities is used (Ex 2013-0321 J11.8). An amount of $330.7M is allocated to the Prescribed Facilities. The projected end-of-year 2014 and 2015 amount Due to Province is forecast using the long-term target rate of return of 5.15 per cent as per the Ontario Nuclear Funds Agreement.

Numbers may not add due to rounding.

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Table 3

Table 3
AMPCO Revised Ex J13.6 Attachment 1 Hypothetical
Bruce Facilities - Asset Retirement Obligation, Nuclear Segregated Funds, and Asset Retirement Costs ($M)
Years Ending December 31, 2010 to 2015

Line No.	Description	Note	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2014 Plan	2015 Plan
			(a)	(b)	(c)	(d)	(e)	(f)
	ASSET RETIREMENT OBLIGATION							
1	**Opening Balance**	1	5,315.0	5,356.9	6,107.6	7,125.4	7,434.9	7,745.5
2	**Darlington Refurbishment Adjustment**	2	(204.4)	0.0	0.0	0.0	0.0	0.0
3	**Adjusted Opening Balance** (line 1 + line 2)		5,110.7	5,357.0	6,107.7	7,125.5	7,434.8	7,745.5
4	**Used Fuel Storage and Disposal Variable Expenses**		17.8	27.0	44.5	51.6	54.3	56.4
5	**Low & Intermediate Level Waste Management Variable Expenses**		0.9	1.0	1.8	2.8	2.4	3.8
6	**Accretion Expense**		283.1	296.6	327.8	367.8	382.9	397.3
7	**Expenditures for Used Fuel, Waste Management & Decommissioning**		(57.5)	(68.1)	(83.7)	(112.8)	(128.9)	(172.7)
8	**Consolidation and Other Adjustments**		1.9	(1.0)	0.6	0.0	0.0	0.0
9	**Closing Balance Before Year-End Adjustments** (lines 3 through 8)		5,356.9	5,612.5	6,398.7	7,434.9	7,745.5	8030.3
10	**Current Approved ONFA Reference Plan Adjustment**	3	0.0	495.1	706.1	0.0	0.0	0.0
11	**New CNSC Requirements Adjustment**	4	0.0	0.0	20.6	0.0	0.0	0.0
12	**Closing Balance** (line 9 + line 10 + line 11)		5,356.9	6,107.6	7,125.4	7,434.9	7,745.5	8,030.3
13	**Average Asset Retirement Obligation** ((line 3 + line 9)/2)		5,233.8	5,484.8	6,253.2	7,280.2	7,590.2	7,887.9
	NUCLEAR SEGREGATED FUNDS BALANCE							
14	**Opening Balance**	1	5,187.2	5,680.9	6,002.5	6,400.2	7,073.0	7,353.7
15	**Earnings (Losses)** Increased for Dec. 31, 2013 Due to Province Amount	6	418.0	240.1	350.9	624.1	362.2	375.7
16	**Contributions**		113.9	105.5	74.9	85.9	(31.3)	(29.4)
17	**Disbursements**		(38.2)	(24.0)	(28.1)	(37.2)	(50.1)	(89.3)
18	**Closing Balance** (line 14 + line 15 + line 16 + line 17)		5,680.9	6,002.5	6,400.2	7,073.0	7,353.7	7,610.7
19	**Average Nuclear Segregated Funds Balance** ((line 14 + line 18)/2)		5,434.1	5,841.7	6,201.4	6,736.6	7,213.4	7,482.2
	ASSET RETIREMENT COSTS (ARC)							
20	**Opening Balance**	1	1,035.8	817.6	1,288.8	1,944.8	1,844.2	1,743.6
21	**Reconciliation Adjustment**	5	(9.6)	0.0	0.0			
22	**Darlington Refurbishment Adjustment**	2	(182.4)	0.0	0.0	0.0	0.0	0.0
23	**Adjusted Opening Balance** (line 23 + line 24 + line 25)		843.7	817.6	1,288.8	1,944.8	1,844.2	1,743.6
24	**Depreciation Expense**		(26.1)	(23.9)	(69.6)	(100.6)	(100.6)	(100.6)
25	**Closing Balance Before Year-End Adjustments** (line 26 + line 27)		817.6	793.7	1,219.2	1,844.2	1,743.6	1,643.0
26	**Current Approved ONFA Reference Plan Adjustment**	3	0.0	495.1	706.1	0.0	0.0	0.0
27	**New CNSC Requirements Adjustment**	4	0.0	0.0	19.5	0.0	0.0	0.0
28	**Closing Balance** (line 28 + line 29)		817.6	1,288.8	1,944.8	1,844.2	1,743.6	1,643.0
29	**Average Asset Retirement Costs** ((line 23 + line 25)/2))		830.7	805.7	1,254.0	1,894.5	1,793.9	1,693.3

Notes:

1 Opening balances in col. (a) from EB-2010-0008, Ex. C2-1-1 Table 2

2 Adjustment recorded on January 1, 2010 associated with the changes to the end-of-life date assumptions underlying the ARO calculation, as a result of the approval of the definition phase of the Darlington Refurbishment project.

3 Adjustments recorded on December 31, 2011 and December 31, 2012, as per Ex. C2-1-1 Table 4, associated with the current approved ONFA Reference Plan effective January 1, 2012.

4 Represents implementation, in accordance with GAAP, of new CNSC requirements in 2012 to include certain facilites with Waste Nuclear Substance Licenses not included in the 2012 ONFA Reference Plan due to timing of notification by the CNSC. As a result, ARO increased by $2.4M to include a legacy facility not used to support OPG's current operations, of which $1.3M is attributed to prescribed facilities and $1.1M is attributed to Bruce facilities. In accordance with GAAP, this amount was expensed (i.e., not included in ARC) in 2012. ARO increased by a further $19.5M to include a facility dedicated to supporting the Bruce facilities. In accordance with GAAP, this amount was included in ARC.

5 Adjustment to remove from the ARC continuity amounts reflected in the non-ARC portion of PP&E. Total Bruce Lease net revenues are not impacted.

6 As of December 31, 2013 the Decommissioning fund was in an over funded position, the excess $624M was recorded as Due to Province. An allocation factor of 47 per cent to the Bruce Facilities is used (Ex 2013-0321 J11.8). An amount of $293.3M is allocated to the Bruce Facilities. The projected end-of-year 2014 and 2015 amount Due to Province is forecast using the long-term target rate of return of 5.15 per cent as per the Ontario Nuclear Funds Agreement.

Numbers may not add due to rounding.

Table 4 AMPCO Compiled
Nuclear Fixed Asset Removal and Nuclear Waste Management Funds as of End of Year December 31
Years Ending December 31, 2005 to 2015

Line No.	Description	Note or Reference	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Decommissioning Fund		4,583.0	5,169.0	5,075.0	4,325.0	4,876.0	5,267.0	5,342.0	5,771.0	6,591.0
2	Due to Province (Overfunded)	Note 1	(484.0)	(294.0)	(3.0)	0.0	0.0	0.0	0.0	(64.0)	(624.0)
3	Total		4,099.0	4,875.0	5,072.0	4,325.0	4,876.0	5,267.0	5,342.0	5,707.0	5,967.0
4	Used Fuel Fund		2,995.0	3,879.0	4,702.0	4,424.0	5,403.0	6,198.0	6,509.0	7,245.0	8,519.0
5	Due to Province (Provincial Guarantee)	Note 2	(306.0)	(641.0)	(511.0)	460.0	(33.0)	(219.0)	47.0	(235.0)	(990.0)
6	Total		2,689.0	3,238.0	4,191.0	4,884.0	5,370.0	5,979.0	6,556.0	7,010.0	7,529.0
7	Total Nuclear Funds (line 3 + line 6)		6,788.0	8,113.0	9,263.0	9,209.0	10,246.0	11,246.0	11,898.0	12,717.0	13,496.0
8	Less: Current Portion								20.0	27.0	25.0
9	Non-Current Nuclear Funds		6,788.0	8,113.0	9,263.0	9,209.0	10,246.0	11,246.0	11,878.0	12,690.0	13,471.0

Table 4a AMPCO Complied
Annual Change in Decommissioning Nuclear Fund ($M)
Years Ending December 31 2005 to 2013

Line No.	Decommissioning Fund	Note or Reference	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Start		3,882	4,099	4,875	5,072	4,325	4,876	5,267	5,342	5,707
2	Return on Investment		459	592	5	(681)	631	465	108	469	854
3	Reimbursement of Expenditures		(7)	(6)	(99)	(69)	(80)	(74)	(33)	(40)	(34)
4	Due to Province	Note 1	(235)							(64)	(560)
5	Due From Province	Note 1		190	291	3					
6	End		4,099	4,875	5,072	4,325	4,876	5,267	5,342	5,707	5,967

Table 4b AMPCO Complied
Annual Change in Used Fuel Nuclear Fund ($M)
Years Ending December 31, 2005 to 2013

Line No.	Used Fuel Fund	Note or Reference	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Start		2,118	2,689	3,238	4,191	4,884	5,370	5,979	6,556	7,010
2	Contributions		454	454	788	454	339	264	250	182	184
3	Return on Investment		283	443	55	(719)	664	557	87	584	1,131
4	Reimbursement of Expenditures		(16)	(13)	(20)	(13)	(24)	(26)	(26)	(30)	(41)
5	Due to Province	Note 2	(150)	(335)			(493)	(186)		(282)	(755)
6	Due From Province	Note 2			130	511			266		
7	Increase in Due From Province	Note 2				460					
8	End		2,689	3,238	4,191	4,884	5,370	5,979	6,556	7,010	7,529

Note

1 By December 31, 2005 the Decommissioning Fund is Overfunded, relative to the 1999 Reference Plan, with an excess amount of $484.0M which was recorded as Due to Province. By December 31, 2006, a new 2006 Reference Plan was in place therefore increasing the Decommissioning Liability Cost required. Even though the Decommissioning funded earned $592M, OPG recorded $190M from the $484 in available Due to Province credits to the Decommissioning Fund Balance. Still by December 31, 2006 OPG had $294M in excess funding which was recorded as Due to Province. By the December 31, 2007 the Decommissioning Fund earned only $5, which is less than the Target Rate of Return. OPG therefore supplemented the earnings with the Due to Province Credits available. OPG decreased the Due to Province by $291 and by the December 31, 2007 still had $3M in excess funding which was recorded as Due to Province (Credit). Similarly in 2008 the Decommissioning Fund earnings did not match the target rate of return (lost earning in 2008), and therefore OPG supplemented the remaining Due to Province Credits it had. By the December 31, 2008 OPG has nil in Due to Province, no credits to use when needed.

2 Given a Provincial Guarantee excess for the first 2.23 Fuel Bundles, if this portion earns a rate of return less than the target rate of return, the Province is obligated to make additional contributions (i.e. as in 2007, 2008, and 2011). However if first 2.23M bundles earn a rate of return greater than the target rate of return, the Province is entitled to the excess (i.e. as in 2005, 2006). Note in Ex-2010-0008 it was estimated that the 2.23 Fuel Bundles would be reached in 2012, however the Used Fuel Fund is not in an Overfunded position and therefore earnings reflect actual market earnings

OPG 2003 ~~Q4~~ Annual Financial Results

As required by the *Nuclear Safety and Control Act* (Canada), and under the terms of ONFA, effective as at July 31, 2003, the Province issued a guarantee to the Canadian Nuclear Safety Commission ("CNSC"), on behalf of OPG, for up to $1.51 billion. This is a guarantee that there will be sufficient funds available to discharge the current nuclear decommissioning and waste management liabilities. The provincial guarantee will supplement the Used Fuel Fund and the Decommissioning Fund until they have accumulated sufficient funds to cover the accumulated liabilities for nuclear decommissioning and waste management. The guarantee, taken together with the establishment of the new segregated custodial funds, was in satisfaction of OPG's nuclear licencing requirements with the CNSC. OPG pays the Province an annual guarantee fee of 0.5 per cent of the amount guaranteed by the Province.

Under ONFA, the Province guarantees OPG's return in the Used Fuel Fund at Ontario Consumer Price Index ("CPI") plus 3.25 per cent ("committed return"). The difference between the committed return on the Used Fuel Fund and the actual net return, based on the fair value of fund assets, which includes realized and unrealized returns, is due to or due from the Province. Since OPG accounts for the investments in the funds on an amortized cost basis, the amount due to or due from the Province recorded in the consolidated financial statements is the difference between the committed return and the actual return based on realized returns only. At December 31, 2003, the Used Fuel Fund assets included a receivable from the Province of $10 million. If the investments in the Used Fuel Fund were accounted for at fair market value in the consolidated financial statements, at December 31, 2003, there would be an amount due to the Province of $71 million.

Under ONFA, a rate of return target of 5.75 per cent per annum was established for the Decommissioning Fund. If the rate of return deviates from 5.75 per cent, or if the value of the liabilities changes under the OPG Reference Plan (1999), the Decommissioning Fund may become over or under funded. Under ONFA, if there is a surplus in the Decommissioning Fund such that the liabilities, as defined by the OPG Reference Plan (1999), are at least 120 per cent funded, OPG may direct 50 per cent of the excess over the liability amount to be transferred to the Used Fuel Fund as a contribution and the OEFC is entitled to the remaining 50 per cent of such surplus. At December 31, 2003, the Decommissioning Fund was fully funded and there were no amounts owing.

The fair values and the amortized cost of the securities invested in the segregated funds, which include the Used Fuel and Decommissioning Funds, as at December 31, 2003 are as follows:

(millions of dollars)	**Amortized Cost Basis**	**Fair Value**
Cash and cash equivalents and short-term investments	**139**	**139**
Marketable equity securities	**2,556**	**2,795**
Bonds and debentures	**635**	**637**
Receivable from the OEFC	**1,892**	**1,892**
Administrative expense payable	**(4)**	**(4)**
	5,218	**5,459**
Due from (to) Province – Used Fuel Fund	**10**	**(71)**
Total	**5,228**	**5,388**

OPG 2004 Financial Results

depreciation, the remaining service life of Pickering A Unit 4 by five years, from 2012 to 2017. This reduces depreciation expense by approximately $20 million annually.

Accretion

OPG records the present value of its future costs for fixed asset removal and nuclear waste management as a long-term liability. This liability is discussed in detail in Note 8 to the consolidated financial statements as at and for the year ended December 31, 2004. Accretion expense reflects the change in the present value of this liability since the end of the prior period. This expense is impacted by factors such as any changes in the estimate of the amount of the future liability for fixed asset removal and nuclear waste management, any changes to the discount rate used to determine the present value, and the increase in the present value due to the passage of time.

Accretion expense for 2004 was $453 million compared with $430 million for 2003. The increase of $23 million for 2004 was due to the higher liability base compared to last year as a result of the increase in the present value of the liability due to the passage of time.

Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

As required under the Ontario Nuclear Funds Agreement ("ONFA"), OPG maintains segregated custodial funds to fund the future costs of managing used nuclear fuel created by OPG's nuclear plants (the "Used Fuel Fund") and to fund the future costs of decommissioning these plants, including the long-term management of low and intermediate level waste (the "Decommissioning Fund"). Under the ONFA, the Used Fuel Fund and the Decommissioning Fund (together the "Funds") are segregated from the rest of OPG's assets. The Province has a security interest in the Funds. OPG's obligations relate to the Pickering and Darlington nuclear plants that are operated by OPG, and also the Bruce nuclear plant that is leased by OPG to Bruce Power.

OPG deposits amounts into the Funds on a quarterly basis consistent with approved cost estimates and payment schedules. In 2004, OPG contributed $454 million to the Funds. Assets in the Funds are invested in fixed income and equity securities, which are recorded as long-term investments and accounted for at their amortized cost by OPG. Therefore, gains and losses are only recognized upon sale of the underlying security. As such, there may be unrealized gains and losses associated with the Funds which OPG does not recognize on its balance sheet. The balance of the Funds, on an amortized cost basis, as at December 31, 2004 was $5,976 million compared to $5,228 million as at December 31, 2003.

Under the ONFA, OPG's liability for nuclear used fuel costs is effectively capped at $5.94 billion on a present value basis as of January 1, 1999, assuming no more than 2.23 million bundles of used fuel waste are produced. OPG is responsible for all incremental costs relating to the management of used fuel bundles in excess of 2.23 million.

Under the ONFA, the Province guarantees the annual rate of return in the Used Fuel Fund at 3.25 per cent plus the change in the Ontario Consumer Price Index ("committed return"). OPG recognizes the committed return on the Used Fuel Fund in earnings on the nuclear fixed asset removal and nuclear waste management funds. The difference between the committed return on the Used Fuel Fund and the actual market return, based on the fair value of fund assets, which includes realized and unrealized returns, is due to or from the Province. Since OPG accounts for the investments in the segregated funds on an amortized cost basis, the amount due to or due from the Province recorded in the consolidated financial statements is the difference between the committed return and the actual return based on realized returns only.

At December 31, 2004, the Decommissioning Fund was fully funded based on the estimate of costs to complete decommissioning under the current approved ONFA Reference Plan (the 1999 Reference Plan). The earnings recognized on the investments in the Decommissioning Fund would be limited such that the amortized cost balance of the fund would equate to the cost estimate of the liability. These realized gains may be recognized in subsequent periods provided the fund balance does not exceed that cost estimate. At December 31, 2004, net unrealized gains in the Decommissioning Fund totalled approximately $273 million (fund assets at amortized cost of $3,858 million and market value of $4,131

Accretion

OPG records the present value of its future costs for fixed asset removal and nuclear waste management as a long-term liability. This liability is discussed in Note 9 to the consolidated financial statements as at and for the year ended December 31, 2005. Accretion expense reflects the change in the present value of this liability since the end of the prior period. This expense is impacted by factors such as any changes in the estimate of the amount of the future liability for fixed asset removal and nuclear waste management, any changes to the discount rate used to determine the present value, and the change in the present value due to the passage of time.

Accretion expense for 2005 was $467 million compared with $445 million in 2004. The increase in the accretion expense was due to the higher liability base compared to last year as a result of the increase in the present value of the liability due to the passage of time.

Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

OPG is responsible for the ongoing long-term management and disposal of radioactive waste materials and used fuel resulting from operations and future decommissioning of its nuclear generating stations. OPG's obligations relate to the Pickering and Darlington nuclear plants that are operated by OPG, as well as the Bruce A and B nuclear plants that are leased by OPG to Bruce Power.

In order to fund these liabilities, OPG established and manages, jointly with the Province, a Used Fuel Fund and a Decommissioning Fund (the "Nuclear Funds"), which are funded by OPG in accordance with the Ontario Nuclear Funds Agreement ("ONFA"). The Used Fuel Fund is intended to fund future expenditures associated with the disposal of highly radioactive used nuclear fuel bundles. The Decommissioning Fund was established to fund future expenditures associated with nuclear fixed asset removal and the disposal of low and intermediate level nuclear waste materials. OPG maintains the Nuclear Funds in third party custodial accounts that are segregated from the rest of OPG's assets.

Assets in the Nuclear Funds are invested in fixed income and equity securities, which OPG records as long-term investments at their amortized cost. Therefore, gains and losses are recognized only upon the sale of an underlying security. As such, there may be unrealized gains and losses associated with the investments in the Nuclear Funds, which OPG has not recognized in its consolidated financial statements. The balance of the Nuclear Funds on an amortized cost basis, as at December 31, 2005, was $6,788 million compared to $5,976 million as at December 31, 2004. This balance is referred to as the nuclear fixed asset removal and nuclear waste management funds in OPG's consolidated financial statements.

Under ONFA, the Province guarantees the annual rate of return in the Used Fuel Fund at 3.25 per cent plus the change in the Ontario Consumer Price Index ("committed return") over the long term. OPG recognizes the committed return on the Used Fuel Fund and includes it in earnings on the nuclear fixed asset removal and nuclear waste management funds. The difference between the committed return on the Used Fuel Fund and the actual market return, based on the fair value of the assets, which includes realized and unrealized returns, is due to or from the Province. Since OPG accounts for the investments in the Nuclear Funds on an amortized cost basis, the amount due to or due from the Province recorded in the consolidated financial statements is the difference between the committed return and the actual return based on realized returns only. At December 31, 2005, the Used Fuel Fund included an amount due to the Province of $4 million (2004 – $4 million). If the investments in the Used Fuel Fund were accounted for at fair market value in the consolidated financial statements, at December 31, 2005, there would be an amount due to the Province of $306 million (2004 – $156 million). In addition, under ONFA, the Province is entitled to any surplus in the Used Fuel Fund, subject to a threshold funded ratio of 110 per cent compared to the value of the associated liabilities.

Under ONFA, the Decommissioning Fund has a long-term target rate of return of 5.75 per cent per annum. OPG bears the risk and liability for cost estimate increases and fund earnings associated with the Decommissioning Fund. At December 31, 2005, based on the estimate of costs to complete under the current approved ONFA Reference Plan (currently the 1999 Reference Plan), the Decommissioning

Fund was fully funded on a market value basis and on an amortized cost basis. When the Decommissioning Fund is overfunded on an amortized cost basis, OPG will limit the earnings it recognizes in its consolidated financial statements, through a charge to the Decommissioning Fund with a corresponding payable to the Province, such that the amortized cost balance of the Decommissioning Fund would equal the cost estimate of the liability based on the 1999 Reference Plan. These realized gains may be recognized in subsequent periods provided the Decommissioning Fund balance declines below the then currently approved cost estimate.

At December 31, 2005, the Decommissioning Fund asset value on an amortized cost basis was $4,099 million compared to a market value of $4,583 million, the difference representing net unrealized gains of $484 million. Under the ONFA, if there is a surplus in the Decommissioning Fund such that the liabilities, as defined by the then current ONFA Reference Plan, are at least 120 per cent funded, OPG may direct up to 50 per cent of the surplus over 120 per cent to be treated as a contribution to the Used Fuel Fund, and the OEFC is entitled to the remaining 50 per cent of such surplus. Any overfunding of the liability is payable to the Province on termination of the Decommissioning Fund. Therefore, the accounting for this overfunded position requires an adjustment to the amortized cost value of the assets in the Decommissioning Fund. This adjustment reduced the value of the assets by $7 million, to equal the value of the liabilities as defined by the current approved ONFA reference plan. If the investments in the Decommissioning Fund were accounted for at fair market value in the consolidated financial statements at December 31, 2005, and the Decommissioning Fund was terminated under the ONFA, there would be an amount due to the Province of $484 million (2004 – $249 million).

Realized earnings on the Nuclear Funds for the year ended December 31, 2005 were $381 million compared to $313 million for 2004, an increase of $68 million. The increase in earnings in 2005 was largely due to higher earnings in the Used Fuel Fund as a result of a larger asset base due to growth through a combination of earnings and contributions, and a higher Ontario CPI compared to 2004.

Regulated – Hydroelectric Segment

(millions of dollars)	**2005**	**2004**
Revenue, net of Market Power Mitigation Agreement rebate	**792**	824
Fuel expense	**254**	255
Gross margin	**538**	569
Operations, maintenance and administration	**77**	74
Depreciation and amortization	**68**	71
Property and capital taxes	**18**	18
Income before interest, income taxes and extraordinary item	**375**	406

Revenue

(millions of dollars)	**2005**	**2004**
Spot market sales, net of hedging instruments	**260**	971
Market Power Mitigation Agreement rebate	**(65)**	(194)
Regulated generation sales [1]	**558**	-
Variance accounts	**2**	-
Other	**37**	47
Total revenue	**792**	824

[1] Regulated generation sales includes revenue of $210 million that OPG received at the Ontario spot market price for generation over 1,900 MWh in any hour during 2005.

OPG 2005 Financial Results

The nuclear fixed asset removal and nuclear waste management funds as at December 31, 2005 and 2004, consist of the following:

(millions of dollars)	**Amortized Cost Basis** **2005**	**2004**	**Fair Value** **2005**	**2004**
Decommissioning Fund	**4,106**	3,858	**4,583**	4,131
Due to Province – Decommissioning Fund	**(7)**	-	**(484)**	(249)
	4,099	3,858	**4,099**	3,882
Used Fuel Fund [1]	**2,693**	2,122	**2,995**	2,274
Due (to) from Province – Used Fuel Fund	**(4)**	(4)	**(306)**	(156)
	2,689	2,118	**2,689**	2,118
	6,788	5,976	**6,788**	6,000

[1] The Ontario NFWA Trust represents $1,003 million as at December 31, 2005 (2004 – $794 million) of the Used Fuel Fund on an amortized cost basis.

The amortized cost and fair value of the securities invested in the segregated funds, which include the Used Fuel Fund and Decommissioning Fund, as at December 31, 2005 and 2004 are as follows:

(millions of dollars)	**Amortized Cost Basis** **2005**	**2004**	**Fair Value** **2005**	**2004**
Cash and cash equivalents and short-term investments	**516**	211	**515**	211
Marketable equity securities	**3,772**	3,056	**4,547**	3,472
Bonds and debentures	**1,757**	723	**1,762**	732
Receivable from the OEFC	**759**	1,993	**759**	1,993
Administrative expense payable	**(5)**	(3)	**(5)**	(3)
	6,799	5,980	**7,578**	6,405
Due to Province – Decommissioning Fund	**(7)**	-	**(484)**	(249)
Due to Province – Used Fuel Fund	**(4)**	(4)	**(306)**	(156)
Total	**6,788**	5,976	**6,788**	6,000

The bonds and debentures held in the Used Fuel Fund and the Decommissioning Fund as at December 31, 2005 and 2004 mature according to the following schedule:

(millions of dollars)	**Fair Value** **2005**	**2004**
Less than 1 year	**-**	-
1 - 5 years	**769**	259
5 - 10 years	**485**	233
More than 10 years	**508**	240
Total maturities of debt securities	**1,762**	732
Average yield	**4.3%**	4.1%

2008 Q1

Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

Decommissioning Fund

The Decommissioning Fund was established to fund the future costs of nuclear fixed asset removal and long-term low and intermediate level nuclear waste management and a portion of used fuel storage costs after station life. Upon termination of the Ontario Nuclear Funds Agreement ("ONFA"), the Province has a right to any excess funding in the Decommissioning Fund, which is the excess of the fair market value of the Decommissioning Fund over the estimated completion costs as per the most recently approved ONFA Reference Plan. When the Decommissioning Fund is overfunded, OPG limits the earnings it recognizes in its consolidated financial statements, through a charge to the Decommissioning Fund with a corresponding payable to the Province, such that the balance of the Decommissioning Fund would equal the cost estimate of the liability based on the most recently approved ONFA reference plan. The payable to the Province could be reduced in subsequent periods in the event that the Decommissioning Fund earns less than its target rate of return or in the event that a new ONFA reference plan is approved with a higher estimated decommissioning liability. If the Decommissioning Fund were underfunded, the earnings for the Decommissioning Fund would reflect actual fund returns based on the market value of the assets.

The Decommissioning Fund's asset value on a fair value basis was $4,980 million at March 31, 2008 compared to $5,072 million as at December 31, 2007. The decrease in asset value in the Decommissioning Fund of $92 million was primarily due to significant volatility and unfavourable returns in the capital markets during the first quarter of 2008. As at December 31, 2007, the Decommissioning Fund was overfunded by $3 million when compared to the 2006 ONFA reference plan cost to complete, and the fund balance was reduced by a payable to the Province. The Decommissioning Fund was underfunded at March 31, 2008, and as a result the payable to the Province was nil.

Used Fuel Fund

Under the ONFA, the Province guarantees OPG's annual return in the Used Fuel Fund at 3.25 per cent plus the change in the Ontario Consumer Price Index ("committed return") for funding related to the first 2.23 million used fuel bundles. OPG recognizes the committed return on the Used Fuel Fund and includes it in the earnings on the nuclear fixed asset removal and nuclear waste management funds. The difference between the committed return on the Used Fuel Fund and the actual market return, based on the fair value of the Used Fuel Fund's assets, which includes realized and unrealized returns, is recorded as due to or due from the Province. The asset values as at March 31, 2008 and December 31, 2007, were offset by a payable to the Province of $362 million and $511 million, respectively. The offset relates to the committed return adjustment. At March 31, 2008, the Used Fuel Fund asset value on a fair value basis was $4,338 million compared to $4,191 million as at December 31, 2007. The increase in the Used Fuel Fund was due to the committed return and contributions to the fund.

The market volatility during the first quarter of 2008 did not have a significant impact to Used Fuel Fund balance as a result of the Province's rate of return guarantee.

Regulatory Assets

At March 31, 2008, the regulatory assets were $367 million compared to $356 million as at December 31, 2007. OPG recorded $33 million in the deferral account related to the increase in OPG's liabilities for nuclear used fuel management and nuclear decommissioning and low and intermediate level waste management arising from the 2006 Approved Reference Plan. OPG also deferred an additional $4 million of deferred non-capital costs incurred for nuclear generation development initiatives.

The increase in the regulatory assets was partially offset by the reduction in the balance of the Pickering A return to service deferral account due to amortization of $29 million during the three months ended March 31, 2008.

OPG 2008 Financial Results Annual

In order to meet the federal and provincial GHG emission targets previously identified under the heading, *Environmental Stewardship,* there is a risk that OPG will be required to either reduce GHG emissions or purchase offsets, which could have a material adverse impact to OPG.

RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province, the other successor entities of Ontario Hydro, including Hydro One Inc. ("Hydro One"), the IESO, and the OEFC. OPG also enters into related party transactions with its joint ventures. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

These transactions are summarized below:

	Revenue	Expenses	Revenue	Expenses
(millions of dollars)	2008		2007	
Hydro One				
Electricity sales	35	-	28	-
Services	-	7	-	12
Province of Ontario				
GRC water rentals and land tax	-	151	-	129
Guarantee fee	-	4	-	8
Used Fuel Fund rate of return guarantee	-	(971)	-	(130)
Decommissioning Fund excess funding	-	(3)	-	(291)
OEFC				
GRC and proxy property tax	-	215	-	199
Interest income on receivable	-	-	-	(6)
Interest expense on long-term notes	-	215	-	187
Capital tax	-	36	-	35
Income taxes	-	88	-	(51)
Indemnity fees	-	-	-	-
IESO				
Electricity sales	5,330	127	5,094	104
Revenue limit rebate	(277)	-	(227)	-
Ancillary services	155	-	145	-
Other	-	-	-	1
	5,243	(131)	5,040	197

At December 31, 2008, accounts receivable included nil (2007 – $2 million) due from Hydro One and $207 million (2007 – $179 million) due from the IESO. Accounts payable and accrued charges at December 31, 2008 included $1 million (2007 – $2 million) due to Hydro One.

CORPORATE GOVERNANCE

Corporate Governance

National Instrument 58-101, *Disclosure of Corporate Governance Practices*, has been implemented by Canadian securities regulatory authorities to provide greater transparency for the marketplace regarding issuers' corporate governance practices. Information with respect to OPG's Board of Directors is as follows:

Board of Directors and Directorships

OPG's Board of Directors is made up of 12 individuals with substantial capability in managing and restructuring large businesses, managing and operating nuclear stations, managing capital intensive

ONTARIOPOWER GENERATION

ONTARIO POWER GENERATION INC.

CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2012

The nuclear fixed asset removal and nuclear waste management funds as at December 31 consist of the following:

(millions of dollars)	Fair Value 2012	2011
Decommissioning Fund	**5,771**	5,342
Due to Province – Decommissioning Fund	**(64)**	-
	5,707	5,342
Used Fuel Fund [1]	**7,245**	6,509
Due (to) from Province – Used Fuel Fund	**(235)**	47
	7,010	6,556
Total Nuclear Funds	**12,717**	11,898
Less: current portion	**27**	20
Non-current Nuclear Funds	**12,690**	11,878

[1] The Ontario NFWA Trust represented $2,559 million as at December 31, 2012 (2011 – $2,296 million) of the Used Fuel Fund on a fair value basis.

The fair value of the securities invested in the Nuclear Funds as at December 31 is as follows:

(millions of dollars)	Fair Value 2012	2011
Cash and cash equivalents and short-term investments	**335**	555
Alternative investments	**362**	212
Pooled funds	**2,093**	1,842
Marketable equity securities	**5,670**	4,863
Fixed income securities	**4,523**	4,345
Derivatives	**-**	2
Net receivables/payables	**41**	38
Administrative expense payable	**(8)**	(6)
	13,016	11,851
Due (to) from Province	**(299)**	47
	12,717	11,898

The bonds and debentures held in the Used Fuel Fund and the Decommissioning Fund as at December 31 mature according to the following schedule:

(millions of dollars)	Fair Value 2012	2011
1 – 5 years	**1,151**	1,153
5 – 10 years	**631**	594
More than 10 years	**2,741**	2,598
Total maturities of debt securities	**4,523**	4,345
Average yield	**2.7%**	2.8%

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these wastes. The current assumptions used to establish the accrued L&ILW management costs include a L&ILW deep geologic repository (L&ILW DGR). Agreement has been reached with local municipalities for OPG to develop a deep geologic repository for the long-term management of L&ILW adjacent to the Western Waste Management Facility.

OPG has suspended design activities pending receipt of the site preparation and construction licence which is expected in the first half of 2015.

Liability for Non-Nuclear Fixed Asset Removal Costs

The liability for non-nuclear fixed asset removal primarily represents the estimated costs of decommissioning OPG's thermal generating stations. The liability is based on third-party cost estimates after an in-depth review of active plant sites and an assessment of required clean-up and restoration activities. As at December 31, 2013, the estimated retirement dates of the thermal stations for the purposes of this liability are between 2014 and 2030. The discount rates range from 1.5 percent to 5.8 percent. The undiscounted amount of estimated future cash flows associated with the non-nuclear liabilities is $491 million in 2013 dollars.

As at December 31, 2013, in addition to the $134 million liability for active sites, OPG has an ARO of $220 million for decommissioning and restoration costs associated with plant sites that are no longer in use for electricity generation, including the Nanticoke and Lambton generating stations.

Ontario Nuclear Funds Agreement

The Decommissioning Fund was established to fund the future costs of nuclear fixed asset removal, long-term L&ILW management and a portion of used fuel storage costs after station life. As at December 31, 2013, the Decommissioning Fund was in an overfunded position.

The Used Fuel Fund was established to fund future costs of long-term nuclear used fuel waste management. OPG is responsible for the risk and liability of cost increases for used fuel waste management, subject to graduated liability thresholds specified in the ONFA, which limit OPG's total financial exposure at approximately $12.9 billion in present value dollars as at December 31, 2013, based on used fuel bundle projections of 2.23 million bundles, consistent with the station life assumptions included within the initial financial reference plan. The graduated liability thresholds do not apply to additional used fuel bundles beyond 2.23 million.

OPG makes quarterly payments to the Used Fuel Fund over the life of its nuclear generating stations, as specified in the ONFA. Required funding for 2013 under the ONFA was $184 million (2012 – $182 million), including a contribution to the Ontario NFWA Trust (the Trust) of $154 million (2012 – $149 million). Based on the approved 2012 ONFA Reference Plan, OPG is required to contribute annual amounts to the Used Fuel Fund, ranging from $139 million to $193 million over the years 2014 to 2018 (Refer to Note 15).

The NFWA was proclaimed into force in November 2002. As required under the NFWA, OPG established the Trust in November 2002 and made an initial deposit of $500 million into the Trust. The NFWA required OPG to make annual contributions of $100 million to the Trust, until such time that the NWMO proposed funding formula, designed to address the future financial costs of implementing the Adapted Phase Management approach, was approved by the Federal Minister of Natural Resources. In 2009, this funding formula was approved. The Trust forms part of the Used Fuel Fund, and contributions to the Trust, as required by the NFWA, may be applied towards OPG's ONFA payment obligations.

As required by the terms of the ONFA, the Province has provided a Provincial Guarantee to the Canadian Nuclear Safety Commission (CNSC) since 2003, on behalf of OPG. The *Nuclear Safety and Control Act* (Canada) requires OPG to have sufficient funds available to discharge the current nuclear decommissioning and waste management liabilities. The Provincial Guarantee provides for any shortfall between the CNSC consolidated financial guarantee requirement and the Nuclear Funds. OPG pays the Province an annual guarantee fee of 0.5 percent of the amount of the Provincial Guarantee provided by the Province. The current value of the Provincial Guarantee amount of $1,551 million is in effect through to the end of 2017. In each of January 2013 and 2014, OPG paid a guarantee fee of $8 million based on a Provincial Guarantee amount of $1,551 million.

Decommissioning Fund

Upon termination of the ONFA, the Province has a right to any excess funding in the Decommissioning Fund, which is the excess of the fair market value of the Decommissioning Fund over the estimated completion costs, as per the most recently approved ONFA Reference Plan. When the Decommissioning Fund is overfunded, OPG limits the earnings it recognizes in its consolidated financial statements by recording a payable to the Province, such that the balance of the Decommissioning Fund is equal the cost estimate of the liability based on the most recently approved ONFA Reference Plan. The payable to the Province may be reduced in subsequent periods in the event that the Decommissioning Fund earns less than its target rate of return or in the event that a new ONFA Reference Plan is approved with a higher estimated decommissioning liability. When the Decommissioning Fund is underfunded, the earnings on the Decommissioning Fund reflect actual fund returns based on the market value of the assets.

The Province's right to any excess funding in the Decommissioning Fund upon termination of the ONFA results in OPG capping its annual earnings at 3.25 percent plus long-term Ontario Consumer Price Index (CPI), which is the rate of growth in the liability for the estimated completion cost, as long as the Decommissioning Fund is in an overfunded status.

The Decommissioning Fund's asset value on a fair value basis was $5,967 million as at December 31, 2013, which was net of the due to the Province of $624 million, as the asset value of the fund was higher than the liability per the approved 2012 ONFA Reference Plan. As at December 31, 2012, the Decommissioning Fund's asset value on a fair value basis was $5,707 million, also higher than the liability per the 2012 ONFA Reference Plan. Under the ONFA, if there is a surplus in the Decommissioning Fund such that the liabilities, as defined by the most recently approved ONFA Reference Plan, are at least 120 percent funded, OPG may direct up to 50 percent of the surplus over 120 percent to be treated as a contribution to the Used Fuel Fund and the OEFC would be entitled to a distribution of an equal amount. Since OPG is responsible for the risks associated with liability cost increases and investment returns in the Decommissioning Fund, future contributions to the Decommissioning Fund may be required should the fund be in an underfunded position at the time of the next liability reference plan review.

The investments in the Decommissioning Fund include a diversified portfolio of equities and fixed income securities that are invested across geographic markets, as well as investments in infrastructure and Canadian real estate. The Nuclear Funds are invested to fund long-term liability requirements and, as such, the portfolio asset mix is structured to achieve the required return over a long-term horizon. While short-term fluctuations in market value will occur, managing the long-term return of the Nuclear Funds remains the primary goal.

Used Fuel Fund

Under the ONFA, the Province guarantees OPG's annual return in the Used Fuel Fund at 3.25 percent plus the change in the Ontario CPI for funding related to the first 2.23 million of used fuel bundles (committed return). OPG recognizes the committed return on the Used Fuel Fund and includes it in the earnings on the nuclear fixed asset removal and nuclear waste management funds. The difference between the committed return on the Used Fuel Fund and the actual market return, based on the fair value of the Used Fuel Fund's assets, which includes realized and unrealized returns, is recorded as due to or due from the Province. The due to or due from the Province represents the amount the fund would pay to or receive from the Province if the committed return were to be settled as of the consolidated balance sheet date. As prescribed under the ONFA, OPG's contributions for incremental fuel bundles are not subject to the Province's guaranteed rate of return, but rather earn a return based on changes in the market value of the assets of the Used Fuel Fund.

As at December 31, 2013, the Used Fuel Fund asset value on a fair value basis was $7,529 million. The Used Fuel Fund value included a due to the Province of $990 million related to the committed return adjustment. As at December 31, 2012, the Used Fuel Fund asset value on a fair value basis was $7,010 million, including a due to the Province of $235 million related to the committed return adjustment.

Under the ONFA, the Province is entitled to any surplus in the Used Fuel Fund, subject to a threshold funded ratio of 110 percent compared to the value of the associated liabilities.

The nuclear fixed asset removal and nuclear waste management funds as at December 31 consist of the following:

	Fair Value	
(millions of dollars)	**2013**	**2012**
Decommissioning Fund	**6,591**	5,771
Due to Province – Decommissioning Fund	**(624)**	(64)
	5,967	5,707
Used Fuel Fund [1]	**8,519**	7,245
Due to Province – Used Fuel Fund	**(990)**	(235)
	7,529	7,010
Total Nuclear Funds	**13,496**	12,717
Less: current portion	**25**	27
Non-current Nuclear Funds	**13,471**	12,690

[1] The Ontario NFWA Trust represented $2,668 million as at December 31, 2013 (2012 – $2,559 million) of the Used Fuel Fund on a fair value basis.

The fair value of the securities invested in the Nuclear Funds as at December 31 is as follows:

	Fair Value	
(millions of dollars)	**2013**	**2012**
Cash and cash equivalents and short-term investments	**262**	335
Alternative investments	**598**	362
Pooled funds	**2,173**	2,093
Marketable equity securities	**7,332**	5,670
Fixed income securities	**4,713**	4,523
Net receivables/payables	**32**	41
Administrative expense payable	**-**	(8)
	15,110	13,016
Due to Province	**(1,614)**	(299)
	13,496	12,717

The bonds and debentures held in the Used Fuel Fund and the Decommissioning Fund as at December 31 mature according to the following schedule:

	Fair Value	
(millions of dollars)	**2013**	**2012**
1 – 5 years	**1,334**	1,151
5 – 10 years	**871**	631
More than 10 years	**2,508**	2,741
Total maturities of debt securities	**4,713**	4,523
Average yield	**3.2%**	2.7%

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6. FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT LIABILITIES

The liabilities for fixed asset removal and nuclear waste management on a present value basis as at March 31, 2014 and December 31, 2013 consist of the following:

(millions of dollars)	March 31 2014	December 31 2013
Liability for nuclear used fuel management	**10,086**	9,957
Liability for nuclear decommissioning and low and intermediate level waste management	**6,012**	5,946
Liability for non-nuclear fixed asset removal	**358**	354
Fixed asset removal and nuclear waste management liabilities	**16,456**	16,257

Nuclear Funds

Beginning January 1, 2014, the Company applied ASC 946 for all investments owned by the Decommissioning Fund and the Used Fuel Fund. OPG's consolidated financial statements retained investment company accounting for the Nuclear Funds. The adoption of investment company accounting for the Nuclear Funds did not result in an effect on net income or change in net assets from operations as investments held by OPG's Nuclear Funds continue to be recorded at fair value.

The policy for distinguishing the nature and type of investments made by OPG which retain investment company accounting from other investments made by OPG is that these investments have the attributes of an investment company in accordance with ASC 946 as amended by Accounting Standards Update 2013-08, *Financial Services – Investment Companies (Topic 946): Amendments to the Scope, Measurement, and Disclosure Requirements.*

The historical cost, gross unrealized aggregate appreciation and depreciation of investment, gross unrealized foreign exchange gains and fair value of the Nuclear Funds as of March 31, 2014 are summarized as follows:

(millions of dollars)	Decommissioning Fund	Used Fuel Fund [1]	Total
Historical cost	**5,837**	**7,633**	**13,470**
Unrealized gains			
Gross unrealized aggregate appreciation	**1,041**	**1,233**	**2,274**
Gross unrealized aggregate depreciation	**(98)**	**(101)**	**(199)**
Gross unrealized foreign exchange gains	**98**	**142**	**240**
	6,878	**8,907**	**15,785**
Due to Province	**(845)**	**(1,262)**	**(2,107)**
Total fair value	**6,033**	**7,645**	**13,678**
Less: current portion	**9**	**7**	**16**
Non-current fair value	**6,024**	**7,638**	**13,662**

[1] The Ontario NFWA Trust represented $2,913 million as at March 31, 2014 of the Used Fuel Fund on a fair value basis.

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6. FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT LIABILITIES

The liabilities for fixed asset removal and nuclear waste management on a present value basis as at June 30, 2014 and December 31, 2013 consist of the following:

(millions of dollars)	June 30 2014	December 31 2013
Liability for nuclear used fuel management	**10,207**	9,957
Liability for nuclear decommissioning and low and intermediate level waste management	**6,081**	5,946
Liability for non-nuclear fixed asset removal	**360**	354
Fixed asset removal and nuclear waste management liabilities	**16,648**	16,257

Nuclear Funds

Beginning January 1, 2014, the Company applied ASC 946 for all investments owned by the Decommissioning Fund and the Used Fuel Fund. OPG's consolidated financial statements retained investment company accounting for the Nuclear Funds. The adoption of investment company accounting for the Nuclear Funds did not result in an effect on net income or change in net assets from operations as investments held by OPG's Nuclear Funds continue to be recorded at fair value.

The policy for distinguishing the nature and type of investments made by OPG which retain investment company accounting from other investments made by OPG is that these investments have the attributes of an investment company in accordance with ASC 946 as amended by Accounting Standards Update 2013-08, *Financial Services – Investment Companies (Topic 946): Amendments to the Scope, Measurement, and Disclosure Requirements.*

The historical cost, gross unrealized aggregate appreciation and depreciation of investments, gross unrealized foreign exchange gains and fair value of the Nuclear Funds as at June 30, 2014 are summarized as follows:

(millions of dollars)	Decommissioning Fund	Used Fuel Fund [1]	Total
Historical cost	**5,980**	**7,850**	**13,830**
Unrealized gains			
Gross unrealized aggregate appreciation	**1,151**	**1,369**	**2,520**
Gross unrealized aggregate depreciation	**(73)**	**(72)**	**(145)**
Gross unrealized foreign exchange gains	**14**	**30**	**44**
	7,072	**9,177**	**16,249**
Due to Province	**(972)**	**(1,291)**	**(2,263)**
Total fair value	**6,100**	**7,886**	**13,986**
Less: current portion	**5**	**10**	**15**
Non-current fair value	**6,095**	**7,876**	**13,971**

[1] The Ontario NFWA Trust represented $2,984 million as at June 30, 2014 of the Used Fuel Fund on a fair value basis.

9.9 Primary (reprioritized) - What other deferral accounts, if any, should be established for OPG?

246. AMPCO agrees with Board Staff that an account should be set up to capture the Gross Revenue Charge (GRC) costs for return to ratepayers.

247. AS discussed under Issue 8.1 and 8.2, AMPCO recommends that the Board establish a deferral account to record 50% of any transfer of funds envisaged by section 4.7.3 of ONFA to be applied to the Used Fuel Fund in a future application.

12. IMPLEMENTATION

12.1 Oral Hearing: Are the effective dates for new payment amounts and riders appropriate?

248. AMPCO submits the effective dates of the payment amounts for the Regulated Nuclear and Previously Regulated Hydroelectric should be the first day of the month following the Board's payment amounts order.