Ontario Power Generation Inc. (Re)

Ontario Energy Board Decisions

Ontario Energy Board

Panel: Marika Hare, Presiding Member; Christine Long, Member; Allison Duff, Member

Decision: November 20, 2014.

No. EB-2013-0321

2014 LNONOEB 42

IN THE MATTER OF an Application by Ontario Power Generation Inc. Payment Amounts for Prescribed Facilities for 2014 and 2015 IN THE MATTER OF the Ontario Energy Board Act, 1998, S.O.1998, c.15, (Schedule B); AND IN THE MATTER OF an application by 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.

(589 paras.)

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DECISION WITH REASONS

EXECUTIVE SUMMARY

1 This is the Decision of the Ontario Energy Board (the "Board") regarding an application filed by Ontario Power Generation Inc. ("OPG"). OPG is the largest electricity generator in Ontario. Provincial regulation requires that the Board set the rates that OPG charges for the generation from its nuclear facilities (Pickering and Darlington) and most of its hydroelectric facilities (e.g. Sir Adam Beck I and II on the Niagara River). The rates charged by OPG are referred to as payment amounts and are expressed in dollars per megawatt-hour ($/MWh). These payment amounts are included in the electricity costs which are shown as a line item on the electricity bill from a customer's distributor, and make up about half the total of an average household bill.

2 Payment amounts for electricity generated from OPG's two nuclear facilities and six of its hydroelectric facilities (on the Niagara, Welland and St. Lawrence Rivers) were last set for the period 2011 and 2012. These amounts remained in place for 2013 as OPG did not file a payment amounts application for 2013. Payment amounts are set by the Board in accordance with provincial regulations which stipulate, among other matters, which facilities are included in the payment amounts. As of July 1, 2014 these facilities include 48 hydroelectric plants that were not previously covered by the regulation. These hydroelectric plants are referred to as the "newly regulated" hydroelectric facilities in this Decision.

3 If the payment amounts were approved by the Board as proposed by OPG, the bill impact on a typical residential customer would be an increase of $5.31 per month, or a 23.4% increase over current payment amounts. However, this Decision adjusts numerous elements that factor into the calculation of the resulting payment amounts. These include elements such as costs, revenues, taxes and production forecasts. The approximate impact on the payment amounts as a result of this Decision is an increase of 10% over the payment amounts that OPG is currently paid, a significant reduction over the increase requested by OPG. This is an approximation only, as the exact number cannot be determined until OPG reflects all aspects of this Decision that factor into the calculation of the resulting payment amounts.

4 OPG filed an incomplete application at the end of September 2013. The proceeding leading to this Decision was extremely lengthy, due to the delay in the filing of a complete application, several updates to the evidence from December 2013 to July 2014, and complexities associated with the amount of information for which confidential treatment was sought.

5 In reaching its findings, the Board was aided by the participation of 20 parties, representing diverse customer interests and policy matters, and Board staff. The Board also took note of 41 letters of comment received from customers and numerous independent consultant reports. In addition, the Auditor General's report[1] was filed in this proceeding and provided context to OPG's human resources issues.

6 This Decision of the Board addresses issues in the detail required to set the payment amounts for 2014 and 2015. The Decision is organized into the following major sections: introduction, regulated hydroelectric facilities, nuclear facilities, corporate matters, design of payment amounts and implementation of the Decision. Key highlights of this Decision include:

* Reduction in OPG's proposed Operations, Maintenance and Administration budget in both the nuclear and hydroelectric sides of the business mainly due to excessive compensation. The reductions total $100 M per year.
* Approval of a $1,364.6M addition to rate base due to the completion and in-service addition of the Niagara Tunnel, a reduction of $88M from what OPG had requested to be included.
* Approval of the in-service additions associated with the Darlington Refurbishment project for 2014 and 2015.
* Denial of the request for approval of commercial and contracting strategies with respect to the Darlington Refurbishment project.
* Rejection of the accrual method of accounting for determining pension and other post-employment benefit costs for ratemaking in 2014 and 2015.
* Adjustment of the debt:equity ratio from 53:47 to 55:45.
* Direction to OPG to undertake independent and comprehensive benchmarking studies for the hydroelectric business and for corporate support costs, and to undertake a comprehensive compensation study.
* Effective date for the commencement of these new payment amounts will be November 1, 2014.

1 INTRODUCTION

7 Ontario Power Generation Inc. filed an application with the Ontario Energy Board on September 27, 2013. The initial application was deemed by the Board to be incomplete, and the complete application was not filed until December 5, 2013. The application was filed under section 78.1 of the *Ontario Energy Board Act, 1998*, S.O 1998, c. 15 (Schedule B) (the "Act"), seeking approval for payment amounts for OPG's previously regulated hydroelectric facilities and nuclear facilities for the test period January 1, 2014 through December 31, 2015, to be effective January 1, 2014. The application also seeks approval for payment amounts for newly regulated hydroelectric facilities to be effective July 1, 2014. The Board assigned the application file number EB-2013-0321.

8 OPG requested, and the Board issued, an order declaring the current payment amounts interim for the previously regulated hydroelectric facilities and nuclear facilities as of January 1, 2014 and for the newly regulated hydroelectric facilities as of July 1, 2014, pending the Board's final decision.

1.1 Legislative Requirements

9 Section 78.1(1) of the Act establishes the Board's authority to set the payment amounts for the prescribed generation facilities. Section 78.1 can be found at Appendix A of this Decision. Section 78.1(4) states:

> The Board shall make an order under this section in accordance with the rules prescribed by the regulations and may include in the order conditions, classifications or practices, including rules respecting the calculation of the amount of the payment.

10 Section 78.1(5) states:

> The Board may fix such other payment amounts as it finds to be just and reasonable,

(a) on an application for an order under this section, if the Board is not satisfied that the amount applied for is just and reasonable; or

(b) at any other time, if the Board is not satisfied that the current payment amount is just and reasonable.

11 Ontario Regulation 53/05, *Payments Under Section 78.1 of the Act*, ("O. Reg. 53/05") provides that the Board may establish the form, methodology, assumptions and calculations used in making an order that sets the payment amounts. O. Reg. 53/05 also includes detailed requirements that govern the determination of some components of the payment amounts. O. Reg. 53/05 can be found at Appendix B.

12 On November 27, 2013, O. Reg. 53/05 was amended to require regulation by the Board of 48 additional hydroelectric stations.

1.2 The Prescribed Generation Facilities

13 OPG owns and operates both regulated and unregulated generation facilities. As set out in section 2 of O. Reg. 53/05, the regulated, or prescribed, facilities consist of six previously regulated hydroelectric generating stations and two nuclear generating stations. As amended in November 2013 and set out in section 2 and the schedule of O. Reg. 53/05, the newly regulated hydroelectric facilities are comprised of 48 stations. OPG operates these stations in 4 plant groups, as shown in the table below. The regulated facilities produce more than half of the electricity consumed in Ontario.

Table 1: Prescribed Generation Facilities

Previously Regulated Hydroelectric		Newly Regulated Hydroelectric		Nuclear	
Station	MW	Plant Group	MW	Station	MW
Sir Adam Beck I	427	Ottawa St. Lawrence	1,526	Pickering Units 1&4	1,030
Sir Adam Beck II	1,499	Central Hydro	108	Pickering Units 5-8	2,064
Sir Adam Beck PGS	174	Northeast	818	Darlington	3,512
DeCew Falls I	23	Northwest	658		
DeCew Falls II	144				
RH Saunders	1,045				
TOTAL	**3,312**		**3,110**		**6,606**

14 In 2010, the operations of Pickering Units 1 and 4 (formerly referred to as Pickering A) and Pickering Units 5 - 8 (formerly referred to as Pickering B) were amalgamated into a single station.

15 OPG also owns the Bruce A and B nuclear generating stations. These stations are leased on a long term basis to Bruce Power L.P. Under section 6(2)9 of O. Reg. 53/05, the Board must ensure that OPG recovers all the costs it incurs with respect to the Bruce nuclear generating stations. Under section 6(2)10 of O. Reg. 53/05, the revenues from the lease, net of costs, are to be used to reduce the payment amounts for the prescribed nuclear generating stations.

16 OPG has entered into a Memorandum of Agreement with its shareholder. This Memorandum sets out the shared expectations of OPG and its shareholder regarding OPG's mandate, governance, performance and communications. Included in its provisions related to the nuclear mandate are expectations related to continuous improvement, benchmarking, and improved operations. The Memorandum is reproduced at Appendix C.

1.3 Previous Proceedings

17 The current application is OPG's third cost of service application. The previous proceedings were assigned file numbers EB-2007-0905, *2009 LNONOEB 114* and EB-2010-0008, *2011 LNONOEB 57*.[2]

18 In 2012, OPG filed an application, EB-2012-0002, seeking approval to adopt Generally Accepted Accounting Principles of the United States ("USGAAP") for regulatory accounting purposes and to clear 2012 year-end deferral and variance account balances for all accounts except for four. Parties to the proceeding achieved settlement and the Board accepted the settlement proposal. The EB-2012-0002 decision established payment amount riders for 2013 and 2014 to clear the 2012 account balances. In this proceeding OPG proposes disposition of the four accounts not previously cleared in EB-2012-0002.

1.4 The Application

19 The application filed on September 27, 2013 was underpinned by OPG's 2013-2015 business plan. The application, as filed, was deemed by the Board to be incomplete and OPG filed additional evidence on December 5, 2013 to meet the Board's filing requirements. If approved, the application would result in an increase of $5.36 on the monthly total bill for a typical residential customer consuming 800 kWh per month. This information was published in the Notice of Application in 88 newspapers throughout the province.

20 OPG filed an impact statement on December 6, 2013 (Exhibit N1) that updated the application to reflect material changes in costs and production forecasts for the 2014-2015 period which were included in OPG's 2014-2016 business plan. As the bill impact resulting from the Exhibit N1 update would result in an increase of $5.94 on the monthly total bill, the Board determined that further notice was required.

21 A second impact statement was filed on May 16, 2014 (Exhibit N2) to update the application to reflect material changes in costs and production forecasts that had arisen since the first impact statement was filed in December 2013. The bill impact of the subsequent Exhibit N2 update was proposed to be an increase of $5.31 per month. Based on the Exhibit N2 update, OPG is seeking an increase of 23.4% on payment amounts.

22 The proposed revenue requirement, as updated on May 16, 2014, is summarized in the following table.

Table 2: Proposed Revenue Requirement

$million	Previously Regulated Hydroelectric		Newly Regulated Hydroelectric		Nuclear		
	2014	2015	2014 [1]	2015	2014	2015	TOTAL
Expenses							
OM&A [2]	145.1	140.0	117.5	237.3	2,401.4	2,419.8	5,461.1
Gross Revenue Charge/Nuclear Fuel	267.2	280.8	37.8	77.5	266.5	260.5	1,190.3
Depreciation	82.1	81.9	31.1	63.1	273.7	288.5	820.4
Property Tax	0.3	0.3	0.1	0.1	15.9	16.4	33.1
Income Tax	49.7	64.2	15.0	42.7	108.3	16.8	296.7
Cost of Capital							
Short-term Debt	3.6	4.6	0.9	2.3	1.6	2.1	15.1
Long-term Debt	127.0	126.2	31.1	62.7	57.4	58.3	462.7
Return on Equity	225.6	227.7	55.3	113.2	101.9	105.3	829.0
Adjustment for lesser of UNL or ARC [3]					74.6	70.3	144.9
Other Revenue	(34.0)	(34.6)	(11.4)	(23.1)	(33.2)	(30.5)	(166.8)
Bruce Net Revenue					(39.7)	(40.6)	(80.3)
Revenue Requirement	866.6	891.1	277.3	575.8	3,228.4	3,166.9	9,006.1
Deferral and Variance Accounts		70.6				62.2	132.8

Note 1: The newly regulated hydroelectric revenue requirement reflects July 1, 2014

Note 2: OM&A - Operations, Maintenance and Administration Costs

Note 3: UNL - unfunded nuclear liability, ARC - asset retirement cost

23 To achieve the revenue requirement and disposition of balances in the four deferral and variance accounts, OPG requested the payment amounts and riders shown in the following table, which also provides the current payment amounts and riders.

Table 3: Payment Amounts and Riders

$/MWh	Previously Regulated Hydroelectric	Newly Regulated Hydroelectric	Nuclear
Current			
Payment Amount	35.78		51.52
Rider (2013) [1]	3.04		6.27
Rider (2014) [1]	2.02		4.18
Proposed			
Payment Amount	42.75	47.57	67.60
Rider (2015)	3.36		1.35

Note 1: Payment Amount Riders established by EB-2012-0002

24 A summary of the approvals that OPG is seeking in the current application is found at Appendix D.

1.5 The Proceeding

25 Details of the procedural aspects of the proceeding are provided at Appendix E.

26 In the EB-2010-0008 decision, the Board stated that it "will explore with OPG and stakeholders how best to identify issues in the next proceeding to ensure that the highest priority issues are identified early." The Board also expressed concern that "an inordinate focus on lower priority issues diminishes the time and resources available to pursue the more substantive, higher priority issues." As a result, the Board established a process for categorizing primary and secondary issues in this cost of service proceeding and made provision for a settlement process for certain issues. Any unsettled primary issues would proceed to oral hearing and any unsettled secondary issues would proceed to written hearing.

27 The Board convened a settlement conference between OPG and the parties on May 21 to 26, 2014. No settlement was achieved. The Board established the final prioritized issues list for the proceeding in June, 2014. That issues list is found at Appendix F.

28 The Board received 41 letters of comment in response to the Notices of Application. The Board has reviewed each of these letters. The letters raise a variety of issues, many of which are dealt with in this Decision. Many of the letters of comment expressed concern about the request to increase payment amounts and the difficulty customers faced in paying current electricity bills without any additional increase. Although the Board will not address each letter specifically, the comments have been taken into account in the Board's deliberations.

29 Two parties applied for, and were granted, observer status. Twenty parties applied for and were granted intervenor status. The submissions of the following parties are referred to in this Decision: Association of Major Power Consumers in Ontario ("AMPCO"), Canadian Manufacturers & Exporters ("CME"), Consumers Council of Canada ("CCC"), Energy Probe Research Foundation ("Energy Probe"), Environmental Defence, Green Energy Coalition ("GEC"), Independent Electricity System Operator ("IESO"), Lake Ontario Waterkeeper ("Waterkeeper), London Property Management Association ("LPMA"), Power Workers' Union ("PWU"), School Energy Coalition ("SEC"), Society of Energy Professionals ("Society"), Sustainability-Journal and Vulnerable Energy Consumers Coalition ("VECC").

30 During the proceeding, confidential treatment was sought for a large number of documents.

31 This Decision addresses issues in the detail required to set the payment amounts for 2014 and 2015. The Decision is organized into the following major sections: the regulated hydroelectric facilities, nuclear facilities, corporate matters, design of payment amounts and implementation of the Decision.

2 REGULATED HYDROELECTRIC FACILITIES

2.1 Hydroelectric Production Forecast

(Issues 5.1 and 5.2)

32 At the highest level, OPG's payment amounts result from a simple equation: OPG's reasonably incurred costs divided by the number of megawatt-hours it is expected to produce (i.e. the production forecast). The production forecast put forward by OPG, therefore, is a major input in the calculation of final payment amounts. OPG proposed for the Board's approval a production forecast of 32.5 TWh[3] for 2014 and 33.5 TWh for 2015.

33 OPG's historical hydroelectric production and production forecast for 2014 and 2015 are summarized in the following table. The production includes the Niagara Tunnel Project which went into service in March 2013.

Table 4: Hydroelectric Production Forecast

TWh	2010 Actual	2011 Approved	2011 Actual	2012 Approved	2012 Actual	2013 Budget	2013 Actual	2014 Plan	2015 Plan
Niagara	12.4	12.9	12.6	12.9	11.9	12.2	12.4	12.8	13.5
Saunders	6.5	7.0	6.9	7.0	6.5	6.2	6.5	6.3	6.7
Sub-Total	**18.9**	**19.9**	**19.5**	**19.9**	**18.4**	**18.4**	**18.9**	**19.1**	**20.2**
Newly Regulated	10.0		11.5		10.9	12.4	12.5	12.4	12.5
Total	**28.9**		**31.0**		**29.3**	**30.8**	**31.4**	**31.5**	**32.7**
Exhibit N1 Update - Previously Regulated only, no change for Newly Regulated								**32.5**	**33.5**
Source: Exh E1-1-2, Exh L-1-Staff-2, Exh N1-1-1									

34 OPG uses computer models to predict water flow and production forecast for the previously regulated hydroelectric facilities and the larger of the newly regulated hydroelectric facilities. The production forecast for the 27 smaller newly regulated hydroelectric facilities is based on historical production.

35 The hydroelectric water conditions variance account captures the impact of the difference between forecast and actual water conditions for the previously regulated hydroelectric facilities. OPG proposes that the variance account also apply to the larger of the newly regulated hydroelectric facilities.

36 OPG's production forecast did not include an adjustment for surplus baseload generation. This condition occurs when electricity production from baseload facilities (such as nuclear and hydroelectric) exceeds Ontario demand. When OPG is unable to store water in a surplus baseload generation situation, the financial impact of the foregone revenue is recorded in the surplus baseload generation variance account.

37 CME observed that the balances in the variance account are large and submitted that the Board should embed some level of surplus baseload generation into the payment amounts by adjusting OPG's production forecast. In reply, OPG submitted it did not disagree with CME's proposal, but chose to maintain the Board-approved approach in EB-2010-0008, utilizing a variance account rather than including a forecast production adjustment.

38 Board staff observed that actual surplus baseload generation in 2011 and 2012 was significantly lower than forecast for those 2 years. Board staff and several other parties submitted that the production forecast, without surplus baseload generation adjustment, was appropriate.

Board Findings

39 The Board accepts the hydroelectric production forecast as filed. The forecast methodology was based on the methodology used in EB-2010-0008 for the previously regulated hydroelectric production forecast. The same production forecast methodology was applied to the larger of the newly regulated hydroelectric assets. The hydroelectric production forecast of 66.0 TWh (32.5 TWh for 2014 and 33.5 TWh for 2015) is reasonable.

40 OPG provided estimates of surplus baseload generation in 2014 and 2015 for information purposes only, not for the purpose of adjusting its hydroelectric production forecast and revenue requirement calculation. As a result, the Board does not find it necessary to comment on the 2014 and 2015 estimates provided, as the actual revenue implications will be captured in the surplus baseload generation variance account.

41 The Board will not implement CME's proposal to include a forecast production adjustment given the uncertainties in any surplus baseload generation forecast for the previously regulated or the newly regulated hydroelectric facilities.

2.1.1 Hydroelectric Incentive Mechanism

(Issues 5.3 and 5.4)

42 OPG has the ability to store water at its pump generating station, and at some of its other hydroelectric facilities. Water can be "held back" during periods of low demand (and low market prices), and then released during periods of higher demand (and consequently higher market prices). Shifting production of relatively low cost hydroelectric power from periods of low demand to periods of high demand will generally benefit all consumers by lowering the market price during high demand periods.

43 OPG could be paid the same amount for production no matter what the market price is, however, OPG would have no built in monetary incentive to shift its regulated hydroelectric generation from periods of low demand to periods of high demand. For this reason, starting with the incentive in *O. Reg. 53/05*, OPG has been provided with an incentive to shift its hydroelectric production from times of low demand to times of high demand.

44 In OPG's last payments proceeding (EB-2010-0008) the Board found that a revised hydroelectric incentive mechanism for production from OPG's regulated hydroelectric assets was appropriate. The approved hydroelectric incentive mechanism was based on sharing 50% of the hydroelectric incentive mechanism revenues through revenue requirement adjustments, retention by OPG of an equal amount and sharing of any additional net revenues.

45 The EB-2010-0008 decision also directed OPG to undertake an analysis of the interaction between the hydroelectric incentive mechanism and surplus baseload generation. OPG's analysis indicated that as a result of surplus baseload generation reducing the monthly average hourly production threshold for the hydroelectric incentive mechanism, there was an unintended benefit to OPG. The 2011-2013 unintended benefit to OPG has been determined to be $6.8M.[4]

46 In the current proceeding, OPG has proposed an enhanced hydroelectric incentive mechanism that is based on a forecast of consumer benefits and which it considered to be administratively simpler. The mechanism would apply to both previously and newly regulated hydroelectric facilities. OPG estimates the consumer benefits resulting from the enhanced hydroelectric incentive mechanism to be $36M in each of 2014 and 2015 and proposes X-factor adjustments to the hydroelectric incentive mechanism and surplus baseload generation monthly calculations such that the benefits are shared and the unintended benefit to OPG is corrected. OPG's proposal also included elimination of the revenue requirement adjustment and no further additions to the hydroelectric incentive mechanism variance account.

47 OPG indicated that it would not change how the previously and newly regulated hydroelectric facilities are operated under the enhanced hydroelectric incentive mechanism. Under that premise, the IESO submitted that the enhanced hydroelectric incentive mechanism is acceptable from a market efficiency perspective.

48 Board staff submitted that the enhanced hydroelectric incentive mechanism is based on OPG's forecast of benefits and could generate results that are one-sidedly beneficial to OPG. However, OPG argued that actual benefits could be lower, so the proposal is symmetric.

49 Board staff submitted that the current hydroelectric incentive mechanism should be retained with revenue requirement adjustments of $22M in 2014 and $37M in 2015 to reflect the addition of the newly regulated hydroelectric facilities. While the current mechanism provides for 50:50 revenue sharing, Board staff submitted that the Board could consider a graduated sharing such that more was returned to ratepayers at higher revenue levels. Board staff submitted that an after-the-fact adjustment to the monthly average hourly production threshold that corrects for surplus baseload generation impacts should be processed. The staff submission was supported by most parties.

50 OPG stated that the Board staff submission is inferior to the enhanced hydroelectric incentive mechanism proposed by OPG. However, if the Board adopts the approach put forward by Board staff, the hydroelectric incentive mechanism variance account should be symmetrical, protecting both ratepayers and OPG. OPG also argued that there is no need for a graduated sharing mechanism as it would have the effect of reducing the amount of time shifting that OPG performs.

51 CME and VECC submitted that the December 31, 2013 balance in the surplus baseload generation account should be adjusted by the $6.8M unintended benefit. This matter is also noted in the deferral and variance account section of this Decision.

Board Findings

52 The Board finds that the current incentive mechanism has encouraged appropriate use of the regulated hydroelectric facilities to supply energy in response to market prices. OPG's witnesses testified that they are incented to move production from periods of low value to periods of high value, based on market signals.

53 The Board does not approve OPG's proposed new enhanced hydroelectric incentive mechanism. OPG failed to demonstrate to the Board that the enhanced mechanism was superior to the current mechanism in terms of incentives for OPG or benefits to ratepayers.

54 OPG's enhanced hydroelectric incentive mechanism proposal is predicated on forecasts of consumer cost changes and cost reductions, resulting from its customer benefits analysis. The Board finds that OPG's enhanced hydroelectric incentive mechanism proposal fundamentally shifts from a revenue sharing concept to an estimate of forecast consumer benefits.

55 Further, the enhanced hydroelectric incentive mechanism is dependent upon OPG's forecasts and estimates, as OPG proposes to close the variance account established by the Board in the last proceeding to any further additions. The purpose of the variance account was to enable the sharing of actual revenues above the hydroelectric incentive mechanism threshold, between OPG and ratepayers.

56 Board staff recommended the Board maintain the current hydroelectric incentive mechanism and direct OPG to change its monthly average hourly production threshold calculation to address any unintended benefit in 2014 and 2015. OPG has the information required to make the calculation as it provided the unintended benefit from March 2011 to December 2013. The Board sees merit in Board staff's proposal for the following reasons:

* It provides ratepayers with a revenue sharing potential beyond the forecast in the revenue requirement adjustment.
* It provides OPG with the incentive to maximize actual revenues beyond the forecast, in responding to market prices.
* It is very similar to the existing incentive, yet provides a simple way to correct for the unintended surplus baseload generation benefit.

57 The Board finds the structure of the current variance account appropriate as a mechanism for sharing actual revenues beyond the threshold implicit in the revenue requirement adjustment. The Board will not change the structure of the variance account and will maintain its asymmetrical structure for 2014 and 2015. The Board reiterates its findings in the EB 2010-0008 decision that this incentive is a premium paid by ratepayers to OPG so OPG will operate in a way which is of greater benefit to ratepayers. With the addition of the newly prescribed assets to the hydroelectric generating business, the forecast of benefits arising from the hydroelectric incentive mechanism has increased significantly. For this reason, the Board will change the threshold levels for sharing given OPG's forecast of benefits. A second change from the previous mechanism is to utilize 50% of the forecast in the revenue requirement.

58 The Board finds no compelling reason to change the revenue sharing ratio from the current 50:50 split. Alternative proposals were made in submissions only, and therefore not explored in the hearing.

59 As a result, the Board finds the revenue requirement will be adjusted by $39M in 2014 and $48M in 2015, which is 50% of the forecast hydroelectric incentive mechanism revenues of $78M and $96M for the previously regulated and newly regulated hydroelectric assets.[5] The next $39M of hydroelectric incentive mechanism revenues in 2014 and $48M in 2015 will be retained by OPG. Therefore, the $78M and $96M will be the new thresholds, with any additional revenues beyond those amounts shared equally between OPG and ratepayers enabled by the variance account.

60 OPG shall allocate the revenue requirement adjustment between the previously regulated and newly regulated hydroelectric assets as appropriate.

2.1.2 Energy Storage

(Issue 5.1(a))

61 Sustainability-Journal submitted that the use of energy storage to meet peak demand instead of peak generation systems would reduce cost and emissions. Examples of energy storage include the Enwave Toronto District Heating system and ground source systems. Sustainability-Journal submitted that, while the OPA and IESO have plans to enter into contracts to build storage systems, the consideration of long term storage options has been limited. Sustainability-Journal argued that OPG and other organizations regulated by the Board, should be required to produce public reports that consider energy storage options.

62 OPG replied that it does not have the type of energy storage facilities described by Sustainability-Journal and has no plans to build such facilities. Its view was that it is not necessary for OPG to produce reports on the matter.

Board Findings

63 The Board will not direct OPG to undertake a study of energy storage facilities and opportunities as described by Sustainability-Journal. OPG has indicated it does not intend to pursue such projects, and therefore, the further study of energy storage would not be a wise use of ratepayer money. The government's Long-Term Energy Plan discusses energy storage technologies. The Board will not prescribe a role for OPG in developing those technologies; however, the Board encourages OPG to keep abreast of new technologies in energy storage.

2.2 Hydroelectric OM&A and Benchmarking

(Issues 6.1 and 6.2)

64 OPG seeks approval of operating costs of $494.7M in 2014 and $503M in 2015 for the previously regulated hydroelectric facilities. OPG seeks approval of operating costs of $372.9M in 2014 and $378M in 2015 for the newly regulated hydroelectric facilities.

65 Hydroelectric facility operating costs include OM&A costs, an allocation of corporate support and centrally held OM&A, gross revenue charges (taxes and water rental component governed by legislation), and depreciation and taxes. This section of the Decision addresses hydroelectric OM&A and benchmarking. The other components of hydroelectric operating costs are discussed later in this Decision.

66 OPG's historical and forecast OM&A for the previously regulated hydroelectric facilities are summarized below.

Table 5: Previously Regulated Hydroelectric OM&A

$million	2010 Plan	2010 Actual	2011 Approved	2011 Actual	2012 Approved	2012 Actual	2013 Budget	2013 Actual	2014 Plan	2015 Plan
Base	61.8	59.4	68.7	50.1	62.1	60.2	71.9	61.6	74.6	68.6
Project	5.3	5.4	9.7	6.6	10	13.6	13	14.7	13.5	17.9
SubTotal Operations	67.1	64.8	78.4	56.7	72.1	73.8	84.9	76.3	88.1	86.5
Corporate Costs	25.1	22.4	24.8	22.0	26.3	24.5	29.7	26.1	29.8	26.9
Centrally Held Costs	20.3	19.6	22.9	15.9	25.5	19.6	25.1	20.7	26.1	26.0
Asset Service Fee	2.0	2.1	2.1	1.6	2.0	1.8	1.7	1.6	1.5	1.7
SubTotal Other	47.4	44.1	49.8	39.5	53.8	45.9	56.5	48.4	57.4	54.6
Total OM&A	**114.5**	**108.9**	**128.2**	**96.2**	**125.9**	**119.7**	**141.4**	**124.7**	**145.5**	**141.1**
Exhibit N1 Update									**149.2**	**144.2**
Exhibit N2 Update									**145.1**	**140.0**

Sources: Exh F1-1-1 Table 1, Exh L-6.1-CCC-17, Exh L-1-Staff-2 Table 15, Exh N2-1-1 Attachment 5

67 OPG's historical and forecast OM&A for the newly regulated hydroelectric facilities are summarized below.

Table 6: Newly Regulated Hydroelectric OM&A

$million	2010 Plan	2010 Actual	2011 Plan	2011 Actual	2012 Plan	2012 Actual	2013 Budget	2013 Actual	2014 Plan	2015 Plan
Base	93.7	100.0	103.7	106.0	108.8	102.9	113.2	103.5	113.4	113.7
Project	37.1	39.8	27.3	21.6	20.6	20.3	16.0	23.1	24.5	32.1
SubTotal Operations	130.8	139.8	131.0	127.6	129.4	123.2	129.2	126.6	137.9	145.8
Corporate Costs	N/A	31.4	N/A	32.3	N/A	36.6	38.8	35.2	42.1	39.6
Centrally Held Costs	N/A	19.0	N/A	25.1	N/A	33.1	47.2	31.8	49.6	48.7
Asset Service Fee	N/A	3.6	N/A	3.4	N/A	3.3	3.1	3.0	2.9	3.0
SubTotal Other		54.0		60.8		73.0	89.1	70.0	94.6	91.3
Total OM&A		**193.8**		**188.4**		**196.2**	**218.3**	**196.6**	**232.5**	**237.1**
Exhibit N1 Update									**239.3**	**242.6**
Exhibit N2 Update									**234.9**	**237.3**

Sources: Exh F1-1-1 Table 2, Exh L-6.1-CCC-18, Exh L-1-Staff-2 Table 16, Exh N2-1-1 Attachment 5

68 There were several submissions on base and project OM&A variances. Parties observed a trend of historical under-spending versus forecast but no operational repercussions as a result of the under-spending. Board staff submitted that base and project OM&A costs should be reduced by $8.2M for each test year on the basis of OPG's updated 2014 year end forecast. SEC and LPMA proposed reductions on the basis of their analysis of historical variances.

69 As OPG only provided an updated 2014 year end forecast for base and project OM&A, Board staff also proposed reductions of an additional $27.2M, allocated to other OM&A costs for each test year, on the basis of over-forecasting expenses. The submissions of other parties on these costs are noted in the corporate support cost section of this Decision.

70 As the application is based on a forward test period, OPG submitted that consideration should be given to forecast events in the business plan for 2014 and 2015. OPG submitted that the Board staff reference to the updated 2014 year end forecast for base and project OM&A is cherry picking and that the historical under-spending means that work was reprioritized to deal with unfilled vacancies and that OPG overcame these issues with only minor impacts to the business.

Benchmarking

71 OPG filed reliability, cost and safety performance benchmarking for the hydroelectric business with its application. Board staff observed that OPG purchases raw databases and submitted that the benchmarking provided in the application is not done independently. OPG's witnesses stated that they have not commissioned any independent hydroelectric benchmarking and they do not have plans to do any.[6] OPG indicated that EUCG and Navigant are third parties who act independently to define, collect and verify the raw data reported by OPG, although these third parties do not produce any reports.

72 OPG confirmed that only base OM&A costs are benchmarked. SEC submitted the benchmarking results should be of little comfort to the Board as significant costs have been excluded from the analysis. OPG replied that some costs are excluded as the North American hydroelectric utilities that provide the data want the benchmarking data framed without corporate costs.

73 The Society argued that the Board does not possess the necessary expertise to make any prudent judgment on hydroelectric OM&A. In the Society's view, benchmarking has limited practical value as there are no comparable organizations with regard to scale, diversity and complexity of OPG hydroelectric operations.

74 Both Board staff and SEC submitted that the Board should direct OPG to conduct a fully independent and fully allocated OM&A benchmarking exercise so that there is an appropriate structure for the hydroelectric incentive regulation framework.

Board Findings

75 OPG has historically over-forecast hydroelectric base and project OM&A. The variance analysis of the base and project OM&A for the historical period 2010 to 2013 clearly indicates that actual spending has been consistently less than OPG had forecast. While OPG argues that the approved OM&A should be based on test period events and the business plan underpinning the application, OPG's forecasting methodology in the current proceeding is similar to that described in previous proceedings. In these prior periods, OPG has managed its hydroelectric operations with a lower than forecast base and project OM&A envelope, with only one year being a minor exception. OPG has confirmed that this trend of under-spending relative to forecast is likely to materialize in 2014 as well.[7] The pre-filed evidence and the testimony of OPG's witnesses confirm that the hydroelectric facilities have been operated safely, reliably and meet environmental standards.

76 When using a forward test year methodology, historical actuals are informative. In this case, the Board is influenced by OPG's consistent historic under spending but is still mindful of OPG's submissions with respect to the need for its proposed OM&A levels for the 2014 and 2015 period. In considering these factors, the Board finds that a base and project OM&A reduction of 4.2% for the regulated hydroelectric assets is appropriate. The reduction would be $9.5M in 2014 and $9.8M in 2015. As the majority of hydroelectric OM&A expense is related to compensation, this reduction to the hydroelectric OM&A budget for each of the two years will be subsumed into the disallowances for compensation discussed later in this Decision.

77 The Board finds the hydroelectric benchmarking to be inadequate. The analysis of externally provided OM&A, reliability and safety databases and the reporting is done by OPG, not an independent third party. Further, in the two previous cost of service applications and the current application, OPG has provided OM&A benchmarking information that only considers base OM&A which is only 50% of total OM&A expenses. The Board observes that OPG's nuclear business benchmarking is further advanced than its hydroelectric business benchmarking. The Board notes that OPG responded to Board direction from EB-2007-0905 regarding the benchmarking of the nuclear business. In 2009, ScottMadden Inc., assisted by OPG, identified key performance metrics for benchmarking and identified the peer groups for comparison. The nuclear cost benchmarking includes the allocation for corporate costs. OPG has adopted the ScottMadden methodology and format in full for its annual nuclear benchmarking reporting.

78 The Board orders OPG to have a comparable fully independent benchmarking study undertaken of the hydroelectric operations as soon as possible. The results of this study will be important in developing the incentive regulation methodology for OPG. Data used in the study should be as recent as possible (i.e. not older than 2013), without creating delays in the completion and dissemination of the study.

79 With respect to the Society's view that little weight should be placed on any benchmarking, the Board reminds the Society that the Act and *O. Reg. 53/05* provide the Board with the authority to set payment amounts for OPG's regulated facilities. In addition the Memorandum of Agreement between OPG and the Shareholder requires that OPG's regulated assets be subject to public review and assessment by the Board. The Memorandum of Agreement also requires OPG to establish operating and financial results and measures that will be benchmarked against the performance of the top quartile of electricity generating companies in North America.

2.3 Hydroelectric Capital Expenditure and Rate Base

(Issues 2.1, 4.1, 4.2 and 4.3)

80 OPG seeks Board review of the capital expenditures proposed for 2014 and 2015. These capital expenditures have no impact on the payment amounts for 2014 and 2015 unless the projects are completed and go into service during this period. Board acceptance of the budget does however provide guidance to OPG with respect to the reasonableness of the budget.

81 OPG's historical and forecast capital expenditures for the previously regulated and newly regulated hydroelectric facilities are summarized below.

Table 7: Hydroelectric Capital Expenditures (excluding Niagara Tunnel)

$millions	2010 Budget	2010 Actual	2011 Approved	2011 Actual	2012 Approved	2012 Actual	2013 Budget	2013 Actual	2014 Plan	2015 Plan
Niagara Plant Group	36.2	28.5	30.7	27.2	30.9	27.1	28.8	20.9	24.8	34.3
Saunders GS	17.3	11.8	9.2	8.1	5.9	2.7	5.0	5.8	9.7	3.9
Newly Regulated *	80.2	68.6	76.7	61.4	91.4	80.1	71.4	60.5	91.0	100.0
Total	**133.7**	**108.9**	**116.6**	**96.7**	**128.2**	**109.9**	**105.2**	**87.2**	**125.5**	**138.2**

Source: Exh D1-1-1 table 2 and Exh L-1-Staff-2 Attachment 1 Table 8

* Note: Amounts for Newly Regulated shown under the Board Approved columns are OPG Budget amounts.

82 Board staff submitted that a $38M reduction to test period capital was appropriate on the basis of the regulatory delays and economic considerations for the Ranney Falls project. Board staff noted that this reduction would not impact rate base since the planned in-service date is after the test period. OPG replied that there is nothing to suggest that regulatory approvals will not be forthcoming for the Ranney Falls project.

83 To assess whether test period capital expenditure was reasonable, AMPCO analyzed historical expenditures and determined that for the period 2010 to 2013, OPG spent 81% of the previously regulated hydroelectric facilities budget and 85% of the newly regulated hydroelectric facilities budget. On this basis, AMPCO proposed that reductions to the proposed hydroelectric capital expenditures in the test period in the amount of $43.4M were appropriate. OPG argued that applying historical variances to the test period ignores the evidence filed in support of capital spending in the test period.

84 OPG is also seeking approval of regulated hydroelectric in-service additions to rate base of $119.9M, $86.1M and $151.6M for 2013, 2014 and 2015, respectively. OPG's historical and proposed rate base for the test period is set out in the following table.

Table 8: Hydroelectric Rate Base

$millions	2010 Budget	2010 Actual	2011 Approved	2011 Actual	2012 Approved	2012 Actual	2013 Budget	2013 Actual	2014 Plan	2015 Plan
Niagara Plant Group excluding NTP	2,489.7	2,452.5	2,482.5	2,437.1	2,474.3	2,422.0	2,405.0	2,404.6	2,391.4	2,378.1
Niagara Tunnel	-	18.3	-	18.1	-	17.8	1,143.6	1,140.4	1,473.6	1,457.7
Saunders GS	1,301.7	1,300.1	1,298.8	1,294.4	1,291.0	1,281.7	1,260.5	1,261.3	1,240.5	1,226.4
NPG Cash Working Capital	23.6	26.4	21.5	21.5	21.5	21.7	21.7	21.7	21.7	21.7
NGP Materials & Supplies	0.7	0.7	0.6	0.8	0.6	0.8	0.7	0.5	0.7	0.7
Newly Regulated *							2,507.0	2,518.4	2,502.6	2,519.2
Newly Reg. Cash Working Capital *							0.7	8.3	8.3	8.3
Newly Reg. Materials & Supplies *							8.3	0.6	0.7	0.7
Total	**3,815.7**	**3,798.0**	**3,803.4**	**3,771.9**	**3,787.4**	**3,744.0**	**7,347.5**	**7,355.8**	**7,639.5**	**7,612.8**
Source: Exh B1-1-1 Table 1 and Exh B2-2-1 Table 1 and Exh L-1-Staff-2 Attachment 1 Table 2										
* Note: Amounts for Newly Regulated shown for 2013 are for illustrative purposes.										

85 Based on Board staff's analysis of historical in-service additions for projects greater than $5M, staff observed the forecast additions were generally overstated in the period 2010 to 2013 and proposed a $13M per year reduction for the test period.

86 SEC reviewed in-service additions for the previously regulated hydroelectric facilities and determined that in aggregate 72.8% of forecast was placed in-service. The following table was filed in the SEC submission.

Table 9

In-Service Capital Additions (excluding NTP) ($M)					
	2010	**2011**	**2012**	**2013**	**Average**
Previously Regulated Plan	60.9	42.9	51.5	44.3	49.9
Previously Regulated Actual	20.0	63.5	15.5	46.4	36.4
Variance (%)	***32.8%***	***148.0%***	***30.1%***	***104.7%***	*72.8%*
Source: D1/1/2/Table 5. L/1.0/Sch 1 Staff-002/Attach 1/Table 2 (2013 Actuals).					

87 On the basis of SEC's analysis, LPMA proposed that the Board approve 72.8% of the proposed rate base additions for the test period. SEC's analysis of historical capital expenditure for both the previously and newly regulated hydroelectric facilities indicated that 83.3% of plan went into service. SEC proposed that the Board approve 83.3% of the proposed rate base additions for the test period.

88 Project delays can contribute to in-service addition variances; however, OPG pointed out that there is a cyclical pattern to the variances for the previously regulated hydroelectric facilities. OPG stated that the 2013 variance is minor and an indication of improved forecasting. Further, the major drivers of variances are projects subject to section 6(2)4 of *O. Reg. 53/05* which provides for the recording of variances between actual and forecast costs, and are addressed by the capacity refurbishment variance account.

Board Findings

89 The Board finds that the hydroelectric capital budget for projects coming into service during the test period is reasonable. The projects are supported by business cases approved by the appropriate level of authority within OPG. The Board is providing no explicit approval in this Decision for the capital budget associated with multi-year hydroelectric projects which do not come into service during the test period. As a result, the Board will not reduce OPG's capital budget based on historic budgets exceeding actual expenditures as proposed by certain intervenors and Board staff. The Board is satisfied with OPG's evidence regarding the delays in prior projects to explain historical under spending.

90 Regarding OPG's proposed in-service capital additions, the evidence indicates no clear pattern of historical variances which can be used to predict actual rate base additions for 2014 and 2015. OPG failed to meet its in-service capital addition budget (or approved level) for its previously regulated hydroelectric facilities in 2010 and 2012, however the budget was exceeded in 2011 and 2013. In the case of additions being lower than budgeted, OPG's witnesses testified that issues arose on specific projects that led to in-service date delays beyond the year in which they were proposed to be in-service. The Board notes that in years in which capital additions exceeded the budget, the amount of overage was much less than the years when the capital additions were below the budgeted level. Over the four year period (2010 to 2013) SEC put forward that the average capital additions were only about 73% of the planned in-service additions.

91 The Board finds that some level of reduction to the in-service capital additions is required. OPG has not satisfied the Board that it will meet its in-service capital addition budget for 2014 and 2015. Rather than the $13M reduction per year suggested by Board staff, the 17% reduction suggested by SEC or the 27% reduction proposed by LPMA (the latter both based on the four year average additions variance), the Board finds it appropriate to reduce the capital in-service additions by 10% in 2014 and 2015. This amount represents a relatively minor reduction but reflects the fact that the Board is not satisfied by the evidence provided that there will not be in-service delays in 2014 and 2015. The capital additions approved by the Board are therefore $119.9 M in 2013 (actuals), $77.5M in 2014 and $136.4M in 2015.

2.4 Niagara Tunnel Project

(Issues 4.4 and 4.5)

92 The Niagara Tunnel Project is a 10.2 km long tunnel constructed by OPG with a diameter of 12.7 metres which runs under the City of Niagara Falls. Its purpose is to increase the flow of water to the Niagara plant group, and thereby increase generation by 1.6 TWh annually. After several years of construction, the asset was placed in service in March 2013 at a cost about 50% greater than originally budgeted.

93 In this application, OPG is seeking the Board's approval to close $1,452.6M in capital expenditures (in-service) (see line 5 of Table 10) to the test period rate base. OPG states that the cost above the original budget arose entirely from the fact that the rock conditions encountered during construction were worse than OPG reasonably anticipated.[8]

94 The Board's consideration of the costs of the Niagara Tunnel Project is guided by section 6(2)4 of *O. Reg. 53/05*, which states:

> The Board shall ensure that Ontario Power Generation Inc. recovers capital and non-capital costs, and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2, including, but not limited to, assessment costs and pre-engineering costs and commitments,
>
> i. if the costs and financial commitments were within the project budgets approved for that purpose by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., or
>
> ii. if the costs and financial commitments were not approved by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., if the Board is satisfied that the costs were prudently incurred and that the financial commitments were prudently made.

95 The OPG Board of Directors approved the expense of $985.2M in 2005, prior to the Board's first order in 2008. OPG states that the issue before the Board is whether the $491.4M in expense beyond the $985.2M was prudently incurred. None of the parties have disputed this assertion.

96 The PWU submitted that the geological investigations and studies undertaken were appropriate and that OPG's conduct during and after the differing subsurface condition dispute was appropriate. PWU states the $491M additional cost was incurred reasonably and prudently. However, a number of parties found fault with OPG's management of the Niagara Tunnel Project, and argued for a range of disallowances to the amount closing to rate base.

Background

97 The initial budget for the project approved by OPG's Board of Directors in 2005 was $985.2M. There were a number of delays and cost over-runs resulting from unanticipated subsurface conditions. Ultimately the total cost of the Niagara Tunnel Project was $1,476.6M of which OPG is seeking to close $1,452.6M to rate base in this application.[9] A summary of project costs is provided in the table below.

Table 10: Niagara Tunnel Project

	$ millions*	Pre- 2008 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Test Year	2015 Test Year	Total
1	Budget Approved/Revised by OPG Board	985.0	985.0	1,600.0	1,600.0	1,600.0	1,600.0	1,600.0	1,600.0	1,600.0	
2	Capital Expenditures	300.2	131.3	213.5	231.8	264.2	231.2	86.6	13.0	0.4	
3	Accumulated Capital Expenditures	300.2	431.5	645.0	876.8	1,141.0	1,372.2	1,458.8	1,471.8	1,472.2	
4	Gross Plant in-service (Opening Balance)	19.2	19.2	19.2	19.2	19.2	19.2	19.2	1,458.4	1,471.4	
5	Gross Plant additions	-	-	-	-	-	-	1,439.2	13.0	0.4	1,452.6
6	Gross Plant in-service (Closing Balance)**	-	-	-	-	-	-	1,458.4	1,471.4	1,471.8	

Source: OPG Reply Argument p 26 & Exh L-4.5-Staff-25

*Numbers may not add up due to rounding

** To calculate the total cost of the Niagara Tunnel Project, $4.6M in removal costs (treated as operating expenses) is added to the $1,472.2M in total capital (in-service) expenditures. This results in a Niagara Tunnel Project total cost of **$1,476.6M**. The $4.6 M is recorded in the Capacity Refurbishment Variance Account.

98 OPG's preparatory geotechnical investigation for a Niagara Tunnel began in 1983. The tunnel passes through geologically challenging conditions, including the Queenston shale formation. OPG's initial investigations included 59 boreholes and an exploratory adit (a test tunnel).

99 OPG undertook a request for proposal process in 2004/2005. The request for proposal mandated a tunnel boring process, which was a requirement of the environmental assessment. The request for proposal was based on OPG's geotechnical investigations and OPG's risk assessment analysis. Strabag AG of Austria and its wholly owned subsidiary Strabag Inc. ("Strabag") were the successful bidders.

100 Strabag's bid was based on a "design-build" approach, whereby OPG would hire a single firm (i.e. Strabag) to design and build the project to OPG's pre-established specifications.[10] The OPG Board of Directors approved the release of $985.2M, of which $112M was contingency. The business case presented to the OPG Board of Directors stated that the project economics compared favourably against other renewable generation options. The Design Build Agreement with Strabag was signed in August 2005. The new tunnel was projected to be in service by June 2010 and was expected to increase generation by 1.6 TWh. The initial cost of the tunnel itself, as reflected in the Design Build Agreement, was $622.6M to be paid to Strabag.

101 The terms of the Design Build Agreement were based in part on a Geotechnical Baseline Report. The purpose of the Geotechnical Baseline Report was to establish a contractual baseline for subsurface hydro-geological conditions. Initially OPG prepared a geotechnical baseline report which was included with the request for proposal and bidders including Strabag provided geotechnical baseline reports (based on OPG's report) with their bids -- these are referred to in the evidence as Report A and Report B respectively. The final Geotechnical Baseline Report (sometimes referred to in the evidence as Report C) was negotiated jointly by OPG and Strabag as part of the Design Build Agreement. Unless otherwise specified, references to the Geotechnical Baseline Report in this Decision refer to this final Report C.

102 In the event that the actual subsurface conditions were found to be materially different from the conditions anticipated in the Geotechnical Baseline Report, the Design Build Agreement provided a number of potential remedies. If OPG agreed that there was a "differing subsurface condition", the parties could negotiate changes to the schedule and price. If OPG did not agree that there was a differing subsurface condition, the Design Build Agreement outlined a dispute resolution process, which included recourse to a third party Dispute Review Board.[11]

103 One of the subsurface issues addressed in the Geotechnical Baseline Report was "overbreak". Overbreak is the cracking and loosening of rocks above the tunnel boring machine[12] as it moves through the rock to create the tunnel. It was recognized by both OPG and Strabag that overbreak could be an issue, particularly in the Queenston shale formation through which portions of the tunnel were expected to pass. OPG's original assessment was that there would be approximately 45,000 m^3 of overbreak, whereas Strabag estimated only 15,000 m^3. In the final Geotechnical Baseline Report (which was part of the Design Build Agreement), the parties agreed to a figure of 30,000 m^3.

104 Construction began in September 2005. Excavation by the open tunnel boring machine commenced in September 2006. Starting in spring 2007, significant quantities of overbreak were reported, which resulted in delay and additional expense to Strabag. Strabag considered this excessive overbreak to be due to a differing subsurface condition more significant than had been previously identified, and attempted to negotiate changes to the Design Build Agreement with OPG. By February 2008, it was clear that the parties would be unable to resolve the issue on their own, and the dispute was referred to a Dispute Review Board.

105 Strabag argued before the Dispute Review Board that one or more differing subsurface conditions existed based on five issues of dispute, including the excessive amount of overbreak. OPG's position was that no differing subsurface condition existed and that Strabag was at fault for the overbreak because it substantially modified its tunnel boring machine design and rock support from the original proposal.

106 The Dispute Review Board held that for three of the issues identified (large block failures, insufficient "stand-up" time, and an issue related to tunneling under the buried St. Davids Gorge) there was no differing subsurface condition. For the other two issues (excessive overbreak and the table of rock conditions and rock characteristics) the Dispute Review Board found that there was a differing subsurface condition. With respect to the differing subsurface conditions, the Dispute Review Board report stated:

> Since the development of the [Geotechnical Baseline Report] was the mutual responsibility of both Parties, we recommend that the Parties negotiate a reasonable resolution based on a fair and equitable sharing of the cost and time impacts resulting from the overbreak conditions that have been encountered and the support measures that have been employed.[13]

107 Following negotiation, OPG agreed to pay Strabag an extra $40M to resolve all issues to November 30, 2008 (Strabag had claimed additional costs of $90M). After considering several options, OPG determined that the best way to ensure the completion of the Project was to renegotiate the Design Build Agreement. The excessive amount of overbreak required tunnel profile restoration (infill to restore tunnel profile to a circular shape), realignment of the tunnel route, and additional cost and time. An Amended Design Build Agreement, based on target cost instead of fixed price, was approved by the OPG Board of Directors in May 2009. The total project cost estimate was revised to $1.6 billion, of which $985M was now allocated to Strabag for constructing the tunnel. The Amended Design Build Agreement moved the completion date for the project from June 2010 to June 2013. The supporting business case stated that completing the tunnel was still economic when compared with alternative energy supply options.

108 Ultimately the tunnel was completed in March 2013, for less than the $1.6 billion revised cost. The final total cost for the Niagara Tunnel Project was $1,476.6M (see footnote to Table 10). Strabag earned a number of incentives for completing the project ahead of the revised schedule and for less than the revised budget.

109 As part of its application, OPG filed a report by Mr. Roger Ilsley, a geotechnical and tunnel expert. The report concluded that OPG's site investigations were appropriate and completed to professional standards. Similarly Strabag's design work was completed to professional standards.[14] Mr. Ilsley also appeared as a witness at the oral hearing.

Geotechnical Baseline Report

110 The submissions of Board staff, AMPCO, CME and SEC criticized the Geotechnical Baseline Report. OPG was solely responsible for the initial Report A which was the basis for the request for proposal and subsequent reports. The bidders provided Report B, a supplemented version of Report A, with their bids. The final Report C was agreed to by OPG and the successful bidder, Strabag. It was submitted that the contractually binding Report C was ambiguous and not in compliance with the *Geotechnical Baseline Reports for Construction -- Suggested Guidelines*. AMPCO submitted that the ambiguity in the original Report A misled Strabag to propose open tunnel boring instead of closed tunnel boring and that OPG's expert, Mr. Ilsley, agreed in cross examination that Report C was ambiguous.[15]

111 As summarized in the Dispute Review Board's report:

> The [Dispute Review Board] agrees that the Table of Rock Conditions and Rock Characteristics is inadequate to be used for the identification of [Differing Subsurface Conditions] and, further, that the inclusion of such terms as the "closest match" and "all other conditions" essentially renders the concept of [Differing Subsurface Conditions] meaningless and makes the [Geotechnical Baseline Report] defective.[16]

112 OPG spent $57M on geotechnical investigations. OPG asserts that this was a considerable amount of investigation, and the results were unchallenged by five contractors who did not seek additional geotechnical data to submit their bids. Further, the geotechnical investigation and results were supported by Mr. Ilsley. The guidelines for geotechnical baseline reports recognize that it is not always possible to describe geologic conditions precisely. OPG stated that AMPCO's criticism that the geotechnical baseline report was misleading to bidders is incorrect as Strabag considered both closed and open tunnel boring.

113 In OPG's view, the parties have not pointed to a single action that OPG took that was unreasonable in developing the Geotechnical Baseline Report.

Risk Management

114 The submissions of Board staff, AMPCO and SEC find fault with OPG's risk assessment process and the risk OPG assumed in the project. Some parties noted that OPG's contracting approach was a risk since tunnels in North America have traditionally been constructed using Design-Bid-Build contracts instead of Design Build. SEC observed that of the 59 borehole tests conducted, only 20 were located along the proposed route. SEC also questioned OPG's decision to rely on 1993 borehole data as testing methods and instrumentation had likely improved in the interim.

115 In OPG's view the Design Build approach was selected to appropriately allocate project risk and to obtain as much upfront price certainty as possible. OPG stated that the criticisms of the vintage of borehole data are contrary to the evidence of Mr. Ilsley, who testified that while the electronic methods to record geotechnical results have improved, the tests themselves are unchanged.

116 OPG submitted that all the project risks identified by OPG were mitigated to low risk except subsurface conditions which remained at medium risk. OPG's mitigation activity to move the risk from high to medium was the extensive field investigation over 10 years, the 3 stage geotechnical baseline report process and contingency for the tunneling work. While total project contingency was $112M, the contingency for the tunneling portion of the project was $96M. OPG stated that to mitigate to low risk would be costly. As OPG assumed full responsibility for geological conditions in design build, the parties submitted that OPG assumed too high a risk.

117 OPG replied that, "While it is clear in hindsight that OPG underestimated the potential severity of the rock conditions encountered, particularly the nature and extent of the overbreak, this occurred because the rock conditions were much more challenging than OPG, its experts and Strabag expected based on extensive geotechnical sampling and analysis, and not because OPG's risk identification and quantification efforts were deficient."[17]

Contract Renegotiation

118 Several parties submitted that OPG was not prudent in its renegotiations with Strabag and that the Amended Design Build Agreement did not reflect sharing of responsibility for losses as determined by the Dispute Review Board. SEC observed that few options were presented to the OPG Board of Directors and that the Amended Design Build Agreement was for all intents and purposes final when it was presented to the OPG Board.

119 When Strabag filed its claim for $90M, tunneling had advanced to the 3 km point. OPG had paid Strabag $40M, or $13.3M/km. CME observed that the Amended Design Build Agreement provided for an additional $243M for the remaining 7 km, or $34.7M/km. CME submitted that OPG should not have paid Strabag more than $13.3M/km for the remaining 7 km, and that the difference would result in a $149M disallowance.

120 A number of parties submitted that OPG could have achieved a better result through the Amended Design Build Agreement. OPG stated that the understanding of the parties with respect to sharing of risk is incorrect. At the end of three years of work, Strabag had a loss of $90M, which was settled by a $40M payment. Strabag finished the tunnel with what OPG characterized as a very small profit after an additional four years of work. OPG argued that CME's understanding of additional costs per km are incorrect as the $90M claim did not include tunnel profile restoration, which had to be undertaken in addition to completion of the remaining 7 km.

121 OPG also argued that there would have been significant costs for terminating the Strabag contract. Mr. Ilsley referred to the Seymour-Capilano project in Vancouver which was rebid at 1.8 times the original cost for the remaining 40% of the work with potential litigation by the original contractor.[18]

Disallowances Proposed by Parties

122 Board staff and the parties have proposed reductions to the rate base addition ranging from $50M to $407.4M:

* Energy Probe submitted that a $50M rate base addition reduction was appropriate as OPG's use of the design build model limited its ability to terminate Strabag.
* Board staff listed 7 items to deduct from rate base additions totaling $105M, including the $40M paid to Strabag pursuant to its claim, design costs, overhead costs and carrying charges.
* In addition to $149M related to contract renegotiation, CME agreed with several of the items that Board staff proposed for disallowance, and proposed a $208.5M total disallowance.
* SEC proposed that rate base additions should be reduced by $245.7M, i.e. half of the amount in excess of the originally approved $985.2M
* AMPCO's submission listed 9 items, including the entire diversion tunnel expense beyond the original estimate of $280.3M and $10.8M paid to OPG's representative, Hatch. AMPCO submitted that $407.4M should be removed from OPG's proposed rate base additions.

123 OPG replied that all of these disallowances should be rejected, and that the analysis of Board staff and parties is inadequate. Other than Mr. Ilsley, there were no expert witnesses that gave evidence related to the Niagara Tunnel. OPG argued that the parties did not fully understand the evidence and the arguments are selective reviews based on hindsight. Although the parties claimed imprudence, in OPG's view the parties failed to identify a single action that OPG took or failed to take that was unreasonable at the time.

124 OPG stated that the Niagara Tunnel Project costs are reasonable and that "if the rock conditions had been known in advance with perfect foresight, the tunnel would have cost at least what OPG paid and may have cost more."[19]

Board Findings

125 The Board finds that $1,364.6M in Niagara Tunnel Project capital expenditures (in-service) should close to rate base in the test period. This represents a disallowance of $88.0M (or approximately 6%) from the $1,452.6M proposed by OPG. The disallowances are based primarily on OPG's response to the Dispute Review Board's decision and recommendations, in particular OPG's decision to pay $40M for claims prior to December 2008, and the terms negotiated with Strabag in the Amended Design Build Agreement.

126 The Board accepts OPG's argument that the Board's review of the Niagara Tunnel Project is a "prudence review", and that the Board is not permitted to use hindsight when considering OPG's actions. The Board also accepts OPG's assertion that, pursuant to section 6(2)4 of *O. Reg. 53/05*, only the $491.4M in expenses incurred after 2008 are subject to review. As a result, the Board will not opine on the actions of OPG prior to the commencement of the Board's regulation of OPG in 2008.

Settlement of Strabag's $90M Claim

127 In its report, the Dispute Review Board recommended "that the Parties negotiate a reasonable resolution based on a fair and equitable sharing of the cost and time impacts resulting from the overbreak conditions that have been encountered and the support measures that have been employed. Both Parties must accept responsibility for some portion of the additional cost, but at the same time the Contractor must have adequate incentives to complete the Work as soon as possible."[20]

128 Based in part on this recommendation, OPG decided on two courses of action. First, it agreed to settle all of Strabag's pre-December 2008 claims for $40M (Strabag had claimed $90M). Second, OPG determined that the best solution moving forward was to renegotiate the Design Build Agreement with Strabag. The resulting Amended Design Build Agreement target cost was $985M plus incentives (compared with the Design Build Agreement contract cost of $622.6M).

129 The Project was completed pursuant to the terms of the Amended Design Build Agreement. Strabag earned the incentives described in the Amended Design Build Agreement. Overall OPG estimates that Strabag earned a profit of approximately $26M on the Project as a whole.[21]

130 Several parties questioned whether the Amended Design Build Agreement appropriately allocated responsibility for the additional costs between OPG and Strabag. OPG's witnesses testified that absent a successfully renegotiated Design Build Agreement, Strabag would have likely walked away from the Project. OPG would then have been forced to find a new contractor to complete the Project. OPG expected that the costs of finding a new contractor at that stage of the Project would have greatly exceeded the cost of renegotiating the Design Build Agreement with Strabag.

131 The Board is not satisfied that paying Strabag $40M for its claims up to December 2008 was prudent. This Board finds that the non-binding recommendations of the Dispute Review Board were reasonable, and that some level of shared responsibility between OPG and Strabag was appropriate. However, paying a $40M settlement (44% of Strabag's $90M claim) is excessive in the Board's view. There were five issues of dispute that were referred to the Dispute Review Board. The Dispute Review Board found that OPG was not responsible for three of the five issues and that OPG had only joint responsibility for the remaining two issues. No evidence was filed on the relative value or cost of the five issues. OPG's witnesses testified that the individual issues were not quantified.

132 As a result of the contract renegotiation with Strabag, OPG had the right to audit Strabag's claimed losses of $90M. To the extent that the $90M was not substantiated in the audit, the $40M payment could be reduced proportionately. OPG's witnesses testified that OPG's internal auditors conducted the audit and found that a total of $12.6M was not associated with legitimate expenses, resulting in a loss of only $77.4M.[22] The auditors did not recognize inter-company transfers within Strabag's organization, thereby reducing the amount from $90M to $77.4M.[23] OPG's evidence was that they could reduce the $40M settlement proportionately based on the audit, but did not do so.[24]

133 The Board is unable to find that a $40M settlement of Strabag's claim was prudently incurred. In the absence of information regarding the costs attributable to each of the five issues, the Board must use its judgment of what is a reasonable amount. In determining the amount, the Board has decided to utilize the findings of the Dispute Review Board. As a result, the Board finds that OPG's ratepayers should not pay any amount for the three issues which OPG was not responsible, but should pay 50% of two issues for which OPG was jointly responsible. In addition, the Board is persuaded by the results of OPG's audit and considers the $77.4M to be the appropriate starting point for the Board's calculation, not the $90M claim by Strabag. There was no evidence or testimony provided supporting Strabag's claimed amount. As a result, the Board finds that ratepayers should only pay 20% of the $77.4M audited amount, or $15.5M. In addition, the Board denies the associated carrying costs of the disallowed $24.5M,[25] which results in a reduction of another $3.5M.[26] The Board finds this disallowance of $28.0M reasonable given the evidence provided.

Terms of the Amended Design Build Agreement

134 The Board finds that not all of the costs associated with the Amended Design Build Agreement should be passed on to ratepayers.

135 The Board accepts that absent a revised Design Build Agreement, there was a possibility that Strabag would have abandoned the Project. Had that occurred, the cost of completing the Project with a new contractor might well have exceeded the costs of the Amended Design Build Agreement. In the Board's view, however, the possibility of project abandonment and the speculation of the financial impact of this does not justify the level of incentives offered to Strabag in the Amended Design Build Agreement. The question is not: Would it have cost OPG more had Strabag walked away? Instead, the salient question is: Could OPG have achieved better terms than it did in negotiating with Strabag to move forward after the Dispute Review Board findings?

136 The risk of the contractor abandoning the Project was recognized in the original 2005 Business Case. The project risk profile identified this risk as "medium" before mitigation, and "low" after mitigation. The mitigation activity described in the project risk profile was a requirement for the contractor to provide bonds and/or letters of credit as security, and to provide a parental guarantee. As part of the Design Build Agreement, Strabag was required to post a letter of credit for $70M, and provide a parental indemnity guaranteeing Strabag's performance of the contract and indemnifying OPG for any damages resulting from a breach by Strabag.[27] The Indemnity Agreement provided that Strabag's parent company "irrevocably and unconditionally agrees to indemnify and save harmless OPG from and against all costs, damages, expenses, losses, liabilities, demands, claims, suits, actions, proceedings, judgments and obligations (including, without limitation, legal fees and expenses) arising in respect of any breach" of the Design Build Agreement. The Indemnity Agreement further allowed OPG to make credit inquiries about the parent company, and provided OPG with three years of financial statements.[28]

137 OPG's witnesses further confirmed that Strabag would suffer serious repercussions were it to walk away from the Project, including being sued by OPG for breach of contract, and suffering a serious blemish on its business reputation.[29]

138 Strabag, therefore, had very strong incentives to reach an agreement with OPG to find a way to complete the Project. Walking away from the Project would have been an extremely expensive and unpalatable option for Strabag, and for its parent company.

139 Under these circumstances, the Board finds that the incentives offered to Strabag through the Amended Design Build Agreement were excessive. OPG understood that a contractor default was a potential risk, and indeed it took steps that should have mitigated that risk through a letter of credit and a comprehensive parental indemnity. However, when it came time to renegotiate the Design Build Agreement, OPG did not properly use its leverage to secure a more favourable deal. The Board will disallow recovery of $60M.[30] The Board is mindful of the Dispute Review Board's recommendation that Strabag have appropriate incentives to complete the work. However, in the Board's view the Amended Design Build Agreement provided adequate "incentive" even without the specific incentive clauses. OPG agreed to pay Strabag hundreds of millions of extra dollars more than was provided for in the original Design Build Agreement. In the Board's judgment, the provision for incentives above this was not necessary and not prudent.

140 The total disallowance related to the capital expenditures of the Niagara Tunnel Project is $88.0M, which the Board finds to be imprudently incurred. The Board approves $1,364.6M as the amount of Niagara Tunnel Project capital expenditures (in-service) to close to rate base in the test period.

2.5 Hydroelectric Other Revenue

(Issue 7.1)

141 OPG earns revenue from a number of sources other than through the regulated payment amounts for hydroelectric generation. These sources of other revenue include ancillary services, segregated mode of operations and water transactions.

142 The historical and forecast other revenues for the previously regulated and newly regulated hydroelectric facilities are summarized in the following table.

Table 11: Hydroelectric Other Revenue

$million	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2013 Actual	2014 Plan	2015 Plan
Previously Regulated Ancillary Services	26.2	22.2	20.8	17.8	37.1	18.1	18.5
Seg Mode of Operation	-0.9	1.7	-0.8	1.6	4.1	0.0	0.0
Water Transactions	5.5	7.5	1.6	6.0	1.0	1.7	1.7
HIM Adjustment				6.5	6.5		
Total	**30.8**	**31.4**	**21.6**	**31.9**	**48.7**	**19.8**	**20.2**
Total: Exhibit N1 Update (Ancillary Services: $32.2M - 2014, $32.9M - 2015)						**33.9**	**34.6**
Newly Regulated Ancillary Services	**26.4**	**26.1**	**25.9**	**22.2**	**35.7**	**22.7**	**23.1**
Source: Exh G1-1-1, Exh L-1-Staff-2, Exh N1-1-1							

143 The IESO purchases the following ancillary services from OPG: black start capability, reactive support/voltage control service, automatic generation control and operating reserve. A forecast of the revenues from ancillary services is applied as an offset to the hydroelectric revenue requirement. Differences between the forecast and actual revenues are recorded in the Ancillary Services Net Revenue Variance Account -- Hydroelectric. OPG has proposed that the account also apply to the newly regulated hydroelectric facilities.

144 The Exhibit N1 update is the result of higher forecast revenue for operating reserve and a new contract for regulation service, resulting in an increase in ancillary services revenue forecast for the previously regulated hydroelectric facilities of $14.1M in 2014 and $14.4M in 2015.

145 In the current application OPG has applied an escalation factor of 2% to the 2013 ancillary services budget amount to determine the forecast for 2014, which was escalated to determine the 2015 forecast. Both AMPCO and LPMA submitted that the forecast should be based on 2013 actuals and then escalated as proposed by OPG. CME submitted that the forecast should be based on the average of 2011-2013 actuals and then escalated as proposed by OPG. In response, OPG stated that some of the services are market based and some are contractual, and that forecasting requires more rigor than reference to historical values.

146 Segregated mode of operation transactions occur at the Saunders GS. Units at Saunders can be segregated, when pre-arranged, to serve the Hydro Quebec control area. OPG has forecast revenue from segregated mode of operation on the basis of a three year rolling average (2010-2012). AMPCO, CME and LPMA have proposed test period forecasts based on a three year rolling average that includes 2013 actuals. OPG argued that these submissions are opportunistic and would not have been made if the 2013 actuals reduced the average.

147 Water transactions between OPG and the New York Power Authority allow the two parties to use a portion of the other's share of water for electricity generation. In the previous proceedings, water transaction forecasts were based on the average of the three historical years. In the current application, water transaction volumes are forecast to decrease by 65% due to the diversion capability of the Niagara Tunnel which went into service in March 2013. OPG's forecast is based on the 2010-2012 average actual water transactions reduced by 65%. CME submitted that the forecast should be based on 2011-2013 average actuals.

148 Board staff observed that the historical other revenue variances were mainly due to ancillary services, for which there is a variance account. Board staff submitted that the proposed hydroelectric other revenues were appropriate.

Board Findings

149 The Board accepts the Exhibit N1 forecast revenues of $32.2M in 2014 as a result of ancillary services from previously regulated assets and $22.7M from the newly regulated assets, and $32.9M and $23.1M respectively in 2015 for these assets. The Board notes that the Ancillary Services Net Revenue Variance Account will continue throughout this period, accounting for any changes in revenues from the activities.

150 With respect to revenues from Segregated Mode of Operation, the Board will continue with the methodology established by the Board in EB-2007-0905 which uses a three-year historical average for the forecasting of 2014 and 2015. However, the Board will use the most recent historical actuals in calculating this average, thus the three years will be 2011, 2012 and 2013. This results in net revenue of $1.7M from segregated mode of operation for each of 2014 and 2015.

151 For net revenue from water transactions the Board accepts a departure from the methodology approved by the Board in EB-2007-0905 and EB-2010-0008, as the evidence is compelling that water transactions will be decreased as a result of the Niagara Tunnel being in-service. Similar to the determination of the segregated mode of operation forecast, the Board will use the most recent historical actuals for 2011, 2012 and 2013. As the Niagara Tunnel came into service in March of 2013, the 65% reduction is only applied to one quarter of the 2013 water transaction revenue. Hydroelectric Other Revenue of $1.3M related to water transactions will be included in each of 2014 and 2015. Once further actual data is available with the Niagara Tunnel in-service, this reduction by 65% should prove to be unnecessary and the previous methodology of the three year historical average may again be applicable.

152 As per the Board's findings in this Decision with respect to a revised methodology for the hydroelectric incentive mechanism, additional other revenues of $39M and $48M shall be appropriately allocated by OPG between the previously and newly regulated hydroelectric facilities and included in the revenue requirement determination for 2014 and 2015.

3 NUCLEAR FACILITIES

3.1 Nuclear Production Forecast

(Issue 5.5)

153 A key component of this Decision is the Board's determination of the appropriate nuclear production forecast for the determination of the payment amounts. OPG used the same methodology to determine the production forecast as in the previous proceeding. This resulted in a forecast of 48.5 TWh for 2014 and 46.1 TWh for 2015. OPG's historical nuclear production and test period production forecast are summarized in the following table.

Table 12: Nuclear Production Forecast

TWh	2010 Plan	2010 Actual	2011 Approved	2011 Actual	2012 Approved	2012 Actual	2013 Budget	2013 Actual	2014 Plan	2015 Plan
Darlington	27.8	26.5	28.9	29.0	29.0	28.3	26.9	25.1	28.4	26.1
Pickering	20.3	19.2	22.0	19.7	23.0	20.7	21.1	19.6	21.3	21.9
Total		**45.7**	**50.9**	**48.7**	**52.0**	**49.0**	**48.0**	**44.7**	**49.7**	**48.0**
Exhibit N1 Update - Darlington									28.1	24.7
Exhibit N1 Update - Pickering									20.9	21.3
Total - revised N1									**49.0**	**46.1**
Exhibit N2 - Darlington (no change from N1)									28.1	24.7
Exhibit N2 Update - Pickering									20.4	21.3
Total - revised N2									**48.5**	**46.1**

Sources: Exh E2-1-2, Exh L-1-Staff-2, Exh N1-1-1, Exh N2-1-1

154 OPG's test period forecast includes a 0.5 TWh adjustment (a reduction) in each year for major unforeseen events. This level of adjustment was approved for the first time for the 2011-2012 test period in the Board's previous decision.

155 The Exhibit N1 update is based on selected updates from the 2014-2016 business plan. The number of planned outage days at Pickering increased by 86.6 days which reduced the test period production forecast by 1.0 TWh. Darlington's production forecast was reduced by 1.6 TWh due to an increase in planned outage days and a reduction of 0.28 TWh related to higher lake water temperature.

156 The Exhibit N2 update is based on a further increase of 21 planned outage days at Pickering and a higher forecast of forced loss rate at Pickering resulting in a production forecast decrease of 0.5 TWh in 2014.

157 No party proposed changes to the Pickering production forecast.

158 Board staff submitted that the 61.9 day increase in outage days at Darlington is responsive to OPG senior management business planning direction to consider the significant historical variances. The major 2015 Darlington outage is related to moving the planned vacuum building outage from 2021 to 2015. OPG states that the length of the 2015 vacuum building outage is dependent on emergency service water piping work and emergency coolant injection valve replacement. Board staff questioned why this critical path work was not identified in the initial application. Board staff submitted that a production forecast reduction of only 0.28 TWh related to higher lake water temperature was appropriate for the test period.

159 The Board staff submission was supported by most parties. However, AMPCO submitted that the Darlington production reduction related to higher lake water temperatures should not be approved. In AMPCO's view the 2014-2016 business plan is based on the actuals prior to 2013. The actual production losses due to high lake water temperature in 2013 are much lower than 2012, and AMPCO submitted that the Board should not approve the 0.28 TWh reduction.

160 The challenge of the nuclear production forecast by OPG senior management is part of the review that all production forecasts are subject to, and the process surrounding the update was not different. OPG submitted that the adjustment was the result of rigorous reassessment and lessons learned from recent outages. While the specific tasks on the critical path are not discussed in detail in the pre-filed evidence, the complexity of the vacuum building outage is discussed. OPG observed that the Board staff submission focused on the tasks during the vacuum building outage but ignored the updated evidence that 22 of the 61.9 outage day increase is related to other Darlington outages.

161 Production losses related to lake water temperature are based on reviewing historical performance. OPG submitted that the evidence is based on the best information available and that AMPCO's submission should be given no weight.

Board Findings

162 The Board approves a nuclear production forecast of 49.0 TWh for 2014 and 46.6 TWh for 2015 to be used in the calculation of payment amounts.

163 OPG's forecast as filed in the updated impact statements (Exhibits N1 and N2) is accepted with one exception as discussed later in this Decision. The forecast as amended by updates filed in December 2013 and May 2014 was based on the business plan for 2014 to 2016. This business plan addresses the historically large and persistent gap between forecast and actual nuclear production. The revised forecast is in response to Senior Management's direction and was to ensure that the planned outage days recognize the scope and complexity of the proposed work. The revised forecast in Exhibit N2 reflects a more complete understanding of the work required at the Pickering units. As a result, the Board agrees with OPG that the nuclear production forecast represents "OPG's most complete and accurate forecast for 2014 and 2015".[31]

164 The decrease in production forecast for 2015 is the result of the decision to combine work at Darlington to include a vacuum building outage, a station containment outage and critical path work related to emergency service water piping work and emergency coolant injection valve replacement. The Board finds that OPG has demonstrated that combining this work results in net positive benefits and has been already approved by the Canadian Nuclear Safety Commission. The Board accepts that this work should be undertaken in 2015 and will result in a reduced forecast of nuclear production[32]

165 The one exception to accepting the nuclear production forecast as proposed by OPG is that the Board will remove the adjustment for major unforeseen events of 0.5 TWh for each of 2014 and 2015. This adjustment is tied to the Board's acceptance of OPG's evidence that the forecasts are based on OPG's best evidence which explains the technical and operational reasons for its updates to the production forecast, and that the resulting forecast is as accurate as possible. It follows then, that with the confidence OPG has in its forecast and the more detailed scrutiny which was undertaken in producing this forecast, that an allowance for unforeseen events is no longer required.

166 The Board finds that the argument of some parties for further adjustments to the forecast, for example due to water temperatures, is not compelling.

167 The quantity of nuclear production of 49.0 TWh in 2014 is equal to the highest amount over the period 2008 to 2013 and is therefore considered by the Board to be achievable and reasonable. The forecast amount of 46.6 TWh for 2015 is also considered by the Board to be reasonable.

3.2 Nuclear OM&A and Benchmarking

(Issues 6.3 and 6.4)

168 OPG seeks approval of operating costs of $2,957.5M in 2014 and $2,985.2M in 2015 for the nuclear facilities. The nuclear facility operating costs include base, project and outage OM&A, Darlington Refurbishment and New Nuclear OM&A, an allocation of corporate support and centrally held OM&A, nuclear fuel costs, Pickering Continued Operations costs, and depreciation and taxes. This section of the Decision addresses nuclear OM&A costs and benchmarking. The other components of nuclear operating costs are discussed later in this Decision.

169 OPG's historical and forecast OM&A for the nuclear facilities are summarized below. OPG applied for a total OM&A budget $2,401.4M for 2014 and $2,419.8M for 2015. The compound annual growth rate from 2010 actual to 2015 forecast is 3.5%.

Table 13: Nuclear OM&A

$million	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
Base	1,181.4	1,249.1	1,102.6	1,127.7	1,151.1	1,154.0
Project	142.7	111.6	111.5	105.7	113.9	106.4
Outage	278.2	215.0	214.3	277.5	262.7	330.7
SubTotal Operations	1,602.3	1,575.7	1,428.4	1,510.9	1,527.7	1,591.1
Darlington Refurbishment	3.2	2.6	2.8	6.3	19.6	18.2
Darlington New Nuclear	23.2	15.7	24.7	25.6	-	-
Corporate Costs	226.5	233.1	408.4	428.3	433.9	417.4
Centrally Held Costs	161.6	267.1	342.7	409.9	418.2	419.8
Asset Service Fee	24.5	22.1	23.0	22.7	23.3	26.8
SubTotal Other	439.0	540.6	801.6	892.8	895.0	882.2
Total OM&A	**2,041.3**	**2,116.3**	**2,230.0**	**2,403.7**	**2,422.7**	**2,473.3**
Exhibit N1 Update					**2,491.8**	**2,531.3**
Exhibit N2 Update					**2,401.4**	**2,419.8**
Sources: Exh L-1-Staff-2 Table 19, Exh N2-1-1						

170 Some parties proposed reductions to the OM&A forecast. These reductions ranged from $100M in the test period (Board staff), $100M per year (SEC and LPMA), $150M per year (CME), to $1.225 billion (GEC). The supporting rationale for the reductions was poor benchmarking results or excessive compensation. Part of Board's staff's proposed reduction was also based on excessive corporate support cost. OPG replied that the proposed reductions are punitive and that none of the parties challenged specific evidence related to base, project and outage OM&A.

171 Environmental Defence submitted that $1 billion of the test period OM&A expense is related to Pickering. It argued that this amount is unreasonable as other power sources, for example, conservation and imports from Quebec, are more cost-effective. Environmental Defence submitted that the operation of Pickering will also curtail renewable power generation. OPG argued that it is improper to determine payment amounts on the basis of the cost of other sources of power. Further, there is an insufficient record to assess cost and practicality of other sources of power.

Benchmarking

172 Benchmarking of the nuclear facilities is mandated by the August 17, 2005 Memorandum of Agreement between OPG and the Shareholder.[33]

> OPG will seek continuous improvement in its nuclear generation business and internal services. OPG will benchmark its performance in these areas against CANDU nuclear plants worldwide as well as against the top quartile of private and publicly- owned nuclear electricity generators in North America. OPG's top operational priority will be to improve the operation of its existing nuclear fleet.

173 The Memorandum of Agreement further requires that:

> OPG will annually establish 3 --5 year performance targets based on operating and financial results as well as major project execution. Key measures are to be agreed upon with the Shareholder and the Minister of Finance. These performance targets will be benchmarked against the performance of the top quartile of electricity generating companies in North America.

174 In the first cost of service proceeding, the Board found that the benchmarking filed was insufficient. As a result, the Board directed OPG to retain an expert to prepare a comprehensive benchmarking analysis of OPG's nuclear operations. OPG filed benchmarking reports that assessed 2008 performance prepared by ScottMadden Inc. for the EB-2010-0008 proceeding. OPG has adopted the ScottMadden reporting format and annually benchmarks its nuclear performance against "20 performance metrics and then sets operational, financial and generation performance targets that will move OPG nuclear closer to top quartile industry performance over the business planning period as part of top-down business planning process adopted in response to ScottMadden's work."[34]

175 The results of OPG's benchmarking of three key metrics for the nuclear facilities for the period 2008 to 2013, and the targets for 2014 and 2015 are summarized in the following table.[35] The three key metrics identified by ScottMadden are World Association of Nuclear Operators Nuclear Performance Index, Unit Capability Factor and Total Generating Costs per MWh. Note that Pickering A and B were combined by OPG after 2010, and therefore the units are not ranked separately by OPG after that time (though ScottMadden had created separate targets for Pickering A and B in its 2009 report). OPG has performed very poorly on all three of the key metrics.

Table 14 – Summary of Nuclear Benchmarking

	---Rolling Actual Results---						---Annual Target ---		
	a	b	c	d	e	f	g	h	i
Darlington	2008	2009	2010	2011	2012	2013	2014 "Scott Madden" Phase 2 Report	2014 2013-2015 Business Plan	2015 2013-2015 Business Plan
WANO NPI (Index)	95.67	95.10	94.10	92.80	96.30	90.75	98.60	97.90	96.10
2-Year Unit Capability Factor (%)	91.99	90.20	89.40	89.60	92.00	90.44	93.30	93.50	86.30
3-Year Total Generating Costs ($/New MWh)	30.08	32.77	33.55	33.05	31.67	34.42	36.75	36.21	42.78
Pickering									
WANO NPI (Index)	60.90	67.17	64.30	66.10	64.70	67.52	77.83	72.00	74.20
2-Year Unit Capability Factor (%)	67.65	74.47	74.57	72.50	75.62	75.77	82.10	79.90	82.10
3-Year Total Generating Costs ($/New MWh)	67.05	66.42	65.62	65.86	67.16	67.18	66.84	66.08	60.25
Pickering A									
WANO NPI (Index)	60.84	61.10	47.70				70.90		
2-Year Unit Capability Factor (%)	56.60	68.00	63.30				84.30		
3-Year Total Generating Costs ($/New MWh)	92.27	95.41	90.21				70.81		
Pickering B									
WANO NPI (Index)	60.93	70.20	72.60				81.30		
2-Year Unit Capability Factor (%)	73.17	77.70	80.20				81.00		
3-Year Total Generating Costs ($/New MWh)	58.68	54.64	54.79				64.80		

Sources:
Column a - EB-2010-0008 Exh F5-1-1 page 12 (Scott Madden Phase 1)
Column b - EB-2010-0008 Undertaking J3.5 Attachment 1 page 4
Column c - Exh L-6.4-SEC-92
Column d - Exh F2-1-1 Attachment 1 page 3
Column e - Exh L-6.4-SEC-92
Column f - Vol 5 Oral Hearing Transcript June 18, 2014
Column g - EB-2010-0008 Exh F2-1-1 Attachment 1 (Annual Targets agreed based on Scott Madden for inclusion in 2010-2014 Business Plan)
Column h- EB 2013-0321 Exh F2-1-1 page 15 (Annual Targets)
Column i - Exh F2-1-1 Attachment 2 (2013-2015 Nuclear Business Plan - Annual 2015 Target)

Q1
Q2
Q3
Q4

OPG Nuclear	2008	2011
WANO NPI (Index)	17th out of 20	24th out of 27
2-Year Unit Capability Factor (%)	18th out of 20	25th out of 28
3-Year Total Generating Costs ($/New MWh)	16th out of 16	12th out of 14

176 Table 14 was initially prepared by Board staff for cross examination and subsequently reviewed by OPG and filed as undertaking J5.2.

177 Column g of Table 14 lists the 2014 targets OPG established with ScottMadden in 2009. It was recognized at the time that the targets would not result in best quartile performance but that achievement of the targets would close the gap. Board staff submitted that OPG's performance to date and the test period targets fall short of these targets. During the oral hearing, OPG's witness indicated that achieving top quartile is not an objective.[36] Board staff submitted that the Memorandum of Agreement could have referred to benchmarking without referring to top quartile, and that it is clearly the shareholder's expectation that OPG set targets to achieve top quartile. CME submitted that OPG's performance as set out in Table 14 falls far short of what ratepayers should reasonably expect. CME noted that in the previous proceeding, the Board sent a signal that OPG must take responsibility for improving its performance by reducing the nuclear payment amounts by $145M.

178 Using data in the benchmarking report for 2011 filed with the application,[37] Board staff estimated that annual nuclear costs would be reduced by $300M if OPG's total generating costs were at the midpoint for the comparators. Board staff did not propose disallowances of this magnitude, but submitted that it would be reasonable for the Board to expect that OPG's efficiency and productivity should be improving. Recognizing that total generating cost includes OM&A, fuel and some capital costs, CME submitted that an OM&A reduction of $150M per year was appropriate.

179 The Pickering units, in particular units 1 and 4, perform poorly compared to the targets established. GEC submitted that, while OPG and the shareholder may want to run uneconomic plants, the issue before the Board is whether it is appropriate to allow full recovery of the costs OPG proposes. GEC estimated that test period OM&A requirements would be reduced by $1.225 billion based on industry median levels for Pickering, and reduced by $322M if Pickering operated at OM&A levels similar to Darlington. GEC submitted that OPG should be required to study the economics of a range of Pickering shutdown scenarios for the next proceeding.

180 OPG stated that there have been positive developments in benchmarking and cited Pickering unit-specific forced loss rate and unit-specific capability factor improvements. It is premature to state that OPG will not meet 2014 targets for the key metrics. OPG expects that Darlington 2014 total generating cost will be marginally below best quartile and that the total generating cost gap at Pickering has narrowed. OPG argued that the disallowances proposed by Board staff and CME should be rejected as the benchmarking report for 2011 does not reflect the impact of the Business Transformation initiative. OPG also referred to the Goodnight Consulting Inc. staffing study. OPG indicated that Goodnight determined that due to technology differences, OPG's CANDU plants require 1,431 more Full Time Equivalents ("FTEs") than comparator plants and eliminated these FTEs from the staffing study. OPG estimated that this represents $184M of unavoidable OM&A.

181 As the shareholder has concurred with the business plans that underpin the application, OPG replied that the shareholder has no concerns with OPG's performance under the Memorandum of Agreement.[38] OPG argued that it is not contractually committed to, or required to target or perform to top quartile standards, and that it is not aware of any case where the Board considered failure to achieve top quartile performance in setting rates.

Board Findings

182 The benchmarking of OPG's nuclear operations is an important reference for the Board. OPG has continued to produce annual nuclear benchmarking reports based on the format and methodology set out in 2009 by the consulting firm ScottMadden. The benchmarking is responsive to the Memorandum of Agreement with the Shareholder and provides the Board with comparative information for its review in a cost of service application. It is the Board's expectation that OPG will continue to produce annual nuclear benchmarking reports based on the ScottMadden methodology and that OPG will file these reports in future cost of service applications.

183 The benchmarking results for 2008 to 2013 and the targets for the test period were reviewed in this proceeding. The analysis was complicated by the presentation of rolling averages for the historical period and annual targets for the future period. The analysis was further complicated by the reorganization of Pickering. The Board recognizes that some individual units at Pickering and Darlington have improved performance in one or more of the metrics. In OPG's view, it has improved as a major operator in the three key metrics, but in comparison to the industry, OPG is just stable, because the industry also is changing.

184 Despite these factors, there is no dispute that OPG's performance in the three key metrics is not top quartile, nor does it demonstrate continuous improvement. In fact, for many of the measures OPG remains in the third or fourth quartile. It is also reasonable to conclude that OPG will not reach the aspirational 2014 targets set by ScottMadden and OPG in 2009 in order to close the gap. This is not the type of performance that ratepayers would expect. OPG is not satisfied with its performance either: "... clearly we would like to see better performance from our plants."[39]

185 In its submission, Board staff included calculations of the cost of OPG's performance relative to the midpoint for comparators' total generating cost for 2011 for illustrative purposes. CME submitted that a $150M OM&A reduction per year was appropriate on the basis of this gap. The Board agrees with OPG that reductions of $150M to $300M per year on the basis of nuclear benchmarking is not appropriate as the impact of Business Transformation is not reflected in the 2011 total generating costs. However, the Board notes that OPG's total generating cost targets for 2014 and 2015 take into account Business Transformation and those targets are second and third quartile.

186 OPG also argued that the Board staff and CME calculations were flawed as there is unavoidable OM&A related to the CANDU technology. The Board does not agree that the calculations were flawed for this reason. The ScottMadden methodology, which has been accepted by OPG for benchmarking, considered technology differences and found that the best overall financial comparison metric for OPG facilities is total generating cost per MWh.

187 Both Environmental Defence and GEC have proposed significant reductions related to poor economic performance of the Pickering units. The Board does not agree with these submissions. The government's direction on the operation of Pickering is set out in the Long-Term Energy Plan.

188 The Board finds that OPG's proposed nuclear OM&A costs should be reduced. The Memorandum of Agreement provides that "OPG's top operational priority will be to improve the operation of its existing nuclear fleet." In conjunction with ScottMadden, OPG itself set targets for 2014 that will not be met. Although the Memorandum of Agreement is not a contract for this purpose, it is clearly OPG's shareholder's intention that OPG improve continually, and at least target top quartile performance. OPG accepts that benchmarking is a valuable tool, and accepts that it has not achieved the results it wanted to achieve. It does not appear to accept, however, that there should be any repercussions from this poor performance in the way of disallowances. Benchmarking serves as a guide only. However, it is clear that OPG's inability to achieve even average performance imposes a significant cost on ratepayers. The Board finds that it is not reasonable to pass all of these costs on to ratepayers.

189 There is no specific budget "line item" related to overall nuclear performance and benchmarking. However, the majority of OM&A costs are predominantly related to staffing levels, compensation and pension related costs. Therefore, the Board's disallowances with respect to this issue are incorporated within its disallowances under the compensation section of this Decision.

3.3 Nuclear Fuel

(Issue 6.5)

190 Nuclear fuel costs include the cost of fuel bundles, used fuel storage cost and fuel oil for standby generators. As updated in Exhibit N2, OPG has forecast an amount of $266.5M for nuclear fuel procurement for 2014 and $260.5M for 2015.

191 AMPCO submitted that based on the average of 2010 to 2013 actuals, the test period fuel oil expense should be reduced by $3.5M. OPG did not respond to this submission.

192 In response to direction from the previous cost of service decision, OPG filed the Uranium Procurement Program Assessment Study prepared by Longenecker and Associates ("Longenecker").[40] Longenecker confirmed that US nuclear generators require inventory of 30 to 35% of annual requirements. OPG stated that test period carrying costs would be reduced by $4.7M if OPG's inventory levels were reduced to 30%. CME submitted that a reduction of $4.7M is appropriate. OPG argued that CME's proposal was unreasonable as contractual obligations as well as financial and physical risk coverage limits need to be considered.

193 CME observed that the proposed fuel costs are higher than historical and submitted that each test year be no more than the 2013 expense of $244.7M. OPG replied that there is no support for this submission as fuel expense is a function of production. In addition, OPG indicated that the 2013 fuel expense was based on production of 44.7 TWh and the production forecast for each test year is higher.

194 Board staff suggests that OPG be required as part of its next payments application to provide a study demonstrating how its nuclear fuel requirements and cost estimates reflect appropriate strategies for balancing costs and risks. Further, Board staff suggested that the analysis be based on the approaches that OPG has found appropriate and that Longenecker found to be "good utility practice" in its study. Board staff suggested OPG should also provide details regarding planning for lower nuclear fuel inventory requirements for when Pickering will cease operations. OPG argued that the Longenecker study was completed in 2012 and as Board staff had no issues with the findings, there was no need for a new study.

Board Findings

195 The Board finds that OPG met the directive in the EB-2010-0008 decision when it commissioned Longenecker, an independent consultant, to conduct a review of OPG's uranium procurement program.

196 The Board accepts the findings in the Longenecker & Associates report which concludes that OPG's procurement is undertaken in a professional manner and that its strategy is prudent. The Board is encouraged that three of the four recommendations made in the report have been accepted and are being implemented. The one recommendation not being pursued by OPG is with respect to "off-market" transactions. The Board agrees this recommendation is inconsistent with OPG's policy and the government's procurement guidelines to which it is subject.

197 The Board will not make any changes to OPG's proposed inventory target levels, which will be achieved by the end of 2015. The observation that the reduced inventory levels may be achieved by the end of 2014 is unsupported.

198 The Board does not agree that a study to examine various nuclear fuel cost management options in anticipation of the changes once the Pickering station is closed should be undertaken at this time. Given the station is not proposed to close until 2020, the Board agrees with OPG that undertaking such a study would not be a reasonable expenditure of time and money.

199 Although several parties put forward suggestions for reducing the nuclear fuel cost expenditures, there was no substantial evidence provided regarding the options proposed. As OPG points out, fuel expenses are a function of production, so a simple comparison of costs in the previous three years is not a suitable predictor of future costs.

200 The Board finds OPG's proposed costs of $266.5M for 2014 and $260.5M for 2015 to be reasonable and are therefore accepted. However the final nuclear fuel cost will increase due to the increased nuclear production forecast the Board has set. OPG shall confirm the final test period nuclear fuel costs in the payment amounts order process.

3.4 Pickering Continued Operations

(Issue 6.6)

201 Pickering Continued Operations will extend the life of Pickering units 5 to 8 from 2015/2016 to 2020. OPG seeks approval of 2014 OM&A expense of $38.9M for the project which would bring the total project cost to $192M.

202 OPG filed an updated 2012 business case for the project.[41] OPG reported that the net system benefit of Pickering continued operations is $520M. An OPA letter filed with the application suggested that the cost advantage of Pickering continued operations is $100M. The OPA did not provide oral testimony in the proceeding, but did file written responses on July 25, 2014 to questions raised by GEC relating to Pickering continued operations.

203 Board staff submitted that the test period expenditures are appropriate and that for the test period, the Board should rely on the Long-Term Energy Plan which states;

> The continued operation of Pickering facilitates the refurbishment of the first units at Darlington and Bruce by providing replacement capacity and energy without greenhouse gas emissions while managing prices. However, an earlier shutdown of the Pickering units may be possible depending on projected demand, the progress of the fleet refurbishment program, and the timely completion of the Clarington Transformer Station.[42]

204 AMPCO submitted that the net present value of continued operations is high, as the analysis did not consider sunk costs of $140M, a low demand scenario and risk related to pressure tube and calandria contact. AMPCO did not support any continued operations expenditure as it believes that the net present value of continued operations is a cost not a benefit. OPG argued that the business case included contingency for the issue of the potential risk associated with the pressure tube and calandria contact.

205 GEC observed that there is a considerable difference between the continued operations benefit determined by OPG and the OPA. GEC questioned the factors analyzed in the sensitivity analysis. In particular, GEC questioned whether the full cost of surplus baseload generation was considered by OPG and the OPA. In GEC's view, the Board should not approve payment amounts that have a perverse effect on ratepayers. As the economic benefit of continued operations is questionable, GEC submitted that the incremental cost of running Pickering in the test period ($126M in 2014 and $310M in 2015) should be disallowed.

206 OPG argued that OPA analysis did consider potential surplus energy and that this was confirmed in the written responses filed by the OPA on July 25, 2014.

207 GEC recognizes that operation of some Pickering units has system planning benefits, however, as units 1 and 4 (formerly Pickering A) under-perform on all benchmarking indicators versus units 5 to 8 (formerly Pickering B), GEC submitted that the Board should not "reward" OPG for the continuing losses with respect to units 1 and 4. OPG replied that it operates Pickering as one station and that the Long-Term Energy Plan includes Pickering in-service beyond the test period.

208 GEC submitted that $6.6M of test period expense allocated to Pickering for the fuel channel life extension project should be allocated to Darlington as the additional fuel channel life is not required for Pickering station life of 2020. However, OPG argued that an objective of the fuel channel life extension project is to operate all Pickering units to 2020 without a life management outage on any unit.

209 In the event the Board is not prepared to implement cost reductions related to Pickering, GEC submitted that the Board should require OPG to provide, in the next payment application, a detailed analysis of the net benefits of continued operation of Pickering units. GEC further submitted that the analysis should consider shutdowns of either the A or B units or all units, including staffing considerations. OPG argued that the study should not be ordered and that the Board should rely on the Long-Term Energy Plan.

Board Findings

210 The Board approves the OM&A costs in the amount of $38.9 M to enable the completion of the initiative to extend the operating life of Pickering units 5 to 8 to the year 2020. The Board finds these costs to be prudent and notes that this initiative is on time and on budget to be completed by the end of 2014.

211 The 2014 costs to complete the continued operations initiative include Fuel Channel Life Extension costs. The Board does not accept GEC's argument that these should be disallowed or reallocated to Darlington. OPG's evidence demonstrates that these costs are related to Pickering continued operations.

212 It is important to recognize that the extension of the Pickering units is consistent with the Province of Ontario's Long-Term Energy Plan. Further, benefits from Pickering continued operations were confirmed by the OPA. Lastly, the continued operations of Pickering has been reviewed by the Canadian Nuclear Safety Commission resulting in the renewal of Pickering's power reactor operating license to August 31, 2018.

213 Challenges to the value and economic merits of the Pickering continued operations were made by GEC and AMPCO, including whether the analysis was incorrect as the assessment omitted the impact of surplus generation. The Board accepts OPG's evidence that surplus baseload generation was included in the OPA's analysis.

214 The Board reiterates its view that the project is consistent with government direction, and that benefits (while significantly reduced from OPG's estimate) were determined by the OPA to be positive. The OPA also brought to the Board's attention the non-economic benefits of Pickering Continued Operations. For these reasons, the Board does not see the value of directing OPG to complete a detailed analysis of the net benefits of continued operation of Pickering units.

3.5 Nuclear Capital Expenditure and Rate Base

(Issues 2.1, 4.6, 4.7 and 4.8)

215 OPG has applied for total capital expenditures of $196.3M in 2014 and $143.9M in 2015, excluding the Darlington Refurbishment Project. The proposed capital expenditure for 2014 represents a decrease over 2013 actuals. OPG states that the decrease in 2015 is due to a reduction in the number of capital projects. OPG also seeks Board approval for nuclear in-service additions of $158.3M for 2014 and $141.7M for 2015.

216 OPG's historical and forecast capital expenditures for the nuclear facilities, excluding Darlington Refurbishment, are summarized in the following table.

Table 15: Nuclear Operations Capital Expenditures (excluding Darlington Refurbishment Project)

$millions	2010 Budget	2010 Actual	2011 Approved	2011 Actual	2012 Approved	2012 Actual	2013 Budget	2013 Actual	2014 Plan	2015 Plan
Darlington NGS	24.3	33.8	12.8	47.9	5.6	50.5	68.8	76.4	20.6	9.5
Pickering NGS	22.6	93.0	1.5	56.1	0.5	78.7	67.2	90.6	22.2	2.2
Nuclear Support	58.0	30.1	3.9	31.2	0.7	16.7	13.0	24.0	4.2	1.3
Total Portfolio Projects (Allocated)	104.9	156.9	18.2	135.2	6.8	145.9	149.0	191.0	47.0	13.0
Facility Projects (to be Released)	36.6	-	74.0	-	55.0	-	-	-	0.0	0.0
Portfolio Projects (Unallocated)	30.4	-	79.8	-	110.3	-	1.4	-	128.0	109.2
Total Portfolio Projects	171.9	156.9	172.0	135.2	172.1	145.9	150.4	191.0	175.0	122.2
P2/3 Isolation	8.8	5.9	-	-	-	-	-	-	0.0	0.0
Minor Fixed Assets	20.2	15.4	19.7	12.9	19.5	15.5	19.9	10.2	21.3	21.7
Total Nuclear Operations Capital	**200.9**	**178.2**	**191.7**	**148.1**	**191.6**	**161.4**	**170.3**	**201.2**	**196.3**	**143.9**

Source: Exh D2-1-2 Table 4 & Exh L -1-Staff-2 Attachment 1 Table 11

217 Based on historical overestimating of capital budgets and approvals, Board staff proposed that a 10% reduction to the requested amounts would be a more reasonable level of forecast expenditure. Several parties agreed with the Board staff submission. CME observed that a historical comparison of Board approved amounts with actuals results in a difference of 20%.

218 OPG submitted that the analysis of historical trends is not a review of reasonableness of the test period nuclear capital project forecast.

219 With respect to nuclear rate base additions excluding Darlington Refurbishment, a summary of historical and forecast additions is provided below.

Table 16: Nuclear Operations In-Service Additions (excluding Darlington Refurbishment Project)

	2010		2011		2012		2013		2014	2015
$millions	Budget	Actual	Approved	Actual	Approved	Actual	Budget	Actual	Plan	Plan
Darlington NGS	43.1	31.2	32.9	32.3	90.1	52.9	89.9	183.7	43.9	7.7
Pickering NGS	103.1	166.8	4.5	27.4	17.9	41.0	53.6	97.1	48.8	12.5
Nuclear Support Divisions	25.1	35.6	67.9	30.6	12.5	22.5	17.4	30.7	6.4	0.7
Supplemental in-Service Fcst	-	-	50.5	-	47.6	-	-		37.9	99.1
Minor Fixed Assets	20.2	15.4	19.7	12.9	19.5	15.5	19.9		21.3	21.7
TOTAL	**191.5**	**249.0**	**175.5**	**103.2**	**187.6**	**131.9**	**180.8**	**311.5**	**158.3**	**141.7**

Source: Exh D2-1--3 Table 4 & Exh L-1-Staff-2 Attachment 1 table 2

220 In the previous payments case, the Board expressed concern with the forecasting of nuclear in-service additions. The EB-2010-0008 decision states, "In the next proceeding, the Board will re-examine the issue of rate base additions and the accuracy of OPG's forecasts in this area."[43]

221 Board staff submitted that OPG has a recent history of over estimating in-service additions by 12% in the period 2010 to 2012, and submitted that the rate base should be adjusted to reflect a reduction of $18M and $17M from the proposed in-service amounts for 2014 and 2015 respectively. AMPCO and CME supported Board staff's submission.

222 OPG argued that Board staff's analysis was incorrect as the 2013 variance was not factored into the analysis.

Board Findings

223 The Board finds that OPG's proposed capital expenditure budget for projects coming into service during the test period is reasonable. The projects are supported by business cases approved by the appropriate level of authority within OPG. The Board is providing no explicit approval in this Decision for the capital budget associated with multi-year nuclear projects (excluding the Darlington Refurbishment Project) which do not come into service during the test period. Although OPG has underspent during the three year period from 2010 - 2012 relative to its approved or budgeted capital expenditures, this is not true of 2013. The Board notes variation in the actual capital expenditures ranging from $148.1M in 2011 to $201.2 in 2013. The requested capital expenditures for 2014 and 2015 fall in the range of previous actual expenditures.

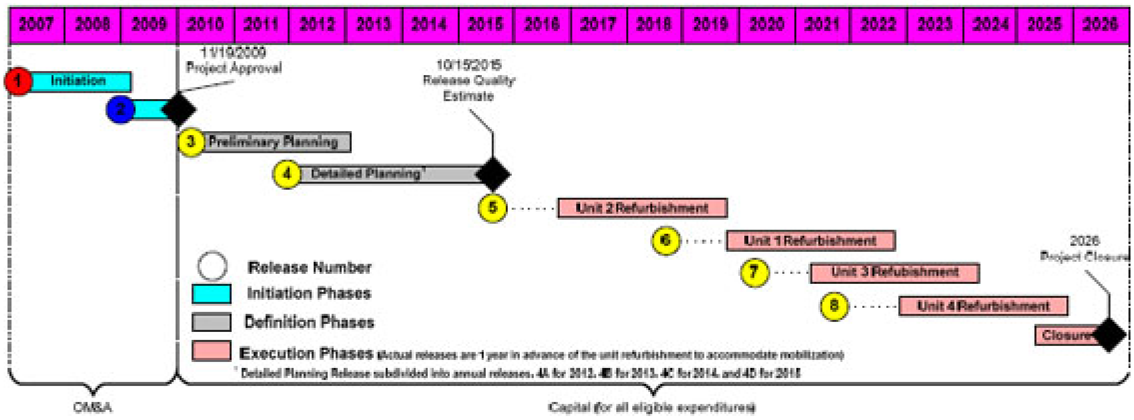
224 With respect to in-service additions, the Board has reviewed the data over a longer term period (2010-2013). The Board notes that the actual additions to rate base vary, with 2013 actual in-service additions significantly higher than previous years. OPG's proposed in-service additions for the test period fall well within the range of historical actuals. The Board approves the proposed test period in-service additions for nuclear projects (excluding the Darlington Refurbishment Project) of $158.3M in 2014 and $141.7M in 2015.

3.6 Darlington Refurbishment Project

225 In February 2010, OPG announced it was proceeding with Darlington Refurbishment to extend plant life by 30 years to 2045-2050. OPG continues to have high confidence that the project will cost less than $10 billion (in terms of 2013 dollars) or $12.9 billion including capitalized interest and future escalation.

226 The refurbishment project phases are presented in the figure below.[44] This strategy was approved by OPG's Board of Directors in November 2013. The project is currently in the detailed planning and definition phase. A major milestone is the release quality estimate expected in October 2015, followed by refurbishment of Unit 2 in October 2016.

Figure 1: Overview of the Darlington Refurbishment Release Strategy



227 In the current proceeding OPG seeks:

* Approval of OM&A expenditures of $6.6M in 2014 and $18.2M in 2015.
* Approval of in-service additions to rate base of $5.0M in 2012, $104.2M in 2013, $18.7M in 2014 and $209.4M in 2015.
* A finding that proposed capital expenditures of $839.9M in 2014 and $842.5M in 2015 are reasonable.
* Recovery of capital cost portion of the Capacity Refurbishment Variance Account December 31, 2013 balance in the amount of $5.7M.
* A finding that commercial and contracting strategies are reasonable.

3.6.1 OM&A Expenditures

(Issue 6.7)

228 Only Lake Ontario Waterkeeper ("Waterkeeper") made submissions on OM&A related to the Darlington Refurbishment Project. Waterkeeper submitted that the Board needs to ensure that adequate provision has been made for the environment, and that such a finding would fall under the Board's public interest mandate. Waterkeeper asked that the Board put two conditions on the approvals contained within this application.

229 First, that OPG be required to provide updates concerning the progress and actual costs of the Environmental Assessment Follow-up studies, other refurbishment project environmental monitoring studies and any adaptive management projects.

230 Second, Waterkeeper asked that the Board require OPG to provide detailed updates to show how its environmental oversight bodies have taken account of the environmental effects of the Darlington Refurbishment Project. Specifically, OPG should be able to demonstrate how they can prevent, mitigate and learn from environmental accidents or contingencies.

231 OPG argued that environmental regulatory oversight of OPG rests with the Canadian Nuclear Safety Commission, and that providing environmental assessment related filings to the Board is not required.

Board Findings

232 The Board approves OM&A expenditures of $6.6M in 2014 and $18.2M in 2015 for the Darlington Refurbishment Project.

233 The Board acknowledges that environmental regulatory oversight for the Darlington Refurbishment Project falls within the jurisdiction of the Canadian Nuclear Safety Commission. However, the Board is responsible for considering the costs that will ultimately flow through to payment amounts and will be borne by ratepayers. Accordingly, the Board will require OPG to file at its next cost of service proceeding updates of actual costs of environmental assessment follow-up studies, costs of environmental monitoring studies and costs of any adaptive management projects. The Board will impose the first condition on OPG as described by Waterkeeper. This condition relates directly to the Board's mandate to consider costs. The Board will not require OPG to provide the information contained in the second condition proposed by Waterkeeper. This information falls within the mandate of OPG's environmental regulatory authorities.

3.6.2 In-Service Additions to Rate Base

(Issue 4.9)

234 As filed on September 27, 2013, OPG requested approval for Darlington Refurbishment Project in-service additions of $18.7M and $209.4M in 2014 and 2015 respectively.

235 OPG filed two updates to the Darlington Refurbishment Project evidence:

* As reported in Exhibit N1 filed on December 6, 2013, Darlington Refurbishment Project in-service additions were revised to $26.1M in 2014 and $310.0M in 2015.
* As noted in Exh D2-2-2 filed on July 2, 2014, in-service additions were revised to $67.2M in 2014 and $222.7M in 2015.

236 The original filing and the two updates for 2014 and 2015 in-service additions are summarized below.[45] The in-service additions are related to campus plan projects i.e. facilities and infrastructure, to support current operation, the refurbishment and operation after refurbishment. As the revenue requirement impact was not material, OPG did not propose any changes to its request for in-service amounts.

$ millions	Originally Filed Exhibit D2-2-1			As updated Exhibit N1-1-1 and D2-2-1 Attachment 5			As Updated Exhibit D2-2-2		
	Final In-Service Date	2014	2015	Final In-Service Date	2014	2015	Final In-Service Date	2014	2015
Darlington OSB Refurbishment	Jul-15	-	29.7	Oct-15	-	37.7	Aug-15	-	45.1
D2O Storage Facility	Apr-15	-	83.5	Oct-15	-	94.2	Jan-17	15.5	1.0
DN Auxiliary Heating System	Mar-15	-	36.3	Apr-15	-	43.5	Mar-15	-	75.3
Water & Sewer	Nov-14	12.2	-	Nov-13	-	-	Nov-15	22.6	6.6
Elec Power Distribution System	Apr-15	4.4	6.2	Jun-14	10.0	-	Nov-14	12.0	-
Darlington Energy Complex	Jul-13	-	-	Jul-14	6.0	-	Jul-15	2.1	4.1
RFR Island Support Annex	Apr-16	-	-	May-15	-	25.4	Apr-16	-	-
Other Campus Plan projects	various	-	-	various	10.2	-	various	15.1	7.6
Safety Improvement Opportunities	various	-	42.7	various	-	90.5	various	-	83.0
Other Station Modifications	various	2.1	11.1	various	-	18.7	various	-	-
Total		**18.7**	**209.4**		**26.1**	**309.9**		**67.2**	**222.7**

237 Environmental Defence submitted that the in-service additions are not appropriate as OPG has not established that the assets are required "but for" the Darlington Refurbishment. The assets will only provide benefit to ratepayers as part of the overall Darlington Refurbishment Project and should not be included in rate base until the refurbished units are in-service. One of the reasons that the Board rejected construction work-in-progress for the Darlington Refurbishment Project in the EB-2010-0008 proceeding was that it was still in the definition phase. Environmental Defence observed that the project is still in the definition phase.

238 Several parties sought clarification from OPG at the technical conference and oral hearing about its request with respect to Darlington Refurbishment in-service additions. Parties sought to understand the extent of project completion in the test period. In particular, the evidence filed in July 2014 indicated that the D2O (heavy water) storage facility and Auxiliary Heating System project were delayed and/or projected to be over-budget.

239 OPG indicated that costs and timelines for the D2O storage facility have changed as the scope of work was not well understood initially and there were new seismic requirements from the Canadian Nuclear Safety Commission. Similarly, OPG indicated there were scope changes arising from the contractor's original underestimation of scope complexity for the Auxiliary Heating System project.

240 Based on its review of the evidence, which included reports of consultants retained by OPG to provide external independent oversight of the Darlington Refurbishment, GEC submitted that OPG has not demonstrated prudence in expenditure decisions, project planning or expenditure management. Even though some of the projects may be in-service, similar to Environmental Defence, GEC submitted that the projects are not required but for Darlington Refurbishment. Both Environmental Defence and GEC referred to an Alberta Court of Appeal decision that found that the used and useful principle requires that the facilities be required, not merely in use. However, in reply, OPG argued that the Alberta Court of Appeal decision was related to a provision of an Alberta statute that is not established law in Ontario.

241 Board staff and several other parties expressed some concern with OPG's proposal to retain its original in-service addition request despite updated information about the status of individual campus plan projects. The parties proposed revisions to OPG's request.

242 PWU submitted that OPG's proposal could be problematic for the Board to apply the principle of used and useful and to make a determination of what amounts should be added to rate base. The PWU's preference is for the Board to make a determination based on the updated in-service addition amounts.

243 In SEC's view, the rate base additions should be limited to $34.6M in 2014 and $6.6M in 2015 related to the water and sewer project and the electrical distribution project. There is insufficient evidence for some of the other projects and the remaining proposed additions should not be approved until the refurbished units are running. For projects for which there is insufficient evidence, SEC proposed additions to the Capacity Refurbishment Variance Account and review in a future application when supporting evidence was available. This matter is also noted in the Deferral and Variance Account section of this Decision.

244 Board staff recommended that the Board accept the amounts that OPG seeks to close to rate base, but that the approval should not be considered a finding of prudence for the D2O storage facility. CME agreed with staff, but submitted that a 10-20% reduction was appropriate to redress management failures identified by OPG's external consultant. VECC submitted that until the cost of managerial errors and remedial expenditures was independently determined, no additions to rate base should be approved.

245 It is OPG's view that all the campus plan projects will be used or useful when placed in-service and useful to the station generally, not wholly related to Darlington Refurbishment. There is sufficient evidence for all the projects and explanation for scope changes that led to cost increases for projects.

Board Findings

246 The Board will approve OPG's proposed test period in-service additions of $18.7M in 2014 and $209.4M in 2015.

247 Proposed in-service amounts represent assets that will come into service in the test period. OPG has sought to include some test period amounts which represent part of the larger Darlington Refurbishment Project. OPG submitted that the campus plan projects related to the proposed in-service additions are not wholly related to the Darlington Refurbishment Project, but are useful to the on-going operations of Darlington as well. The Board has considered this evidence and agrees that the campus plan projects described are useful to the on-going operations of Darlington. The Board finds OPG's proposal to be reasonable in the specific circumstances in this case.

248 While Board staff agreed with the proposed amounts to be added to rate base for 2014 and 2015, they cautioned that the D2O project will not be fully complete until January 2017. Board staff agreed that a portion of the costs should be included in rate base but took the position that the Board's approval should not be considered to be a finding of prudence for the entire D2O project. The Board agrees. OPG has confirmed its understanding that the inclusion of test period amounts related to a portion of a project does not mean that the entire project is being accepted by the Board. A prudence review should take place when the D2O project is completed and fully in-service which it is expected will be OPG's next payment case.

249 The Board also considered the argument put forward by CME that a reduction of between 10-20% be made to the in-service additions related to the D2O project and the Auxiliary Heating System project. The Board accepts OPG's evidence that the increased costs represent more accurate project costs and therefore the Board will not require a reduction.

3.6.3 Test Period Capital Additions

(Issue 4.10)

250 As originally filed in September 2013, Darlington Refurbishment Project capital expenditure was forecast to be $837.4M in 2014 and $631.8M in 2015. While the project is in the detailed planning and definition phase, facility and infrastructure projects to support or extend Darlington station life have commenced.

251 OPG updated its forecast of capital expenditure twice during the proceeding resulting in an increase of the proposed capital expenditures to $839.9M in 2014 and $842.5M in 2015.

252 Both Environmental Defence and GEC argued that the levelized unit energy cost analysis for Darlington Refurbishment is flawed and submitted that the capital expenditure request is not reasonable. Criticisms included consideration of externalities and limited costing of alternatives.

253 Board staff recommended that the Board not make a finding on the reasonableness of proposed capital expenditures as most of the projects would not go into service in the test period. Board staff indicated that the evidence was not complete regarding the amount comprising the updated capital expenditures for 2014 and 2015. OPG did not clarify or produce a list of projects in its reply argument. CME agreed with Board staff, noting that there was significant uncertainty around the estimates for projects making up the Darlington Refurbishment Project.

254 SEC also agreed with Board staff, noting that although there was a lot of evidence filed, it was not sufficient to allow the Board to make a binding determination on test period capital for Darlington Refurbishment. SEC noted that the independent reports on the campus plan projects were critical of the cost overruns, and submitted that the $1.7 billion proposal was unlikely to be correct and unlikely to be prudently incurred. OPG argued that the overall impact of the campus plan project overruns was minimal and that OPG has been responsive to the independent oversight of the project.

Board Findings

255 The Board indicated in an earlier ruling in this proceeding that it will not consider, as a threshold issue, whether the Darlington Refurbishment Project should proceed.[46] The Board maintains that the decision to refurbish Darlington is a decision that has been made by the provincial government and forms a key component of the Long-Term Energy Plan. As such, at this time the Board needs only to focus on the test period capital expenditures.

256 The Board notes that the majority of the capital expenditures proposed will not be added to rate base within the test period. The Board will not determine whether the amounts are reasonable or not, deferring that decision until OPG seeks to add these capital expenditures to rate base.

3.6.4 Commercial and Contracting Strategies

(Issue 4.11)

257 OPG sought the Board's approval of its commercial and contracting strategies for the Darlington Refurbishment Project. OPG is utilizing a "multi-prime contractor model" where there is more than one prime contractor and the owner has a separate contract with each prime contractor. As the integrator between contractors, OPG retains project management responsibility and design authority. OPG has engaged external technical and project management experts to assist with this project management. The benefits of this model are that OPG retains control over the project, including deliverables, costs and schedules. OPG filed an Assessment of its Commercial Strategies prepared by Concentric Energy Advisors, dated September 2013.[47]

258 Many of the contracts will be target priced contracts. Under this model contractors receive incentives to meet cost and timeline targets. If the targets are missed, contractors will receive less incentive, but will receive payment for reasonably incurred expenses.

259 The strategies for the five major work packages (Re-tube and Feeder Replacement, Turbines and Generators, Fuel Handling, Steam Generators, and Balance of Plant) were reviewed by Concentric Energy Advisors. The Concentric reports filed with the application concluded that the strategies were reasonable and prudent.

260 In support of its application, OPG presented Mr. John Reed, a principal from Concentric Energy Advisors as a witness in the oral hearing. Mr. Reed stated in his evidence that for each of the major work packages for which Concentric offered an opinion, Concentric concluded that the company's conduct was within a range of "reasonable behaviour" and did represent "acceptable risk."[48]

261 It was not clear to Board staff or the parties what OPG was seeking from the Board related to commercial and contracting strategies or why such a finding was necessary. Board staff submitted that any decision on this matter would be a form of project management and that no specific approval should be provided.

262 In SEC and CME's view, OPG's request is an attempt to "buy insurance" and to insulate OPG from commercial and contractual risks and from criticism in future proceedings. Approval of contracting and commercial strategies is neither necessary nor desirable.

263 OPG argued that a finding of reasonableness by the Board does not eliminate the need for future prudence review, but will enable the review to be assessed in the appropriate context.

264 Both GEC and Environmental Defence submitted that OPG's commercial and contracting strategies are contrary to the Long-Term Energy Plan as they expose ratepayers to too much risk. The evidence suggests that OPG bears the primary risk for overruns with respect to 93% of the project costs.[49] Environmental Defence was critical of cost overruns on previous projects including most recently the Niagara Tunnel Project and the Darlington Refurbishment campus plan projects. Environmental Defence submitted that there is no ratepayer protection for replacement power associated with project delays.

265 OPG clarified that the 93% of project costs includes OPG internal costs, and that only 27% of the $10 billion estimate is on a target price basis.[50]

266 GEC submitted that the project risk will not be monetized until the release quality estimate is complete; therefore, it is premature to structure the commercial arrangements and contract strategy. While OPG has stated that allocating more risk to contractors would have significant cost, GEC submitted that the commercial and contracting strategy should be informed by an understanding of the risks. Optimal allocation of those risks will enable compliance with the principles of the Long-Term Energy Plan.

267 OPG argued that GEC and Environmental Defence have taken a narrow view of risk. There is a multi-faceted risk minimization approach including OPG's retention of project management responsibility, a significant testing effort in advance of the release quality estimate and continuous internal and external oversight. While the parties claim that a fixed price turnkey arrangement is the only means to minimize risk, this is not possible for a mega project like Darlington Refurbishment as there are risks that contractors would not be willing to take on.

Board Findings

268 The Board will not make a finding that the commercial and contracting strategies used by OPG in the Darlington Refurbishment Project are reasonable.

269 OPG proposed this issue in the draft issues list filed with the application. However, during the oral phase of the hearing it was unclear how a finding of reasonableness would be defined and why such an approval by the Board was necessary. On the last day of the hearing, in response to the Board's questioning as to what the Board would be approving if it determined that the contracting strategy was reasonable, OPG clarified that the Board would not be approving the contracts, it would not be approving the conduct of the contract negotiations, and it would not be approving the procurement process. The Board would not be approving any prices established through the contracting process, nor would the Board be approving the selection of the winning proponent(s).[51]

270 In OPG's view, the Board would be making a finding of reasonableness in respect of the guiding principles forming the contracting strategy which OPG described as including;

1. A multi-prime contractor model in which OPG retains overall project management and design authority responsibility;
2. The division of the work into 5 work packages;
3. A model where the prime contractor is responsible for some combination of engineering, procurement and construction within each of the 5 work packages; and
4. The means by which risk would be allocated.[52]

271 The Board will not make the finding requested by OPG for two reasons.

272 First, the application before the Board is an application for payment amounts for the years 2014 and 2015. The Board is of the view that the commercial and contracting strategies approval sought by OPG extends beyond a determination of those payment amounts. While there may be a tangential link between a contracting strategy and the rates requested, the Board finds that the link in this case is not direct enough. The Board agrees with Board staff that the request, as defined by OPG, is tantamount to an approval of project management which is not the role of the Board. Project Management and project execution are the responsibility of OPG.

273 If the Board were to make a finding on the reasonableness of the commercial and contracting strategies, the onus would be on OPG as the applicant to provide the Board with sufficient evidence to satisfy the Board that the commercial and contracting strategies are reasonable. Given the guiding principles articulated by OPG, the Board would have required far more evidence than was presented to reach those conclusions. On July 2, 2014, OPG filed reports that independently assessed the execution of some infrastructure projects related to the refurbishment. The reports prepared by Burns & McDonnell and Modus Strategic Solutions were critical of project execution and raised concerns including the impact on Darlington Refurbishment schedule and costs. In fact, the Board had to take a two-week recess from the proceeding to provide parties with the opportunity to review and analyze the reports filed on July 2, 2014.

274 The Board, in order to make any determination, must be satisfied that a thorough and complete hearing of this issue has taken place. The Board is not satisfied that this has occurred.

3.6.5 Darlington Refurbishment and Long-Term Energy Plan

(Issue 4.12)

275 In Board staff's view, the Darlington Refurbishment is aligned with the Long-Term Energy Plan, however, the other parties submitted that it was premature to make a finding. OPG observed that the province has very clearly indicated that Darlington Refurbishment is a key part of the Long-Term Energy Plan and that no concerns have been raised with respect to compliance.

276 The Board will not opine on whether OPG's nuclear refurbishment process for Darlington aligns with the Government of Ontario's Long-Term Energy Plan. The Board considers this review to be outside of its mandate. A key component of the principles outlined in the Long-Term Energy Plan is the appropriate allocation of risk as it relates to nuclear refurbishment. The Board is of the view that for the reasons previously stated, the amount of evidence related to appropriate risk allocation would be insufficient for the Board to reach such a finding.

3.7 Nuclear Other Revenue

(Issue 7.2)

277 OPG receives revenue from non-energy businesses and that revenue is applied as an offset to the nuclear revenue requirement. These businesses are heavy water services, isotope sales and inspection and maintenance services. The nuclear facilities also provide ancillary services as described in the Hydroelectric Other Revenue section of this Decision. Variances between forecast and actual ancillary services revenue are recorded in the Ancillary Service Net Revenue Variance Account -- Nuclear.

278 The table below sets out the actual and forecast levels for other revenue.

Table 17: Nuclear Other Revenue

$million	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2013 Actual	2014 Plan	2015 Plan
Heavy Water Sales and Processing	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
Sub-total	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							

279 Board staff observed that OPG regarded its 2013 budget as "a return to more normal conditions for sales of heavy water, heavy water detritiation services and isotope sales."[53] However, the 2013 actual total other revenue was $12.8M or 51% higher than 2013 budget. OPG subsequently described the lower test period forecast as "a return to a more normal level of revenues for heavy water sales and processing."[54] Board staff submitted that the Board should consider the 2013 actual nuclear other revenue as the normal level for the test period and approve $37.6M for each of 2014 and 2015. OPG argued that heavy water sales and processing are subject to services provided to external parties and maintenance of the tritium removal facility and that it is not appropriate to consider just historical levels.

280 AMPCO submitted that OPG's 2014 and 2015 forecasts for Heavy Water Sales and processing are too low based on historical actuals, and proposed that a 4 year average be used to forecast the test period. LPMA proposed that a 3 year average be used. OPG argued that there is no pent up demand for heavy water sales and processing. The 2011 and 2012 revenues were related to the restart of Bruce and Point Lepreau reactors. OPG submitted that forecasting is more complex than relying on the past.

Board Findings

281 The Board accepts OPG's arguments that higher historic revenues in 2011 and 2012 from Nuclear Other Revenues may have been impacted by one-time events such as the increased sales to Bruce Power and Point Lepreau and may not be indicative of future revenues in the test period. The Board finds however that OPG has not substantiated its forecast decline for Nuclear Other Revenues. As a result, the Board finds the 2013 actual Nuclear Other Revenues of $37.6M to be appropriate for 2014 and for 2015.

4 CORPORATE COSTS

4.1 Compensation

(Issue 6.8)

282 Compensation is one of OPG's largest expenses. Compensation costs include salaries, wages, current pension expenses and other post-employment benefit ("OPEB") expenses and are expected to be $1,604.2M in 2014 and $1,618.1M in 2015; for a total of $3,222.3M in the test period. This amount is approximately 35% of OPG's annualized requested revenue requirement of $9.28 billion. There is no single "line item" for OPG's compensation costs. These costs are spread throughout various OM&A budgets and to some minor extent, are included in capital budgets.

283 The majority of OPG's compensation costs relate to its unionized work force in the PWU and the Society. Approximately 86% of compensation costs in 2014 are for employees represented by these two unions. OPG is required to collectively bargain with the PWU and the Society. The current collective agreement for the PWU covers the period April 1, 2012 to March 31, 2015. The Society collective agreement covers the period January 1, 2013 to December 31, 2015. OPG's position is that the requirement to bargain collectively with its unions places restrictions on its ability to control its compensation costs. The 2013-2015 business plan assumes no PWU increase for the period beginning April 1, 2015 other than a one per cent increase for step progression. For the Society the 2013-2015 business plan assumes a zero per cent increase over the test period, again with a one per cent increase for step progression.[55]

284 Broadly speaking, OPG's total compensation costs are the function of two things: the number of employees, and the amount that employees are paid, including pension expenses and benefits. Efforts to control costs can focus on either of these elements, or both.

285 Many parties argued that OPG's compensation costs are excessive, and that the Board should disallow recovery for a portion of the costs. CME argued that the evidence was clear that OPG is both overstaffed, and that its compensation levels significantly exceed industry benchmarks. It proposed disallowances of $146M in 2014 and $144M in 2015. SEC argued that although OPG had made significant progress in addressing its overstaffing issues, its compensation levels remained excessive and that there were serious concerns regarding a lack of management oversight and accountability. SEC recommended disallowances of $100M in each of the test years. Both LPMA and CCC argued for the same reductions, on largely the same basis. Staff argued for OM&A reductions totaling $170M over 2 years, of which the majority would be attributable to compensation.

286 OPG submits that its compensation costs should be accepted by the Board as filed. It argued that there is no evidence that OPG could have reached a more favourable result through its collective bargaining and arbitration processes. OPG submits that it achieved very positive results in its most recent collective agreements: a "net zero" result for the PWU, and a modest wage increase for the Society, which was imposed by an arbitrator. OPG argues that it is legally required to collectively bargain within the confines of the Ontario *Labour Relations Act*, and that it achieved the best results possible under that framework. It relies on the evidence[56] of Dr. Richard Chaykowski, who testified that general compensation benchmarking studies are of limited value in a collective bargaining environment. The PWU and Society made similar arguments.

Board Findings

287 The Board has determined that it will disallow $100M from OPG's proposed total OM&A expenses in each of 2014 and 2015. This OM&A reduction relates directly to what the Board finds to be excessive compensation, and it applies to both the nuclear and hydroelectric businesses.

288 OPG's high total compensation costs have been a matter of concern for the Board for many years. In OPG's first payments proceeding (EB-2007-0905) the Board disallowed $35M in OM&A costs related to poor performance at Pickering A. The Board also found that OPG had not been responsive to benchmarking recommendations. The Board ordered OPG to conduct additional benchmarking studies for its next application.

289 The Board revisited compensation issues in OPG's second payments proceeding (EB-2010-0008). In that decision, the Board stated that it was "of the view that OPG has opportunities to reduce the overall number of employees further as a means of controlling total costs and enhancing productivity."[57] The Board also found that, "the [compensation] analysis provides sufficient evidence to conclude that for a significant proportion of OPG's staff the compensation is excessive based on market comparisons." The Board disallowed $145M in nuclear compensation costs over the two year test period. The Board further directed OPG to retain an expert to conduct benchmarking studies on its nuclear staffing and on its overall compensation levels.

290 Since the last payments case, OPG undertook a number of measures in an attempt to control its overall compensation costs. In 2011, OPG introduced a Business Transformation initiative to reduce staff levels in response to expected decreases in capacity and energy production in the coming years. The Business Transformation initiative has resulted in a steady decline in the number of employees in both the regulated and unregulated sides of its business. From 2011 to 2015, OPG will reduce its staff numbers by approximately 1,300 in its regulated businesses, which is more than 10% of its complement. OPG estimates that these staff reductions result in savings of approximately $550M -- i.e. absent the Business Transformation initiative OPG would have incurred $550M more in costs for the period 2011 to 2015.[58]

291 Despite OPG's reduction of 10% of its workforce in the regulated business, total compensation amounts are forecast to go up over the test period: from $1,581M in 2010 to a forecast of $1,618.1M in 2015. This is due to higher average compensation per employee. The large average increases are driven in part by increased pension costs resulting from changes to the discount rate.[59]

292 The Board is not the only body that has expressed concern regarding OPG's compensation levels. On December 10, 2013, the Auditor General of Ontario released its annual report which included a review of OPG human resources polices over a 10 year period. The Auditor General noted that "OPG's generous compensation and benefits negatively impact electricity costs."[60] The Auditor General stated that despite the Business Transformation process, there are still many areas relating to compensation and benefits practices that need further improvement.[61]

293 There is significant evidence on the record that OPG's overall compensation costs are higher than they should be. This evidence includes the Auditor General's annual report (the details of which were reviewed with OPG in the hearing), the Goodnight Consulting report and the AON Hewitt report. The nuclear benchmarking reports based on the ScottMadden methodology further details OPG's poor overall cost effectiveness. These reports are discussed below. The Board observes a number of factors that drive these excessive compensation costs: too many staff and management, too much compensation (including pensions) for many of OPG's unionized employees, and a lack of management oversight with respect to performance management and overtime.

4.1.1 Staffing Levels

294 The following table summarizes historic and test period staffing levels.

Table 18: Staffing Levels

Full Time Equivalent ("FTE")	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
Nuclear	8,445.4	8,215.1	6,761.8	6,554.2	6,579.7	6,519.9
Previously Regulated Hydroelectric	359.7	369.4	343.8	321.5	343.1	340.9
Newly Regulated Hydroelectric	584.3	617.4	600.9	584.0	599.5	582.2
Allocated Corporate Support	1,091.4	1,072.4	2,299.0	2,142.7	2,043.8	1,952.6
TOTAL	**10,480.8**	**10,274.3**	**10,005.5**	**9,602.4**	**9,566.1**	**9,395.6**
Management	1,101.7	1,099.2	1,095.6	1,091.0	1,101.0	1,076.3
Society	3,269.0	3,254.6	3,112.6	2,909.2	3,043.3	2,965.6
PWU	6,012.9	5,840.7	5,711.0	5,542.0	5,371.7	5,300.3
EPSCA	97.2	79.8	86.3	60.2	50.1	53.4
TOTAL	**10,480.8**	**10,274.3**	**10,005.5**	**9,602.4**	**9,566.1**	**9,395.6**

Source: J9.7, EPSCA - Electrical Power Systems Construction Association

295 The area where OPG has made the most progress is with respect to staffing levels, as demonstrated by the staff reductions they have achieved through the Business Transformation initiative. At the Board's direction, OPG retained Goodnight Consulting Inc. ("Goodnight") to conduct a staffing benchmarking study for the nuclear business specifically.62 Goodnight compared OPG's nuclear staffing levels against the 16 largest nuclear stations in the United States. Goodnight made certain adjustments to exclude activities specific to CANDU technology (which is not used in the United States), and to account for OPG's shorter work week. Goodnight was able to find suitable comparators for 5,574 positions. Goodnight was not able to benchmark 2,101 positions, mostly CANDU specific, due to lack of comparable benchmarks. Of the support functions, only corporate support dedicated to the nuclear business was considered.[63]

296 Goodnight concluded that, for the positions surveyed, OPG was 17% (866 positions) above the comparable benchmark as of July 2011. By February 2013 the situation had measurably improved: 7.6% (394 positions) over the benchmark. An update as of March 2014 showed additional improvement: 4.7% (244 positions) over the benchmark. By the end of the test period, OPG will likely be close to the benchmark level for the positions surveyed.

297 Although the Board recognizes that OPG has made progress in reducing its staffing numbers to approach industry standard levels, the Board finds that OPG remains overstaffed in the test period.

298 Several parties critiqued the Goodnight study, arguing that it was faulty because it did not include a large number of staff positions (and thereby likely underestimated the amount of overstaffing). They also argued that it failed to sufficiently recognize the unique features of OPG's CANDU technology (and thereby did not present a proper comparison for benchmarking). The Board is aware of the limitations of benchmarking, and recognizes that the Goodnight study cannot be expected to provide a precise "number" by which OPG is over (or under) staffed. The Board is satisfied, however, that Goodnight's methodology was sound and that its analysis is directionally correct. The Board finds that OPG is still moderately overstaffed with respect to the positions surveyed by Goodnight in the test period.

299 Several parties further noted that, although total employee numbers are down significantly, the number of management staff has barely moved: 1,101.7 in 2010 versus 1,101 and 1,076.3 forecast for 2014 and 2015 respectively. As a result, the percentage of employees that are managers has increased from approximately 10.5% in 2010 to 11.5% in 2015. The number of senior management and executive positions, the highest paid managers, has in fact increased significantly in recent years. The Report of the Auditor General revealed that from 2005-2012, the number of executives increased 74% and that the number of senior managers increased by 47%.[64] Many vice presidents and directors (40 as of 2012) do not have specific job titles or job descriptions. OPG stated that the duties and responsibilities of these vice presidents and directors would be set by their direct supervisors, but that there was no document describing what their job was.[65] OPG further stated that some of the increases in the number of senior management related to Business Transformation (5 directors) and the Darlington Refurbishment Project (13 directors).[66]

300 The Board finds that OPG has not sufficiently justified the number of its management positions. Business Transformation will result in the reduction of 1,300 positions for OPG's regulated business by the end of 2015, but the number of management positions is essentially unchanged. Although the Board accepts that there is not a perfect straight line correlation between decreases in non-management headcount and management headcount, the Board would expect a level of corresponding reduction for management positions. OPG submitted that increases in managers were necessary for Business Transformation and the Darlington Refurbishment Project. The Board finds that required increases in management associated with these incremental activities, are not sufficient to justify the total complement of management positions.

301 The costs related to excessive numbers of managers are significant. Had management positions been reduced in proportion to the reduction in overall staffing numbers, test period compensation would be lower. OPG's witness also confirmed that the Auditor General's report indicated there was an increase in senior management positions without formal job descriptions.[67] The Board finds this unacceptable. Management positions generally have the highest salary, pension and benefit costs. Basic controls must be utilized to justify each position on a needs basis and approvals must be documented. There is a cost associated with each position, and the needs and benefits must be clearly understood to justify the cost.

4.1.2 Compensation Per Employee

302 OPG's compensation package includes base salary, incentives, pensions and benefits. OPG's forecast average compensation per employee for 2015 is $205,914 for Management, $176,508 for Society employees, and $163,458 for PWU employees.[68] This represents a significant increase in average compensation since 2010: 1.82% for Management, 10.35% for Society employees, and 19.73% for PWU employees. OPG stated that it is required to collectively bargain with its unionized employees, which places restrictions on its ability to reduce compensation levels and, to a lesser extent, staffing levels. OPG has more flexibility with respect to management compensation.[69]

303 The Auditor General's report raised many concerns regarding OPG's compensation levels and practices, many of which were reviewed through the course of the hearing. Amongst other things, the Auditor General expressed concern over salary levels at OPG generally, and noted that for many positions at OPG, the <u>average</u> earnings at OPG exceeded the <u>maximum</u> potential earnings for the comparable position in the Ontario public service generally. The Auditor General views the public service as an appropriate general comparator for OPG.

304 The Board directed OPG to file a comprehensive compensation benchmarking study as part of this proceeding. OPG retained AON Hewitt to prepare this report (the "AON Report"). The AON Report was prepared in late 2011, and updated in 2013. As such it does not include increases in the average compensation for OPG's unionized workers since 2013 (nor any changes at the comparator companies). It covers salary benchmarking for the regulated business (both nuclear and hydroelectric). The AON Report has a section on total cash compensation (which excludes pensions), and a separate section for pensions.

Total Cash Compensation

305 With respect to total cash compensation, AON considered three comparator groups: Group 1 (power generation, electric utilities nuclear R&D), Group 2 (nuclear power generation and electric utilities), and Group 3 (general industry). The table below summarizes the results for total cash compensation (base salary and short term incentive). It does not include compensation costs related to pensions.

Table 19
Total Cash Compensation
% Differential vs 50th Percentile

%	Group 1	Group 2	Group 3
PWU	20.5	19.1	29.4
Society	-2.9	-3.8	23.3
Management	3.0	-3.4	20.9
	All job families	Admin, Engineering, Environment, Finance, Maintenance, Operations	Admin, Finance, IT, HR, Corporate Services

306 The AON Report concluded that the PWU is compensated at significantly higher than the 50th percentile for all three groups, whereas the Society and OPG management are compensated at close to the 50th percentile for Groups 1 and 2, and well above the 50th percentile for Group 3. The findings of the AON Report are consistent with evidence filed with the Board in previous proceedings, and OPG stated that it was not surprised by the results of the survey.[70] If PWU salaries were at the 50th percentile, OPG estimates its costs would have been reduced by $96M in 2014 and $94M in 2015.[71]

307 OPG's position on the AON Report (which was broadly supported by the Society and the PWU) is that although the information is interesting, it does not assist OPG in achieving better results through the collective bargaining process.

308 OPG presented evidence from Dr. Chaykowski to support its position. Dr. Chaykowski testified that unions typically have a great deal of negotiating power because if negotiations fail they will end up in binding arbitration. Dr. Chaykowski indicated that arbitration decisions are usually favourable to unions. Although arbitrators are supposed to take into account the employer's ability to pay, in Dr. Chaykowski's opinion they usually do not.[72] Arbitrators typically use "patterning" to set salary levels, whereby they compare the situation before them with recent agreements obtained by similar unions in similar industries. Dr. Chaykowski stated that the best comparators for OPG were Bruce Power and Hydro One, although he conceded different arbitrators might use different (though broadly similar) comparators.[73]

309 Dr. Chaykowski's evidence highlighted many of the challenges OPG faces in controlling costs in a unionized environment. He also stated that OPG wage settlements generally had been favourable when compared to what he viewed as the appropriate comparators.[74] However, pursuant to the terms of his retainer with OPG, Dr. Chaykowski was not asked to provide an opinion on the specific results achieved by OPG for its current collective agreements. Dr. Chaykowski was also not asked to provide an opinion on the appropriateness of OPG's overall compensation costs.[75]

310 OPG relies on Dr. Chaykowski's evidence to submit that it could not have achieved better results in its collective bargaining efforts. OPG states that no party has been able to demonstrate what better alternatives were reasonably available to it.

311 The Board does not accept that the costs arising from OPG's collective agreements -- in particular the agreement with the PWU -- are reasonable. The compensation package for PWU employees increased from 2010 to 2015 by 19.73%, almost double the 10.35% for the Society over the same time period.

312 The AON Report demonstrates that OPG compensates the PWU significantly in excess of the industry benchmark. The Board finds that Group 2 is the most appropriate comparator for OPG. Group 2 is a small cohort of nuclear related comparators: Atomic Energy of Canada Limited, Bruce Power, Candu Energy Inc., Hydro Quebec, and New Brunswick Power. All are unionized and have or had, in the case of Hydro Quebec nuclear operations. Three of them, including Bruce Power, which is in fact the comparator OPG prefers, are in Ontario. On average, these companies were able to achieve significantly better results than OPG through their compensation management and collective bargaining efforts with respect to PWU equivalent positions. The Board has no specific information as to how these results were achieved, but the Board does have sufficient evidence to conclude that these similar companies with comparable positions achieved superior results. OPG accepted that, as the Board is not involved in any of its collective bargaining activities, it can only judge the reasonableness of the outcome by examining the final results.

313 The Board was assisted by the analysis provided in the AON Report. The Board directs OPG to file a similar, independent, comprehensive compensation study that compares OPG compensation with broadly comparable organizations in the next cost of service application. The study should cover a significant proportion of OPG positions.

314 The Board does not accept OPG's argument that it should only be compared against successor companies to Ontario Hydro, in particular Bruce Power. OPG provided evidence comparing it with some of the other successor companies to Ontario Hydro, and argued that it had done well in comparison. Even to the extent that these were the only suitable comparators (an idea the Board rejects), the Board is not satisfied with the quality of the comparison conducted by OPG.

315 OPG provided two comparisons: a comparison of 2013 wage levels between OPG and Bruce Power for certain positions, and a general wage increase comparison between OPG and six Ontario Hydro successor companies from 2001-2012. All of the analysis was conducted by OPG.

316 For the wage comparison between Bruce Power and OPG, only 12 positions are compared. The positions were selected by OPG. The wage comparison does not include pensions or OPEBs, which are a significant component of OPG's compensation package. It compares only the top band in each category, and does not take into account the number of employees that might be in that band, or in any other band. In addition, the Auditor General discovered that approximately 1,200 unionized staff at OPG were in fact paid more than the maximum amount set out in the salary bands. The comparison presented by OPG does not mention this, and absent the Auditor General's report the Board in all likelihood would not have had this information.[76]

317 OPG conceded that different comparisons were possible, and that different companies might choose to present the data in different ways. For example, Hydro One had presented a comparison in a recent application which indicated that it had achieved favourable compensation results when compared to OPG.[77] The Board prefers the evidence of an expert third party to the less rigorous analysis conducted by OPG.

Pension Costs

318 Pension costs are a major driver of total compensation costs. OPG proposes to recover $471.3M in 2014 and $405.3M in 2015 for pensions, excluding tax impacts. These amounts include the current service costs under compensation, as well as the pension component of centrally held costs.

319 OPG's pension plan is very generous. The AON Report benchmarked the employer paid value of OPG's pension versus the comparator group. It concluded that OPG's pensions and benefits are significantly more generous than those of its comparators. The value of OPG's pensions as a percentage of base pay was approximately 33% higher than that of the comparator group. The value of OPG's life insurance benefits and medical and dental benefits were also significantly higher than those of its comparators.[78] These pension amounts are in addition to the total cash compensation analysis referenced above in Table 19 which shows the differential to the 50th percentile.

320 The OPG pension plan as it is constituted at present requires an employer to employee contribution ratio of at least 3:1.[79] The Auditor General's report indicated that "Since 2005, the employer-employee ratio at OPG has been around 4:1 to 5:1, and significantly higher than the 1:1 ratio at the Ontario Public Service".[80] Board staff and SEC submitted that this ratio is too rich when compared with other plans. Board staff submitted that there is no evidence that this contribution ratio is required for OPG to be competitive in attracting new employees. A 1:1 ratio would reduce pension expense for the regulated business by $60M annually.[81] Board staff submitted that reductions would be $140M if special payments were included. OPG argued that the richness of the plans was the result of Ontario Hydro decisions. OPG was required to adopt collective agreements and the pension plan in 1999. The special payments relate to past service and OPG argued that changes to pension plans can be made only prospectively. The Board is concerned that no changes were made to pension benefits in the current collective agreements. OPG had a report prepared by Towers Watson in 2011 (updated in 2013) which indicates that, absent significant changes, OPG's current pension plan is unsustainable and risks bankrupting the company.[82] OPG had this report during the negotiations for its current collective agreements. Despite this, OPG signed a collective agreement with the PWU that contained no changes to the pension plan.

321 OPG did not file the Towers Watson report in the arbitration hearing with the Society.[83] It appears to the Board to be highly relevant that the status quo with respect to pensions was (and remains) in danger of bankrupting the company. The arbitration decision includes a lengthy section on OPG's ability to pay for the new agreement, and a section on the appropriate pension contribution. Arbitrator Albertyn concludes that no changes are necessary to the status quo with respect to pension contributions.[84] Despite Dr. Chaykowski's belief that arbitrators pay only "lip service" to a company's ability to pay,[85] the Board is concerned that OPG did not bring this very important report to the arbitrator's attention.

322 The Board is also concerned that OPG appears to have no concrete plan regarding how it will address the very serious issues raised in the Towers Watson report. Absent some form of intervention by the government, OPG's only solution to the problem appears to be a plan to pass all of the costs on to ratepayers in future proceedings.[86]

323 SEC submitted that implementation of the potential changes outlined in the Towers Watson report would reduce pension and OPEB costs by $118M annually. OPG argued that the impacts of the potential changes outlined in the report are not additive.

324 OPG's pension plan is extremely generous and extremely costly. The Board finds that it is not reasonable that all of these costs be passed on to ratepayers. The Board is also concerned that OPG, the largest utility the Board regulates, has a pension plan that appears to be unsustainable, and that very little seems to have been done to address this. The Board does not accept OPG's assertion that the issue of pension costs is beyond its control. The Board finds that OPG should be moving towards a 1:1 employer-employee contribution ratio, and that the 50th percentile for pension costs is the appropriate target, consistent with the Board's findings on wages and salaries. Disallowances for pension and OPEB costs are subsumed in the annual $100M compensation disallowance.

4.1.3 Other Compensation Issues

325 The Board is also troubled by a lack of management oversight in some areas, which was noted in the Auditor General's report. Performance reviews of unionized staff, which are supposed to be conducted prior to an employee's advancement through the salary bands, appear to often not occur. In cross examination, OPG's witness stated that there was in fact no formal requirement for performance reviews at all.[87]

326 The Board also notes the Auditor General's comments in its report with respect to OPG's management of overtime. The Auditor General found that "management of overtime at OPG still required significant improvement" and that in a significant number of cases there was no supporting documentation for overtime approval.[88] This has been identified as an area of poor planning, and thus the Board finds this to be an area of potential improvement in efficiency.

327 The Board observes the link between OPG's poor performance in the three key metrics of nuclear benchmarking presented in the annual reports based on the ScottMadden methodology (Total Generating Cost, Unit Capability Factor and Nuclear Performance Index), and high staff compensation costs. As described in further detail in the Nuclear OM&A and Benchmarking section, OPG has failed to reach the targets it set for itself in the Total Generating Cost metric. Compensation costs are a major driver of the "costs" side of the Total Generating Cost equation, and OPG's high compensation costs are undoubtedly one of the reasons that it performs so poorly on this metric. OPG's poor productivity -- in other words its poor performance on the key "bang for buck" metric -- results in significant incremental expense. These are matters that are broadly speaking at least partially within the control of OPG's management, and it is not reasonable to pass all of these costs on to ratepayers.

328 For illustrative purposes and based on the 2012 OPG nuclear benchmarking report, Board staff estimated the savings if OPG's Total Generating Cost was at the median. Costs would be reduced by approximately $300M per year (Total Generating Cost Differential x production forecast). If OPG were to actually achieve top quartile, the savings would be $725M per year. The Board will not make disallowances even close to these amounts. However poor management controls, and overall productivity are a consideration in the Board's findings.

4.1.4 Conclusion with Respect to Disallowances to OM&A for Excessive Compensation

329 The Board disallows $100M in each of 2014 and 2015 due to the finding of excessive compensation. As detailed above, there are several drivers to this finding: excessive salaries (chiefly relating to the PWU), excessive pension costs, too many unionized and management staff, poor performance on the Total Generating Cost metric (which is related to excessive salaries and number of staff), and a lack of management oversight with respect to performance management and overtime.

330 One of the Board's important functions is to act as a market proxy. Regulation exists to prevent the abuse of monopoly power. Absent regulation, monopoly service providers would be able to pass on any cost to its captive consumers, and there would be little incentive for the provider to exercise cost control or seek efficiencies. The Board finds that it would not be reasonable to pass all of OPG's compensation costs on to ratepayers.

331 The Board has relied to some extent on the benchmarking evidence before it in making this decision. Benchmarking analysis is commonly used by both the Board and other regulators to assist with the assessment of the reasonableness of a utility's costs or performance. OPG itself recognizes the value of benchmarking, which is shown by its support of the ScottMadden nuclear benchmarking studies. OPG's shareholder is also a supporter of benchmarking: the Memorandum of Agreement between OPG and its shareholder in fact requires OPG to benchmark itself against other electricity generators, and to set performance measures against these benchmarks.

332 The Board is mindful that benchmarking, while useful, is not a precise tool. It provides a high level picture of OPG's compensation situation, but cannot be expected to produce an exact dollar figure by which OPG's compensation is too high (or, in theory, too low). For this reason, the Board will not simply make disallowances based on a straight mathematical differential between OPG and the 50th percentile of the appropriate benchmark. The Board also understands that there are limits to what OPG can achieve on a year to year basis,[89] and that it has made some progress in recent years. The Board is therefore making disallowances that are significantly less than what the evidence could in theory support. The Board believes that, taking all of the factors into consideration, a $100M disallowance per year is a reasonable result.

333 The table below outlines the areas of concern to the Board and provides an estimate of all the costs associated with each item. Some of these items, such as the historical variance trend for hydroelectric OM&A line, are discussed in more detail in other sections. The Board is not making disallowances in the amounts shown in the chart. Rather, the table is designed to itemize the factors that went into the Board's decision to make the annual $100M disallowance. It is for illustration only, and it is not an exhaustive list of the areas where improved cost control should be achieved -- for example OPG's poor performance on the Total Generating Cost metric is not included in the chart. The Board also recognizes that there may be some level of overlap between the categories.

Table 20: Factors Supporting Compensation Disallowance

Reduction in $million		2014	2015	Regulated Business Affected
1	Hydroelectric (historical base and project OM&A trend, budget vs. actual spend)	9.5	9.8	Hydroelectric
2	PWU at 50th percentile (wages only based on the AON report) includes corporate support cost reduction	96.0	94.0	Hydroelectric and Nuclear
3	Pension Cost Reduction (assume reduction to bring to comparable levels as per the AON Report and Towers Watson Report)	60.0	60.0	Hydroelectric and Nuclear
4	Management Reduction to reflect 10.5% management in total staffing – salary impact only	18.2	16.9	Hydroelectric and Nuclear
5	Reduction of 244 staff positions – wage impact only (as per the Goodnight benchmarking study.)	19.8	1.8	Nuclear

Note 1: Section 2.2 of this Decision
Note 2: Undertaking J9.11 and section 4.1.2 of this Decision
Note 3: Exh L-6.8-Staff-121 and Undertaking J9.10
Note 4: Table 18 of this Decision and Undertaking J9.7, 2014: 107.9 Management FTE x $168,297 = $18.2M, 2015: 100.3 Management FTE x $168,408 = $16.9M
Note 5: Undertaking J9.7, Total nuclear FTEs in 2013 less 244 FTEs = 8220.8 FTE, 2014: (8370.3-8220.8) x $131,149 = $19.8M, 2015: (8234.0-8220.8) x $136,918 = $1.8M

334 The Board recognizes that OPG will have to pay its unionized employees pursuant to the terms of its collective agreements, however the Board finds these costs to be unreasonable, and will not pass them on to ratepayers.

4.1.5 The Court of Appeal's Decision

335 In the previous OPG payments case (EB-2010-0008), the Board made disallowances in the amount of $145M on account of excessive nuclear compensation costs. This decision was appealed by OPG. The appeal was dismissed at the Divisional Court; however OPG was successful before the Ontario Court of Appeal. The Court of

Appeal's decision has now been appealed to the Supreme Court of Canada, and that appeal is expected to be heard in December 2014.

336 The Court of Appeal held that OPG's test period compensation costs were "committed", and therefore were subject to a prudence review. In conducting a prudence review, the Board was not permitted to use hindsight in assessing the reasonableness of OPG's decisions to commit to the costs: in other words the Board could only use information that was available, or should have been available, to OPG at the time the costs were committed to.

337 Although OPG refers to its compensation costs as "committed" in its argument, it is not clear exactly what costs OPG believes have been committed to. Although collective agreements are in place for much of the test period, this is only one factor (albeit a significant one) in determining the amounts that OPG will have pay in compensation over the test period. Management costs, staffing levels, overtime costs and other cost drivers are not determined by OPG's collective agreements, and have generally not been committed to.

338 In the previous proceeding (EB-2010-0008) OPG also referred to its test period compensation costs as being largely "committed." Indeed that was the major issue in its appeals. However, it was revealed in this proceeding that there was in fact significant room for OPG to control compensation costs over the 2011-2012 test years: in 2011 and 2012 OPG's Business Transformation initiative ended up saving OPG almost exactly the $145M disallowed by the Board.[90] OPG's compensation costs are clearly in some measure controllable, and OPG has effectively acted to control them to some degree in the past.

339 Even to the extent that OPG's 2014 and 2015 compensation costs are "committed", the Board has considered the Court of Appeal's decision and is satisfied that it has taken the decision into account. The Court of Appeal's decision states that the Board cannot use hindsight in assessing the prudence of committed costs. Even if one were to accept that OPG's test period compensation costs are entirely committed, the Board is not using hindsight to assess the reasonableness of OPG's collective bargaining practices (or any other compensation costs). All of the evidence relied on by the Board is information that OPG either had available to it when it committed to its compensation costs, or should have had before it.

4.2 Pension and Other Post-Employment Benefits Accounting

(Issue 6.8)

340 OPG's historical and forecast pension and OPEB expenses are summarized in the following table. The current service cost of pension and OPEB is part of compensation while the remainder is part of centrally held costs.

Table 21: Pension and OPEB

	$million	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	Total 2008-13	2014 Plan	2015 Plan
	Pension									
1	Accrual Basis - recoverable in payment amounts	121.4	141.4	150.1	195.0	286.1	383.3		471.3	405.3
2	Cash Basis	198.6	206.1	208.5	235.5	297.1	242.9		321.9	329.6
3	Difference (1-2)	(77.2)	(64.7)	(58.4)	(40.5)	(11.0)	140.4	(111.4)	149.4	75.7
	Other Post-Employment Benefits									
4	Accrual Basis - recoverable in payment amounts	119.2	162.5	161.0	173.2	203.0	231.3		204.6	212.8
5	Cash Basis	44.2	43.1	43.4	48.4	57.9	61.2		89.6	95.8
6	Difference (4-5)	75.0	119.4	117.6	124.8	145.1	170.1	752.0	115.0	117.0

Source: Chart 4 AIC, JT2.40, J9.6, Exhibit N2
2008-2013 excludes newly regulated hydroelectric
Note 1: The source for the 2015 and 2014 cash basis is J9.6

341 For 2014 and 2015, OPG proposes rate recovery of its pension and OPEB costs based on the accrual method of accounting: $1,294M in total. As noted in lines 1 and 4 of Table 21, in 2014, $471.3M would be recovered for pensions and $204.6M would be recovered for OPEBs. In 2015, $405.3M would be recovered for pensions and $212.8M would be recovered for OPEBs. The accrual basis recognizes these expenses when the entitlement to pension and OPEB is earned, not when OPG actually has to pay them out.

342 SEC submitted that pensions and OPEB recovery should be determined on a cash basis. CME, CCC and LMPA supported SEC's submissions to use the cash basis for rate recovery. The cash basis recognizes the expense when cash payments are made, as opposed to the accrual method in which the expense includes future liabilities. In theory, over time, the accrual and the cash method should result in the exact same amount of total expense.

343 Board staff supported use of the cash method for pensions and the accrual method for OPEBs, provided that OPG be directed to set up an irrevocable trust or fund for the recovery in excess of OPEB cash requirements. In the absence of a set-aside mechanism, Board staff supported the use of the cash basis for both pensions and OPEBs.

344 For tax purposes, a tax liability is created on OPG's corporate financial statements when the accrued expense exceeds the cash expense. Including an amount to recover the tax liability associated with higher accrued expenses increases the proposed revenue requirement. Parties submitted that adopting the cash method would reduce the proposed revenue requirement by $609.4M in 2014 and 2015, not just the $457.1M[91] difference between the cash and accrual expenses because of the decreased tax recovery amount.

345 There is currently no consistency among utilities in the use of either cash or accrual method for rate recovery of pension and OPEB costs. Both methodologies have been approved by the Board. The Board has approved OPG's payment amounts based on the accrual method since EB-2007-0905, the first cost of service proceeding. OPG indicated that the majority of regulated entities use the accrual method. OPG submitted that the Board should consider the accounting and ratemaking treatment of pensions and OPEB as part of a generic proceeding. Until the generic proceeding is concluded, OPG proposed the Board maintain the accrual method for determining payment amounts.

346 Board staff submitted that the cash basis for pension and OPEB determination has been more stable and will continue to be more stable than the accrual basis which is significantly affected by discount rates. OPG replied that there is no basis for claims or predictions on the magnitude or direction of the difference between the cash and accrual method.

347 Based on review of 2008 to 2013 data, Board staff determined that OPG has been authorized to collect $752M more in OPEB and $111.4M less in pension expenses than OPG has been required to pay out. Board staff submitted that OPG has used this over-collection for general corporate purposes, and that the money has not been set aside to cover the costs when they actually come due at some point in the future. Board staff submitted that the historical over-collection of $752M could be used to offset the regulatory liability for future OPEB costs.

348 Extrapolating the 2014-2015 trend, Board staff estimated OPG could over-collect $1.2 billion in OPEB expenses within the next 10 years. OPG's witnesses agreed that cash amounts would likely be less than accrual amounts for the next 10 years for OPEBs, but disagreed with Board staff's estimate of $1.2 billion in over collection.

349 OPG characterized Board staff's suggestion that the $752M difference between the cash and accrual methods be used to offset future cash expense as a claw back. OPG argued that the cash flow generated from payment amounts is spent as OPG determines. In addition, there is no link to the pension and OPEB costs approved in payment amounts to what OPG ultimately spends.

350 OPG argued that if the cash basis is used for ratemaking, it would ultimately be required to increase its borrowings. Ratepayers would be required to pay for that debt and OPG's financial ratios would be affected.

351 OPG indicated that USGAAP requires the use of accrual accounting for pensions and OPEB to be used in its corporate financial statements, and that if recoveries from ratepayers were on a cash basis, OPG would not be able to record the difference as regulatory assets. Board staff noted that Hydro One, which also reports under USGAAP, recovers pension expense on a cash basis with no apparent conflict with USGAAP.

352 Board staff submitted that the Board could consider the cash basis for pension and OPEB for the test period pending a generic proceeding on pension and OPEB costs and recovery mechanisms.

353 Board staff submitted that if the Board were to approve recovery based on the cash method a new variance account would be required, since OPG has the discretion to contribute more than the minimum amount determined by its actuary to the pension plan. The variance account would enable the tracking of any additional cash contributions made by OPG to be considered in the future for recovery.

354 OPG submitted that the determination of pension and OPEB expense was not an issue on the issues list and that OPG did not file expert evidence on the matter, nor did any other party. In OPG's view, the matter is very complex and best suited to a generic proceeding.

Fund or Irrevocable Trust for OPEB

355 While OPG makes contributions to a registered pension plan, there is no equivalent plan for OPEB. The accrual amounts are determined by OPG's actuary and used in OPG's corporate financial statements as required under USGAAP. OPG's actuary also determines the minimum cash requirements for its pension and OPEB plans based on legislation and regulations.

356 Board staff submitted the Board could approve the accrual method for OPEB on the condition that OPG establishes a set-aside mechanism, such as an irrevocable trust or fund for OPEB, similar to what was referred to the in the Federal Energy Regulatory Commission's Statement of Policy report PL93-1-000.[92] Board staff also submitted that if the Board had any reservations about a fund or trust, the Board could limit recovery of OPEB expense as determined by the cash method, or OPG's out-of-pocket test period costs. OPG submitted that the Board has no jurisdiction to order OPG to set up an irrevocable trust or fund. OPG argued that the matter is complex and submitted that a segregated fund could be considered as part of a generic proceeding.

Board Findings

357 The Board will only allow OPG to recover its cash requirements for pensions and OPEBs in 2014 and 2015, approving a revenue requirement of $836.9M for pension and OPEB.

358 The Board will reduce the total proposed amount to be recovered in rates by $457.1M, which is a reduction of $225.1M in proposed pensions and $232.0M in proposed other post-employment benefit amounts.[93] OPG's most recent actuarial valuation as at January 1, 2014 by AON Hewitt was filed in evidence.[94] The Board relies on the AON Hewitt valuations of the cash requirements in 2014 and 2015 and sets OPG's payment amounts accordingly.

359 In addition, the Board approves the establishment of a new deferral account to record the differential between the accrual and cash valuations for pension and OPEB expenses. The Board's reasons follow in the sections below.

360 OPG and some parties suggested that the Board hold a generic hearing to review pension and OPEB costs. The Board agrees and believes that a generic proceeding on the regulatory treatment and recovery of pension and OPEB costs would be beneficial. A generic proceeding could enhance understanding of the different rate making options, establish policy and decide on how best to apply that policy to OPG and other Board-regulated entities. Transition to a different accounting treatment of pensions and OPEBs for OPG, if required, would be addressed by the Board in OPG's next cost of service proceeding, having been informed by the outcomes of the generic proceeding.

361 The Board is not necessarily permanently moving from an accrual to a cash basis for setting OPG's payment amounts. The Board is providing OPG with sufficient revenue to fund its cash needs for 2014 and 2015 until a comprehensive review of pensions and OPEB is undertaken through a generic proceeding. The Board is concerned that any money collected from ratepayers today, in excess of the cash requirements, is not being used to fund future pension and OPEB cash requirements. The Board has considered both OPG's needs and those of ratepayers. In the absence of a Board policy, the Board will not allow the collection of funds from ratepayers in 2014 and 2015, of an amount higher than OPG's cash needs, when OPG's use of the excess funds is not understood, and the benefit to ratepayers is uncertain.

362 Until Board policy is established, the Board approves a new deferral account to record the differential between the accrual and cash valuations for pension and OPEB expenses. Based on the policy outcome of the generic proceeding, a future panel will decide on the appropriate disposition (if any) of the deferral account balance.

363 At this time, the scope of the generic proceeding is unknown. For clarification, the Board is not setting aside the difference between the cash and accrual amounts for this test period, for purposes of another future prudence review of these costs. The 2014 and 2015 payment amounts will be final in that respect. Any future treatment regarding the deferral account would be limited to the outcomes of the generic proceeding as they relate to the accounting or mechanics of recovery, as applicable.

364 The application indicated a differential amount of $457.1M based on the 24-month period in 2014 and 2015. However, the $457.1M will be subject to change given the approved effective dates of the payment amounts and OPG's final actuarial evaluations at the end of 2014 and 2015.

365 OPG indicated that the determination of pension and OPEB expenses for ratemaking was not an issue on the issues list. The Board agrees that the exact words "accounting methods for ratemaking" were not on the issues list. However, the issue was raised in numerous interrogatories and extensively during the pre-hearing technical conference and the oral phase of the hearing. In addition, every proposed expense, particularly material expenses of $1,294M, must be reviewed by the Board to order to determine OPG's payment amounts.

OPEB Costs

366 Board staff submitted that historical over collection of OPEB expenses should be used to offset the regulatory liability for the future. OPG submitted that Board staff's proposal amounts to a "claw back". The Board does not agree with OPG's characterization and the use of the term "claw back". The amount and use of any excess collected to date from ratepayers must be clearly understood and resolved before the Board allows any further collection in excess of requirements in 2014 and 2015.

367 On a prospective basis, Board staff estimated that maintaining accrual accounting for ratemaking would result in an over-collection in OPEB revenue of $1.2 billion every 10 years. OPG took issue with Board staff's $1.2 billion estimate. OPG's witnesses indicated a cash flow analysis had been completed, yet were unable to provide any specifics, stating it would be "likely in the next 10 years"[95] before actual OPEB cash payments would exceed the accrual expense. The Board does not find OPG's answer sufficient. The Board has little evidence by which to understand the magnitude or duration of the potential over collection of OPEB costs from ratepayers, but the prospective numbers are alarming.

368 The Board is not confident OPG has undertaken the level of cash flow analysis required to ensure it will have sufficient cash available as a corporation, when its cash needs exceed accrued expenses. It would be inappropriate to collect revenues today in excess of cash requirements and then turn to ratepayers in the future, when cash requirements exceed accrued expenses. The Board must ensure ratepayer interests over time are fully considered.

Pension Costs

369 From 2008-2013 cash funding requirements for pensions exceeded accrued expenses by $111.4M; the opposite of OPEB costs. However, in 2014 and 2015 accrued pension expenses exceed cash funding requirements by $149.4M in 2014 and $75.7M[96] in 2015.

370 With accrued pension expenses exceeding cash requirements in 2014 and 2015, the Board's concerns relating to OPEB costs regarding the magnitude and duration of over collection and the associated cash flow analysis apply equally to pension costs.

Prior Board Decisions

371 The Board is directing the use of the cash basis of recovery for 2014 and 2015. This is different from prior OPG decisions. In OPG's last cost of service proceeding, EB-2010-0008, the Board found no compelling reason to change OPG's approach of using the accrual method. The Board noted that consistency in accounting treatment which allows comparison of year-over-year results to be advantageous for assessing reasonable cost levels.

372 This panel agrees with the EB-2010-0008 decision as consistency is desirable in order to compare these costs. However, in this case the benefits of consistency are outweighed by the concern regarding the significant increase in payment amounts to recover accrued expenses. In 2011 and 2012, the accrued expenses for pensions were $195.0M and $286.1M respectively. In 2014 and 2015, the forecast accrued expenses are almost double at $471.3M and $405.3M.

373 In reply submission, OPG indicated that while the figures may be different from its last cost of service proceeding in EB-2010-0008, "the circumstances have not changed". The Board disagrees. The circumstances have changed as the accrued expenses are increasing and volatile, dependent upon the assumptions adopted by OPG's management, such as the appropriate discount rate. Volatility in the test years was evident when OPG filed its Exhibit N1 impact statement in December 2013, months after filing its Application. After updating the discount rate and mortality rate assumptions applied to its pension plan, accrued expenses in 2014 and 2015 increased, exceeding OPG's materiality threshold and increasing the proposed revenue requirement by $142.3M. This was followed by the Exhibit N2 impact statement filed in May 2014, which based on higher discount rates for the pension plan, decreased the revenue requirement by $278.7M.

Implications of Cash Method

374 OPG submitted that the cash basis would ultimately require OPG to increase its borrowings and ratepayers would have to pay for that debt. In addition, the cash basis would affect financial ratios. The Board has approved OPG's capital expenditures and rate base for 2014 and 2015. The payment amounts include a weighted average cost of capital. In addition, every cost that OPG requires to recover to run its business and the opportunity to realize its regulated rate of return, underpins the payment amounts.

375 The Board does not understand what additional borrowing would be required to fund the regulated side of OPG's business.

376 OPG prepares its financial statements in accordance with USGAAP, which requires pensions and OPEB costs to be determined on the accrual method. In reply argument, OPG identified corporate financial reporting issues such as qualified audit opinions and the recognition of existing regulatory assets if the Board were to utilize the cash basis for ratemaking while its corporate financial statements were based on the accrual method. The issue of cash versus accrual is one of timing. This Board does not regulate financial reporting requirements, but is confident OPG's management, its Audit Committee and external auditors will reflect the outcomes of this Decision in its financial statements.

377 Given the Board's position on these matters, the additional information provided by OPG in its reply argument regarding its discussions with Ernst & Young LLP was not helpful to the Board. As an aside, however, the Board also notes that it is not generally appropriate to file "new evidence" following the closing of the evidentiary portion of the proceeding.

Pension and OPEB Cost Variance Accounts

378 OPG has the ability to contribute additional funds to its pension plan in excess of the minimum cash requirements to reduce its unfunded liability. The Board recognizes this opportunity and does not want to dissuade OPG from contributing more than the cash amounts approved in its payment amounts. The total unfunded liability on OPG's corporate balance sheet was $5,469M as of December 31, 2013: a pension deficit of $2,461M; a supplementary pension plan deficit of $289M; and OPEB deficit of $2,719M. In addition, AON Hewitt determined the pension plan had a small solvency deficit on January 1, 2014, which will require additional funds to eliminate.

379 The Board will use its available ratemaking tools so as to not discourage OPG from making additional contributions, in addition to its minimum cash requirements, to decrease its unfunded liability without financial hardship. The Board approves a new variance account to track any contributions that differ from the minimum cash requirements, as included in the 2014 and 2015 payment amounts. Interest will apply to this variance account given that it relates to cash payments.

380 In addition, the Board has approved the establishment of a new deferral account to track the differential between the accrued and cash valuations for pensions and OPEBs. The Board approves the accrual of interest on the variance account balance related to additional cash contributions made, but does not approve the accrual of interest on the deferral account balance given that it tracks non-cash items. This treatment is consistent with OPG's current variance account based on the accrual method.

381 Given the effective date for OPG's 2014 and 2015 payment amounts, the current payment amounts which include accrued pension and OPEB expense will remain in place until November 1, 2014. Correspondingly, the current Pension and OPEB Cost Variance Account will operate until that date to track variances from actual to forecast accrued expenses. After the effective date, the new variance account will be used to track variances from actual to forecast cash expenses. The new deferral account will capture initially the differences between cash and accrual pension and OPEB amounts included in evidence commencing with the effective date. The deferral account balance should be adjusted for future actuarial valuations and actual cash payments on an annual basis until considered by the Board.

4.3 Corporate Support Costs

(Issue 6.9)

382 OPG is structured such that certain corporate groups provide services and incur costs in support of the hydroelectric and nuclear businesses. Corporate groups include Business and Administrative Services, Finance, People & Culture, Commercial Operations & Environment, and Corporate Centre. OPG is asking for approval of corporate support costs, which are $505.8M in 2014 and $483.9M in 2015.

383 As shown in Table 5 (to a minor extent),Table 13 and the following table, corporate support costs have increased significantly over the 2011 - 2013 period due to the implementation of a centre-led organization driven by the Business Transformation initiative.

Table 22: Corporate Support Costs

$millions	2010 Plan	2010 Actual	2011 Approved	2011 Actual	2012 Approved	2012 Actual	2013 Budget	2013 Actual	2014 Plan	2015 Plan
Nuclear	247.0	226.5	249.2	233.1	450.3	408.4	451.0	428.3	433.9	417.4
Previously Regulated HE	25.1	22.4	24.8	22.0	29.0	24.5	29.7	26.1	29.8	26.9
Newly Regulated HE							38.8	35.2	42.1	39.6
Total	272.1	248.9	274.0	255.1	479.3	432.9	519.5	489.6	505.8	483.9

Source: Exh F3-1-2 Tables 1,2,3 Exh F3-1-1 page 2 and 3, Exh L-1-Staff-2

384 Board staff observed that many of the corporate support functions are what AON Hewitt would compare with "general industry". The AON Hewitt National Utility Survey indicated that the general industry comparable jobs are significantly overpaid by OPG by about 20 to 29% versus P50 (the 50th percentile). The Auditor General's analysis of administration, finance and human resources jobs indicated that the majority of these jobs are overpaid at OPG as compared with the Ontario Public Service. The Auditor General also observed that the Goodnight benchmarking found that nuclear support functions were generally overstaffed while nuclear operational functions were generally understaffed. OPG replied that it is bound by collective bargaining and committed costs cannot be reduced.

385 OPG has access to raw cost data from EUCG for the information technology function and Electric Utility HR Metrics Group for the human resources function. OPG prepares benchmarking reports from this data, but there is no independent benchmarking analysis. Board staff observed that the last independent benchmarking study of the finance function was conducted in 2010 based on 2008 data. Board staff submitted that independent benchmarking of the corporate support function is required given the significant changes resulting from Business Transformation. The analysis would need to be normalized and reflect the period before and after Business Transformation.

386 The 2011 information technology and 2012 human resources benchmarking results prepared by OPG indicate that OPG is not performing in the top quartile with respect to cost. Board staff submitted that test period OM&A reductions would be appropriate. However, OPG argued that the submission did not recognize the benefits that OPG achieved in the contract with its information technology service provider and that the Board staff interpretation of the human resources benchmarking was not appropriate.

387 Given the consistent over-forecasting, Board staff submitted that a $25M reduction to nuclear OM&A was appropriate. LPMA determined that the previously regulated hydroelectric facilities corporate support costs were 11.7% over-forecast in the 2010 to 2013 period and proposed reductions of $8.4M in 2014 and $7.8M in 2015. On the basis of 7.2% over-forecasting in the historical period, LPMA proposed reductions of $31.2M in 2014 and $30.1M in 2015 for nuclear corporate support costs. SEC submitted that OPG corporate support costs should be reduced by $35M in each of the test years on the basis of historical over-forecasting and benchmarking results.

OPG argued that all of these submissions should be rejected as they do not address the evidence in relation to the test period costs, or consider the reasons for the historical variances.

Board Findings

388 OPG introduced the Business Transformation initiative in 2011 and implemented the centre-led organization in 2012. The Board acknowledges the impact of OPG's Business Transformation initiative on the number of staff, including corporate support staff. Efficiencies should be achieved and duplication reduced with the organization for corporate support functions.

389 In addition, the Board acknowledges OPG's commitment to proceed with an open competition for the next IT service contract[97] as a positive step, however any cost savings will not impact the test period.

390 The Board finds the Goodnight nuclear staffing analysis was informative for this proceeding. While corporate support functions were reviewed by Goodnight, only corporate support dedicated to the support of nuclear operations was considered.

391 The Board finds the internal benchmarking analysis undertaken by OPG based on the raw cost data from EUCG for the information technology function and Electric Utility HR Metrics Group for the human resources function to be inadequate. The human resources benchmarking is based on 2012 data, the information technology benchmarking was based on 2011 data and no recent benchmarking was filed for the finance function. Efficiency gains in the corporate support functions are not apparent in the benchmarking information that OPG has filed with the application.

392 Parties indicated that OPG has historically forecast higher corporate support costs than it actually spent. The Board finds it difficult to draw conclusions from the historical variance analysis as provided in evidence, as the underlying numbers are affected by employee migration to centre-led functions as a result of Business Transformation. Corporate support costs have increased significantly over the 2011 to 2013 period, but it is not clear to the Board that there has, or will be, an off-setting reduction in the other business units as a result of OPG's centre-led restructuring.

393 The Board made a disallowance of $100M to OPG's OM&A proposed budgets for 2014 and 2015 for overall compensation, which includes employees in corporate support functions. The Board will not make a further reduction related to corporate support costs.

394 The Board directs that an independent benchmarking study be undertaken of corporate support functions and costs given the significant changes resulting from the Business Transformation initiative. The results of this study will need to be shown in a manner that facilitates transparent comparison before and after Business Transformation.

4.4 Centrally Held Costs

(Issue 6.10)

395 Centrally held costs are company-wide costs recorded centrally. They are:

* Pension and OPEB costs not directly included in business unit costs
* Insurance
* Performance incentives
* IESO non-energy charges
* Other -- labour related costs, ONFA guarantee fee, business claims and settlements

396 Pension and OPEB costs are discussed in the Pension and OPEB Accounting section of this Decision. Performance Incentives are discussed in the Compensation section. There were no submissions on the other components of centrally held costs. The Board approves OPG's test period proposed expense for centrally held costs other than pension and OPEB and performance incentives.

4.5 Asset Service Fees and Other Operating Costs

(Issues 6.14 and 6.15)

397 Service fees for centrally held assets, e.g. OPG head office, are charged to the regulated and unregulated businesses. No submissions were filed on the matter.

398 The Board approves the proposed asset service fee amounts of $1.5M and $1.7 M for the previously regulated hydroelectric facilities, $2.9M and $3.0M for the newly regulated hydroelectric facilities and $23.3M and $26.8M for the nuclear facilities for the years 2014 and 2015 respectively.

399 In deriving the asset service fees OPG followed the methodology accepted by the Board in EB-2010-0008. The increases over the test period have been sufficiently explained and are reasonable. The allocation to each of the businesses is approved.

4.6 Depreciation

(Issues 6.11 and 6.12)

400 There were two key issues to be considered in respect of depreciation: first, the appropriate method for the determination of service life and second, the appropriate service life for the Niagara Tunnel.

401 As directed by the Board in EB-2010-0008, OPG filed an independent depreciation study undertaken by the consultant Gannett Fleming.[98] An updated study was filed to account for recent material changes, e.g. the Niagara Tunnel Project.[99]

402 The Gannett Fleming study was based on the average life group method which applies a common life estimate to each of the asset vintages and each of the assets within each vintage. Board staff submitted that OPG should be directed to file another independent depreciation study using the equal life group method which segregates assets into groups of assets with the same life expectancy and plant-life statistics are derived from the group's estimated survivor curve. OPG submitted that the Board should reject that submission. Gannett Fleming's position is that while the equal life group method is superior, there is insufficient information in the case of OPG's assets to apply this method. The Gannett Fleming report also noted that other regulated utilities, e.g., Enbridge Gas Distribution and Union Gas use the average life group method.

403 OPG submitted that it would be too costly to develop the data to support the equal life group method, and that it is impractical and potentially impossible to do so.

404 Submissions were also filed on the service life of the Niagara Tunnel. Gannett Fleming recommended 95 years. It was not apparent from the Gannett Fleming studies that the useful lives of the two existing tunnel linings (Sir Adam Beck) were actually 120 years. In an interrogatory response,[100] OPG informed the Board that in 1999 it had extended the useful lives of these assets. As the Sir Adam Beck tunnels have been in-service for close to 60 years and have an assumed useful life of 120 years, Board staff submitted that the Niagara Tunnel should be expected to have a service life in the range of 125 to 150 years, and that a mid-point of 135 years would be a reasonable estimate given the advanced technology and materials used for its construction. LPMA proposed 138 years and SEC proposed 150 years. OPG argued that there was no evidentiary basis for the proposals of the parties.

Board Findings

405 The Board finds that OPG responded appropriately to the direction in EB-2010-0008 by having an independent depreciation study undertaken. The Board accepts the study results, predicated on OPG's continued application of the average life group method. The Board will not require OPG to file another study using the equal life group method, as the data is not available. The Board accepts Gannett Fleming's evidence that OPG lacks the necessary data to use the equal life group method and the cost to develop the data would be prohibitive.

406 OPG's depreciation and amortization expense for the test period incorporates all the recommendations made by Gannett Fleming. The Board accepts the evidence of Gannett Fleming and its recommended 95 year useful life for the Niagara Tunnel. Although the useful lives of the Sir Adam Beck Tunnels are longer than 95 years, the useful lives were reviewed and extended after 45 years in-service. The Board will not consider extending the useful life of the Niagara Tunnel at this time.

407 The Board approves the depreciation expenses as filed to be included in the calculation of the payment amounts.

4.7 Taxes

(Issue 6.13)

408 OPG seeks approval for property taxes of $16.3M in 2014 (assuming full year for the newly regulated hydroelectric facilities) and $16.8M in 2015 for the regulated business. No submissions were filed on property taxes, and the Board approves OPG's request.

409 OPG uses the taxes payable method for determining regulatory income tax for the regulated facilities. The tax is allocated based on each business's regulatory taxable income. OPG seeks approval of income tax expense of $187.9M in 2014 (assuming full year for the newly regulated hydroelectric facilities) and $123.7M in 2015 for the regulated business.

410 This section addresses two sub-issues relating to a tax loss carry-forward from 2013 and deferred taxes associated with the newly regulated hydroelectric assets.

4.7.1 Tax Loss Carry-Forward

411 In 2013, OPG incurred a regulatory tax loss of $211.6M that OPG attributes to a shortfall in nuclear production. OPG submitted that the associated tax loss carry-forward that was created should not be applied to regulatory taxable income in 2014 to reduce the tax provision included in the payment amounts. OPG argued that OPG's shareholder incurred the costs associated with the loss in 2013 and should receive the benefit of the resulting tax loss carry-forward in 2014. As a result, OPG posted an accounting entry to its corporate retained earnings, to the benefit of its shareholder. OPG relied upon a principle that "benefits follow costs" as stated in the *Accounting for Public Utilities*, published in the United States in 2005 to support its proposal.

> ...if ratepayers are held responsible for costs, they are entitled to the tax benefits associated with the costs. If ratepayers do not bear the costs, they are not entitled to the tax benefits associated with the costs.[101]

412 OPG also referred to two prior decisions in which the Board referenced this principle, namely the OPG EB-2007-0905 decision and the Great Lakes Power EB-2007-0744, *2009 LNONOEB 101* decision. In OPG's submission, the situation in 2013 is similar to the situation in 2007 when it incurred a tax loss and the Board did not approve the associated tax loss carry-forward for determining OPG's 2008 payment amounts.

413 OPG also argued that the Board cannot adjust rates in a future period without a deferral or variance account, as this would amount to retroactive ratemaking.

414 Board staff submitted that the tax loss should be carried forward and applied to the test period tax provision to the benefit of ratepayers. OPG's payment amounts that were in effect in 2013, when the tax loss occurred, included a recovery amount for income tax. The 2013 payment amounts were established based on the 2011 and 2012 test period and included recovery of approved income tax amounts of $60.9M and $91.1M respectively. The payment amounts approved for 2011 and 2012 persisted into 2013 as OPG did not apply for new 2013 payment amounts. Board staff submitted that since ratepayers have borne the tax costs included in the payment amounts in 2013, the 2013 regulatory tax loss carry-forward calculated by OPG should be used to reduce regulatory taxable income in 2014.

415 Board staff submitted that this treatment is consistent with the Board's long-established policy requiring tax loss carry-forwards to be applied to reduce regulatory taxable income, as stipulated in the 2006 Electricity Distribution Rate Handbook.[102] At the hearing, Board staff cited several Board examples of electricity distributors in their rate applications carrying forward income tax losses from a prior year(s) to reduce or eliminate taxable income in a future year's test period. In addition, Board staff cited several Board decisions approving tax loss carry-forwards to reduce regulatory income taxes.

416 LPMA and CME supported Board staff's submission.

417 SEC supported Board staff's submission yet also referred to the "benefits follow costs" principle which was used by the Board in OPG's first payment amount decision (EB-2007-0905). SEC submitted that the "benefits follow costs" principle was used by the Board to ensure that there was a principled way of allocating costs and benefits to regulated and unregulated periods, which was not the case for OPG in 2013. In this case, the loss arose during a period in which OPG was collecting regulated rates from ratepayers. That is a similar situation to the electricity distributors, who do have to apply tax loss carry-forwards in one regulated year to reduce taxable income in subsequent regulated years.

418 SEC submitted that the "benefits follow costs" principle was never intended to allow a utility to collect money from ratepayers for PILs, then keep that money for their own purposes because they were unable to operate the regulated business at a profit.[103]

419 In reply, OPG argued that Board staff incorrectly applied the principle in its submission and SEC fundamentally misunderstood the Board's application of the principle. OPG asserted that the tax loss arose because of an operating loss. As OPG and its shareholder had to bear the operating loss, not ratepayers, OPG submitted that its shareholder is entitled to receive the benefit of the associated tax loss.

Board Findings

420 The Board directs OPG to reduce its 2014 income tax provision to recognize and carry forward its regulatory tax loss in 2013. This finding is consistent with Board policy as indicated in the Board's 2006 Electricity Distributor's Rate Handbook (the "Handbook") and in subsequent Filing Requirements.[104] The Board understands the policies contained in the Handbook and the Filing Requirements apply to electricity distributors, not directly to OPG as an electricity generator, yet finds that the underlying Board policy should be applicable to OPG in this application.

421 The rate regulation of the electricity distribution sector shows a history of tax loss carry-forwards being routinely used in the rate setting process for distributors. This approach is completely consistent with Board policy for tax losses to be applied to reduce income tax to be included in rates, and there is no reason for OPG to be treated any differently in this instance.

422 OPG referred to two decisions in which the Board did not apply the policy, namely OPG's EB-2007-0905 decision and Great Lakes Power's EB-2007-0744 decision. The Board finds that the circumstances in these two cases were unique and are not comparable to OPG's current circumstances.

423 The Board's findings in the EB-2007-0905 decision address the fact that OPG was not regulated by the Board prior to 2008, when the tax loss occurred. The Government set OPG's rates in 2005, 2006 and 2007. The Board's EB-2007-0905 decision in 2008 did not reference the policy in the Handbook. The Board finds that the circumstances in OPG's first payment amounts proceeding were unique and the Board's finding in that case resulted from the absence of information and the Board's uncertainty regarding OPG's tax calculation.

> The Board is not convinced that there are any "regulatory tax losses" to be carried forward to 2008 and later years, or if there are any, that the amount calculated by OPG is correct...The Board does not have the information necessary to determine the tax benefits which should be carried forward to offset payment amounts in 2008 or later periods.[105]

424 The circumstances in the Great Lakes Power EB-2007-0744 proceeding were unique as Great Lakes Power Limited conducted both regulated and non-regulated businesses. The Board's decision addressed the fact that the corporate tax loss carry-forwards arose due to losses in Great Lake Power Limited's non-regulated businesses. The Board referred to the "stand-alone principle" and that it would be inappropriate for regulated service rates to be affected by the income or loss of a non-regulated business.[106]

> It would be fundamentally unfair to take such tax losses into account when setting rates for regulated service. To abandon the stand-alone principle in this case would give rise to the inappropriate result that rates for regulated service would be affected by the income or loss of a non-regulated business.

425 OPG's circumstances in 2013 are distinct from the two referenced Board decisions. In 2013, when OPG's tax loss arose, OPG was regulated by the Board and there is no evidence filed to indicate the tax loss was related to OPG's non-regulated businesses. To the contrary, the first line of OPG's reply argument under the Loss Carry-Forward section heading states that the $211.6M regulatory tax loss in 2013 was due to a shortfall in nuclear production.

426 OPG made a decision to maintain its (then current) payment amounts for 2013. OPG decided not to apply to the Board to change its payment amounts for 2013 based on updated information, including an updated nuclear production forecast. The fact that OPG incurred a tax loss was a risk OPG decided to take on its own accord and should not change the application or treatment of the Board's tax loss carry-forward policy.

427 In addition, even if one accepted the argument that the circumstances of these prior cases were similar to OPG in 2013, the Board continued to apply the Handbook's policy to electricity distributors after both of those decisions were issued.[107] Accordingly, the Board does not consider either case to have set a precedent. Further, it is apparent to the Board from the submissions of OPG and the parties that the "benefits follow cost" principle has been interpreted differently by the parties.

428 OPG argued that application of the policy would result in retroactive rate making during the term of a final rate order without a deferral or variance account. The issue before the Board is a tax loss carry-forward. The tax loss is carried forward to a subsequent year by definition. The question in this application is whether OPG's shareholder or its ratepayers receive the future benefit, the opportunity to reduce a future year's tax provision by the amount of the tax loss from a prior year.

429 The Board does not find there to be an issue with retroactive rate making in the context of tax loss carry-forwards in this case. The Board policy was established in 2005 and it has been applied in subsequent years. The Board's Handbook policy did not and does not require the establishment of a deferral account. Therefore, there is no issue of retroactive ratemaking in the Board's view.

4.7.2 Deferred Tax

430 The December 31, 2013 audited financial statements indicate $181M in deferred income taxes for the newly regulated hydroelectric facilities. OPG submitted that the deferred income taxes on OPG's December 31, 2013 financial statements is to be excluded from the revenue requirement impacts associated with regulating the newly regulated hydroelectric assets. The deferred tax is related to pension and OPEB expense recognition and higher capital cost allowance that is allowed for tax purposes compared to OPG's accounting depreciation.

431 The Board is required to accept the assets and liabilities of the newly regulated hydroelectric facilities as set out in OPG's December 31, 2013 audited financial statements. This requirement is set out in *O. Reg. 53/05, section 6*(2)11 part ii

> The Board shall accept the values for the assets and liabilities of the generation facilities referred to in paragraph 6 of section 2 as set out in Ontario Power Generation Inc.'s most recently audited financial statements that were approved by the board of directors before the making of that order. This includes values relating to the income tax effects of timing differences and the revenue requirement impact of accounting and tax policy decisions reflected in those financial statements.

432 SEC submitted that the $181M net tax liability has been charged as an expense by OPG prior to January 1, 2014, but has not actually been paid yet. SEC disagrees with OPG's proposal which would require ratepayers to pay for tax costs in the future, tax costs incurred prior to the regulation of the newly regulated hydroelectric facilities. SEC submitted that would result in retroactive ratemaking and would be unfair to ratepayers. SEC noted that the Board has never determined that it is appropriate to allow recovery of tax expenses in rates when the taxes were incurred prior to regulation by the Board.

433 SEC submitted that there is nothing in *O. Reg. 53/05* to indicate that the government intended the Board to allow OPG to collect pre-2014 tax expenses from ratepayers in 2014 and beyond. SEC submitted that if the government had intended to require the Board to adopt such a rule, it would have been explicit.

434 LPMA and CME supported SEC's submissions.

435 OPG argued that SEC has not considered the entire provision of section 6(2)11 of *O. Reg. 53/05*. OPG submitted that the wording explicitly provides that the Board, in making its first order, must accept the assets and liabilities approved by the board of directors, including values relating to income tax timing differences and the revenue requirement impact of accounting and tax policy decisions.[108] As deferred tax liabilities relate wholly to income tax timing differences, OPG submitted that the regulation is clear and explicit. Further, OPG stated that the government was aware of the deferred tax liability through its review of OPG's business plan prior to the creation of the regulation.

436 OPG also observed that implementation of the regulation as a means to delineate a starting point was accepted by the Board in OPG's first proceeding in EB-2007-0905.

Board Findings

437 The Board's EB-2007-0905 decision dealt with tax issues that arose prior to regulation of OPG's prescribed assets. In that decision, the Board found that the benefit of tax deductions and losses that arose before the date of the Board's first order should be apportioned between electricity consumers and OPG based on the principle that the party who bears a cost should be entitled to any related tax savings or benefits.

438 The requirement set out in *O. Reg. 53/05, section 6*(2)11part ii, applicable to the newly regulated assets, is more descriptive than the requirement set out in 2008 when the Board issued its first rate order for OPG. The Board finds the regulations are sufficiently explicit; the values related to income tax effects of timing differences and the revenue requirement impact of accounting and tax policy decisions must be accepted by the Board.

439 As a result, the Board accepts OPG's proposed accounting treatment and cost consequences of the $181M in deferred income taxes associated with the newly regulated assets as it relates to income tax decisions reflected in the liabilities as of December 31, 2013. The Board notes that the requirements of *O. Reg. 53/05* are unique to OPG. Deferred taxes are not ordinarily included in the revenue requirement and there is no impact to the current test period revenue requirement as a result of this finding.

5 BRUCE LEASE -- REVENUES AND COSTS

(Issue 7.3)

440 OPG leases the Bruce A and Bruce B generating stations and associated lands and facilities to Bruce Power. Sections 6(2)9 and 6(2)10 of *O. Reg. 53/05* provide that the Board shall ensure that OPG recovers all the costs it incurs with respect to the Bruce nuclear facilities, and that any revenues it earns from the Bruce Lease in excess of costs will be used to offset the nuclear payment amounts.

441 The EB-2007-0905 decision found that the Bruce nuclear facilities should not be treated as if they were regulated facilities. The current basis of accounting used for the Bruce nuclear facilities revenues and costs is USGAAP for non-rate regulated entities.

442 Bruce revenues are derived from base and supplemental payments as set out in the Bruce Lease, used fuel storage and long term disposal services, low and intermediate waste management services, and support and maintenance services as set out in the Bruce Site Services Agreement. Costs include depreciation, which includes asset retirement costs, taxes, accretion, earnings/losses on nuclear segregated funds, the cost of used fuel storage and disposal, and the cost of waste management.

443 The Bruce Lease net revenues are forecast to be $39.7M in 2014 and $40.6M in 2015. If approved, these amounts would offset the nuclear revenue requirement. Variances are tracked in the Bruce Lease Net Revenues Variance Account.

444 SEC submitted that there is a $59M adjustment related to the adoption of USGAAP on January 1, 2011, that should not be permitted. SEC referred to interrogatory response Exh L-1.3-SEC-19 that showed OPG made a $59M one-time transitional adjustment on January 1, 2011 to comply with USGAAP lease accounting requirements. This treatment requires lease payments be recognized retrospectively on a straight line basis from the inception of a lease. SEC proposed that the $59M be credited to a deferral account. OPG argued that the adjustment was a required transition entry as part of the USGAAP opening balance sheet. OPG also argued that the SEC proposal would be inconsistent with Board direction that Bruce Lease net revenues be determined on a GAAP basis for non-regulated entities, and inconsistent with the settlement agreement in the USGAAP and Deferral and Variance Account proceeding, EB-2012-0002.

445 SEC submitted that it would be useful if the cost of generation from the Bruce nuclear facilities was provided to the Board on a regulatory basis in future cost of service proceedings for benchmarking purposes. OPG submitted that this proposal is inappropriate. The Board has already determined that Bruce nuclear facilities will not be treated as if they were regulated facilities. Further, OPG states that it is not privy to Bruce Power's cost of generation information.

Board Findings

446 The net amounts of the Bruce lease revenues and costs of $39.7M for 2014 and $40.6M for 2015 are approved.

447 OPG's adoption of USGAAP was reviewed in EB-2011-0432, *2012 LNONOEB 73* and EB-2012-0002, 2013, LNONOEB 36, and the Board agrees with OPG that the adjustment issue raised by SEC relating to USGAAP was dealt with as part of the settlement of the EB-2012-0002 proceeding. The Board also agrees that the previous cost of service decisions on Bruce Lease revenues and costs determined on the basis of GAPP for non-regulated entities are still appropriate.

448 The Board does not agree with the suggestion of SEC that OPG should file the cost of generation from the Bruce Generating Stations on a regulatory basis in future payment applications. The Bruce Generating Stations are neither regulated by this Board nor included as prescribed assets. The Board would not expect OPG to have information related to Bruce Power's costs and revenues.

6 NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING

(Issues 8.1 and 8.2)

449 OPG incurs liabilities for decommissioning its nuclear stations (including Bruce) and nuclear used fuel and low and intermediate level waste management.

450 The responsibility for funding these liabilities is described in the Ontario Nuclear Funds Agreement. This agreement requires OPG to establish two segregated funds:

* The used fuel fund
    * The decommissioning fund -- to fund the future cost of nuclear fixed asset removal, and low and intermediate level radioactive waste

451 In this proceeding OPG seeks recovery of $847.5M over the 2014 and 2015 test period for nuclear waste management and decommissioning for both prescribed nuclear and Bruce facilities.

452 The Ontario Nuclear Funds Agreement provides for the establishment of a reference plan for nuclear liabilities which must be updated every 5 years. The current approved Ontario Nuclear Funds Agreement reference plan became effective as of January 1, 2012. OPG's contributions to the used fuel fund and the decommissioning fund are determined based on the reference plan cost estimates.

453 The EB-2007-0905 decision approved a methodology for the recovery of nuclear liabilities that recognized a return on rate base associated with asset retirement costs for Pickering and Darlington. The methodology required that the return on the asset retirement cost be limited to the weighted average accretion rate, which is currently 5.37%. The portion of the rate base to which the accretion rate applies is equal to the lesser of (a) the forecast amount of the average unfunded nuclear liabilities related to the Pickering and Darlington facilities, and (b) the average unamortized asset retirement cost included in the fixed asset balances for Pickering and Darlington. In the previous two cost of service applications, and as proposed by OPG in the current application, (b) applies.

454 AMPCO observed that the decommissioning fund was overfunded by $624M at December 31, 2013, i.e. the value of the fund was higher than the balance required to meet all future obligations. The excess funding was shown as "Due to Province" in the audited financial statements.

455 The decommissioning fund has been overfunded in periods prior to Board regulation. AMPCO observed that in 2006, OPG recorded $190M from "Due to Province" credits to balance a $190M liability. AMPCO noted that the "Due to Province" cushion was used in 2006, 2007 and 2008.

456 During the oral component of this proceeding Board staff sought a calculation that reflected the application of the "Due to Province" amount to reduce unfunded nuclear liabilities, assuming a 53% allocation for the prescribed facilities. In completing the undertaking OPG stated that the "Due to Province" amount cannot be used in this manner. The resulting revenue requirement of the hypothetical scenario was higher than that proposed in OPG's application as unfunded nuclear liabilities would be lower than the asset retirement costs. Under the Board-approved calculation methodology for nuclear liabilities cost recovery associated with the prescribed facilities, if the unfunded nuclear liability is lower than the unamortized asset retirement cost (ARC), cost recovery for the portion of the ARC amount is calculated using the higher weighted average cost of capital rate instead of the lower weighted average accretion rate.

457 AMPCO submitted that the calculations provided by OPG were misleading as the Bruce facilities were not considered. AMPCO revised the hypothetical calculations, allocating the $624M "Due to Province Amount" to the prescribed nuclear facilities and the Bruce facilities. AMPCO determined that the test period revenue requirement for nuclear liabilities should be reduced by $28.5M. OPG argued that it has properly reflected the requirements of the Ontario Nuclear Funds Agreement reference plan in the determination of nuclear liabilities and that AMPCO has failed to provide reasons why it disagrees with OPG's interpretation. OPG's treatment of the "Due to Province" amounts associated with the Bruce facilities is consistent with GAAP for non-regulated businesses.

458 AMPCO also observed that when the decommissioning fund is more than 120% overfunded, some of the excess can be transferred to the used fuel fund. AMPCO proposed a deferral account to record the amount the used fuel fund is entitled to. OPG argued that another account would require the Board to modify the scope of the existing Bruce Lease Net Revenues Variance Account.

459 AMPCO submitted that the Board should direct OPG to review its current nuclear liability methodology and any potential alternatives as part of the next payment amounts application.

Board Findings

460 The Board finds that the revenue requirement methodology approved by the Board in EB-2007-0905 continues to be appropriate for recovering nuclear liabilities. The Board does not find it necessary to direct a review of the current methodology at this time given the extensive Board review of the rate making options in EB-2007-0905.

461 The Board will not direct OPG to use the excess earnings in the Decommissioning and Used Fuel funds to decrease the revenue requirement by $28.5M as proposed by AMPCO as the funds are "Due to Province" as stipulated in the Ontario Nuclear Funds Agreement reference plan. The Board is satisfied that the current over funding position will not result in a cash withdrawal from the fund to the Province. In addition, given the long-term nature of the fund, it is appropriate for any periodic over earning to be retained within the fund to offset future potential under earning.

462 The Board will not approve the creation of a deferral account to record any excess earning in the decommissioning fund over 120%. Although any excess over 120% could be transferred to the used fuel fund, the Board does not find it necessary to create a regulatory asset when the reference plan is the source of record keeping and is updated every 5 years. The Board has no authority over the segregated funds or the reference plan for nuclear liabilities established by the Ontario Nuclear Funds Agreement.

463 The Board approves the recovery of $847.5M over the 2014 and 2015 test period for nuclear waste management and decommissioning for both prescribed nuclear and Bruce facilities.

7 CAPITAL STRUCTURE AND COST OF CAPITAL

(Issues 3.1 and 3.2)

7.1 Capital Structure

464 OPG did not apply for a change in capital structure in this proceeding. Rather, OPG proposed to use the same capital structure (53% debt and 47% equity) for all the regulated facilities, including the newly regulated hydroelectric facilities, which was originally approved in the first cost of service proceeding, EB-2007-0905, and again in the last cost of service proceeding, EB-2010-0008. In the current proceeding, OPG's proposed capital structure was supported by evidence (the "Foster report")[109] and expert testimony from Ms. Kathleen McShane of Foster Associates, Inc.

465 During the oral hearing, several parties challenged OPG's position that the capital structure was unchanged by the proposed $4 billion addition of the newly regulated hydroelectric facilities and Niagara Tunnel to rate base. These parties submitted that OPG's business risk has changed and that the equity thickness should be 42 to 43%.

466 SEC disagreed with Ms. McShane's view that the newly regulated hydroelectric facilities are more risky than the previously regulated hydroelectric facilities, but less risky than the nuclear facilities. SEC submitted that Ms. McShane has no independent knowledge of the business risks of the newly regulated hydroelectric facilities or the Niagara Tunnel, including First Nations issues, operating constraints or storage.

467 Noting that the Board concluded in EB-2007-0905 that the 47% equity thickness recommended by Drs. Kryzanowski and Roberts was appropriate, SEC submitted in the current proceeding that applying the methodology and parameters set out in Drs. Kryzanowski and Roberts' evidence in EB-2007-0905, namely 40% hydroelectric equity thickness and 50% nuclear equity thickness, to the proposed test period rate base would result in an overall equity thickness of 42.34%.

468 Board staff submitted that the Board did not approve the methodology of Drs. Kryzanowski and Roberts in EB-2007-0905, and that in the EB-2010-0008 proposal for technology specific cost of capital, Drs. Kryzanowski and Roberts revised the parameters to 43% hydroelectric equity thickness and 53% nuclear equity thickness. Should the Board accept the methodology and apply 43% equity thickness to all the hydroelectric facilities, Board staff submitted that the OPG equity thickness would be 45 to 46%.

469 OPG argued that none of the cost of capital experts that appear before the Board, including Drs. Kryzanowski and Roberts, have expertise in hydroelectric generation facilities. While the parties have challenged OPG's evidence and proposed reductions to equity thickness, none of the parties filed expert evidence to support their positions.

470 OPG also argued that matters raised by some parties, e.g. comparisons with lower equity thickness for generators in other provinces by VECC, and the stand alone principle and 90% debt proposed by the Society, were previously addressed in EB-2007-0905. Further, as OPG is planning on spending more than $1.5 billion on the Darlington Refurbishment Project in the test period, OPG contends that its financial risk will increase in the test period.

Board Findings

471 In this application OPG did not request a change to its capital structure, claiming there had been no significant changes in the risks faced by its regulated asset portfolio that are not captured elsewhere in the application. While the application was filed in September 2013, no evidence was filed by OPG to substantiate this conclusion with respect to changes in risk until the interrogatory phase of the proceeding in March 2014.

472 The Foster report dealing with the capital structure and risk was not filed until March 19, 2014 in response to an interrogatory by SEC. The Board finds this late filing to be unfortunate, because the time between the report being publicly available and the date for intervenors to advise the Board of their intentions to file evidence was less than one week. The Board suspects that, had the Foster report been filed sooner, parties may have been in a better position to assess the merits of retaining their own expert on this matter. As it was, no alternative expert analysis was proffered and arguments by all parties were largely based on challenges to the Foster report.

473 The Board believes it would have been helpful to have had additional expert and independent evidence. The Board notes OPG's assessment that there had been no significant changes in risks was made before Foster Associates, Inc. was retained.[110] OPG appears to have made the initial assessment entirely on its own.

474 The Board cannot accept that business risk has not changed since the capital structure was last reviewed in 2010. Since that time, 48 additional hydroelectric facilities have been added to the inventory of prescribed assets, accounting for 12.4 TWh of energy forecast to be produced in 2014 and 12.5 TWh in 2015. These assets, together with the Niagara Tunnel which was brought into service in 2013, increase the proportionate share of rate base related to hydroelectric facilities from about half in 2010 to approximately two-thirds now. The relative business risk of hydroelectric generation versus nuclear has been accepted by the Board as being lower in previous proceedings,[111] even though setting the capital structure on a technology specific basis has not. The critical question therefore becomes whether business risk has changed in a significant enough way to warrant a change in capital structure, and in which direction is this change -- lower or higher risk?

475 The Board finds that including additional hydroelectric units to the roster of prescribed assets lowers the business risk for several reasons. Subject to Board approval through this proceeding, these additional assets will be subject to treatment under a number of previously approved Board deferral and variance accounts for a host of variables, all of which reduce business risk. Since the equity component was first set, a new pension variance account has been approved by the Board. This variance account decreases OPG's forecast risk associated with pension and OPEB costs. The proportion of regulated assets between hydroelectric and nuclear generation has changed, with hydroelectric facilities now having a much larger share of the generating capacity of OPG than previously. It was acknowledged by OPG's consultant that hydroelectric facilities have lower risk than nuclear.[112] The new assets being added to rate base have long remaining service lives (average of 58 years for the newly prescribed assets[113]) and 95 years for the Niagara Tunnel. As long as there is rate regulation, these assets will produce power and revenue certainty until the end of their useful lives.

476 The Board considered the Foster report and makes the following observations.

* No independent analysis was undertaken of the operating costs and lives of the newly prescribed assets. The consultant's opinion was based on discussions with OPG staff only. While information obtained from operating personnel is an important component to assessing risk, the lack of independent knowledge of the circumstances of OPG's newly regulated hydroelectric operations is a concern.
* The opinion that the newly regulated assets have increased risk due to their location in Northern Ontario within First Nations communities and their traditional ways of life was not substantiated by fact. It appears this was conjecture on the part of the consultant based on conversations with OPG management.
* There was no evidence as to the impact of a change in equity thickness on the credit metrics.

477 OPG raised various other arguments with respect to the need for at least the same, or higher, equity thickness. One of these arguments was that there is a greater risk associated with the future move to incentive regulation. The Board does not accept that moving to incentive regulation significantly increases risk to the entity such that the capital structure should be reset, and has not done so for any of the other companies that it regulates. For example, the Board set the capital structure for all electricity distributors at a 40% equity to debt ratio in December 2006. As new incentive regulation models for electricity distributors evolved in 2008[114] and 2012[115], this capital structure was not revisited. Similarly, the capital structure for the natural gas distributors did not change as a result of moving to a long-term incentive regulatory mechanism for the setting of rates for these distributors. In addition, OPG is not actually being moved to incentive regulation in the current proceeding, and any potential changes to business risk this may entail could be considered in the incentive regulation proceeding. The Board therefore is not persuaded by the comments made by OPG and its consultant that the future move to an incentive regulatory mechanism for OPG increases business risk such that a higher equity thickness should be considered.

478 Instead, the Board has determined that business risk has changed for this payment setting period, and that the business risk is reduced. The business risk is reduced because of the addition of significant hydroelectric assets to rate base, which are less risky than nuclear assets.[116] The Board finds that a more appropriate equity thickness is 45%. This equity thickness is still considerably higher than any other entity regulated by the Board.

479 The Board does not accept the Society's argument that due to the change in the energy environment that the well accepted principles of a stand-alone entity should be abandoned and also that OPG can have up to a 90% debt operating structure due to its ownership structure. The Board has previously commented on the validity of the stand-alone principle and as neither of these issues was explored in sufficient detail through cross-examination or the production of independent expert evidence, the Board sees no justification for such a major change.[117]

480 In reaching this conclusion the Board was mindful of the Fair Return Standard as articulated by the courts, and the need to observe the requirements of consideration of comparable investment, financial integrity and capital attraction. However, the Fair Return Standard is sufficiently broad to allow a regulator to apply informed judgment and discretion in the determination of a rate regulated entity's cost of capital. The Board believes that a reduction to equity thickness is based on the evidence in this case, the Board's best judgment and is a reasonable outcome.

481 As a result of its review, the Board finds that the capital structure should be based on 45% equity and 55% debt.

7.2 Return on Equity

482 OPG's current proposal is to apply 9.36%, the Board's ROE for 2014 cost of service applications, for 2014 and 9.53% for 2015 based on Global Insights data from September 2013.

483 In the event that the Board's ROE for 2015 cost of service applications was available at the time of the payment order, Board staff submitted that the Board's ROE, based on more recent *Consensus Forecasts*, be used instead of the 9.53% proposed by OPG based on Global Insights data from September 2013.

484 OPG replied that Board staff's proposal would involve data after the close of record and would be a departure from the methodology used for setting the ROE in the second year of the test period as adopted by the Board in the previous payment amounts decisions.

485 In addition to proposing a 90% debt structure, the Society submitted that the allowed return should be the social discount rate. OPG argued that the social discount rate was not addressed in this proceeding.

Return on Equity for Newly Regulated Hydroelectric Facilities

486 In the current application, OPG proposes to add $2.5 billion to rate base in relation to the newly regulated hydroelectric facilities.

487 Environmental Defence did not object to the addition, referring to the requirements of *O. Reg. 53/05*, however, Environmental Defence submitted that 50 to 60% of the addition is related to the revaluation of assets process that occurred when OPG was created as one of the successors to Ontario Hydro. Environmental Defence submitted that this portion of OPG's rate base should not earn the ROE, but instead should attract a return based on long-term debt. Environmental Defence also submitted that the Board should consider this treatment for the previously regulated hydroelectric facilities in the next proceeding.

488 OPG argued that "a package of assets" was sold to OPG in exchange for certain debt and equity amounts as part of the restructuring process. This was done to make OPG a viable operation on a stand-alone basis. Further, Environmental Defence's submission is inconsistent with the Board's treatment of the previously regulated hydroelectric facilities in the first proceeding.

489 CME submitted that the Board should consider the cost of capital supporting the newly regulated hydroelectric assets at December 31, 2013. The newly regulated hydroelectric facilities, on a stand-alone basis at December 31, 2013, were producing an actual loss from operations. In CME's view, the cost of capital supporting the newly regulated hydroelectric assets should be the interest rate that applies to "stranded debt" which CME estimates to be 5.9%.

490 OPG argued that the newly regulated hydroelectric facilities, prior to becoming regulated, were being financed by the debt and equity of the consolidated OPG. The fact that the newly regulated hydroelectric facilities were not earning their cost of capital on December 31, 2013 does not mean that their cost of capital was equal to the cost of debt. Further, OPG's 2013 audited financial statements do not contain an impairment charge for these assets.

Board Findings

491 With respect to Return on Equity, the Board's Return on Equity for 2014, 9.36% will apply for the 2014 test year. As the Board's 2015 cost of capital parameters will be available when the payment order process for the current proceeding is underway, the Board's Return on Equity for 2015 will apply for the 2015 test year.

492 The Board notes that the revaluation of the newly regulated assets was undertaken at the time of Ontario Hydro restructuring about 15 years ago. As a result of this restructuring, Environmental Defence proposes to have the newly regulated assets earn a return based on long-term debt. The Board finds this inappropriate and inconsistent with prior Board Decisions, e.g., EB-2007-0905 when the previously regulated hydroelectric facilities were first regulated by the Board.

493 The Board has reviewed CME's submission and has determined that the Return on Equity determined above will apply to all regulated assets.

7.3 Short Term Debt and Long Term Debt

494 OPG proposes, for Board approval, the following debt rates for the test period.

	2014	2015
Long-term Debt	4.85%	4.86%
Short-term Debt	1.87%	2.89%

495 There were no opposing submissions filed.

496 The Board accepts that the long-term and short-term debt rates proposed by OPG are appropriate. The final approved debt costs will be adjusted by the rate base and capital structure findings found elsewhere in this Decision.

8 DEFERRAL AND VARIANCE ACCOUNTS

497 There are currently 15 deferral and variance accounts for OPG that were established pursuant to *O. Reg. 53/05* or Board decisions.

498 In the EB-2012-0002 USGAAP and Deferral and Variance Account proceeding, the Board accepted the settlement proposal of the parties. The audited balances as of December 31, 2012 in the deferral and variance accounts were approved for disposition, except for four accounts. The EB-2012-0002 proceeding established payment riders for 2013 and 2014. The 2014 riders are $2.02/MWh for the previously regulated hydroelectric facilities and $4.18/MWh for the nuclear facilities.

8.1 Clearance of Accounts in the Current Proceeding

(Issues 9.1, 9.2, 9.3 and 9.4)

499 In the current proceeding, OPG seeks clearance of the 2013 year end balances for the following four accounts in riders starting January 1, 2015.

* Hydroelectric Incentive Mechanism Variance Account
    * Hydroelectric Surplus Baseload Generation Variance Account
    * Capacity Refurbishment Variance Account -- Hydroelectric and Nuclear (OPG is not seeking clearance of the nuclear non-capital cost account additions)
* Nuclear Development Variance Account

500 The audited 2013 year-end balances for the hydroelectric accounts listed above is $126.9M, however, OPG proposes to clear the capacity refurbishment variance hydroelectric sub-account over 2 years. The 2015 hydroelectric amortization amount proposed is $70.6M. The audited 2013 year-end balance for the nuclear accounts listed above is $62.2M.

501 Board staff and LPMA had no concerns with the balances in the four accounts for which OPG seeks disposition in this proceeding. LPMA submitted that the recovery period could be extended if mitigation is required. Board staff submitted that the right to re-examine the accounts that are not being disposed in this proceeding should be reserved for the future application that will dispose of them. In reply, OPG accepted that these accounts should be re-examined when the balances are disposed.

502 SEC submitted that there is no basis on which to approve the addition of several Darlington Refurbishment campus plan projects to rate base, e.g. the Darlington Operations Support Building refurbishment. SEC submitted it would be reasonable to add this to the Capacity Refurbishment Variance Account, so that when proper evidence is filed in a future proceeding, it can be added to rate base at that time. OPG argued that there is no basis to SEC's objections and no reason to conclude that the balance in the capacity refurbishment account is incorrect.

503 The 2013 year-end balance in surplus baseload generation account is $19.2M. The 2011-2013 unintended benefit to OPG of the interaction between surplus baseload generation and the hydroelectric incentive mechanism has been determined to be $6.8M in undertaking J4.7. Both CME and VECC submitted that the $6.8M should be returned to ratepayers. OPG argued that the proposed adjustment is improper because it amounts to retroactive ratemaking. The Board's EB-2010-0008 decision established the terms for account entries and no party argued that the balances in the accounts were not accurately calculated.

Board Findings

504 The Board approves disposition of the audited December 31, 2013 balances in the four variance accounts. The Board does not find it necessary to mitigate the rate impact for the Capacity Refurbishment Variance Account hydroelectric sub-account with a 2 year amortization period as the account balance is $112.7M. As proposed by OPG, the riders shall commence on January 1, 2015. The riders will end on December 31, 2015.

505 The Board will not adjust the balance in the Hydroelectric Surplus Baseload Generation Variance Account to eliminate the unintended benefit realized by OPG, as proposed by CME and VECC. The Board does not find it appropriate to alter the terms and calculation approved in EB-2010-0008 to accommodate new information that was not available at the time of the Board's decision. Changing the December 31, 2013 account balance would not be retroactive ratemaking, as any variance account balance is subject to change prior to final disposition by the Board. However, the proposed adjustment would be improper as this was not addressed in the Board's EB-2010-0008 decision.

506 In addition, the Board will not require OPG to make additional entries to the Capacity Refurbishment Variance

Account. The Board has approved the rate base additions related to the Darlington Refurbishment campus plan projects as proposed by OPG, and therefore, there is no residual unapproved balance to transfer to the variance account as proposed by SEC.

8.2 Continuation of Accounts and New Accounts

(Issues 9.5, 9.7, 9.8. 9.9)

507 OPG requested the continuation of the following accounts:

* Hydroelectric Water Conditions Variance Account
    * Ancillary Services Net Revenue Variance Account -- Hydroelectric and Nuclear Sub-Accounts
* Hydroelectric Incentive Mechanism Variance Account
    * Hydroelectric Surplus Baseload Generation Variance Account
* Income and Other Taxes Variance Account
* Tax Loss Variance Account
* Capacity Refurbishment Variance Account
* Pension and OPEB Cost Variance Account
* Impact for USGAAP Deferral Account
    * Hydroelectric Deferral and Variance Over/Under Recovery Variance Account
* Nuclear Liability Deferral Account
* Nuclear Development Variance Account
    * Bruce Lease Net Revenues Variance Account -- Derivative and Non-Derivative Sub-Accounts
    * Pickering Life Extension Depreciation Variance Account
    * Nuclear Deferral and Variance Over/Under Recovery Variance Account

508 The total year end 2013 debit balance for all accounts is $217.3M for the previously regulated hydroelectric facilities and $1,478.4M for the nuclear facilities. OPG plans to seek clearance of the December 31, 2014 balances in all its deferral and variance accounts through a separate application to be filed in 2014.

509 As set out in EB-2012-0002, OPG will terminate the Tax Loss Variance Account and the Impact for USGAAP Deferral Account on December 31, 2014, with any remaining balance transferred to the over/under variance accounts. OPG has proposed an enhanced hydroelectric incentive mechanism in the current proceeding that eliminates the need for future additions to the Hydroelectric Incentive Mechanism Variance Account.

510 OPG has proposed to extend the application of four variance accounts specific to hydroelectric operations and three common cost variance accounts (i.e., accounts that impact both hydroelectric and nuclear operations) to its newly regulated hydroelectric operations. The newly regulated hydroelectric accounts would be subaccounts of existing accounts. Entries to the accounts would commence on the effective date of the payment amounts.

511 In the EB-2012-0002 settlement proposal, accepted by the Board, no interest was to be applied to the balance in the Pension and OPEB Cost Variance Account for the 2 year period ending December 31, 2014. OPG proposes that interest will resume on January 1, 2015. Board staff submitted that the variances in the Pension and OPEB Cost Variance Account have been actuarially determined and that interest should not apply to be consistent with other decisions of the Board. OPG did not reply on this matter.

512 No parties objected to OPG's proposal to extend existing accounts to include the newly regulated hydroelectric facilities.

513 Board staff and other parties have supported the continuation of the current hydroelectric incentive mechanism, and keeping the hydroelectric incentive mechanism variance account open to additions. Board staff and other parties also submitted that the Hydroelectric Incentive Mechanism Variance Account should also apply to the incentive mechanism revenue related to the newly regulated hydroelectric facilities. OPG agreed that it would be appropriate to continue additions to the account if the Board decides to retain the current hydroelectric incentive mechanism. However, the current variance account is asymmetrical. If OPG fails to earn its half of the incentive net revenues, it owns the loss, whereas ratepayers are fully protected. OPG submitted that the account should act both ways.

514 If the Board approves a cash basis for pension and OPEB, Board staff submitted that it would be reasonable for the Board to approve a variance account for differences in forecast cash payments included in revenue requirement and actual cash payments. It would also be reasonable that carrying charges would apply to the cash variance. OPG has serious concerns with respect to cash basis determination for pension and OPEB. However, if the Board proceeds with this methodology, the account would be required.

515 Board staff submitted that Ministry of Natural Resources approval of a 10 year gross revenue charge holiday for the Niagara Tunnel Project is highly likely, however, that holiday is not reflected in the current application. Board staff submitted that an account should be set up to capture the gross revenue charge costs for return to ratepayers. OPG had no objection to this submission.

516 In its submission on nuclear liabilities, AMPCO proposed a deferral account to record 50% of an excess of 120% of the decommissioning fund balance. SEC submitted that there is a $59M adjustment related to the Bruce Lease and the adoption of USGAAP on January 1, 2011, that should not be permitted. SEC proposed that the $59M be credited to a deferral account. OPG does not support either of these accounts, arguing that there is no basis for making the adjustments.

Board Findings

517 The Board approves the continuation of existing deferral and variance accounts as proposed by OPG, with two exceptions.

518 First, the Board directs OPG to maintain the Hydroelectric Incentive Mechanism Variance Account as the Board has rejected the alternative enhanced hydroelectric incentive mechanism proposal. OPG will maintain the current mechanism with the one variation that eliminates the unintended benefit to OPG. As a result, the variance account will also be maintained to track any revenues earned over the incentive thresholds of $78M in 2014 and $96M in 2015. The Board will maintain the account's asymmetrical structure and purpose, and extend the account's application to include the newly regulated hydroelectric assets.

519 Second, the Board rejects OPG's proposal to accrue interest on the balance in the Pension and OPEB Variance Account after December 31, 2014. The Board finds no compelling reason to change OPG's current practice of maintaining the balance without interest, which was part of the EB-2012-0002 settlement proposal approved by the Board.

520 Regarding the creation of new accounts, the Board accepts OPG's proposal to extend seven variance accounts to the newly regulated hydroelectric assets. The Board has included an eighth account, the Hydroelectric Incentive Mechanism Variance Account as previously approved. New sub accounts will need to be created for the newly regulated assets, extending the applicability of the existing variance accounts. Entries to the accounts will commence on the effective date of the payment amounts for the newly regulated hydroelectric facilities.

521 In addition, the Board approves the creation of a variance account to track any variance in the gross revenue charge forecast to be paid for the Niagara Tunnel Project. A charge is forecast and included in the 2014 and 2015 payment amounts, yet the approval is outstanding for a 10-year gross revenue charge exemption for the Niagara Tunnel Project. The new account will be called the Gross Revenue Charge Variance Account.

522 As noted in the Pension and OPEB Accounting section of this Decision, the

523 Board approves a new variance account to track any contributions that differ from the minimum cash requirements, as included in the 2014 and 2015 payment amounts. Interest will apply to this variance account given that it relates to cash payments. This new account will be called the Pension & OPEB Cash Payment Variance Account.

524 In addition, the Board has approved the establishment of a new deferral account to track the differential between the accrued and cash valuations for pensions and OPEBs. The Board does not approve the accrual of interest on the deferral account balance given that it tracks non-cash items. The new account will be called the Pension & OPEB Cash Versus Accrual Differential Deferral Account.

525 As proposed by OPG, the Tax Loss Variance Account and the Impact for USGAAP Deferral Account will be terminated effective December 31, 2014.

8.3 Future Disposition of Accounts

(Issue 9.6)

526 As noted previously, OPG plans to seek clearance of the December 31, 2014 balances in all its deferral and variance accounts through a separate application to be filed in 2014.

527 Board staff observed that the current proceeding is the third proceeding in which OPG has filed for clearance of deferral and variance accounts on the basis of forecasts with audited account balances filed later in the proceeding. No other utilities do this and this type of filing creates inefficiency as initial assessments are repeated when the audited balances are filed. Board staff suggested that the Board may wish to consider whether it will permit OPG to continue to file on the basis of estimates. Board staff also submitted that OPG did not provide sufficient rationale with its application, as filed on September 27, 2013, to limit clearance to only four deferral and variance accounts. The Board may wish to consider that the most effective and efficient means of assessing deferral and variance account balances is to do so at the time of also assessing a utility's costs of service, given the links between certain of the accounts and the revenue requirement.

528 OPG replied that the efficiency impact of filing deferral and variance account balances on a forecast basis is insignificant. Limiting account clearance to 4 accounts was sensible and appropriate given the size, duration and complexity of the current application. OPG stated that its approach made the current case more manageable.

529 LPMA submitted that the Board could consider denying additional carrying costs for the accounts OPG has proposed not to clear in this proceeding. OPG replied that this matter was not put to an OPG witness. The submission is punitive and should be rejected.

Board Findings

530 The Board does not endorse OPG's decision to bifurcate its cost of service issues into two separate proceedings, deferring its application for disposition of deferral and variance accounts to a later date. The Board accepted OPG's separate application in the EB-2012-0002 proceeding application but the Board did not intend to endorse a new, unique rate-setting approach for OPG. It is not a common practice of any other entity regulated by the Board to apply for a separate proceeding to dispose of deferral and variance accounts, other than when the entity is under a long-term incentive regulation method for rate-setting. This is not the case for OPG at this time. The Board does not accept OPG's statement that it proposed this two-step approach in order to manage and expedite the review of other issues in the application. With all of the complex issues included in this application, adding the clearance of deferral and variance accounts would not have added significant time or burden to this proceeding.

531 As a result of OPG deferring its application for disposition of deferral and variance accounts, the Board is unable to render a decision on the need for rate mitigation in 2014 and 2015, based on the overall bill impact resulting from OPG's operations. This creates a difficult situation for ratepayers who will not understand the full impact on payment amounts for 2014 and 2015 until the second application is completed. Based on the evidence filed, the account balances to be cleared in a second application will be significant.

532 While the Board has approved OPG's proposal to limit the clearance of deferral and variance accounts in this proceeding to the four accounts put forth by OPG, it is the Board's expectation that going forward, all accounts should be reviewed and disposed of in a cost of service proceeding unless there is a compelling reason to not do so. The Board agrees with Board staff that the optimal time to review all accounts is at the time of a cost of service review, based on the most recently audited account balances rather than forecasts. Any mitigation measures that may be required can also be considered at that time. This approach is consistent with the treatment of deferral and variance accounts for electricity distributors.

9 REPORTING AND RECORD KEEPING REQUIREMENTS

(Issue 10.1)

533 Board staff observed that OPG has in several instances made changes to regulatory accounting during the period outside of its payment applications. The changes affect the accounting basis on which the rates were approved. As an example, Board staff noted that OPG extended the useful life of Pickering effective December 31, 2012, resulting in a decrease in depreciation of $47M annually.

534 Board staff submitted that OPG should be directed to first seek Board approval through an accounting order that outlines the nature of the change and the impact. Board staff suggested that a revenue requirement threshold of $20M be used, for accounting changes, whether arising from a single or multiple transactions, and noted that the EB-2012-0002 has a similar provision for nuclear liability accounting changes that have a revenue requirement impact of $10M or more annually. SEC did not agree with a threshold as any change could be applicable for three years before rates are changed.

535 OPG submitted that a requirement to seek Board approval for accounting changes would be a burden for both OPG and the Board. However, OPG concluded that the Board staff submission is really focused on accounting changes that impact depreciation expense and the related impact on accumulated depreciation and rate base. OPG replied that it would support the expansion of the nuclear liability requirement set out in EB-2012-0002 to include impacts of changes in station useful lives on non-asset retirement cost component of nuclear fixed assets reflected in rate base. This requirement would capture future changes similar to the $47M Pickering depreciation expense example.

536 If the Board is inclined to require accounting orders for a broader range of accounting matters, OPG submitted that a $20M threshold would be more appropriate to keep the requirement manageable.

Board Findings

537 The Board will not require OPG to seek prior Board approval of all accounting changes made between payment amount applications. The Board finds accounting decisions should continue to be made by OPG's management. The Board's responsibility is to approve the future recovery of expenses through the determination of

OPG's payment amounts, based on the evidence available. At that time, the Board will opine on the proposed, underlying accounting treatment by OPG.

538 Upon application for new payment amounts and where an accounting change has occurred, OPG must include historical information that enables the comparison between years of expenses and impact on elements which form part of the payment calculation. This will involve the preparation of continuity schedules showing the impact of the accounting change such that year over year comparisons are transparent and readily apparent. The Board notes that this is not a new requirement, as the OPG filing guidelines (EB-2011-0286, *2011 LNONOEB 340*) already stipulate that changes in accounting methodologies that affect any of the historic, bridge or test years must be provided.

539 OPG also has nuclear liabilities reporting requirements as set out in EB-2012-0002.

> OPG shall file an accounting order application with the Board and provide notice to intervenors of record in EB-2012-0002 if, other than as a result of an Ontario Nuclear Funds Agreement Reference Plan update, OPG proposes to effect an accounting change impacting the calculation of its Nuclear Liabilities that results in a revenue requirement impact for the prescribed facilities that is neither reflected in the current or proposed payment amounts nor recorded in the Nuclear Liability Deferral Account (including, without limitation, any change in the useful lives of any asset for depreciation or amortization purposes). OPG shall not be required to apply for such accounting orders if the impact on the annualized revenue requirement impact for the prescribed facilities is less than $10M.[118]

540 In this proceeding, OPG has agreed to expand these requirements to include impacts of changes in station useful lives on the non-asset retirement cost component of nuclear fixed assets reflected in rate base. As a result, the Board approves this extension of the nuclear reporting requirements and requires OPG to provide notice to any additional intervenors of record in this proceeding, EB-2013-0321, *2014 LNONOEB 39*.

10 METHODOLOGIES FOR SETTING PAYMENT AMOUNTS

10.1 Incentive Regulation

(Issue 11.1)

541 *O. Reg. 53/05* empowers the Board to establish the "form, methodology, assumptions and calculations" to be used in setting payment amounts for OPG's prescribed generation assets. While the current proceeding is the third cost of service proceeding, the Board has indicated its intention to "implement an incentive regulation formula for OPG when it is satisfied that the base payment provides a robust starting point for that formula."[119] The Board has communicated its intention in the report, *A Regulatory Methodology for Setting Payment Amounts for the Prescribed Generation Assets of Ontario Power Generation Inc.*, EB-2006-0064, issued on November 30, 2006, the EB-2010-0008 Decision with Reasons issued on March 10, 2011 and most recently, the *Report of the Board on Incentive Rate-making for Ontario Power Generation's Prescribed Generation Asset*, EB-2012-0340, 2013, LNONOEB 38, issued on March 28, 2013.

542 On the basis of a consultative process, the EB-2012-0340 report set out a timeline to establish incentive regulation for the hydroelectric business and multi-year cost of service for the nuclear business assuming a 2014-2015 cost of service application filing in mid-2013. As the current application was not filed until September 2013 and a decision is not expected until late 2014, Board staff has submitted that working groups would not be initiated until early 2015, at the earliest. It would be many months before a Board report based on the working group's analysis and recommendations could be issued. Board staff submitted that it is unlikely that incentive regulation will be implemented prior to the filing of an application for 2016 payment amounts.

543 In reply, OPG suggested that the working groups could be initiated in November 2014. OPG has contracted with London Economics Inc. to conduct the independent hydroelectric study requested by the Board in EB-2010-

0008. OPG proposed that the working groups could review that study, and that the study and any working group materials could be made public once the decision in the current proceeding was issued.

544 Notwithstanding the Board's position, CCC has submitted that OPG may not be the type of entity that can be regulated through an incentive regulation model. CCC submitted that the working groups should consider whether incentive regulation is appropriate for OPG as a threshold issue.

545 LPMA submitted that incentive regulation for the hydroelectric facilities may be premature as there is no history related to the newly regulated hydroelectric facilities under regulation. The Society submitted that "incentive rates are an implicit acknowledgement of a lack of expertise."[120]

Board Findings

546 The Board has indicated in previous decisions its objective of having OPG payment amounts set on an incentive regulation methodology ("IRM"). The Board continues to believe that a long-term, properly designed IRM has the potential to lead to operational efficiencies and innovation, and thus lower electricity costs. Progress in this direction of an IRM to payment setting has been made, with the issuance of the Board's Report on *Incentive Regulation for Ontario Power Generation's Prescribed Assets* (EB-2012-0340).

547 OPG shall file the London Economics Inc. study immediately upon completion. Recommendations on the details of the IRM are to be established through a working group, comprised of OPG, Board staff and stakeholders. The Board sees no reason for delay. The Board remains committed to setting payment amounts for the nuclear assets under IRM as well. However, the Board will wait until the Darlington Refurbishment Project is further advanced before issuing further direction in this regard.

10.2 Payment Design and Mitigation

(Issue 11.2 and 11.3)

548 OPG has determined that the payment amount increase sought in the current application, including the newly regulated hydroelectric facilities, is 23.4%. The estimated bill impact is an increase of $5.31 per month on the bill of a typical residential consumer. As the bill impact is less than 10%, OPG has not proposed any mitigation.

549 Board staff noted that the 23.4% increase in payment amounts is the largest increase OPG has proposed in a cost of service application. In addition, OPG will be seeking to dispose of further significant balances by way of a stand-alone deferral and variance account application shortly following this proceeding. Board staff submitted that some consideration of mitigation was appropriate.

550 The newly regulated hydroelectric facilities currently receive payment for generation based entirely on the Hourly Ontario Energy Price ("HOEP"). OPG seeks a payment amount of $47.57/MWh, which is a 59% increase over the $30/MWh proxy for HOEP that OPG has assumed for this application. Board staff submitted that the Board could consider approving half of the increase for the 2014 test year, and the full increase for the 2015 test year. These 2014 payment amounts would be higher than the 2009-2013 historical HOEP. SEC disagreed with the Board staff proposal. SEC submitted that the intent of *O. Reg. 53/05* is that the newly regulated hydroelectric facilities will move to a "normal" regulated rate effective July 1, 2014.

551 OPG argued that the Board staff proposal without a deferral account is really the confiscation of prudently incurred costs that OPG is legally entitled to recover. The proposal is contrary to expert reports filed in other Board proceedings that refer to phase-in of rates and deferred amounts recognized as regulatory assets, and implementation such that there is no harm to the utility.

Board Findings

552 The design of the regulated hydroelectric and nuclear payment amounts is the same as had been established through the previous two payment amount proceedings, and no changes have been proposed. The Board accepts the existing payment amounts design for 2014 and 2015.

553 No mitigation of payment amount increases is approved in this Decision. It should be noted that the total bill impact to ratepayers over the test period will be dependent upon another application and proceeding related to disposition of OPG's deferral and variance account balances as at December 31, 2014, and which will likely seek rate riders starting in 2015 to account for the clearance of these deferral and variance accounts. The need for mitigation should be an issue in this subsequent proceeding, in the context of OPG's total bill impact.

11 IMPLEMENTATION

(Issue 12.1)

554 OPG requests an effective date of January 1, 2014 in respect of the previously regulated hydroelectric and nuclear facilities, and an effective date of July 1, 2014 for the newly regulated hydroelectric facilities. With respect to the newly regulated hydroelectric facilities, section 6(2)11 of *O. Reg. 53/05* states the following:

> In making its first order under section 78.1 of the Act in respect of Ontario Power Generation Inc. that is effective on or after July 1, 2014, the following rules apply:
>
> i. The order shall provide for the payment of amounts with respect to output that is generated at a generation facility referred to in paragraph 6 of section 2 during the period from July 1, 2014 to the day before the effective date of the order.

555 At OPG's request, the Board issued an interim payment amounts order on December 17, 2013, declaring the payment amounts for the previously regulated hydroelectric and nuclear facilities interim as of January 1, 2014, and the newly regulated hydroelectric facilities as of July 1, 2014.

556 OPG argues that: "having declared current payment amounts interim as of the dates set out above, the OEB is obliged to make the payment amounts it determines to be just and reasonable after a review of the application effective from those dates. The time taken to process and review OPG's application is legally irrelevant."[121] In its Argument-in-Chief, OPG relied on *Bell Canada v. Canada (Canadian Radio-Television and Telecommunications Commission)*, *[1989] 1 S.C.R. 1722* ("Bell"). The Bell decision establishes that the Board has the power to retrospectively set the implementation date of the decision back to the date that payment amounts were declared interim. OPG argues that this power, when coupled with the requirement that the Board must ensure that at all times payment amounts are just and reasonable, amounts to a legal requirement that the Board set the effective date of the order back to the date payment amounts were declared interim.

557 With respect to the newly regulated hydroelectric facilities, CME submitted that section 6(2)11 of *O. Reg. 53/05* cannot override the Board's powers to set just and reasonable rates. The overall impact on consumers of OPG's proposals needs to be considered in the context of the retroactivity component of the relief OPG seeks. CME submitted that none of the retroactive amounts should be recoverable from ratepayers. OPG disagreed with CME's submission observing that there is no conflict between the Act and the regulation as the Act provides for combined operation of section 78.1(2) and the regulation.

558 Board staff argued that the Bell case gives the Board the ability to retrospectively adjust final rate orders back to the date the interim order was issued, but it does not require the Board to do so.

559 Several other parties disagreed with OPG and proposed a range of different effective dates for the respective payment orders. SEC and CCC argued that the timing of the filing of the application was entirely within OPG's control. SEC pointed to the extensive updates that were filed by OPG throughout the proceeding, which resulted in additional delay. These parties submitted the effective date for the previously regulated assets should be the month following the date of the payment order. Board staff submitted that July 1, 2014 should be the effective date for all payment amounts as it was the earliest possible date a decision and payment order could have been completed based on a September 27, 2013 filing.

Board Findings

The Law Respecting Interim Orders

560 The Board does not accept that there is a legal requirement that it set the effective date of its final orders to the date that rates were declared interim. OPG's view is not supported by the wording of the legislation, the case law, nor the Board's practice.

561 The Board's power to set interim rates derives from section 21(7) of the Act: "[t]he Board may make interim orders pending the final disposition of a matter before it." As the use of the word "may" reveals, there is no requirement that the Board issue interim rate orders at all. As the decision to issue an interim order is discretionary, it follows that any decision to draw the effective date of the final payments order back to the date of the interim order is also discretionary. Nothing in the legislation suggests that the issuance of an interim order in any way ties the Board's hands with respect to the effective date of the final order. If the Legislature had intended that the Board be required to match the effective date of an order to the date interim rates were declared, it would have written that into the legislation. This was not done, and the Legislature has instead left the matter to the Board's discretion.

562 The Bell decision referred to by OPG establishes that interim rate orders give the Board the *ability* to retrospectively alter rates (or in this case payment amounts) back to the date the interim order was issued. As the Board stated in its decision in EB-2005-0361, nowhere does Bell state, or even suggest, that the Board is *required* to do so. Instead, the language of Bell suggests a permissive or discretionary approach. The Court stated: "It is inherent in the nature of interim orders that their effect as well as any discrepancy between the interim order and the final order <u>may</u> be reviewed and remedied by the final order."[122] The Bell decision does not support OPG's conclusion that the Board is legally required to align the effective date to the interim date, and OPG has not pointed to any other cases which support its position.

563 The Board issued the interim payment amounts order on December 17, 2013 at OPG's request and without any input from any other party. The Board was clear that by declaring rates interim it was not committing itself to ultimately setting the effective date of the final order to match the interim date: "This determination [i.e. the order declaring payment amounts interim] is made without prejudice to the Board's ultimate decision on OPG's application, and should not be construed as predictive, in any way whatsoever, of the Board's final determination with regards to the effective date for OPG's payment amounts arising from this application."[123]

564 Although OPG questioned in final argument whether the Board even has the ability to set an effective date to some date other than the interim date, it made no comment on this point when it made its request for interim payment amounts, nor when the interim order was issued. Given that the sentence quoted above is commonly included in the Board's interim orders, the Board is surprised to hear for the first time in OPG's final argument that OPG feels the Board lacks this authority. The very reason that the Board generally issues interim orders without seeking submissions from parties is that parties will be given the opportunity to ask questions and make submissions about the effective date of the final order throughout the hearing process. If the Board is legally required to match the effective date to the interim date, as OPG argues, then the issuance of the interim order without process arguably represents a breach of the "right to be heard" principle. In the current case, ratepayer groups would be responsible for hundreds of millions of dollars in costs relating to the "interim" period without being afforded any opportunity for comment at all.

565 OPG argues that the Board has an obligation to ensure that rates are just and reasonable at all times. As a general statement, this is true. However, the Board's power to consider and set what makes a just and reasonable rate is very broad and allows significant flexibility. The obligation to ensure that rates are always just and reasonable does not mean that the Board must examine and adjust a utility's rates on a constant basis. Most utility's rates are set on a forecast basis, for example, and invariably these forecasts turn out to be inaccurate to some extent. Absent extraordinary circumstances, the Board does not intervene to adjust rates simply because actual costs or revenues are different from what was forecast -- even though the Board has the power to do so. In other words, there is a measure of "wiggle room" in a just and reasonable rate. Just and reasonable rates can fall within a range, and there is no defined line past which rates immediately become "unreasonable". Indeed, under incentive regulation rates are deliberately de-coupled from a utility's actual costs. The Board therefore does not agree with OPG's argument that the requirement to ensure just and reasonable rates at all times leads to an automatic requirement to match the effective date with the date interim rates were set.

Effective date for the Nuclear and Previously Regulated Hydroelectric Payment Amounts

566 The Board has determined that the effective date for the payment amounts for the nuclear and previously regulated hydroelectric facilities will be November 1, 2014. The Board is not prepared to accept the January 1, 2014 effective date proposed by OPG as it is contrary to the Board's long-standing practice of setting rates on a forecast (i.e. forward test year) basis.

567 The Board's general practice with respect to the effective date of its orders is that the final rate becomes effective at the conclusion of the proceeding. This practice is predicated on a forecast test year which establishes rates going forward, not retrospectively. Going forward, the utility knows how much money it has available to spend and the ratepayer knows how much it is going to cost to use electricity in order to make consumption decisions. The forecast test year enables both the utility and the ratepayer to make informed decisions based on approved rates. The forecast test year is a pillar in rate setting and the Board's practice must be respected.

568 The Board must control its regulatory process. The Board hears a large number of cases throughout the year and must plan its resources accordingly to ensure cases are completed and decisions are rendered. In cases where utilities have not filed their applications in time to have rates in place prior to the effective date, the Board's practice has typically been to not allow the utility to retrospectively recover the amounts from the period where the interim order was in effect.[124] All applicants are aware of the Board's metrics. The process for an oral hearing is expected to take 235 days from the filing of the application to the issuance of the final decision, and 280 days until the issuance of the rate order.

569 OPG understood the timelines associated with filing a cost of service application and its witnesses confirmed that it was unlikely that the Board could have completed the process by January 1, 2014 given a September 27, 2013 filing date.[125] Even if a complete application had been filed in September, there was no scenario under which the proceeding could have been completed by January 1, 2014. OPG's proposal would result in the entire two-year increase for the previously regulated assets being recovered over a significantly shorter time period, resulting in a higher monthly bill impact increases exceeding the $5.36 and $5.94 identified in the two published Notices of Application. OPG estimated the impact of establishing effective dates of January 1, 2014 for the previously regulated assets and July 1, 2014 for the newly regulated assets was $649M or 43% over current payment amounts,[126] assuming an implementation date of September 1, 2014. A September 1, 2014 implementation date was used to calculate the magnitude of the increase during the oral phase of the proceeding; a November implementation date, assuming OPG's proposed payment amounts, would result in a percentage increase higher than 43%.

570 Ratepayers who made consumption decisions from January 1, 2014 to November 1, 2014, who thought they had already paid their electricity bills may be surprised to learn they will be responsible for additional costs, recovered through higher rates to be included on future bills until December 31, 2015. In addition, a January 1, 2014 effective date would result in some level of inter-generational inequity, to the extent customer profiles changed over that time.

571 The Board finds that the reasons this proceeding could not be completed by January 1, 2014 were almost entirely within OPG's control. OPG's witnesses indicated the earliest date the application would have been ready to file was August 2013. OPG's management made the decision to delay the filing further to include the newly prescribed hydroelectric assets. OPG indicated that it would not be practical or workable to file one application regarding the previously regulated assets first and then file a second application or update for the newly regulated assets at a later date. OPG's management had choices and made decisions regarding the timing, inclusion and exclusion of evidence. For example, OPG indicated its plans to file a separate application for disposition of deferral and variance account balances as of December 31, 2014;[127] an application the Board has yet to receive. In addition, OPG understands that options are available to separate issues in distinct applications for significant issues to expedite the hearing process. In fact, OPG asked the Board to consider a stand-alone Niagara Tunnel Project hearing. The Board responded to OPG's request in a letter dated April 13, 2012 and agreed that given the scale and complexity of the Niagara Tunnel Project, it was appropriate to consider a separate 2013-2014 payment amounts application. In the end, OPG decided not file a separate Niagara Tunnel application nor a payment amount application for 2013 rates.

572 When OPG filed its application on September 27, 2013, it was incomplete. A complete application was filed on December 5, 2013, less than one month before its proposed effective date.

573 The Board decided to issue a notice for the proceeding on October 25, 2013 based on the incomplete application in order to avoid further delay; however, the Board stated: "[t]he timing of any further procedural steps will be dependent on OPG's response to the items noted in this correspondence."

574 On December 6, 2013, one day after filing the complete application on December 5, 2013, OPG filed a major update to its application which required the issuance of a new notice, and essentially brought the proceeding back to step 1. New information continued to be filed, including updated evidence on the Darlington refurbishment project filed on July 2, 2014 which necessitated a delay of the oral hearing by several weeks.

575 The Board's decision is based on a balancing of the interests of the applicant and of the ratepayer. The timing of the application is solely in OPG's control, and the Board's metrics and policies regarding effective dates are well known. For the reasons provided above, the Board approves an effective date of November 1, 2014 for the previously regulated assets.

Effective Date for Newly Regulated Hydroelectric Payment Amounts

576 The Board has determined that the effective date for the final payment amounts shall be November 1, 2014 for the newly regulated hydroelectric facilities. As mandated by *O. Reg. 53/05*, the Board's regulation of the payment amounts for the newly regulated hydroelectric facilities commenced on July 1, 2014. From July 1, 2014 through October 31, 2014 the Board has determined that the payment amounts for the newly regulated hydroelectric facilities will remain HOEP, which is the amount that OPG actually recovered over that time period pursuant to the Board's interim rate order.

577 The Board accepts the arguments of the parties that argued that the Board is not legally required to set July 1, 2014 as the effective date for the final payment amounts applicable to the newly hydroelectric regulated facilities. *O. Reg. 53/05* requires the Board to commence its payment regulation of the newly regulated hydroelectric facilities as of July 1, 2014; it does not require the Board to set the payment amounts at any particular level. In fact the regulation appears to contemplate that the effective date of the final payment order may well come after July 1, 2014: "[t]he order shall provide for the payment of amounts with respect to output that is generated at a generation facility referred to in paragraph 6 of section 2 [i.e. the newly regulated facilities] **during the period from July 1, 2014 to the day before the effective date of the order**."

578 The Board has determined that it is not legally required to set the effective date of the final order for the newly regulated hydroelectric facilities to July 1, 2014. The Board has decided that it would be inappropriate to do so. The Board orders that the effective date for the final payment order for the newly regulated hydroelectric facilities will be November 1, 2014.

579 OPG takes the position that given the September 2013 notice of the proposed amendment to *O. Reg. 53/05* to regulate the newly regulated hydroelectric facilities, OPG could not have filed the application for the associated payment amounts any earlier than it did. OPG argues that it was dependent upon the Ministry's release of the proposal to amend the regulation in order to proceed with the application.

580 The draft regulation was published for comment in July 2013. The notice of the proposed amended regulation was made public in September 2013 and the regulation was filed in November 2013. The Board considers that an application could have been filed shortly after the draft regulation was published for comment (i.e. after July 2013). Indeed OPG did not wait for the regulation to be finalized before filing its original application.

581 It appears to the Board that OPG had various options available to it as to when it could have filed its application. In fact, the inclusion in the application of the newly regulated hydroelectric facilities was an issue of little controversy in this proceeding. One of the options it could have considered was to file the newly regulated hydroelectric portion of the application as an update to the payment amounts case which could have been filed earlier. Instead, OPG waited for the regulation to be issued as a draft before filing the entire payments amounts application. Other options were available as well, all of which could have resulted in finalized payment amounts at an earlier point in time. The Board has based its decision on the regulatory principle that rates should be set on a forward test year basis. The Board reiterates its reasons outlined in respect of the effective date for the nuclear and previously regulated hydroelectric payment amounts. The Board's position is that rates should be based on a forecast test year which establishes rates on a go forward basis, not retrospectively. This allows ratepayers to make informed consumption choices and provides utilities with certainty regarding revenue on a go-forward basis. OPG's evidence regarding when it could have filed its application is not so compelling as to move the Board off its practice of making rates effective in the month following the Board's final decision.

582 In the previous cost of service proceeding, the decision was issued on March 10, 2011 and the effective date was March 1, 2011. The IESO was able to implement the effective date through its billing processes without the necessity for shortfall payment amount riders to cover the period between March 1, 2011 and the date of the final payment amounts order. The Board expects that the same process can be accommodated in the current proceeding with a November 1, 2014 implementation for both the previously regulated and newly regulated assets.

583 The Board directs OPG to file with the Board, and copy to all intervenors, a draft payment amounts order which will include the final revenue requirement and payment amounts for the regulated hydroelectric and nuclear facilities, and reflect the findings made by the Board in this Decision. OPG should also include supporting schedules and a clear explanation of all calculations and assumptions used in deriving the payment amounts and the payment riders. The draft payment amounts order shall be filed by December 1, 2014.

584 OPG is directed to provide a full description of each deferral and variance account as part of the draft payment amounts order.

585 Board staff and intervenors shall respond to OPG's draft payment order by December 8, 2014. OPG shall respond to any comments by Board staff and intervenors by December 12, 2014.

12 COST AWARDS

586 A number of intervenors were deemed eligible for cost awards in this proceeding: Association of Major Power Consumers in Ontario, Canadian Manufacturers & Exporters, Consumers Council of Canada, Energy Probe Research Foundation, Environmental Defence, Green Energy Coalition, Haudenosaunee Development Institute, Lake Ontario Waterkeeper, London Property Management Association, Retail Council of Canada, School Energy Coalition, Sustainability Journal and Vulnerable Energy Consumers Coalition.

587 At the oral hearing on June 12, 2014, the Board set out the process for intervenors to file their cost claims for the period ending June 11, 2014 for interim disposition. The cost award decision was issued on July 24, 2014.

588 A cost award decision for the period starting June 12, 2014 will be issued after the steps set out below are completed.

1. Intervenors eligible for cost awards shall file with the Board and forward to OPG their respective cost claims by December 15, 2014.
2. OPG shall file with the Board and forward to the relevant intervenors any objections to the costs claimed, including any objections to cost claims filed prior to the issuance of this Decision, by December 23, 2014.
3. Intervenors whose costs have been objected to, may file with the Board and forward to OPG any response to the objection by January 7, 2015.

589 OPG shall pay the Board's costs of and incidental to this proceeding upon receipt of the Board's invoice.

DATED at Toronto, November 20, 2014

ONTARIO ENERGY BOARD

Original signed by

Marika Hare
Presiding Member

Original signed by

Christine Long
Member

Original signed by

Allison Duff
Member

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1 Annual Report of the Auditor General of Ontario, Chapter 3.05 OPG Human Resources, December 10, 2013 (Exh KT2.4)

2 The EB-2010-0008 decision was appealed by OPG. The appeal was dismissed at the Divisional Court. OPG was successful before the Ontario Court of Appeal. The Court of Appeal's decision has now been appealed to the Supreme Court of Canada, and that appeal is expected to be heard in December 2014.

3 One terawatt-hour = 1,000,000 megawatt-hours

4 Undertaking J4.7

5 Exh L-5.4-SEC-73

6 Tr Vol 4 page 3

7 Undertaking J3.13

8 Argument-in-Chief page 23

9 The $24M difference is comprised of amounts added to rate base prior to 2008 and an amount attributed to OM&A.

10 The other common approach is design-bid-build, whereby OPG would hire a firm to design the tunnel, issue a request for proposal on the basis of the design, and then select a firm to construct it.

11 Exh D1-2-1 Attachment 6, Design Build Agreement, sections 5.5-5.7.

12 Exh D1-2-1 page 72

13 Exh D1-2-1 Attachment 7 page 18

14 Exh F5-6-1

15 Tr Vol 2 page 53

16 Exh D1-2-1 Attachment 7 page 18

17 Reply Argument page 52

18 Tr Vol 1 page 80

19 Reply Argument page 39

20 Exh D1-2-1 Attachment 7 pages 18-19

21 Tr Vol 2 page 124

22 Exh L-4.5-SEC-41 Attachment 16

23 Tr Vol 2 page 149

24 Exh D1-2-1 page 106

25 $40M -- (20% x $77.4M)

26 $24.5M x 5.25% x 33/12 months

27 Exh D1-2-1 page 37

28 Indemnity Agreement -- Appendix 4.1(e) to the Design Build Agreement.

29 Tr Vol 2 pages 122-123

30 Exh D1-2-1 Attachment 9 - $40M schedule and cost performance incentive, $10M interim completion fee, and $10M substantial completion fee

31 Argument-in-Chief page 63

32 Argument in Chief page 63

33 Appendix C of this Decision

34 Reply Argument page 139

35 Undertaking J5.2

36 Tr Vol 6 pages 119-120

37 Exh F2-1-1 Attachment 1

38 Reply Argument page 134

39 Tr Vol 6 page 13

40 Exh F5-2-1

41 Exh F2-2-3 Attachment 1

42 Exh KT2.2 page 30

43 Decision with Reasons, EB-2010-0008, page 59

44 Exh D2-2-1 Attachment 5 page 27

45 Exh D2-2-2 page 6 Table 1

46 Decision and Order on Issues List and Procedural Order No. 3, February 19, 2014, page 10, "...the examination of cost effectiveness of capital expenditure in the test period is within scope in this proceeding. Parties are reminded that the Board's jurisdiction is the setting of payment amounts and not the management of OPG's activities or the selection of generation options."

47 Exh D2-2-1 Attachment 7

48 Tr Vol 13 pages 148-149

49 Tr Vol 15 page 56

50 Reply Argument page 107

51 Tr Vol 16 page 5

52 Tr Vol 16 page 4 (all subject to available contract options in the market place)

53 Exh G2-1-2

54 Argument-in-Chief page 122

55 Argument-in-Chief page 4

56 Exh F4-3-1 Attachment 1

57 Decision with Reasons, EB-2010-0008, page 85

58 Exh A4-1-1

59 Tr Vol 8 page 40 - MS. LADAK: Yes, in terms of total compensation, wages are going down as a result of headcount reductions. But as a result of pension increases, due to, largely, discount rate changes, total compensation is going up.

60 News Release, Office of the Auditor General of Ontario, December 10, 2013

61 Exh KT2.4, Annual Report of the Auditor General, page 153

62 Exh F5-1-1

63 Exh F5-1-1 page 16

64 Exh KT2.4, Annual Report of the Auditor General, page 159

65 Tr Vol 8 pages 106-107

66 Undertakings J9.1 and J9.2

67 Exh KT2.4, Annual Report of the Auditor General, page 159

68 Undertaking J9.7 Attachment 1

69 Tr Vol 8 page 46

70 Tr Vol 8 pages 73-75.

71 Undertaking J9.11 - This analysis appears to relate to Group 1, as opposed to Group 2. However, the Group 1 and Group 2 placement of the PWU are very similar (20.5% above median for Group 1 and 19.2% above median for Group 2.

72 Tr Vol 8 page 156.

73 Tr Vol 8 pages 54-56

74 Exh F4-3-1 Attachment 1

75 Tr Vol 8 pages 59-60

76 When questioned on this topic, OPG responded by undertaking that the correct number was now 972, not 1,200, and that if those 972 employees (who had higher salary on account of grandfathering) were limited by the maximums in the current salary bands the impact would result in annual savings of $5.6M -- Undertaking J8.1.

77 Tr Vol 8 pages 81-85

78 Exh F5-4-1 pages 32-36

79 The 3:1 figure excludes special payments. If special payments are included the ratio is higher than 4:1.

80 Exh KT2.4, Annual Report of the Auditor General, page 166

81 Exh L-6.8-Staff-121

82 Undertaking JT2.12 Towers Watson CHRC Briefing, December 14, 2011

83 Tr Vol 8 page 155

84 Exh L-6.8-SEC-106, Attachment 1 pages 20-26, 31-32

85 Tr Vol 8 page 156

86 Tr Vol 8 pages 161-162

87 Tr Vol 8 pages 121-123

88 Exh KT2.4, Annual Report of the Auditor General, pages 174-175.

89 For example, the Government of Ontario report released on August 1, 2014, *Report on the Sustainability of Electricity Sector Pension Plans* indicates that a reasonable phase-in period for achieving a pension contribution ratio of 1:1 would be 5 years.

90 Tr Vol 3 pages 68-69, 134

91 Sum of 2014 and 2015 for lines 3 and 6 of Table 21

92 Exh K13.2, FERC PL63-1-000, Post-Employment Benefits Other Than Pensions, Statement of Policy, December 17, 1992

93 Undertaking J9.6 states that the 2015 pension requirement on a cash basis is $329.6M. Correcting the 2015 pension requirement on a cash basis in Chart 1 of undertaking J13.7 results in a, accrual vs cash difference of $457.1M.

94 Undertaking J9.6

95 Tr Vol 13 page 134

96 After adjusting the cash contribution number in 2015 to the amount shown in J9.6 of $329.6M.

97 Technical Conference Tr April 23, 2014, page 138

98 Exh F4-1-1 Attachment 1

99 Exh F5-1-3

100 Exh L-6.12-Staff-160(e)

101 Accounting for Public Utilities, by Robert Hachne and Gregory Aliff, Part V, Chapter 7, September 17, 2005

102 2006 Electricity Distribution Handbook, May 11, 2005, page 61

103 SEC Final Argument page 72

104 A requirement to identify any loss carry-forwards and when they will be fully utilized has been included in the Board's Filing Requirements for electricity distributors' cost of service applications since 2012. With the issuance of the 2012 Filing Requirements (for 2013 rates), the Board included any remaining relevant sections of both the 2000 and 2006 Electricity Rate Handbooks.

105 Decision with Reasons, EB-2007-0905, pages 169-170

106 Decision and Order, EB-2007-0744, Great Lakes Power, pages 40-41

107 Decision and Order, EB-2008-0322, *2008 LNONOEB 102*, Hydro One Remote Communities, page 10, Decision and Order, West Perth Power and Clinton Power Corporation, EB-2009-0262/EB2010-0121, *2011 LNONOEB 35* page 22

108 Reply Argument page 203

109 Exh L-3.1-SEC-24 Attachment 1

110 Application is dated September 27th, 2013 while contract commencement date is September 30th, 2013. (Undertaking J10.2)

111 Decision with Reasons, EB-2010-0008, page 116

112 Tr Vol 10 page 30

113 Undertaking J12.3

114 Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, July 14, 2008

115 Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 18, 2012

116 Exh L-3.1-SEC-24, Attachment 1 page 23, Tr Vol 10 page 30

117 Decision with Reasons, EB-2007-0905, pages 137-142

118 Payment Amounts Order, EB-2012-0002, April 13, 2013

119 Board Report -- A Regulatory Methodology for Setting Payment Amounts for the Prescribed Generation Assets of Ontario Power Generation Inc., EB-2006-0064, November 30, 2006

120 Society Submission page 11

121 Argument-in-Chief, page 146.

122 Bell, page 1752 (emphasis added)

123 Interim Payment Amounts Order, December 17, 2013

124 EB-2012-0165, *2013 LNONOEB 39* (Sioux Lookout); EB-2013-0139, *2014 LNONOEB 47* (Hydro Hawkesbury); EB-2012-0113, *2013 LNONOEB 40*, Centre Wellington; EB-2013-0130, *2014 LNONOEB 28* Fort Frances

125 Tr Vol 2 page 171

126 Undertaking J3.10

127 Exh H1-1-1 page 1

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