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BY E-MAIL

August 19, 2014

Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, Suite 2700
Toronto ON M4P 1E4

Dear Ms. Walli:

Re: Ontario Power Generation Inc.
Board File No. EB-2013-0321

Please find attached the Board staff submission for Ontario Power Generation Inc.'s application for 2014-2015 payment amounts.

Yours truly,

Original signed by

Violet Binette
Project Advisor, Applications

Attach

ONTARIO POWER GENERATION INC.
2014-2015 PAYMENT AMOUNTS

EB-2013-0321

Board Staff Submission

August 19, 2014

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1. INTRODUCTION

Ontario Power Generation Inc. ("OPG") filed an application, dated September 27, 2013, with the Ontario Energy Board under section 78.1 of the *Ontario Energy Board Act,1998,* S.O. 1998, c.15, Schedule B (the "Act") seeking approval for increases in payment amounts for the output of its nuclear generating facilities and the currently regulated hydroelectric generating facilities, to be effective January 1, 2014. The application also seeks approval for payment amounts for newly regulated hydroelectric generating facilities, to be effective July 1, 2014.

The application was updated on December 6, 2013 (Exh N1-1-1 – first impact statement) and May 16, 2014 (Exh N2-1-1 – second impact statement). Additional evidence (Exh D2-2-2) relating to the Darlington Refurbishment Project ("DRP") was filed on July 2, 2014.

As of May 16, 2014, OPG is seeking approval of a revenue requirement of $9.0 billion. The major components of the test period revenue requirement are shown in the table below.

Table 1

	Previously Regulated Hydroelectric		Newly Regulated Hydroelectric		Nuclear	
$million	**2014**	**2015**	**2014**	**2015**	**2014**	**2015**
Return on Capital	356.2	358.5	87.2	178.3	235.6	236.0
Expenses	494.7	503.0	186.5	378.0	2,957.5	2,985.2
Other Revenue	-34.0	-34.6	-11.4	-23.1	-72.9	-71.1
Income Tax	49.7	64.2	14.95	42.7	108.3	16.8
Revenue Requirement	866.6	891.1	277.3	575.9	3,228.5	3,166.9
Disposition of Deferral and Variance Accounts		70.6				62.2
Source: Exh N2-1-1						

The as filed total production for the test period was 161.8 TWh. The Exh N1-1-1 and Exh N2-1-1 impact statements reduced production to 160.5 TWh.

OPG indicated in its published Notice of Application that the application, as filed on September 27, 2013, would result in an increase of $5.36 on the monthly total bill for a typical residential customer consuming 800 kWh per month. As the bill impact resulting from the Exh N1-1-1 update was determined to be $5.94, the Board determined that further notice was required. The bill impact of the Exh N2-1-1 update has been determined to be $5.31. Based on its calculations, OPG is seeking an increase of 23.4% on payment amounts.[1]

In response to the Notices, the Board received 41 Letters of Comment from individuals across Ontario expressing concern about various matters related to the application. Twenty parties applied for, and were granted, intervenor status.

The draft issues list for this proceeding was set out in Procedural Order No. 1, issued on December 20, 2013. The issues were categorized as oral hearing, primary and secondary by submissions of parties to the proceeding. The final list was issued on June 4, 2014 in Procedural Order No.10. As no settlement was reached, all primary issues could be addressed by parties in oral hearing.

The oral hearing for this proceeding commenced on June 12, 2014 and ended on July 18, 2014. There were sixteen hearing days in total. OPG filed its Argument-in-Chief ("AIC") on July 28, 2014.

This submission reflects observations and concerns which arise from Board staff's review of the oral and written evidence, and is intended to assist the Board in evaluating OPG's application and in setting just and reasonable payment amounts. Not all issues on the Issues List are addressed in this submission. Only those issues which, in Board staff's opinion, require comment or analysis are addressed.

The following table will assist with the review of the submission. The revenue requirement impacts are estimates and have been estimated in isolation of other impacts. Where possible, Board staff has reflected the July 1, 2014 effective date for the newly regulated hydroelectric facilities. Based on these estimates, the Board staff submission proposes a revenue requirement reduction of 4%, excluding any mitigation proposals.

[1] Argument-in-Chief page 2

Table 2

Section	Issue/Item	$million	
		2014	2015
3.1	Equity thickness of 46% (Equity thickness of 45% would reduce test period revenue requirement by $28M)	6.5	7.7
4.2	Previously regulated hydroelectric rate base reductions ($18M each year)	0.9	2.7
4.3.3	Niagara Tunnel Project ($105M)	10.5	10.5
4.5	Nuclear rate base reductions ($18M in 2014 and $17M in 2015)	0.9	2.7
5.3.4	HIM revenue offset	22.0	37.0
5.4.5	Nuclear Fuel increase for 1.4 TWh		-5.3
6.1	Hydroelectric OM&A	22.4	35.4
6.7.6	Nuclear OM&A	50.0	50.0
6.10.2	Niagara Tunnel Depreciation at 135 years	5.5	5.5
6.11	2013 Operating Loss applied against 2014 PILs	70.0	
7.2	Nuclear Other Revenue	4.5	7.1
	Sub-Total	193.2	153.3
6.8.3	Pension and OPEBs - Cash Basis	327.5	256.9
10.2	Phase in of Newly Regulated Payment Amounts	16.1	36.6

2. ACCOUNTING REQUIREMENTS

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

In the USGAAP and Deferral and Variance Account proceeding, EB-2012-0002, the Board approved a settlement proposal in which the parties agreed that OPG's adoption of USGAAP for regulatory accounting, reporting and rate-making purposes effective January 1, 2012 was appropriate.

As noted in OPG's 2013 financial statements, "In the first quarter of 2014, the OSC approved an exemption which allows OPG to apply USGAAP up to January 1, 2019."[2] That exemption replaces the previous exemption which was limited to the period before January 1, 2015.

Board staff does not have specific submissions related to USGAAP, but does have a submission on changes to regulatory accounting policies and procedures.

OPG in several instances has made changes to its regulatory accounting during the period outside of its payment applications. These include changes to depreciation expense (via changes in the useful lives of assets) and changes in the treatment of gains and losses on retirement of assets.

When a regulatory accounting change occurs outside of a rebasing, i.e. cost of service, application, it may materially change the revenue requirement underpinning the already established rates. These changes have direct financial impacts on the underlying valuation of the rate base (e.g., NBV of assets arising from changes in assets useful lives) and expenses (e.g., depreciation expense also arising from changes in assets useful lives). These impact the cost of capital in relation to the "return on asset" on the NBV, and the depreciation expense in relation to the "return of asset". The regulatory accounting basis upon which rates were approved by the regulator should not be altered without Board approval.

By way of an example, effective on December 31, 2012, OPG extended the end of service life (useful life) dates and reduced the associated depreciation expense for the Pickering nuclear generating station. The result of this change was a decrease of $47M per year in the depreciation expenses, an amount which was not reflected in the revenue requirement in its last payment proceeding EB-2010-0008.

As part of the EB-2012-0002 proceeding, the revised useful life of Pickering was examined. The settlement agreement and final payment order established the Pickering Life Extension Depreciation Variance Account to record a credit amount of $47M per year from January 1, 2013 until the effective date of new nuclear payment amounts. In the absence of the EB-2012-0002 proceeding ratepayers would have overpaid by $47M in rates.

[2] Exh L-2.1-ED-3 Attachment 1

Board staff submits that the Board should direct OPG to first seek Board approval for regulatory accounting changes through a request for approval of an accounting order, which outlines the nature of the changes, the accounting and the revenue requirement impacts, and if applicable, considerations for requesting the approval of a deferral or variance account(s) in which to capture the impact of the changes to revenue requirement underlying the payment amounts. Staff submits accounting changes, whether arising from a single or multiple transactions, resulting in revenue requirement impacts of $20.0M or more should be addressed by this requirement.

Board staff notes that the payment order for the USGAAP and Deferral and Variance Account proceeding, EB-2012-0002 has a similar provision for nuclear liability accounting changes.

3. CAPITAL STRUCTURE AND COST OF CAPITAL

Issue 3.1 (Primary) - What is the appropriate capital structure and rate of return on equity for the currently regulated facilities and newly regulated facilities?
Issue 3.2 (Secondary) - Are OPG's proposed costs for its long-term and short-term debt components of its capital structure appropriate?

OPG has proposed a cost of capital consistent with the approaches approved by the Board in the previous payments applications EB-2007-0905 and EB-2010-0008.

In its application filed on September 27, 2013, OPG proposed the following for its cost of capital for the test period:

Table 3

	2014		2015	
	Deemed Capital Structure	Rate	Deemed Capital Structure	Rate
Long-term Debt	51.1%	4.85%	51.1%	4.86%
Short-term Debt	1.9%	1.87%	1.9%	2.89%
Equity	47.0%	8.98%	47.0%	8.98%
Cost of Capital for Rate Base funded by Capital Structure	100% (87.8% of Total Rate Base)	6.77%	100% (88.4% of Total Rate Base)	6.79%
Adjustment for lesser of unfunded nuclear liabilities or asset retirement costs	12.2% of Total Rate Base	5.37%	11.6% of Total Rate Base	5.37%
Total Rate Base	100.0%	6.60%	100.0%	6.63%

Source: Exh C1-1-1 Table 1 and 2

In its second update filed in May 2014, OPG updated the ROE to 9.36% for 2014, which is the allowed ROE based on the Board's formula and applicable for 2014 Cost of Service applications. OPG updated the ROE to 9.53% for 2015, which is an estimate based on the Board's ROE formula but using data for 2015 from Global Insights for September 2013. OPG has used Global Insights given that Consensus Forecasts (the data source used by the Board) does not have forecasts beyond a one year horizon.

3.1 Capital Structure

OPG is proposing to maintain the existing deemed capital structure of 53% debt and 47% equity (for the rate base funded by the capital structure, excluding the Adjustment for the lesser on UNL or ARC for nuclear decommissioning costs), as previously approved by the Board. This proposal to maintain the deemed capital structure previously approved by the Board is unaltered by the inclusion of the newly regulated hydroelectric generating facilities to the regulated assets, and the increased capital additions and expenditures for the currently prescribed assets, including the Niagara Tunnel.

In response to Exh L-3.1-Staff-14, OPG explained that it views the newly regulated hydroelectric facilities as being more risky than the previously regulated facilities but less risky than the existing regulated nuclear facilities. In addition, in response to Exh L-3.1-17 SEC-024, OPG filed a study by Kathleen McShane of Foster Associates, Inc. on

"Report to Ontario Power Generation: Common Equity Ratio for OPG's Regulated Generation" dated December 2013. Ms. McShane's conclusion was that, "[b]ased on the analysis conducted, OPG's deemed common equity should, at a minimum, remain at 47%". The report included an analysis of business risk faced by OPG and a summary of the reasons why the newly regulated hydroelectric facilities are subject to relatively higher operating risk than the previously regulated hydroelectric facilities.

SEC, in its cross examination of Ms. McShane,[3] challenged the view that the newly regulated hydroelectric facilities are more risky than the previously regulated facilities. For example, SEC noted that there are greater water constraints on the Niagara River (related to international agreements) than there are on the Abitibi River, and that the newly regulated facilities have more storage capability than the previously regulated facilities.

SEC notes that the Board's general policy is that if business risk changes, the equity ratio should change. In SEC's view, adding 3,000 MW of hydroelectric capacity is a significant change in business risk and SEC has suggested that the deemed equity ratio be lowered from 47% to 45%, on the basis of applying the "methodology" advanced by Drs. Kryzanowski and Roberts in the EB-2007-0905 proceeding. The rationale for this is that Drs. Kryzanowski and Roberts' proposal assumed a 50% equity thickness for nuclear and 40% equity thickness for hydroelectric, reflecting different business risks faced by these business units.[4] SEC's contention is that, in the 2014-2015 test period, the relative weights of hydroelectric and nuclear capacity are changed. With the hydroelectric and nuclear capacities in megawatts approximately equal, a weighted average of the 50% equity thickness for nuclear and 40% equity thickness for hydroelectric would be about 45%.

Board staff notes that Drs. Kryzanowski and Roberts also advanced evidence and testified in the EB-2010-0008 regarding setting technology specific cost of capital. Initially, they proposed equity thicknesses and weighting based on nuclear and hydroelectric generating capacities as had been done in their EB-2007-0905 evidence, but later proposed equity thicknesses of 43% for hydroelectric and 53% for nuclear, and

[3] Oral Hearing Tr Vol 10, page 106

[4] Such as the greater risk of cost overruns or additional regulatory risk due to nuclear safety and operational oversight for nuclear generation, relative to that of major hydroelectric generators such as the Niagara Group and Saunders GS.

technology weightings based on asset net book values as a better basis to determine differential capital structure. Combined, their updated weighted estimate was for a 47% equity thickness for OPG's combined nuclear and hydroelectric prescribed assets.[5]

Based on OPG's proposed rate base for 2014, and equity thicknesses of 43% for both previously and newly regulated hydroelectric and 53% for nuclear, Board staff has estimated a 46% equity thickness based on this "method".

The Board's current policy with regard to capital structure for all regulated utilities is that capital structure should be reviewed only when there is a significant change in financial, business or corporate fundamentals.[6] Board staff agrees that there has been a significant change to the regulated business with the regulation of the newly regulated hydroelectric facilities effective on July 1, 2014. However, Board staff observes that there is no expert evidence on the risk related to the newly regulated hydroelectric facilities except for OPG's. Board staff also notes that the previous decisions have accepted the 47% equity thickness, but not specifically the methodology that Drs. Kryzanowski and Roberts applied. Should the Board agree with that methodology, and with SEC that the newly regulated hydroelectric facilities have the same risk as the previously regulated hydroelectric facilities, an equity thickness of 45% or 46% for the regulated business is reasonable. The impact on test period revenue requirement would be approximately $28M or $14M respectively.

3.2 Long-term and Short-term Debt

OPG's proposals for long- and short-term debt are documented in Exh C1-1-1, C1-1-2 and C1-1-3 of its application. As OPG has noted in its AIC, these were not updated from the original filing on September 27, 2013.

The short-term debt is comprised of a commercial paper program and an accounts receivable securitization program.

OPG's long-term debt outstanding consists of corporate debt held by OEFC and project related debt held by OEFC and the external market. The regulated business is

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[5] Pollution Probe's Written Submissions, EB-2010-0008, December 6, 2010, page 10. The Board also expressed its concerns about robustness of the results from the heuristic approach of Drs. Kryzanowski and Roberts in its EB-2010-0008 Decision, page 117.

[6] Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084), page 49

assigned an allocation of the corporate debt. That allocation is proposed to change in 2014 with the newly regulated hydroelectric facilities. The only project specific debt is related to the Niagara Tunnel Project, for which OPG has agreements with OEFC.

OPG's proposal for short-term debt and long-term debt is consistent with the approaches proposed by OPG and approved by the Board in the previous payments cases EB-2007-0905 and EB-2010-0008.

Board staff submits that the short-term and long-term debt rates are appropriate, but the final level of debt is subject to determination of the rate bases for the 2014 and 2015 test years.

3.3 Return on Equity

In its application filed on September 27, 2013, OPG proposed that the ROE for each of the test years 2014 and 2015 be updated based on data three months in advance of the effective date for the new payments for the 2014-2015 test period.[7] OPG's proposal is consistent with the approach approved by the Board in the previous payments cases (EB-2007-0905 and EB-2010-0008).

Subsequent to the filing of the application, the Board issued a letter on November 25, 2013 for Cost of Capital parameters to be effective January 1, 2014. In that letter, the Board stated:

> "As documented in the *Report of the Board on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors* (EB-2010-0379) issued November 21, 2013, the Board intends to update Cost of Capital parameters for setting rates in cost of service applications only once per year. For this reason, the Cost of Capital parameters above will be applicable for all cost of service applications with rates effective in the 2014 calendar year.
>
> The Board monitors macroeconomic conditions and may issue updated parameters if economic conditions materially change. An applicant or intervenors can also file evidence in support of different Cost of Capital parameters due to the specific circumstances in individual rate hearings, but must provide strong rationale for deviating from the Board's policy."

[7] Exh C1-1-1 page 2

Board staff questioned OPG about its proposal in light of this update of the Board's general policy issued subsequent to OPG's filing of the application on September 27, 2013.[8] In its response to that interrogatory and technical conference questions, OPG maintained its original proposal that the ROE be set based on data three months in advance of the effective date of the payments. As the data supporting the most recent cost of capital parameters is September 2013 and OPG seeks January 1, 2014 effective date for the previously regulated hydroelectric facilities and nuclear facilities, OPG sees no issue.

If the Board accepts the effective date for new payments for 2014 for nuclear and previously regulated hydroelectric on January 1, 2014 as proposed by OPG, Board staff submits that there is concurrence that the 2014 ROE of 9.36% set out in the letter on November 25, 2013, and a 2015 forecasted ROE, should apply.

The January 1, 2014 effective date for the nuclear and previously regulated hydroelectric facilities was examined by the parties and the Board panel in the oral hearing.[9] If the Board approves a later effective date, Board staff submits that the ROE set out in the letter on November 25, 2013 should apply for the payment amounts established for 2014.

Board staff notes that OPG, in the original Application, did not propose a different ROE for the newly regulated assets despite the effective dates of July 1, 2014. Board staff submits that the ROE set out in the letter on November 25, 2013 should apply for the payment amounts established for 2014.

As noted above, OPG has reflected an updated ROE of 9.53% for 2015 based on Global Insights. One possible option for consideration would be if the ROE for 2015 cost of service applications is available at the time of the payment amounts order. In this event, Board staff submits that updating the 2015 ROE based on more current data from Consensus Forecasts would be preferable, as it would reflect more recent data and the consensus of a number of firms, rather than relying on more dated estimates from a single firm, i.e. Global Insights.

[8] Exh L-3.1-Staff-15
[9] Oral Hearing Tr Vol 2 page 169 and Tr Vol 3 page 139

4. CAPITAL EXPENDITURE AND RATE BASE

4.1 Regulated Hydroelectric Capital Expenditure

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

OPG is forecasting hydroelectric capital expenditures of $127.5M and $138.2M for 2014 and 2015 respectively. A breakout of actual and forecasted capital expenditures is set out in Table 4. The table also includes the average annual expenditures, 2010-2013, as calculated by Board staff.

Table 4

Hydroelectric Capital Expenditures

(in millions)	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2013 Actual	2014 Proposed	2015 Proposed	average (2010-2013 actuals)
Niagara Plant Group	$ 28.5	$ 27.2	$ 27.1	$ 28.8	$ 20.9	$ 24.8	$ 34.3	$25.9
Saunders GS	$ 11.8	$ 8.1	$ 2.7	$ 5.0	$ 5.8	$ 9.7	$ 3.9	$7.1
Sub total	**$ 40.3**	**$ 35.3**	**$ 29.8**	**$ 33.8**	$27	**$ 34.5**	**$ 38.2**	$31.4
Newly Regulated								
Ottawa-St. Lawrence Plant Group	$48.4	$27.1	$41.0	$31.7	$28.6	$32.2	$39.0	$36.3
Central Hydro Plant Group	$4.8	$10.1	$8.8	$8.5	$4.8	$26.1	$33.2	$7.1
Northeast Plant Group	$6.4	$10.1	$21.6	$15.6	$12.8	$20.4	$19.5	$12.7
Northwest Plant Group	$9.0	$14.1	$8.7	$15.6	$14.3	$12.2	$8.3	$11.5
Newly Regulated Sub Total	**$68.6**	**$61.4**	**$80.1**	**$71.4**	**$60.5**	**$90.9**	**$100.0**	$68.4
Niagara Tunnel Project	$ 231.8	$ 265.5	$ 231.2	$ 122.9	$86.0	$ 2.0	$ -	$203.6
Total	$ 340.7	$ 362.2	$ 341.1	$ 228.1	$173.2	$ 127.4	$ 138.2	$304.3
Source: Exh D1-1-1 & Exh L Tab1.0 Sch 1 Staff 002 attachment 1 Table 8								

Except for the Ranney Falls project in the Central Hydro Plant Group of the newly regulated hydroelectric facilities, Board staff has no concerns with the proposed expenditures as these are in line with the portfolio approach used by the Hydro-Thermal Operations Unit.[10] As stated by OPG, "For newly regulated hydroelectric facilities, capital expenditures are consistent over the 2010-2013 period and remain in the $60M to $80M per year range, with an increase in 2014 due to the start of construction of the Ranney Falls GS Expansion Project."[11] With capital expenditures of $18.7M in 2014

[10] Exh F1-1-1 Appendix A

[11] Exh D1-1-1 page 1

and $19.2M in 2015,[12] the Ranney Falls project increases the level of capital expenditures for the newly regulated facilities over the historical average by about 55%.

When questioned at the Technical Conference about project particulars, OPG indicated that the current project timetable (as compared to the dates indicated in the original Business Case Summary) was delayed by one year because of the Federal Waterway agreements yet to be concluded. OPG also indicated that it had originally contemplated Ranney Falls to be a FIT program project with an expected revenue stream of 13.3 cents per kWh but that this was no longer the case and that it was working to make the project more economic.[13] Given this level of uncertainty Board staff does not view it reasonable to include the project in the capital expenditure budget for the test period.

Board staff submits that the portfolio approach based capital expenditure budget remain at historical levels since the viability of the Ranney Falls project is undetermined. This conclusion is consistent with the Board's approach as demonstrated in EB-2005-0001, EB-2005-0437 page 9 (February 6, 2007) where the Board found that, "If spending well in excess of historical norms is proposed, the Board must assess whether the increase is justified through the presentation of evidence regarding the Company's analysis, prioritization and judgment regarding budget components".[14] OPG has not provided a sound reason to increase the level of capital expenditures beyond historical levels. This would reduce the hydroelectric capital expenditure budget by $19M in each of 2014 and 2015. Board staff notes that this will not impact the proposed rate base since the planned in-service date for Ranney Falls is beyond 2015.

4.2 Regulated Hydroelectric Rate Base

Issue 2.1 (Primary) - Are the amounts proposed for rate base appropriate?
Issue 4.1 (Secondary) - Do the costs associated with the regulated hydroelectric projects that are subject to section 6(2)4 of O. Reg. 53/05 and proposed for recovery (excluding the Niagara Tunnel Project), meet the requirements of that section?
Issue 4.3 (Secondary) - Are the proposed test period in-service additions for regulated hydroelectric projects (excluding the Niagara Tunnel Project) appropriate?

[12] Exh D1-1-2 Table 1 line 17
[13] Technical Conference April 22, 2014 Tr page 67-69
[14] OPG's Reply Argument EB-2010-0008 page 68

OPG is seeking approval for a hydroelectric rate base of $5,128.0M and $5,084.6M for the previously regulated hydroelectric facilities for the years 2014 and 2015, respectively and a rate base of $2,511.5M and $2,528.2M for the newly regulated hydroelectric facilities for the years 2014 and 2015, respectively. The components of the hydroelectric rate base are summarized in Table 5. Board staff's submission on the Niagara Tunnel Project, including its rate base, is under section 4.3 of this submission.

Table 5

HYDROELECTRIC RATE BASE

(in millions)	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2014 Proposed	2015 Proposed	2012 Board Approved
Niagara Plant Group	$2,452.5	$2,437.1	$2,422.0	$2,405.0	$2,391.4	$2,378.1	$2,474.3
Niagara Tunnel Project	$18.3	$18.1	$17.8	$1,143.6	$1,473.6	$1,457.7	$0.0
Saunders GS	$1,300.1	$1,294.4	$1,281.7	$1,260.5	$1,240.5	$1,226.4	$1,291.0
Working Capital/Material & Supplies	$27.1	$22.3	$22.5	$22.4	$22.4	$22.4	$22.1
Total Previuosly Regulated	$3,798.0	$3,771.9	$3,744.0	$4,831.5	$5,127.9	$5,084.6	$3,787.4
Newly Regulated Hydro	NA	NA	NA	NA	$2,502.6	$2,519.2	NA
Working Capital/Material & Supplies	NA	NA	NA	NA	$9.0	$9.0	NA
Total Newly Regulated	NA	NA	NA	NA	$2,512	$2,528.2	NA
TOTAL HYDROELECTRIC	**$3,798.0**	**$3,771.9**	**$3,744.0**	**$4,831.5**	**$7,639.5**	**$7,612.8**	**$3,787.4**

Source: Exh B2

OPG, at page 10 of its AIC, states that it is requesting approval of the rate base set out in Exhibit B of the pre-filed evidence and that these forecasts were not updated in either the first or second impact statements. At page 20 of the AIC, OPG sets out, as shown in Table 6, the proposed in-service additions (excluding) the Niagara Tunnel Project that underpin the proposed rate base.

Table 6

	2013	2014	2015
In-Service Additions ($M)			
Previously Regulated	$46.4	$23.3	$55.8
Newly Regulated	$73.5	$62.8	$95.8
TOTAL	**$119.9**	**$86.1**	**$151.6**

Board staff notes that the amounts for 2013 are not the amounts shown in the pre-filed evidence. It appears that said amounts may reflect 2013 actuals. The amounts in the pre-filed, subject to OPG's reply, are about $22M for previously regulated hydroelectric facilities and $51M for the newly regulated hydroelectric facilities for a total of $73M.

Board staff asks OPG to confirm the in-service amounts for 2013 that are reflected in the proposed rate base.

Board staff has prepared Table 7 which compares “planned in-service amounts” with the actual in-service amounts in each year.

Table 7

HYDROELECTRIC PROJECTS > $5M

	Planned in-service			
	EB-2010-0008			EB-2013-0321
	2010	2011	2012	2013
*Niagara Plant Group	$ 40.8	$ 14.9	$ 37.7	$ 25.4
Saunders GS	$ 13.1	$ 17.0	$ 5.2	$ -
Total	$ 53.9	$ 31.9	$ 42.9	$ 25.4
	Actual in-service			
	2010	2011	2012	2013
*Niagara Plant Group	$ -	$ 36.0	$ -	$ 24.8
Saunders GS	$ 11.5	$ 18.0	$ 8.7	$ 1.5
Total	$ 11.5	$ 54.0	$ 8.7	$ 26.3
	Over (Under) forecasted rate base			
	2010	2011	2012	2013
*Niagara Plant Group	$40.8	($21.1)	$37.7	$0.6
Saunders GS	$1.6	($1.0)	($3.5)	($1.5)
Total	$42.4	($22.1)	$34.2	($.9)

Source: Exh L-4.3-17 SEC 30
note: ( ) = underforecasted rate base
* excludes Niagara Tunnel Project

Table 7 indicates that for projects >$5M on average over the period 2010-2013 period, in-service amounts have been overstated by about $18M on an annual basis.

This is consistent with the pre-filed evidence which states that, “For Niagara Plant Group and R.H. Saunders GS in 2010, 2011 and 2012, the actual capital in-service amounts were lower in 2010 ($40.9M), higher for 2011 ($20.6M) and lower for 2012 ($36.0M) than the additions forecast in EB-2010-0008.”[15]

[15] Exh D1-2-1 page10

Given this recent history of overstating the project amounts that are forecast to close to rate base during the test period, Board staff submits that hydroelectric rate base should be recalculated reflecting a reduction of $13M for in-service amounts in each of 2014 and 2015. OPG has not provided any compelling evidence that demonstrates an improvement in its forecasting accuracy such that an overstated rate base for the test period will be avoided. Board staff notes that it has not questioned the in-service forecasts for the newly regulated facilities given that there is no regulated history to assess.

4.3 Niagara Tunnel Project ("NTP")

Issue 4.4 (Primary) - Do the costs associated with the Niagara Tunnel Project that are subject to section 6(2)4 of O. Reg. 53/05 and proposed for recovery, meet the requirements of that section?
Issue 4.5 (Primary) - Are the proposed test period in-service additions for the Niagara Tunnel Project reasonable?

4.3.1 Introduction

OPG seeks to increase its 2014 rate base by $1,452.8M in gross plant additions[16] for the NTP. The Niagara Tunnel was put into service in March 2013. The water flow provided by the Niagara Tunnel generates about 1.5 TWh annually at the Sir Adam Beck hydroelectric complex. The levelized unit energy cost ("LUEC") for this investment with a 90 year life is about 6.8 cents/kWh (2009$).[17] For the test period, the associated revenue requirement is $320.2M and this equates to a rate of 10.7 cents/kWh.[18]

OPG's Board of Directors approved the execution of this project and a $985M budget in July 2005. The supporting business case called for a Design-Build Agreement between OPG, the owner, and Strabag AG ("Strabag"), the contractor. The business case reflected a June 2010 in-service date, assumed 1.6 TWh in annual output and an economic life of 90 years.[19]

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[16] Exh L-4.5-Staff-25 Chart 1 row "Gross Plant Additions" column " Total 2005-2015"
[17] Exh D1-2-1 Attachment 8b page 7
[18] As calculated by Board staff…. $320.2M [source: Exh J3.4] / (1.5 TWh x 2)
[19] Exh D1-2-1 Attachment 5 (Niagara Tunnel Project Business Case Summary dated July 28, 2005)

In May 2009, OPG's Board of Directors approved a $615M increase to the project budget, an amended Design-Build Agreement with the contractor and an extension to the in-service date to December 2013. $458.1M of the increase related directly to the tunnel excavation activity carried out under the amended Design-Build Agreement with Strabag. These changes were primarily needed to ensure project completion given the difficulties encountered by the contractor in excavating the tunnel through the Queenston shale formation.[20]

As compared to the original budget and plan approved by OPG's Board of Directors in July 2005 and which gave the go-ahead for the project, the NTP is $491.4M or 50% overspent, the in-service date is about 32 months behind schedule and the annual additional output from waterflow at 1.5 TWh is 6% less than expected due to minor refinements in production forecast modeling.[21] As compared to the revised plan approved by OPG's Board of Directors in May 2009, the project is about $125M or 7.8% underspent, the in-service date is 9 months earlier and the annual output is 6% less than expected.

The Board must consider under Issue 4.4 is whether the NTP costs that OPG seeks to recover from ratepayers meet the requirements of Section 6(2)4 of O. Reg. 53/05. Under Section 6(2)4 of O. Reg. 53/05, the Board is to ensure the recovery of costs, if such costs are within project budgets which had been approved by OPG's Board of Directors prior to April 1, 2008 as set out below:.

> 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

[20] EB-2013-0321 Exh D1-2-1 page 113 and Attachments 8A & 8B (Niagara Tunnel Project Business Case Summary & Recommendation for Submission to the Board of Directors)
[21] Exh E1-1-1 page 3

> 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.

For costs that had not been approved by OPG's Board of Directors prior to April 1, 2008, recovery is contingent on the Board's determination that such costs were prudently incurred and financial commitments prudently made. Accordingly, an examination of prudence pertains to the NTP spending of $491.4M, which is the amount in excess of $985M.

Issue 4.5 asks whether the proposed test period in-service additions for the Niagara Tunnel Project are reasonable. Board staff's submissions on this issue are subsumed under the submissions for Issue 4.4.

4.3.2 Background

OPG awarded the Design-Build Agreement to Strabag in August 2005 and actual excavation started September 2006. The fixed price in the Design-Build Agreement was set at $623M, not including incentives. The cost estimate with incentives was $723.6M.[22]

The Design-Build Agreement included a Geotechnical Baseline Report which among other things set out the rock conditions the contractor was expected to encounter and which would have to be accommodated within the Design-Build cost estimate.[23]

The Design-Build Agreement also provided for non-binding dispute resolution (in the form of a Dispute Review Board) in the event certain defined issues between Strabag and OPG, arose and could not be resolved.

In April 2007 during tunnel excavation the contractor experienced rock fall in the Queenston shale formation which resulted in significant scheduling delays and

[22] Exh D1-2-1 page 38 & 113

[23] This was the third of three Geotechnical Baseline Reports (GBR-C). GBR-A was prepared in 2004 by Hatch Mott MacDonald on behalf of OPG and was included in the request for proposals; Strabag prepared their own GBR-B and this was used to negotiate the GBR-C which was the one included in the contract between OPG and Strabag (Source: summarized from Oral Hearing Tr Vol 2 page 38).

increased costs. Although some level of “overbreak” had been anticipated in the Design-Build Agreement, the amounts encountered were much greater than expected. The previous year the contractor had also changed its approach to the tunnel lining/support method given the anticipated geological conditions. Essentially all of the cost overruns result from the unanticipated amount of the overbreak at the tunnel crown.

The contractor claimed that the Queenston shale formation conditions encountered in April 2007 were not consistent with conditions per the Design-Build Agreement and this constituted a “Differing Subsurface Condition” which warranted cost and schedule relief. Strabag claimed additional compensation totaling $90M to offset these cost over-runs.[24] OPG did not agree with the claim that was ultimately submitted to the Dispute Review Board.

The Dispute Review Board issued non-binding recommendations in August 2008 on each of the specific issues raised by Strabag, being Large Block Failures, St. David’s Gorge, Insufficient Stand-up Time, Excessive Overbreak and Inadequate Table of Rock Conditions and Rock Characteristics.[25] The Dispute Review Board found in OPG’s favour, i.e. no Differing Subsurface Condition with respect to Large Block Failures, the St. David’s George and Insufficient Stand-up Time. With respect to Excessive Overbreak, the Dispute Resolution Board noted that that the Geotechnical Baseline Report was defective and misleading and were it not for the defective Geological Baseline Report a Differing Subsurface Condition would exist.[26] The Dispute Review Board concluded, “**Since both parties jointly developed the Geotechnical Baseline Report any misunderstanding or inappropriate wording should, in the Board’s opinion, be the shared responsibility of both parties.**”[27] The Dispute Review Board further concluded that “**Both parties must accept some 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.**” [28] [emphasis added]

[24] Oral Hearing Tr Vol 1 page 65
[25] Exh D1-2- 1 Attachment 7 (Dispute Review Board Report dated August 30, 2008)
[26] Exh D1-2- 1 Attachment 7 (Dispute Review Board Report dated August 30, 2008) page17
[27] Exh D1-2- 1 Attachment 7 (Dispute Review Board Report dated August 30, 2008) page 16
[28] Exh D1-2- 1 Attachment 7 (Dispute Review Board Report dated August 30, 2008) page19

The Dispute Review Board also found that the Table of Rock Conditions and Rock Characteristics was inadequate to define the subsurface conditions that were encountered and that some descriptive wording therein rendered the concept of Differing Subsurface Conditions essentially meaningless and the Geotechnical Baseline Report defective. The Dispute Review Board concluded that since both parties developed that Geotechnical Baseline Report both parties should share in the shortcomings of the resulting documents.[29]

Subsequent to the publication of the Dispute Review Board's report, OPG and Strabag negotiated a settlement to ensure that the tunnel was completed both safely and expeditiously. An Amended Design-Build Agreement was approved by OPG's Board of Directors in May 2009. Provisions included a target cost of $985M, excluding incentives, new cost & schedule dis/incentives, a December 2013 in service date and a shift in the completion risk profile.

OPG had considered two other options, (i) engage another contractor or (ii) cancel the project, and concluded that proceeding with an Amended Design Build Agreement was the preferred alternative. Engaging a new contractor was more costly and there was a low likelihood of recovering any of the $563M in incurred costs (including an estimated $100M in shut down costs) and nothing to show for it, if the project were cancelled. OPG also calculated a LUEC of 6.8 cents/kWh (2009$) and a Revenue Requirement based cost of 8.7 cents/KWh (2014 $) which it viewed as economic when compared to alternative supply options.

4.3.3 Submission

Board staff submits that not all the costs OPG is seeking to recover from ratepayers, by way of additions to rate base, that are in excess of the amount approved by OPG's Board of Directors in July 2005 meet the tests of prudence and reasonableness. There are 2 basic reasons for this conclusion. The original Geotechnical Baseline Report (which was a key component of the Design-Build Agreement) was defective and OPG's risk management strategy was inadequate.

[29] Exh D1-2- 1 Attachment 7 (Dispute Review Board Report dated August 30, 2008) page 19

Design Build Agreement and Risk Management

The Dispute Review Board Report indicates that there were problems with the Design-Build Agreement.[30]

> "DB contracts require the Parties to jointly negotiate and prepare the contract according to the owner's requirements and the proposer's design, means and methods. Typically during DB negotiations the parties concentrate on getting the contract signed and the work started, often without adequate attention to details of the design, specifications, and payment provisions. It is not uncommon therefore that, after award of DB contracts, problems arise from provisions in the negotiated contract that were either not clearly written, were overlooked, or reflect misunderstandings during negotiations and final drafting of the contract. Subsequently the parties are often able to negotiate acceptable solutions to these problems.
>
> This DBA involves a final lining method for a high-pressure water tunnel that, to the DRB's knowledge, has not been used in North America. Also, this project is using the largest diameter hard rock TBM ever built. These unique features, combined with the other unusual conditions mentioned elsewhere in this report made negotiations a monumental effort, characterized by the OR[owner's representative] as "fast-tracked and extensive" over "a long, hot summer". In hindsight, all of these factors contributed to a contract that had a number of problems, particularly in the GBR and resulting DSC dispute resolution."

OPG's expert witness, Roger Ilsley, concluded that the geotechnical and geologic data gathered by the investigations undertaken by OPG was sufficient and appropriate to meet the inherent challenges in providing the necessary and sufficient data to Strabag for use in the design and construction of the work.[31] For Board staff the overarching

[30] Exh D1-2-1 Attachment 7 page 7

[31] Exh F5-6-1 (Niagara Diversion Tunnel Report dated Sept. 9, 2013) page 20: "The natural variability of the 10.4 km alignment as manifested by variable lithology, high horizontal stresses in varying directions, rock strength anisotropy, adverse groundwater chemistry, methane gas potential, swelling pressures and long term deformation, provided significant challenges to OPG in providing the necessary and sufficient

question pertains to OPG's responsibilities as the owner of the project. OPG as the owner had ultimate control as to the quality and wording of the Design-Build Agreement and the management of risk. The Agreement was negotiated with Strabag, and as a negotiated Agreement, the owner, OPG always had the option of not signing.

The Dispute Review Board noted that with respect to Excessive Overbreak the Geotechnical Baseline Report was defective and misleading and were it not for the defective Geotechnical Baseline Report a Differing Subsurface Condition would exist. The Dispute Review Board concluded that OPG and Strabag were both responsible for the poor wording of the Geotechnical Baseline Report. OPG under cross examination provided its interpretation as to what the Dispute Review Board meant when it used the term "defective" to describe the Geotechnical Baseline Report. OPG stated that all of the Dispute Review Board issues and the assessment of the Geotechnical Baseline Report relate to the differing subsurface conditions, as defined contractually (rather than relating to whether the Geotechnical Baseline Report was or was not defective and the extent to which the appropriate behaviour or actions were undertaken during the course of construction).[32] The witness also interpreted the Dispute Review Board's characterization of the Geotechnical Baseline Report as "defective" to mean inadequate [rather than defective] since the use of "catch-all categories" makes the "differing subsurface condition" based assignment of responsibility irrelevant.[33] Board staff submits that the Board should place little weight on this distinction. Whether because of inadequacy or defect, the outcome was negative.

OPG was not unaware of the subsurface risks associated with the NTP.[34]

- At 14.4 meters in diameter, the Niagara Tunnel is precedent setting for excavation by an open full-face tunnel boring machine in rock.

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data to the Strabag design-build team for their use in the design and construction of the work. The geotechnical and geologic data gathered in the various site investigations as previously described, was sufficient and appropriate to meet these challenges. The field and laboratory testing provided appropriate data for the empirical and numerical analyses conducted. The excavation and instrumentation of the Exploratory Adit provided key data on the ground characterization and behavior. In conclusion, the appropriate and comprehensive designs and construction procedures developed by Strabag (summarized above) were based upon the geological and geotechnical data provided to them in the GDR and GBR."

[32] Oral Hearing Tr Vol 1 page 54

[33] Oral Hearing Tr Vol 1 page 68

[34] Exh D1-2-1 (Capital Expenditures-Niagara Tunnel Project/ Appendix B –Summary of Geologic Investigations page 138)

- Rock is not a uniform material and subsurface conditions can vary considerably over a short distance.
- Despite extensive investigations, rock behaviour during tunneling cannot be precisely predicted from boreholes and adits that provide representative data for only a small percentage of the rock to be excavated. Consequently, tunnel designs are based on experience and interpretation of the geotechnical parameters.
- Actual rock conditions and its behaviour during tunnel construction cannot be fully known before the excavation is complete.
- Subsurface conditions always remain a significant risk to both design and construction of tunneling projects.

OPG acknowledged that it needed to obtain specialized external expertise in tunnel design and construction because such activities are not part of OPG's normal business activities. OPG selected the Design-Build approach, with Hatch Mott MacDonald as the Owner's Representative. This preferred risk management strategy was intended to minimize project duration, capture tunnel contractor experience and innovations, fully integrate construction methods and constructability into the design, appropriately allocate project risks, and obtain as much upfront price certainty as possible.[35]

Both the Quantitative Risk Assessment dated July 27, 2005,[36] and the Project Risk Profile which was included in the July 2005 Business Case Summary, noted the risk that the subsurface conditions could be more adverse than described in the Geotechnical Baseline Report.[37]

OPG's Risk Mitigation activity appears to have lacked sufficient robustness, given the understanding that subsurface conditions always remain a significant risk to both design and construction of tunneling projects. Little if any of the mitigation activities addressed the attributes of Queenston shale. When questioned by a Board panel member at the oral hearing, OPG's expert witness was unable to categorically state whether the testing protocol had changed since 1993, the date of the last testing completed by OPG.[38]

[35] Exh D1-2-1 page 22
[36] Exh D1-2-1 Attachment 4
[37] Exh D1-2-1 Attachment 5 (July 2005 Business Case Summary) Appendix C
[38] Oral Hearing Tr Vol 2 page 66-67

OPG acknowledged that the Sir Adam Beck 2 (“SAB2”) tunnels are not as deep as the NTP and that no portion of the SAB2 tunnels is in the Queenston shale formation.[39]

In responding to a Board panel member, OPG confirmed that the NTP business case reflected a 10% chance that the Geotechnical Baseline Report could be wrong.[40]

Under cross examination OPG confirmed that OPG reached a practical limit, having ”… spent tens of millions on the geotechnical investigations for the project, including the Adit, including boreholes”, to manage the risk.[41] It also appears that the 3 stage Geotechnical Baseline Report process mentioned by OPG, in fact, did the opposite of mitigating OPG’s risk. Under cross examination, OPG’s expert witness attested that he would have advised, given what is known about the challenging subsurface conditions and the significant risk of overbreak, to err on the side of caution (i.e. that OPG not reduce the overbreak baseline from 45,000 cubic meters to 30,000 cubic meters in the final (version C) of the Geotechnical Baseline Report which it negotiated with Strabag).[42] [43] Reducing the baseline, all else equal, increased the probability of triggering a Differing Subsurface Condition to the benefit of Strabag. The actual overbreak turned out to be 60,000 cubic meters of which 50,000 cubic meters was in the crown of the tunnel.[44]

Board staff submits that the risk mitigation strategy turned out to be largely unsuccessful. At the end of the day, the Design-Build Agreement was flawed as were the risk mitigation activities undertaken by OPG. As stated by OPG, it had little practical means to have Strabag absorb a share of the incremental costs, fearful that Strabag would walk away from the project. Under cross examination, OPG, while agreeing that OPG had letters of credit, a parental guarantee and a bond from Strabag, such security wasn’t enough to keep them on the job, given the losses they were facing.[45]

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[39] Exh L-4.4-Staff- 21
[40] Oral Hearing Tr Vol 2 page 131-132
[41] Oral Hearing Tr Vol 2 page 60
[42] Oral Hearing Tr Vol 2 page108-110
[43] OPG in its original Geotechnical Baseline Report (“A”) had posited an overbreak base line of 45,000 cubic meters and Strabag had countered with 15,000 cubic meters in its Geotechnical Baseline Report (“B”).
[44] Oral Hearing Tr Vol 2 page 111
[45] Oral Hearing Tr Vol 2 page147-148

Relief to Strabag

OPG's expert witness explained that the site condition clause, for contingency, has two parts in the Design- Build contract; one for known unknowns and the other for unknown unknowns. Mr. Ilsley agreed for a project of NTP's size it is absolutely essential that the site condition report be right.[46]

An inadequate geotechnical report made it difficult for the Dispute Review Board to make a differing site condition determination. In the NTP situation, the method of mining and support (methodology) (i.e. project specifications and rock behaviour when it is being excavated) may be referred to in the Geotechnical Baseline Report. While methodology is the contractor's responsibility and ground condition is the owner's, there is always the matter of which comes first in any consideration. If the Geotechnical Baseline Report is ambiguous, including the responsibilities for various activities, then there is the tendency for the Dispute Review Board to "split the baby".[47]

OPG indicated to its Board of Directors that Strabag claimed that it had incurred a loss of $90M and that the parties had resolved, in October-November 2008, that OPG would pay Strabag $40M to settle all claims up to November 30, 2008.[48]

Under cross examination, OPG indicated that it believed that the claimed loss was in the range of $77M and on that basis agreed to pay $40M of that. With respect to the post November 30, 2008 period, the amended Design-Build Agreement provided for the payment of 2 completion incentives of $10M each as well as a $40M bonus incentive for cost and schedule completion. On this basis OPG estimated Strabag's profit to be about $26M (- $77M + $40M+ $10M+$10M+$40M = $23M).[49]

Under cross examination by CME, OPG was unable to quantify, in light of the Dispute Review Board's findings that 3 of the 5 events were Strabag's responsibility and not OPG's, or how the $40M was split among the events. This raises the question as to the accuracy of the agreed to $40M given OPG's inability to quantify its components. Under cross examination OPG's expert witness confirmed that while he viewed it

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[46] Oral Hearing Tr Vol 1 page 58
[47] Oral Hearing Tr Vol 1 page 59-62
[48] Exh D1-T2-S1 Attachment 8A (Recommendation for Submission to the Board of Directors)
[49] Oral Hearing Tr Vol 2 page 124

appropriate and reasonable for OPG to renegotiate a revised Agreement with Strabag, he did not necessarily have this same view of the specific agreement that was eventually signed.[50]

OPG's witnesses indicated that if the original Geotechnical Baseline Report had been accurate with respect to the amount of overbreak, then Strabag would have charged more to perform the work from the outset. As the final LUEC associated with the project still compares favourably to alternate new sources of supply, the ultimate cost is therefore still reasonable. Board staff accepts that had all the difficulties with Queenston shale been fully appreciated from the outset, Strabag would have charged more for its work. However, it is not clear that the incremental cost would have been $491M. Certainly some of the additional costs were caused by the delay surrounding the discovery of the overbreak issue, in particular with respect to the increased interest charges and management attention. Additional costs were further incurred to conduct the Dispute Review Board hearing and to re-negotiate the contract.

With respect to Overhead Recovery and Office General Costs of $36M and $72M paid to Strabag under the amended Agreement, these expenses were separately identified under the new Agreement. OPG testified that it was unable to identify where the dollars for these activities in the original Agreement were captured, other than in the total amount of the Agreement being $723M. [51]

Board staff notes that the Dispute Review Board concluded that both parties must accept some responsibility for some portion of the additional costs resulting from the excessive overbreak.[52,53]Although it is clear that OPG assumed responsibility for hundreds of millions of dollars in extra costs, it is not evident what additional costs were borne by Strabag. The chief "cost" to Strabag appears to be a lower profit margin than they had previously expected.

Although it is possible Strabag would have abandoned the project had it been forced to assume too much of the cost, this would have amounted to a breach of contract. OPG would have taken legal action, and whatever the ultimate result, Strabag would have

[50] Oral Hearing Tr Vol 2 page 57
[51] Oral Hearing Tr Vol 1 page 77-78
[52] Exh D1-2- 1 Attachment 7 (Dispute Review Board Report dated August 30, 2008) page 16
[53] Exh D1-2- 1 Attachment 7 (Dispute Review Board Report dated August 30, 2008) page19

suffered very significant costs to both its bottom line (through the forfeited letters of credit and whatever damages OPG was awarded for breach of contract, plus legal fees) and its reputation.[54] Neither Board staff nor OPG can know with certainty at what point Strabag would have decided to walk away from the project, but to do so would have resulted in very significant costs to Strabag – certainly much more "cost" than the reduced profit it ultimately wound up with. In Board staff's view, it is reasonable to expect that OPG could have negotiated a greater "sharing" of the costs resulting from the overbreak.

Reductions to in-service Additions

Board staff submits that the proposed test period in-service additions for the NTP are not reasonable given the defective Design-Build Agreement and an inadequate risk management strategy. The proposed amount of $1,452.8M in gross plant additions to be included rate base in 2014 should be reduced by $105M. The reduction is comprised of the following.

1) $40M paid to Strabag for overrun as of November 30, 2008.
2) $6M in carrying-costs (IDC) on the $40M payment to Strabag[55]
3) $6M in incremental design work (part of the tunnel contract)[56]
4) $26M for the profit provided to Strabag on the basis that OPG did not adequately mitigate the possibility that Strabag could in practice withdraw from the project.
5) $15M in carrying costs on the reasonable expectation that with an amended Design/Build Agreement at the start, there would have been at least a 5% or 3 month improvement in the overall schedule (57 months instead of 60 months).
6) $10M in Office and General cost and Overhead Recovery costs, or 10% of the itemized amount, in that there was no evidence as the amounts which were embedded in the original contract.
7) $2M related to fall of ground when borehole not closed. In September 2009, a fall of ground incident related to failure to grout an open borehole in proximity to excavation occurred. The impact of the incident was a delay of 17 days and $2M.[57]

[54] Oral hearing Tr Vol 2 page 122-125
[55] Calculation: $40M*5.25%* 33mo/12mo. (see Exh L-4.5-Staff-27 for interest rate)
[56] Exh D1-2-1 page 128
[57] AIC page 30

4.4 Nuclear Capital Expenditures

4.4.1 Issue 4.6 Capital Expenditures

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

Section 6(2)4 of O. Reg. 53/05 is reproduced in section 4.3.1 of this submission.

Board staff agrees with OPG that Pickering Continued Operations (including the Fuel Channel Life Cycle Management Project), the Fuel Channel Life Extension project and the Darlington Refurbishment Project are subject to Section 6(2)4 of O. Reg. 53/05 since they serve to increase output or refurbish a prescribed generating station.[58]

4.4.2 Issue 4.7 Capital Expenditures

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

Board staff will address the Darlington Refurbishment Project in section 4.6 of this submission. With respect to the remaining nuclear projects, Board staff has no concerns with the nature of the projects proposed, but does have a concern with the pace proposed.

OPG is proposing to spend $196.3M and $143.9M in 2014 and 2015 on Operations Capital projects. A break-out and history of expenditures is presented in Table 8.

[58] AIC page 36

Table 8

NUCLEAR OPERATIONS CAPITAL EXPENDITURES						
(in millions)	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2014 Proposed	2015 Proposed
Darlington NGS	$33.8	$47.9	$50.5	$68.8	$20.6	$9.5
Pickering NGS	$93.0	$56.1	$78.7	$67.2	$22.2	$2.2
Nuclear Support	$30.1	$31.2	$16.7	$13.0	$4.2	$1.3
Total Portfolio Projects (Allocated)	$156.9	$135.2	$145.9	$149.0	$47.0	$13.0
Facility Projects (to be Released)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Portfolio Projects (Unallocated)	$0.0	$0.0	$0.0	$1.4	$128.0	$109.2
Total Portfolio Projects	$156.9	$135.2	$145.9	$150.4	$175.0	$122.2
P2/3 Isolation	$5.9	$0.0	$0.0	$0.0	$0.0	$0.0
Minor Fixed Assets	$15.4	$12.9	$15.5	$19.9	$21.3	$21.7
Total Nuclear Operations Capital	$178.2	$148.1	$161.4	$170.3	$196.3	$143.9
Source: D2-1-2 Table 2						

A comparison of actual capital expenditures to Budget or Board approved for the 2010 to 2012 period approved is shown in Table 9.

Table 9

NUCLEAR OPERATIONS CAPITAL EXPENDITURES								
	2010 Budget	2010 Actual	2011 Board Approved	2011 Actual	2012 Board Approved	2012 Actual	2013 Budget	2013 Actual
Darlington NGS	$24.3	$33.8	$12.8	$47.9	$5.6	$50.5	$68.8	$76.4
Pickering NGS	$22.6	$93.0	$1.5	$56.1	$0.5	$78.7	$67.2	$90.6
Nuclear Support	$58.0	$30.1	$3.9	$31.2	$0.7	$16.7	$13.0	$24.0
Total Portfolio Projects (Allocated)	$104.9	$156.9	$18.2	$135.2	$6.8	$145.9	$149.0	$191.0
Facility Projects (to be Released)	$36.6	$0.0	$74.0	$0.0	$55.0	$0.0	$0.0	$0.0
Portfolio Projects (Unallocated)	$30.4	$0.0	$79.8	$0.0	$110.3	$0.0	$1.4	$0.0
Total Portfolio Projects	$171.9	$156.9	$172.0	$135.2	$172.1	$145.9	$150.4	$191.0
P2/3 Isolation	$8.8	$5.9	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Minor Fixed Assets	$20.2	$15.4	$19.7	$12.9	$19.5	$15.5	$19.9	$10.2
Total Nuclear Operations Capital	$200.9	$178.2	$191.7	$148.1	$191.6	$161.4	$170.3	$201.2
source: D2-1-2 Table 4 & Exh L Tab 1.0 Sch 1 staff 002 atatchment 1 Table 11								

Board staff notes that as compared to Budget or Board approved amounts over the 2010 to 2013 period, actual capital spending was about 9% less. As compared to just

Board approved amounts it was 20% less. Board staff submits that given a history of overstating its capital expenditure requirements, the proposed amounts less 10% would be a more reasonable level of forecasted expenditure.

4.5 Nuclear Rate Base

Issue 2.1 (Primary) - Are the amounts proposed for rate base appropriate?
Issue 4.8 (Primary (reprioritized)) - Are the proposed test period in-service additions for nuclear projects (excluding those for the Darlington Refurbishment Project) appropriate?

OPG is seeking approval for a nuclear rate base of $3,706.7M and $3,659.0M for the years 2014 and 2015 respectively. The components of nuclear rate base are summarized in Table 10.

Table 10

NUCLEAR RATE BASE

	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2014 Proposed	2015 Proposed
Darlington NGS	$434.9	$443.5	$467.3	$567.9	$666.8	$754.4
Pickering NGS	$1,033.4	$1,024.8	$926.9	$844.7	$772.3	$668.3
Nuclear Support Divisions	$118.3	$107.1	$101.7	$110.1	$135.4	$199.0
Asset Retirement Costs	$1,517.7	$1,490.0	$1,851.1	$1,470.2	$1,389.5	$1,308.8
Cash Working Capital	$14.3	$25.9	$32.0	$32.0	$32.0	$32.0
Fuel Inventory	$335.0	$345.4	$340.7	$313.3	$283.6	$274.4
Materials & Supplies	$441.8	$421.9	$413.3	$418.0	$427.2	$422.0
TOTAL	$3,895.4	$3,858.6	$4,133.0	$3,756.2	$3,706.8	$3,658.9

Source: Exh B3

OPG is forecasting in-service additions of $158.3M and $141.7M in 2014 and 2015 respectively. A breakout of planned and actual in-service additions is presented in Table 11.

Table 11

NUCLEAR OPERATIONS (excluding DRP) In-Service Additions

	2010		2011		2012		2013		2014	2015
	Budget	Actual	Brd App'd	Actual	Brd Appr'd	Actual	Budget	Actual	Proposed	Proposed
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	$0.0	$0.0	$50.5	$0.0	$47.6	$0.0	$0.0		$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**
Over (Under) forecast		**$57.5**		**($72.3)**		**($55.7)**		**130.7**		

Source: Exh D2-1--3 Table 4 & Exh L Tab1.0 Schdule 1 Staff 002 attachment 1 table 2

With respect to nuclear rate base, 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.”[59]

Board staff notes that OPG has had a recent history of over estimating in-service additions. In its pre-filed evidence OPG indicates that its in-service amount for 2010 was greater than planned by $57.7M while the in-service amounts were lower than planned by $72.3M and $56.7M in 2011 and 2012 respectively. [60] The planned in-service amounts for 2010-2013 total $554M.[61] The overstatement of in-service amounts totals $71.3 (-$57.7+$72.3+$56.7) and this equates to 12% over the period. Board staff is of the view that there is no basis to conclude that this history of over-estimating will not repeat itself over the test period. While Board staff does realize that less than forecasted actual in-service amounts i.e. overstated in-service amounts, in the test period self corrects <u>going forward</u> in the subsequent test period’s rate base, this does not offset the associated revenue requirement over-recovered in the test period. Board staff submits that the rate base should be adjusted to reflect a reduction of $18M and $17M in in-service amounts for 2014 and 2015 respectively, which is roughly 12% or proposed additions.

4.6 Darlington Refurbishment Project (“DRP”)

4.6.1 Test Period Capital Expenditures

Issue 4.10 (Primary) - Are the proposed test period capital expenditures associated with the Darlington Refurbishment Project reasonable?

[59] Decision with Reasons, EB-2010-0008, page 59
[60] Exh D2-1-3 page 6
[61] Exh D2-1-3 Table 4

OPG requests that the Board accept its 2014 and 2015 proposed capital expenditures for the DRP on the basis that they are reasonable.

DRP capital expenditure details for the 2010 to 2015 period are shown in Table 12.

Table 12

Darlington Refurbishment Capital Expenditures (in millions)	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2013 Actual	2014 Proposed	2015 Proposed	Total 2010-2015
	$32.6	$91.0	$232.5	$529.8	$430.3	$837.4	$631.8	$2,165
Source: Exh D2-1-2 Table 1 & Exh L Tab 1.0 Sch 1 Staff 002 attachment 1 Table 9								

In its AIC at page 55, OPG indicates that it is now forecasting capital expenditures of $839.9M and $842.5M for 2014 and 2015 respectively, noting that this is an increase from the amounts included in the pre-filed evidence at Exh D2-2-2 page 7.[62] OPG did not itemize the specific projects that comprise the revised totals in the updated evidence to which it referred, being Exh D2-2-2. For completeness of the record, Board staff asks that OPG in its reply argument list the projects, including amounts that comprise the updated capital expenditures for 2014 and 2015. Board staff also asks that OPG confirm which set of capital expenditures it seeks a finding of reasonableness.

Board staff is of the view that the Board should not make a finding on the reasonableness of the proposed capital expenditures as it will be unclear to Board staff what that would mean given that most of the costs associated with these projects will not go into service in the test year. Board staff concurs with OPG's position that capital expenditures remain subject to the Board's future finding of reasonableness or prudence prior to their closing to rate base.[63]

> MR. MILLAR: My question is, in the amounts under bullet 2, for those items that are not actually closing to rate base in the test period, which is most of that money, at some later date those amounts will become used

[62] Exh D2-2-2 was filed with the Board on July 2, 2014. In that this would not normally be described as "pre-filed" evidence, Board staff asks OPG to confirm that the reference is correct. If this is the correct reference, Board staff asks OPG to check the numbers quoted on page 7, specifically "The resulting impact to the 2014 and 2015 capital expenditures, as reported in Exh D2-2-1, Table 1, are an increase in 2014 from **$765.0M** to $839.9M, an increase of $74.9M, and an increase in 2015 from **$736.0M** to $842.5M, an increase of $106.5M."

[63] Oral Hearing Tr Vol 15 page 132

and useful and OPG will return to the Board and seek a finding that it is either reasonable or prudent to close those items to rate base. Is that correct?
MR. KEIZER: From OPG's position, yes……

4.6.2 Test Period In-Service Additions

Issue 4.9 (Primary) - Are the proposed test period in-service additions for the Darlington Refurbishment Project) appropriate?

OPG is forecasting $18.7M and $209.4M in 2014 and 2015 respectively for DRP in-service additions. These are the amounts as originally filed. A breakout of the component projects and the now updated amounts are presented in Table 13.[64]

Table 13

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

During the oral hearing Board staff sought confirmation, given the updated evidence, as to which projects (and amounts) OPG was proposing to put into service in the test period and any determination of prudence sought by OPG in this regard.[65]

[64] Exh D2-2-2 page 4 Table 1
[65] Oral Hearing Tr Vol 15 page 135-144

In response to Undertaking J15.3 (To advise whether a finding of prudence is being sought for matters that are not actually closing to rate base),[66] OPG stated the undertaking to be "OPG to provide a description of what it is currently requesting in regards to DRP in service additions, and how this relates to the September filing and the D2-2-2 exhibit." In the undertaking response, and as repeated in the AIC at page 54, OPG indicated:

UNDERTAKING J15.3

Undertaking

OPG to provide a description of what it is currently requesting in regards to DRP in service additions, and how this relates to the September filing and the D2-2-2 exhibit.

Response

OPG is seeking to add to rate base $18.7M in 2014 and $209.4M in 2015.

These amounts are lower than the $67.2M in 2014 and the $222.7M in 2015 that OPG is now forecasting will come into service in these years (see the table below). In coming to its determination of what amounts should be added to rate base, the OEB should consider the updated forecast information as set out below in the table. However, OPG has not changed its requested in-service amounts to reflect the updated forecast because the revenue requirement impact from the higher forecast in-service amounts is less than the $10M per annum materiality threshold that OPG uses for deciding whether to adjust its proposed revenue requirement.

The proposed in-service amounts represent facilities that will come into service in the test period and are used or useful as explained in greater detail in Ex. JT3.5. In some of the cases below the amounts coming into service represent part of a larger project (OPG has referred to these amounts as "partial in service amounts" elsewhere in the filing). OPG understands that acceptance into rate base of part of a project (i.e. the test period amounts) does not mean that the entire project is being accepted by the Board.

66 Mr. Millar elaborated as to the intent of J15.3 "It was just, it's not clear to me now for which of these line items OPG is seeking a prudence review." Oral Hearing Tr Vol 15 page 143

$ millions	As Updated in Ex. D2-2-2		
	AFS	2014	2015
Darlington OSB Refurbishment	Aug-15	-	45.1
D2O Storage Facility	Jan-17	15.5	1.0
DN Auxiliary Heating System	Mar-15	-	75.3
Water & Sewer	Nov-15	22.6	6.6
Elec Power Distribution System	Nov-14	12.0	-
Darlington Energy Complex	Jul-15	2.1	4.1
RFR Island Support Annex	Apr-16	-	-
Other Campus Plan projects	various	15.1	7.6
Safety Improvement Opportunities	various	-	83.0
Other Station Modifications	various	-	-
Total		**67.2**	**222.7**
OPG's Request		**18.7**	**209.4**

Board staff finds OPG's response puzzling. First it does not speak to the question as presented in transcript. Second, while OPG states it is seeking to add to rate base the in-service amounts as originally proposed, it goes on to say, "In coming to its determination of what amounts should be added to rate base, the OEB should consider the updated forecast information as set out below." It is unclear to Board staff what OPG expects from the Board when it considers the updated forecast.

Board staff accepts that it is neither practical nor desirable to update the application for relatively minor changes to proposed additions to rate base. On this basis, Board staff recommends that the Board accept the amounts that OPG seeks to close to rate base (i.e. the amounts presented in the original application). The value of the actual assets now expected to enter service during the test period is similar, and in fact a bit higher, than the amounts reflected in the original application.

In Board staff's view, however, this approval should not be considered a finding of prudence for the D2O project. Although the value of the actual assets that will enter service in the test period is now expected to be higher than what is reflected in the application, the D2O project (which was forecast to close to rate base at $83.5M in 2015) is no longer expected to be used or useful during the test period. The Board is therefore at this time not in a position to say whether the project is prudent or not. A prudence review for the D2O project should not take place until the Board is reviewing the period during which it is expected to enter service, which presumably will be during OPG's next payments case.

4.6.3 Commercial and Contracting Strategies

Issue 4.11 (Oral Hearing) - Are the commercial and contracting strategies used in the Darlington Refurbishment Project reasonable?

Following some initial cross examination by SEC on Day 15 of the hearing, OPG responded on Day 16 of the hearing with statements "to make very clear what the nature of their ask is in respect of the commercial and contracting strategy."[67] These statements were reproduced at pages 44-45 of the AIC.

> OPG [during oral hearing] stated that it seeks a finding of reasonableness in respect of the guiding principles forming the commercial strategy as follows:
>
> - a multi-prime contractor model in which OPG retains the overall project management and design authority responsibility for the DRP;
> - the division of the DRP into five major packages; RFR, Turbine Generator, Steam Generators, Defueling and Fuel Handling, and Balance of Plant;
> - a model where the prime contractor is responsible for engineering, procurement, and construction (or some combination of those) within each of the five major packages;
>
> - a means to allocate risk to the party most able to manage that risk, through a pricing structure tailored to the level of project definition and the level of required owner oversight. This means the use of target pricing where projects are less defined and require more oversight, and fixed pricing for those projects with greater definition; and
> - for all of the above, subject to the available contract options in the marketplace.
>
> In addition, OPG also noted that if the Board finds that the record is sufficiently developed to render a finding on the reasonableness of the contracting strategies, it requests a finding that OPG's application of the above guiding principles to the contracting strategies is reasonable as it applies to the pricing structure in terms of utilization of fixed, target, or other pricing structures for each of the five major packages.
>
> OPG indicated that it is not requesting approval of the following:

[67] Oral Hearing Tr Vol 16, page 3-5

1) approvals of the contracts,
2) conduct of negotiations or the procurement process,
3) any prices established through the contracting process, and
4) its selection of the winning proponent

While Board staff finds the above to be informative, it remains unclear to staff why OPG needs the Board to make a determination on this issue and the components listed above. It is staff's understanding that the Board has never made a finding on commercial and contracting strategies such as these before. The cross examination on Day 15 indicates that other parties are unclear about the nature of this request as well, similarly the questions from the Board panel on Day 16 of the oral hearing.

In the Board staff submission on the issues list filed on January 21, 2014, Board staff questioned the appropriateness of including the issue on the issues list. Staff 's submission continues to apply:

- January 21, 2014 - A relatively small amount of DRP would be in-service in the test period and it was unclear how much of the strategy applied to those additions.

  Current - It is staff's current understanding that none of the in-service additions are subject to the commercial and contracting strategies.

- January 21, 2014 - In the EB-2010-0008 proceeding, OPG objected to reporting on NTP, submitting that the Board does not have the same role as the OPG Board in overseeing and managing the project. The Board agreed with OPG in EB-2010-0008; the Board does not manage utility projects.

  Current - In asking the Board to make a finding on the reasonableness of the guiding principle of the division of the DRP into five major packages: RFR, Turbine Generator, Steam Generators, Defueling and Fuel Handling, and Balance of Plant, Board staff submits that OPG is seeking a project management type decision from the Board. As a hypothetical situation, if the Board had rationale to support combining the Turbine Generator and Steam Generator packages into a single package and ordered so, Board staff submits that OPG would likely object and respond as it did to the NTP submission in EB-2010-0008.

- January 21, 2014 - It was unclear what a determination on the commercial and contracting strategies in the current proceeding would mean in future applications when more significant amount would be proposed for addition to rate base.

  Current - Board staff continues to have this concern.

The Board decided that issue 4.11 would remain on the issues list on the basis "that ratepayers would benefit from a review of OPG's commercial and contracting strategies."[68] Board staff acknowledges that the provision of the commercial and contracting strategies for the DRP was proactive and transparent and believes that the parties have benefitted from the review.

However, Board's staff's position on this issue is unchanged from its original submission. A Board decision on this matter is a form of project management and the Board does not manage projects. Board staff submits that no specific approval should be provided under this issue. To the extent the Board does grant an approval, it should be very clear respecting what the implications of this approval are.

4.6.4 Long-Term Energy Plan

Issue 4.12 (Primary) - Does OPG's nuclear refurbishment process align appropriately with the principles stated in the Government of Ontario's Long Term Energy Plan issued on December 2, 2013?

Board staff submits that OPG's nuclear refurbishment process aligns appropriately with the principles stated in the Government of Ontario's Long Term Energy Plan issued on December 2, 2013 based on OPG's response to Board staff interrogatory Exh L-4.12-Staff-58, and reproduced in the AIC.

4.6.5 Test Period OM&A

Issue 6.7 (Primary) - Is the test period Operations, Maintenance and Administration budget for the Darlington Refurbishment Project appropriate?

[68] Decision and Order on Issues List and Procedural Order No. 3, February 19, 2014

OPG is seeking approval of OM&A expenditures of $6.6M and $18.2M in 2014 and 2015 respectively. Board staff has no concerns in particular other than how the forecasted costs may be impacted by submissions on OM&A spending in general.

5. PRODUCTION FORECAST

5.1 Regulated Hydroelectric Production Forecast

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

The following summarizes historical and forecast hydroelectric production.

Table 14

TWh	2010 Actual	2011 Approved	2011 Actual	2012 Approved	2012 Acutal	2013 Budget	2013 Actual	2014 Plan	2015 Plan
Niagara	12.4	12.9	12.6	12.9	11.9	12.2	12.4	12.7	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**	**19.0**	**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**	**31.4**	**32.7**
Exhibit N1 Update - Previously Regulated**								**32.4**	**33.5**
** No change for newly regulated									
No change to hydroelectric production forecast in Exh N2									

For the larger hydroelectric facilities (6 previously regulated and 21 newly regulated), the hydroelectric forecast is based on waterflow projections produced by modeling. OPG develops waterflow projections based on factors including monthly lake level projections and several environmental parameters including basin precipitation, runoff, lake evaporation and the impact of ice retardation on river flows. Water availability for specific generating stations is also affected by international agreements on water sharing and environmental conditions. The forecast assumes a 1.5 TWh (full year) increase in production related to the Niagara Tunnel Project.

For the remaining 27 newly regulated facilities, computerized models are not available and the production forecast is based on historical production.

The hydroelectric test period production forecast was updated in December 2013 (Exh N1-1-1) to reflect an increase in water availability for the large hydroelectric facilities.

Board staff submits that the proposed hydroelectric production forecast is appropriate.

5.2 Surplus Baseload Generation ("SBG")

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

The following summarizes historical and test period SBG. OPG did not provide and parties did not ask for the 2013 newly regulated hydroelectric SBG.

Table 15

TWh	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
Previously Regulated	0.1	0.1	0.2	0.6	0.6
Newly Regulated	0.2	0.3		0.4	0.5
Total	**0.3**	**0.4**		**1.0**	**1.1**

Sources: Previously Regulated historical SBG, Exh E1-2-1
Newly Regulated historical, J4.4
Test Period, J4.2 (newly regulated 2014 is July-Dec)

In the previous proceeding, EB-2010-0008, OPG proposed a production forecast that was adjusted by forecast SBG. OPG forecast 0.5 TWh in 2011 and 0.8 TWh in 2012 for the previously regulated hydroelectric facilities. The Board did not approve the adjustment to production forecast and established the SBG variance account instead, with SBG measured on the basis proposed by OPG.

In the current proceeding, OPG has not proposed an SBG adjustment to production forecast. OPG is seeking SBG variance account clearance of $19M – which is related to the 0.4 TWh of SBG for the previously regulated from 2010 to 2013.

In the previous proceeding, the Board directed OPG to provide a more comprehensive analysis of the hydroelectric incentive mechanism ("HIM") structure and the interaction between the mechanism and SBG. The Board indicated that it may be appropriate for OPG to request that the IESO examine the issue. At Exh E1-2-1 page 2, OPG states that it approached the IESO for assistance in the calculation of SBG spill and was advised that the IESO was unable to assist due to lack of data available to the IESO.

OPG has described the methodology developed for determining the foregone production associated with SBG at page 3 of Exh E1-2-1. In cross examination by Board staff, OPG confirmed that if it managed to curtail production by storing water instead of spilling water, production related to the stored water would not be added to the SBG account.[69]

OPG estimates that the Sir Adam Beck Pump Generation Stations ("PGS") provides 600-700 MW of time shifting capability and that the newly regulated facilities have 2,100 MW of time shifting capability behind dams and in forebays.[70] In Exh E1-2-1 at page 4, OPG provides a summary which indicates that it missed only 6% of the opportunities to use the PGS (March 2011 to July 2013), and hence maximized its use to mitigate the impact of SBG.

Staff submits that the current approach to SBG should be maintained. SBG forecasting is clearly difficult as seen from 2011-2012 previously regulated forecast and actual.

5.3 Hydroelectric Incentive Mechanism ("HIM")

Issue 5.3 (Secondary) - Has the incentive mechanism encouraged appropriate use of the regulated hydroelectric facilities to supply energy in response to market prices?
Issue 5.4 (Primary) - Is the proposed new incentive mechanism appropriate?

5.3.1 Background

Incentive mechanisms for production from OPG's regulated hydroelectric assets have been in place since regulated payments were established for these assets. The initial incentive mechanism was embedded in O. Reg. 53/05; subsequent mechanisms have been proposed in OPG's applications and either affirmed or modified in the Board's *Decision with Reasons* in response to these applications. The objective of the incentive mechanism was described in the EB-2007-0905 decision as:

[69] Oral Hearing Tr Vol 4 page 13
[70] Oral Hearing Tr Vol 4 page 30-31

> The objective of the incentive scheme is to provide OPG with an incentive to produce peaking supply in response to demand. The expectation is that this will benefit consumers by having a peaking resource available to improve system reliability and temper market prices through increased supply.[71]

Both consumers and OPG are expected to benefit from the incentive mechanism. How those benefits are generated and distributed is the essential task that the specific mechanism must achieve and the source of divergent opinions among intervenors, OPG and Board staff as to how best to accomplish this.

In the previous cost of service proceeding, EB-2010-0008, OPG presented evidence on the performance of the HIM:

> OPG estimated that between December 2008 and December 2009, the HIM reduced average market prices by $1.14/MWh, and in OPG's view this demonstrates the value of moving energy from off-peak to on-peak. The forecast HIM revenue for 2009 was $12.0 million, but the actual was $23.2 million. The forecast HIM revenue for 2010 was $8.0 million, but the year-to-date actual at the end of August 2010 was $11.0 million. For the test period, OPG forecasted HIM revenues of $13.3 million for 2011 and $16.3 million for 2012. OPG expects market price spreads to decline relative to 2009.[72]

A number of intervenors claimed that these returns to OPG were excessive and, along with Board staff, proposed a sharing mechanism to distribute some of the financial benefits of the HIM to consumers. OPG counter argued that a sharing mechanism would reduce the frequency and extent of time shifting generation through the PGS because of decreased rewards without a commensurate reduction in financial risk. Further, OPG stated that while parties may view a sharing mechanism as beneficial, in OPG's view it comes at a cost of reduced market benefit for consumers.[73] Board staff submitted that the market benefits cited by OPG were largely negated by the preponderance of contract pricing in Ontario's wholesale market. A result of extensive contract pricing is that HOEP is not a reliable indicator of the total cost of energy to consumers.[74] Under cross examination, OPG confirmed that it would operate its

[71] Decision with Reasons, EB-2007-0905, page 51
[72] Decision with Reasons, EB-2010-0008, page 144
[73] Decision with Reasons, EB-2010-0008, page 145
[74] Decision with Reasons, EB-2010-0008, page 145

regulated hydroelectric assets in the same manner, regardless of whether a HIM was in place.

The Board made the following finding:

> The evidence does not support a conclusion that the current structure of the HIM is providing significant benefits for consumers. It is clear that a substantial portion of the market is now under contract and that fluctuations in the market price are largely offset by variations in the Global Adjustment Mechanism. …. The Board finds that the net benefits to consumers are likely substantially less than estimated by OPG on the basis of market price differentials alone.[75]

The Board also expressed concern about the interaction of surplus baseload generation ("SBG") conditions and operation of the PGS. In response to OPG's more moderate approach to using the PGS to offset SBG, the Board directed OPG to act more aggressively:

> "The Board therefore expects OPG to use the PGS to the maximum extent possible to mitigate this additional direct cost on ratepayers. When assessing the circumstances which give rise to lost production due to SBG, the Board will examine the use of PGS and OPG will have to fully justify any instances in which the PGS is not used. If the Board finds that OPG could have, or should have, used the PGS to mitigate SBG, the Board will adjust the balance in the SBG account accordingly."[76]

The Board established a shared distribution of the financial proceeds of the HIM. The Board directed that 50% of the HIM revenues be returned to consumers and incorporated HIM revenues in the revenue requirement ($5M in the 10 months for 2011 and $7M in 2012). Additional revenue up to $5M in 2011 and $7M in 2012 was retained by OPG. The Board also directed OPG to establish a variance account to accumulate HIM revenues above the two dispersions with the proceeds in the account to be shared equally between OPG and ratepayers.[77]

[75] Decision with Reasons, EB-2010-0008, page 146
[76] Decision with Reasons, EB-2010-0008, page 147
[77] Decision with Reasons, EB-2010-0008, page 147

5.3.2 HIM Revenue and Analysis (2010 to 2013)

In EB-2012-0002, OPG noted that the 2013 annualized effect of the EB-2010-0008 decision was sharing of net revenues above $13M. Based on the HIM revenue for 2011 and 2012 noted in Exh H1-1-1 page 4 and the 2013 additions to the HIM account, Board staff has determined the following for the historical period:

Table 16

$million	2011	2012	2013
Offset to revenue requirement	5.0	7.0	6.5
To OPG (1)	5.0	7.0	6.5
Addition to HIM account	1.45 (2.9/2)	0.9 (1.8/2)	2.5
To OPG (2)	1.45	0.9	2.5
HIM Revenue	12.9	15.8	18.0 (13+(2.5x2))

In EB-2010-0008, the Board also instructed OPG to provide further analysis of the HIM and SBG:

> The Board also directs OPG to re-address the HIM structure in its next application. Specifically, the Board expects OPG to provide a more comprehensive analysis of the benefits of the HIM for ratepayers, the interaction between the mechanism and SBG, and an assessment of potential alternative approaches in light of expected future conditions in the contracted and traded market.[78]

In response, OPG filed evidence in EB-2013-0321 that assessed the market benefits of the HIM, analyzed the impact of SBG on the HIM production threshold and proposed an alternative structure for the HIM that would address the "unintended benefit" accruing to OPG from the interaction of SBG with the HIM.[79] OPG also filed expert evidence that provided a review of OPG's proposed variation to the HIM, enhanced HIM ("eHIM"), and alternatives that could address the interaction between SBG and the HIM.[80]

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[78] Decision with Reasons, EB-2010-0008, page 148

[79] Exh E1-2-1, page 6

[80] Exh E1-2-1 Attachment 1

The unintended benefit to OPG of the interaction between SBG conditions and the HIM is the result of SBG reducing the average monthly hourly production threshold for HIM, thus increasing the potential revenues from HIM while also collecting the regulated payment from reduced energy production that is the result of SBG conditions. OPG's solution to this unintended consequence was to introduce eHIM.

5.3.3 eHIM Proposal

OPG proposes that eHIM apply to the previously regulated and newly regulated hydroelectric operations. OPG also proposes that the HIM variance account be closed to further additions.

OPG's explanation of the eHIM includes two major modifications to the HIM. Instead of basing the incentive on actual operation of the PGS and the water storage capabilities of the newly regulated facilities, OPG proposes to base the incentive on a forecast of customer cost changes resulting from economic time shifting of generation. OPG estimates these cost reductions to be \$36M in both 2014 and 2015.[81] The other modification is an "X-factor"; the X-factor is an adjustment to both the HIM and SBG monthly calculations such that the summation of monthly payments to OPG will equal half the estimated annual cost reductions to ratepayers, i.e., \$18M.[82]

The proposed eHIM formula – consisting of HIM and SBG variance account adjustments is as follows.

Monthly IESO Payment[2]	= Regulated payment +
	+ Incentive payment
where	
Regulated Payment	$= (MW_{avg} \times \text{Regulated rate} \times \text{No of hours in month})$
Incentive Payment	$= \text{'X factor'} \times \sum [(MW_i - MW_{avg}) \times HOEP_i]$

[81] OPG identifies a reduction in payments to gas-fired generators and an increase in export revenues less increased gross revenue charges as the cost savings to consumers; Exh E1-2-1, pages 6-7.
[82] Exh E1-2-1, page 12-15.

Monthly SBG Variance Account Entry	= Spill compensation
	+ Incentive payment adjustment
where	
Spill Compensation	$= MW_{SBGavg} \times$ (Regulated rate – GRC) $\times$ No of hours in month)
Incentive Payment Adjustment	= 'X factor' $\times \sum [(MW_{SBGi} - MW_{SBGavg}) \times HOEP_i$

OPG estimates that HIM revenues in 2014 and 2015 would be $78M and $96M respectively if the exisitng HIM operates without the "X Factor". The following table from Exh E1-2-1 illustrates how OPG expects the eHIM to function.

Table 5: Expected Payments and Adjustments

M$	2014	2015
'X' factor	35%	31%
Incentive payment	27	30
Incentive payment adjustment	(9)	(12)
eHIM	18	18

Furthermore, OPG proposes that there be no revenue requirement offset from revenues generated by the eHIM, claiming that since the cost reduction benefits and OPG's payments occur simultaneously there is no need for a revenue requirement offset.[83]

OPG's proposed changes to the HIM generated a number of interrogatories and questions in the technical panel sessions plus substantial testimony through cross-examination.

Exh L-5.3-Staff-61 focused on an alternative to OPG's proposed "X-factor" to remove the unintended benefit to OPG of interaction between the threshold calculation for the HIM and SBG. Staff proposed a "monthly average hourly production adjusted for SBG" as a revised threshold. OPG replied that the Staff proposal would achieve the same outcome as OPG's proposal but it would impose substantial additional settlement and accounting obligations on OPG and IESO. Furthermore, OPG stated that the eHIM

[83] Exh E1-2-1, page 13.

mechanism would achieve the same outcome as the staff proposal but without complications to existing settlement processes.[84]

Cross examination on the Staff proposal further revealed that OPG has the data available to make the adjustments as suggested in Exh L-5.3-Staff-61.[85] Cross examination by CME re-iterated that OPG had all the data available to make retro-active calculations of HIM revenues and SBG energy losses. However, OPG interprets the Board's instructions from its decision on the previous application as prohibiting what appears to be a simple resolution of the "double counting" through deferral and variance account entries.[86]

OPG's proposal for the HIM (separate from the modifications to account for SBG-induced double counting) changes the basis of the "benefits" sharing from the actual revenue generated from time-shifted generation to a "consumer cost reduction" basis. In response to Exh L-5.3-Staff-62, OPG disputes staff's characterization that the consumer costs reductions are "general system benefits" and suggests that this characterization somehow reduces the legitimacy of the cost reductions.[87] Staff agrees that the estimated cost reductions may be real, although these estimated benefits could be variable.

As noted previously, OPG estimates that HIM revenues in 2014 and 2015 will be $78 M and $96 M, respectively, if the existing HIM operates without the "X-factor".[88] Presumably, this is from operating the hydroelectric facilities as in the past and includes time shifting generation from the newly regulated facilities. Based on the 50-50 sharing mechanism established in the past, ratepayers would receive a credit against revenue requirements of 50% of these totals, or $39 M in 2014 and $48 M in 2015. OPG would receive similar amounts. Furthermore, OPG calculates that ratepayers will receive $36 M in cost reduction "benefits" as well, regardless of the actual revenues generated by the HIM. However, OPG under cross examination states that the $78 M and $96 M will not actually be generated through ratepayer payments but that the IESO will use the X-

[84] Exh L-5.3-Staff-061.
[85] Oral Hearing Tr Vol 4 page 20-21.
[86] Oral Hearing Tr Vol 4 pages 110-112.
[87] Exh L-5.3-Staff-062
[88] Oral Hearing Tr Vol 4 pages 115-116.

factor to calculate a monthly amount to be credited to OPG that would sum over the year to $18 M, if OPG's forecasts are correct.[89]

But, OPG appears to contradict this statement in answer to Exh L-5.4-IESO-005 (b). In reply to an inquiry about how OPG would reconcile the difference if incentive payments to OPG were greater or less than the forecast $18 M, OPG said it did not propose to reconcile any difference.[90] This answer implies that there will be a calculation of HIM revenues and if they differ from OPG's forecast estimates and the X-factor which has been set produces revenues greater or less than the target of $18 M annually, OPG will retain those revenues (if actual exceeds estimate) and accept the deficiency (if actual is less than estimated).

Much of what is being proposed depends on OPG's forecasts and estimates. In addition, as the predominant generator in Ontario, OPG has sufficient market power and generation time shifting capability to influence the level of HOEP – the basic determinant of HIM revenues. Therefore, OPG may be able to engineer outcomes that could benefit its revenue streams by using its market power to influence HOEP levels. Actual HOEP generates notional HIM revenues that when the previously selected X-factor is applied exceed the annual target of $18 M. This appears to be the implication of OPG's statement that it will not reconcile any differences nor adjust the X-factor once it is chosen.[91] OPG also states that it is the Board who will select the X-factor, thus legitimizing that vector in the calculation.[92]

OPG has stated that it will operate the facilities in the same manner as previously, taking advantage of price differentials to time shift generation, regardless of the HIM mechanism that is in place. However, OPG has also stated that it would respond to higher (and presumably lower) incentives by accepting greater risks and costs (and presumably less risk and cost in the case of lower incentives) in operating the time shifting facilities.[93] Hence, there appears to be a contradiction in the record as to how OPG may actually react to various levels of incentive. If incentive payments were fixed at a monthly payment with certainty, then OPG may not actually respond to market

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[89] Oral Hearing Tr Vol 4 pages 114-120.
[90] Exh L-5.4-IESO-5.
[91] Exh L-5.4-IESO-5.
[92] Oral Hearing Tr Vol 4, page 120.
[93] Exh L-5.4-IESO-3.

prices to shift generation. As a result of this failure, the general market efficiency benefits may not materialize. Moreover, for OPG to make the statement that it would operate the system in the same manner as previously with HIM revenues limited to $18 M annually when potential revenues are in the $50 M per year range without their proposed changes stretches credulity.

5.3.4 Submission

Reject eHIM

OPG seems to have taken the Board's previous direction to address issues associated with the HIM to mean that the Board wanted a fundamental re-working of how to calculate the shared benefits from the HIM. A "more comprehensive analysis of the benefits of the HIM for ratepayers" is an invitation to inform the Board about OPG's opinion of how consumers benefit from time shifting of generation. Board staff submits this request does not imply, or direct, that OPG should then use this benefit calculation to define the limit for shared revenues generated by the HIM. As OPG has stated in its evidence and in replies to interrogatories, the revenues that could be generated by the HIM, even without extraordinary action by OPG, can far exceed the estimated consumer benefits.

In its proposal, OPG has fundamentally shifted the basis of revenue sharing from the actual revenues that may be generated to an estimated and forecasted consumer benefit. "Consumer benefits" and "HIM revenues" are two different concepts and, as shown in the evidence, with potentially very different revenue impacts for consumers. It should be noted that consumers are the source of all the real revenues associated with the HIM and that "consumer benefits" are a calculated and estimated impact without real revenue transfers, i.e., consumers realize these benefits through the market but actually transfer revenues to OPG when they pay HOEP for energy generated above the monthly daily hourly average.

Hence, Staff is reluctant to accept OPG's proposal for the eHIM because of the potential for OPG to generate results that could be one-sidedly beneficial to OPG without any mechanisms to adjust the sharing of benefits after the fact.

Continue Current HIM with post facto Adjustment

The consumer benefit calculation is independent of the assessment of the interaction between the HIM mechanism and SBG conditions. Board staff and others have proposed a simple after-the-fact adjustment to the HIM monthly average hourly production threshold that corrects for the SBG impacts. In cross examination, OPG has stated that it has the data and measurement capability to calculate the SBG impact and that it could adjust the HIM threshold to reflect this interaction. OPG's objection to this *post-facto* adjustment is that it would complicate the settlement process and procedure with the IESO. However, Board staff and others suggested that there need be no monthly settlement of the HIM transactions and that the revenues accumulated could be held in a deferral account to be distributed later.

OPG has provided the determination of the unintended consequences of the interaction of SBG with HIM for the period March 2011 to December 2013 in Undertaking J4.7.

Revenue Requirement Adjustment

OPG's other major change to the existing mechanism, the discontinuation of the revenue requirement adjustment as the method for distributing the HIM revenues to consumers, is superfluous and unrelated to the Board's previous direction. Revenue requirement adjustments are an efficient way to clear deferral and variance accounts and have direct impacts on payment levels. In the case of the HIM, the evidence presented by OPG indicates that time shifting hydroelectric generation has the potential to generate significant revenues that could reduce consumer payments.

Board staff agrees that an incentive mechanism is an important tool for guiding OPG's operation of the hydroelectric assets. However, balancing the revenues generated by an incentive mechanism and the operating, market and grid efficiencies from time shifting generation is a key objective. Board staff believes that these objectives are best achieved by not placing limits on the extent that OPG will benefit from the time shifting of generation as the proposed eHIM mechanism appears to do. Instead, Board staff believes that OPG should use its PGS, run-of-river and dam facilities to maximize the net revenues generated from time shifting. However, Board staff also supports a revenue sharing mechanism that, at a minimum, gives back to consumers fifty percent of these net revenues through revenue requirement adjustments and deferral accounts.

Board staff also believes that a more generous sharing mechanism that favours consumers through a graduated, increasing percentage of net revenues that changes with the absolute level of revenues generated should be considered by the Board. Ultimately, all these revenues come from consumers and a "fair" sharing should take account that OPG is protected from revenue risk through the payments levels established through the Board.

Net revenues from the HIM should be shared on a minimum of 50 percent for consumers and 50 percent for OPG. Board staff submits that some HIM revenue should be incorporated in revenue requirement, i.e., for 2014, consumers get the first $22M, OPG the next $22M and all revenue above $44M is shared equally; for 2015, when the newly regulated facilities are regulated for the full year, consumers get the first $37M, OPG the next $37M and all revenue above $74M is shared equally.

The Board could consider graduated percentage sharing mechanisms as revenues increase. For example, the first $50M of revenues is shared 50:50, the next $20 M of revenues is shared 60:40 (consumers: OPG) the next $20 M is shared 80:20 and any additional revenues are shared 90:10.[94]

Consumer revenues should be accumulated in a HIM deferral account and distributed to consumers, with interest.

General

This is the third proceeding in which hydroelectric incentives have been proposed and examined. Board staff submits that in each proceeding the evidence has not been clear and that a disproportionate amount of examination is required to understand OPG's analysis and proposals. The Board may wish to consider more prescriptive filing guidelines for this subject.

[94] The shares and thresholds are illustrative and not meant to be a recommendation.

5.4 Nuclear Production Forecast

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

The following table summarizes the nuclear production forecast as filed and as updated.

Table 17

Nuclear Production									
TWh	**2010 Actual**	**2011 Approved**	**2011 Actual**	**2012 Approved**	**2012 Acutal**	**2013 Budget**	**2013 Actual**	**2014 Plan**	**2015 Plan**
Darlington	26.5	28.9	29.0	29.0	28.3	26.9	25.1	28.4	26.1
Pickering	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**

5.4.1 As Filed

The nuclear production forecast filed in the evidence (Exh E2-1-1 and Exh E2-1-2) was based on the 2013-2015 Business Plan (May 16, 2013). OPG's nuclear production forecast methodology is unchanged since its EB-2010-0008 filing with the Board. OPG's nuclear generators are baseload generators. The production forecast is equal to the sum of the nuclear units' generation capacity multiplied by the number of hours in the year, less the number of hours for planned outages plus forced production losses (unplanned outages and unplanned derates) and corrections for generation losses (lake temperature differentials, grid losses and station consumption).[95] Based on factors including prior experience, the extent of planned outages and the impacts of unforeseen events, forced loss rates ("FLR") that result in lost production opportunities are estimated and calibrated.

OPG prepares separate production forecasts for each generating unit within the two nuclear stations. The total station production forecast is the sum of the unit forecasts and the total production forecast is the sum of the station forecasts. By breaking down

[95] Exh E2-1-1, page 4.

the production forecasts to the unit level, OPG can be more precise developing planned outage schedules and assessing past performance for predicting the impacts of FLR.

The test period forecast includes a Darlington vacuum building outage ("VBO") in 2015 in which all 4 units will be shutdown. The VBO was originally scheduled for 2021, but was advanced to 2015 and eliminates the 4 unit shutdown related to a station containment outage ("SCO") which is smaller in scope and shorter in duration than a VBO. OPG's plans to move forward the Darlington VBO by six years requires approval from the Canadian Nuclear Safety Commission ("CNSC"). During cross-examination, OPG confirmed that CNSC had approved OPG's plan to move the VBO forward.[96] OPG also confirmed in response to a Board Staff IR that it had conducted a cost-benefit type of analysis and that there was "….a positive payback to implementing a 12 year VBO/SCO cycle for the life of the plant compared to a 12 year VBO/6 year SCO cycle."[97]

The test period forecast also reflects a reduction in production of 0.5 TWh each year for major unforeseen events. This reduction is incremental to all the adjustments noted above. OPG has included the 0.5 TWh reduction in each year because this adjustment was permitted in the Board's decision in the previous cost of service proceeding, EB-2010-0008.

5.4.2 Exhibit N1 Update

OPG filed a revised production forecast as part of the impact statement filed on December 16, 2013. The revised production forecast was based on another business plan (2014-2016 Business Plan, November 14, 2013). The revised forecast reduced production in 2014 by 0.6 TWh and in 2015 by 2.0 TWh as a result of increased outage days. Exh N1-1-1 provides the following with respect to the reduction in production forecast 6 months after the previous forecast:

> As part of the 2014-2016 Business Plan review process (see Ex A2-2-1), OPG's senior management directed generation planning staff to reassess the plan based on OPG's historical performance in which significant production forecast variances have occurred (i.e., actual generation has been lower than forecast over the past nine years including 2013). The

[96] Oral Hearing Tr Vol 6, page 34-35.
[97] Exh L-5.5-Staff-67

> reassessment revisited both outage scope along with the allowances, with the objective of establishing a more realistic and accurate nuclear production forecast for 2014-2015.[98]

The revised production forecast for the Pickering station is down by a combined 1 TWh (0.4 TWh in 2014 (-1.8%) and 0.6 TWh in 2015 (-2.7%)). The forecast of planned outage days increased a total of 86.6 days over the two years; up 11.9% in 2014 and 17.9% in 2015. The major changes to outage planning in the revised forecast are:

- A 23-day mid-cycle Unit 5 outage in 2014 to measure calandria tube gaps;
- A deferral of unit 4 outage from 2013 to 2014 adds an additional seven days;
- A additional mid-cycle outage adds 28 days in 2015 to focus on preventative maintenance and reduce the risk of future forced outages; and,
- A reassessment of allowances to account for risks that can extend an outage added a total of 28.6 outage days over the two-year test period.[99]

The revised Darlington production forecast reduces output by a total of 1.6 TWh (-0.2 TWh in 2014 (-1.1%) and -1.4 TWh in 2015 (-5.4%)). Planned outage days increase by a total of 61.9 days over the two years; up 5.6% in 2014 and 30.6% in 2015.
A small decrease in production (0.28 TWh) is attributed to higher ambient lake water temperatures which reduce condenser efficiency. The larger impact (an additional decrease of 1.4 TWh) is the result of an increase in planned outage days. An additional 61.9 days of outage are attributed to moving a planned vacuum building outage (VBO) forward from 2012 to 2015 and increased scope and life extension maintenance associated with that outage. The scope of work includes emergency service water piping replacement, emergency coolant valve replacement and pressure relief valve maintenance.[100]

5.4.3 Exhibit N2 Update

Subsequently, OPG filed a revised production forecast as part of the impact statement filed on May 16, 2014. The Exh N2-1-1 update reflects a 0.5 TWh drop in forecast production for Pickering for 2014. There is an increase in outage days related for forced

[98] Exh N1-1-1 page13
[99] Exh N1-1-1 page 14
[100] Exh N1-1-1 page 15

extension to planned outages and the FLR for Pickering has increased from 7.8% to 8.9%.

5.4.4 Production Variances

The filed evidence shows that Pickering energy production has consistently been below forecast or Board approved production in the 2010-12 period; 5.9 % below in 2010, 10.5% in 2011 and 10.0% in 2012. Actual Darlington production variances were of smaller magnitude than the Pickering variances and not consistently below forecast; 4.7% below in 2010, 0.3% above in 2011 and 2.4% below in 2012.[101]

In the period 2008 to 2013, actual total nuclear production was below forecast in each year. The response to Exh L-5.5-LPMA-6 indicates that the average loss of revenue is $178.6M annually.

Forced Loss Rate (“FLR”) is a measure of the percentage of electricity generation that a plant is not supplying because of forced outages and derates (i.e. not planned). The response to Exh L-5.5-SEC-74 indicates that the average FLR for Darlington in the period 2005 to 2013 is 2.0% while the FLR for Pickering for the same period is 13.2%. The response also indicates that Darlington FLR was consistently at the target FLR or below in the period prior to 2010. Since 2010, the Darlington FLR has exceeded the target FLR in 3 years out of 4. Pickering FLR significantly exceeds target in every year from 2005 to 2013 except for one year.

5.4.5 Production Forecast

It is Board staff’s understanding that nuclear production forecasts are built from ground up and refined based on OPG’s experience with many unit outages and prior SCO and VBO. It is unclear how such a forecast produced on May 16, 2013 changed 6 months later and increased outage time by 148.5 days over the test period. In cross examination, OPG witnesses refer to the emergency service water piping and emergency coolant injection valve replacement as “the critical path” and the determining factor in the length of the Darlington 2015 outage.[102] As this critical path work was not

[101] Exh E2-1-2 Table 1.
[102] Oral Hearing Tr Vol 6 page 34

described in the original evidence, staff assumes the need was identified between May and November of 2013.

Board staff notes that OPG's as filed outage OM&A for the test period is $262.7M for 2014 and $330.7M for 2015. The higher 2015 outage OM&A reflects the work required for the "lengthy and complex combined 4 unit VBO/SCO at Darlington."[103] There is no reference to the critical path work in the outage OM&A section of the AIC, although the OPG witnesses described the work as significant. OPG has not revised outage OM&A since September 27, 2013 to reflect the additional 148.5 outage days from Exh N1-1-1 or the additional 21 outage days from Exh N2-1-1 or the critical path work. OPG has adjusted nuclear fuel costs but not outage OM&A. Board staff questions whether the $26M in Chart 1 (Changes Not Included in Impact Statement) of Exh N1-1-1 reflects the additional outage OM&A for the additional outage days and critical path work.

In the previous proceeding, EB-2010-0008, OPG's forecast included an exogenous negative adjustment ("forecast for major unforeseen events") to forecast production levels of 2 TWh in both 2011 and 2012. This adjustment was a new element, absent from OPG's previous application (EB-2007-0905), and is not a standard industry practice. OPG was unaware if any other nuclear utility forecasts major unforeseen events ("MUE"). The Board concluded that

> … a forecast of 50.4 TWh for 2011 and 51.5 TWh for 2012 should be used for determining the revenue requirement. This incorporates an MUE adjustment of 0.5 TWh per year. The Board finds that this provides adequate recognition of past historic variances due to MUE and the possibility of future similar events, but also incorporates the impact of overall performance improvements, recognizes the expectations of the nuclear business and sets an incentive structure that provides benefits to ratepayers while still providing upside potential for OPG.[104]

As noted previously, OPG incorporated the 0.5 TWh per year MUE (or 1.0 TWh in the test period) in its originally filed production forecast. The total of the Exh N1-1-1 and Exh N2-1-1 updates is a reduction of 3.1 TWh in the test period. Board staff observes that the total production impact of the MUE as filed and the two updates is equal to the total MUE OPG sought in its previous application. Board staff questions how rigorous

[103] AIC page 72
[104] Decision with Reasons, EB-2010-0008, page 39

the analysis of production forecast for the updates was and whether the process was intended to propose explanations for what are MUE.

The Exh N1-1-1 update includes a 1.6 TWh reduction for Darlington related to higher lake water temperatures (0.28 TWh) and the increase in outage days for VBO/SCO and critical path work. Board staff submits that the reduction, other than the 0.28 TWh, should not be reflected in the production forecast for Darlington as it was responsive to OPG senior management direction and does not appear to be based on rigorous ground up analysis.

Staff acknowledges that the historical record of production forecasts compared to actual output shows a higher variance for the Pickering units compared to the Darlington production record. The Pickering experience, as compared to Darlington's performance, is a better justification for the direction from OPG's senior management to reassess the production forecast to be more in line with actual historical performance. Board staff recommends that the Board accept the revised production forecast for Pickering of 20.4 TWh in 2014 and 21.3 TWh in 2015.

6. OPERATING COSTS

6.1 Regulated Hydroelectric OM&A

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

The historical, approved and forecast OM&A are summarized in the following table which is an excerpt of the table included in staff's compendium for cross examination.[105] Board staff notes that the Exh N1-1-1 and Exh N2-1-1 updates (both largely affected by pension impacts) are generally off-setting.

[105] Exh K3.7, page 2

Table 18

		Previously Regulated Hydroelectric					Newly Regulated Hydroelectric				
	$million	**2013 Budget**	**2013 Actual**	**2014 Plan**	**2015 Plan**	**2010-2012 Average**	**2013 Budget**	**2013 Actual**	**2014 Plan**	**2015 Plan**	**2010-2012 Average**
1	Base[1]	71.9	61.6	74.6	68.6	59.8	113.2	103.5	113.4	113.7	103.0
2	Project	13	14.7	13.5	17.9	8.5	16.0	23.1	24.5	32.1	27.2
3	SubTotal Operations	84.9	76.3	88.1	86.5	69.3	129.2	126.6	137.9	145.8	130.2
4	Corporate Costs	29.7	26.1	29.8	26.9	23.0	38.8	35.2	42.1	39.6	33.4
5	Centrally Held Costs	25.1	20.7	26.1	26.0	18.4	47.2	31.8	49.6	48.7	25.7
6	Asset Service Fee	1.7	1.6	1.5	1.7	1.8	3.1	3.0	2.9	3.0	3.4
7	SubTotal Other	56.5	48.4	57.4	54.6	43.2	89.1	70.0	94.6	91.3	62.6
8	**Total OM&A**	**141.4**	**124.7**	**145.5**	**141.1**	**114.3**	**218.3**	**196.6**	**232.5**	**237.1**	**192.8**
9	Exhibit N1 Update			**149.2**	**144.2**				**239.3**	**242.6**	
10	Exhibit N2 Update			**145.1**	**140.0**				**234.9**	**237.3**	
	Note 1: The 2011 previously regulated base OM&A is not included in the average; unusual environmental credit (lines 1,3,8)										

In addition to OM&A, operating costs include depreciation and taxes which are discussed later in this submission. The hydroelectric operating costs also include the gross revenue charge (“GRC”) which is governed by legislation and refers to taxes and charges that are required to be paid by owners of hydroelectric generating stations. The GRC consists of a property tax component and a water rental component and is a significant component of total operating costs. The previously regulated hydroelectric GRC is forecast to be $267.3M in 2014 and $280.8M in 2015. The newly regulated hydroelectric GRC is forecast to be $75.6M in 2014 and $77.5M in 2015.

From 2010 to 2013, the previously regulated operations actual OM&A (line 3 of the table) was below approved/budget in each year except for 2012. The actual total OM&A was below approved/budget in each year (line 8 of the table)

In cross examination, OPG confirmed that the variance is largely explained by unfilled vacancies, some of which has been addressed by temporary staff, but that there were no operational repercussions. OPG has managed the unfilled vacancies at a high level and reprioritized work.[106]

Board staff noted that the compound annual growth rate for total OM&A from 2010 actual to 2015 plan (Exh N2-1-1) is 5.2% which is higher than increases related to compensation under collective agreements and inflation.

[106] Oral Hearing Tr Vol 3, page 161

For the newly regulated hydroelectric operations, the actual operations OM&A (line 3 of the table) has averaged $130.2M the period 2010 to 2012. The total OM&A (line 8 of the table) has averaged $192.8M in the period 2010 to 2012. The compound annual growth rate for total OM&A from 2010 actual to 2015 plan (Exh N2-1-1) is 4.1%. Board staff asked OPG whether it was realistic to forecast $232.5M for total OM&A in 2014 when the 2013 actual expense was $196.6M (vs. $218.3M budget). In response to SEC, OPG provided undertaking J4.3 which explained how the 2013 budget was developed. However, Board staff submits that this response does not explain the significant 2013 variance or support the test period OM&A proposal.

For the test period, on the operations side (i.e. line 3) the OPG witnesses spoke about filling vacancies in the test period with staff from the thermal side of OPG's business. In response to examination by Board staff, OPG provided a Q2 2014 OM&A forecast.[107] While the forecast was limited to only operations data, the undertaking confirmed that OPG expects to be below the 2014 OM&A levels proposed in the application.

As there has been consistent under spending with no impact on operations, and as the compound annual growth rate from 2010 to test period forecast is in the 4-5% range, Board staff submits that reductions in hydroelectric OM&A are appropriate as outlined below:

- Consistent with OPG's current 2014 forecast summarized in J3.13, operations OM&A for each test year should be reduced by $1.3M for the previously regulated hydroelectric facilities and by $6.9M for the newly regulated facilities.
- For both previously regulated and newly regulated hydroelectric, the 2013 budget and test period total OM&A are atypical of the actual levels for 2010 to 2012. In the absence of other OM&A data in J3.13, Board staff has based reductions on 2013 other OM&A variances. The 2013 variance of $8.1M should be applied to reduce the other OM&A in each test year for the previously regulated hydroelectric facilities. Similarly, the other OM&A 2013 variance of $19.1M should be applied to reduce the other OM&A in each test year for the newly regulated hydroelectric facilities.

[107] J3.13

The 2013 actual and test year total OM&A resulting from the reductions listed above are shown below:

Table 19

Total OM&A ($million)	2013 Actual	2014 Revised	2015 Revised
Previously Regulated	124.7	135.7	130.6
Newly Regulated	196.6	208.9	211.3

Board staff proposes no further hydroelectric OM&A reductions related to compensation (section 6.7 of the submission) or corporate costs (section 6.9 of the submission) as they are subsumed in the reductions noted above.

6.2 Regulated Hydroelectric Benchmarking

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

The hydroelectric business uses 3 main sources for benchmarking – Electricity Utility Cost Group ("EUCG"), Navigant and Canadian Electrical Association ("CEA"). The main operational benchmarks are: availability, equivalent forced outage rate ("EFOR") and OM&A Unit Energy Cost.

The small plants in the Central Hydro Plant Group are excluded from benchmarking because they are self-dispatchable and have no impact on reliability of the grid.

The evidence at Exh F1-1-1 indicates that the benchmarking databases include 260 to 300 comparator plants. In terms of availability and EFOR, 50-60% of the OPG baseload and large newly regulated plants perform in the top 2 quartiles. In terms of cost, 70-80% of the OPG baseload and large newly regulated plants perform in the top 2 quartiles.

Through interrogatories, the technical conference and cross examination, it was confirmed that none of the benchmarking is done independently by a third party. This was also noted by KPMG in its overall review of benchmarking at OPG.[108] For this

[108] Exh K3.1 – KPMG Assessment of Benchmarking Reports from OPG, prepared for Ministry of Energy

reason, KPMG did not use the “benchmarking” provided for OPG’s hydroelectric facilities in its review.

OPG purchases the raw data from EUCG, Navigant and CEA. The OPG witnesses stated that there are workshops and meetings with these organizations to discuss best practices. OPG stated that most utilities do not independently benchmark hydroelectric facilities. OPG has not completed any independent benchmarking to date and OPG does not intend to on a go forward basis.[109]

With respect to OM&A, in cross examination, OPG also confirmed that it exercises discretion in the costs that are included in the benchmarking analysis, but that there are meetings where reviews are done to ensure data are consistently treated. In terms of the OM&A in the above Table 18, only costs in line 1 are benchmarked. The witness indicated that project OM&A could be quite variable and some utilities don’t do the allocations of “corporate” type costs.

The GRC, while not OM&A is an operating cost. OPG has excluded GRC from the benchmarking because it is a regulatory cost and not within OPG’s control.

Board staff notes that the OPG witnesses responsible for nuclear benchmarking confirmed that all corporate costs and some centrally held costs are included in the Pickering and Darlington benchmarking.[110] As EUCG is one of the sources of hydroelectric cost data and the only source for nuclear cost data, Board staff questions why hydroelectric benchmarking has been limited to base OM&A. While the impact of Business Transformation on the hydroelectric business has been limited, the transfer of any staff to corporate functions would skew any benchmarking results that only rely on base OM&A.

Board staff submits that selectively benchmarking only 50% of total OM&A costs and completely excluding regulatory costs, which are a significant component of operating cost, is not representative of the operations of the hydroelectric facilities. Board staff submits that the Board may wish to consider a more thorough and independent benchmarking process, particularly with hydroelectric IRM on the horizon. While the

[109] Oral Hearing Tr Vol 4, page 3
[110] Oral Hearing Tr Vol 6, page 105, J5.3

independent consultant may come to the conclusion that only a subset of operating cost can be benchmarked, Board staff submits that the review is required.

Board staff also submits that OPG should clearly identify when any benchmarking in its application is the result of independent analysis and when it is not.

6.3 Nuclear OM&A

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

The historical and forecast OM&A are summarized in the following table. Board staff notes that the Exh N1-1-1 and Exh N2-1-1 updates (both largely affected by pension impacts) are generally off-setting.

Table 20

	$million	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
1	Base	1181.4	1249.1	1102.6	1127.7	1151.1	1154.0
2	Project	142.7	111.6	111.5	105.7	113.9	106.4
3	Outage	278.2	215.0	214.3	277.5	262.7	330.7
4	SubTotal Operations	1602.3	1575.7	1428.4	1510.9	1527.7	1591.1
5	Darlington Refurbishment	3.2	2.6	2.8	6.3	19.6	18.2
6	Darlington New Nuclear	23.2	15.7	24.7	25.6	0.0	0.0
7	Corporate Costs	226.5	233.1	408.4	428.3	433.9	417.4
8	Centrally Held Costs	161.6	267.1	342.7	409.9	418.2	419.8
9	Asset Service Fee	24.5	22.1	23.0	22.7	23.3	26.8
10	SubTotal Other	439.0	540.6	801.6	892.8	895.0	882.2
11	**Total OM&A**	**2041.3**	**2116.3**	**2230.0**	**2403.7**	**2422.7**	**2473.3**
12	Exhibit N1 Update					**2491.8**	**2531.3**
13	Exhibit N2 Update					**2401.4**	**2419.8**
14	Pension/OPEB current service	159.5	218.3	265.5	294.6	**236.2**	**242**
15	Total OM&A less pension/OPEB	1881.8	1898.0	1964.5	2109.1	**2165.2**	**2177.8**
	Sources: Exh L-1-Staff-2 Table 19, Exh N2-1-1, J9.7						

In addition to OM&A, nuclear operating costs include nuclear fuel, depreciation and taxes which are discussed later in this submission.

OPG's generation portfolio will change significantly as Pickering is shut down in 2020 and as Darlington is refurbished starting in 2016. In 2011, OPG initiated a Business Transformation ("BT") initiative to align costs with revenue/generation.

To date OPG has used attrition to reduce its year-end 2015 corporate headcount by 2,000 employees, of which 1,300 (and $550M savings between 2011 and 2015) are attributable to the regulated operations.

OPG has also moved to a centre-led organization "to use resources more efficiently and avoid duplication of work." There are centre-led functions for HR, supply chain, finance, communications, etc. Prior to BT, OPG had separate supply chain departments within each business unit. BT and centre led organization resulted in significant staff transfers from the nuclear business to support service groups. The evidence states that the increase in support service costs was offset by an equal decrease in directly incurred costs.

The historical and forecast nuclear staffing and compensation is summarized in the following table. Compensation accounts for 60 to 70% of nuclear total OM&A.

Table 21

		2010 Actual	2011 Actual	2012 Acutal	2013 Actual	2014 Plan	2015 Plan
	Headcount						
1	Nuclear Ops & Projects	8,246	7,901	6,556	6,362	6,329	6,210
2	DRP and New Nuclear	153	241	227	198	266	276
3	Nuclear Corporate Support	871	857	1,941	1,883	1,759	1,683
4	Total (Reg and Non Reg)	9,270	8,999	8,724	8,443	8,354	8,169
5	DRP, New Nuc, Corp Supp	176	283	290	276	367	378
	FTE						
6	Nuclear Ops & Projects	8,292.5	7,988.6	6,536.7	6,353.6	6,315.6	6,243.9
7	DRP and New Nuclear	152.9	226.5	225.1	200.6	264.1	276.0
8	Nuclear Corporate Support	875.0	876.1	2,037.2	1,910.6	1,790.6	1,714.1
9	Total (Reg and Non Reg)	9,320.4	9,091.2	8,799.0	8,464.8	8,370.3	8,234.0
10	DRP, New Nuc, Corp Supp	178.3	268.6	290.7	280.2	368.1	380.4
	Compensation $million						
11	Nuclear Ops & Projects	1,274.6	1,281.5	1,135.7	1,202.3	1,064.1	1,085.6
12	DRP and New Nuclear	23.1	36.3	37.6	40.3	52.2	55.2
13	Nuclear Corporate Support	122.5	129.1	268.2	291.7	290.1	280.5
14	Total (Reg and Non Reg)	1,420.2	1,446.9	1,441.5	1,534.3	1,406.4	1,421.3
	Sources: JT2.33 and J9.7						

The transfer of staff from the nuclear business to corporate support is evident from line 7 of Table 20 and lines 1,3 and 6,8 of Table 21.

For the nuclear business and related corporate support, BT will result in a reduction of 857.2 FTE in the period 2011 to 2015.

Undertaking J9.7 summarizes business unit FTE and compensation as updated for Exh N2-1-1. The undertaking provides a break-out of the pension/OPEB current service costs. This is reflected in line 14 of Table 21. Board staff has determined the following compound annual growth rates.

Table 22

Compound Annual Growth Rate	2010 to 2013	2010 to 2015
Total OM&A	5.6%	3.5%
Total OM&A less pension/OPEB	3.9%	3.0%

The nuclear business and related corporate support OM&A has been significantly improved by BT – OPG's initiative responding to future revenue/generation reductions. As noted below, the OM&A improvements have not yielded better benchmarking performance as OPG's peers have also achieved operational improvements, and OPG's nuclear production/reliability performance has deteriorated, and perhaps other reasons.

Board staff submits that in part due to poor benchmarking results (summarized below), reductions of $100M to the proposed nuclear OM&A for the test period are appropriate. The reductions are noted in the compensation section of this submission (section 6.7) and the corporate cost section of this submission (section 6.9).

6.4 Nuclear Benchmarking

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

6.4.1 Background

OPG is required by its shareholder to undertake benchmarking. In the Memorandum of Agreement with the Shareholder ("MOA"), dated August 17, 2005, OPG agreed that it 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. [Emphasis added]

The MOA 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. [Emphasis added]

Despite the direction contained in the MOA, OPG's initial efforts at benchmarking were lackluster. In the first payments case before the Board (EB-2007-0905), the Board observed that although OPG had retained Navigant to prepare a benchmarking report on nuclear staffing, that report was produced in the proceeding only reluctantly, and OPG had not followed up on any of the recommendations made by Navigant.

> Moreover, the Board was surprised that OPG has not followed up with the suggested Phases 2, 3 and 4 of the benchmarking analysis suggested by Navigant. While the benchmarking is critical to the Board (and it would seem to the shareholder), it appears that OPG has done little since the completion of the Navigant Study. The Navigant Study was delivered two years ago on September 15, 2006. There appear to be no benchmarking studies underway. And OPG has not decided what benchmarking evidence, if any, it will present at the next rates case.[111]

The 2006 Navigant report concluded that OPG nuclear was overstaffed by approximately 12% compared to the appropriate benchmark.

In light of the paucity of benchmarking data presented in the first payments case, the Board directed OPG to retain an expert to prepare a comprehensive benchmarking analysis of OPG's nuclear operations.

> The Board directs OPG to produce further benchmarking studies in its next application that specifically address the questions raised in the proposed Phase 2 and Phase 3 of the Navigant Report. Whether these studies are performed by Navigant or another firm is a matter to be determined by the applicant.[112]

In response to this direction, OPG retained ScottMadden, Inc. ScottMadden produced two reports: a Phase 1 report which benchmarked OPG's performance against comparable North American nuclear companies, and a Phase 2 report which contained ScottMadden's observations and recommendations for improvement. Both of these reports were filed in the second payments case (EB-2010-0008), and a witness from ScottMadden testified at the oral hearing. The reports have also been filed in the current proceeding.

[111] Decision with Reasons, EB-2007-0905, page 30
[112] Decision with Reasons, EB-2007-0905, page 31

The Phase 1 report painted an unflattering picture of OPG's performance. ScottMadden benchmarked OPG against other North American nuclear operators for 19 metrics. Of those 19 metrics, three were identified as "key metrics".

Key Metric	Description	OPG Rank – 2008
NPI - WANO Nuclear Performance Index	Provides a comprehensive overview of a nuclear operator's overall operating performance.	17th out of 20
TGC – Total Generating Cost per MWh	Highest indicator of an operator's overall financial performance. This metric is the sum of non-fuel operating costs per MWh, fuel costs per MWh, and capital costs per MWh, and represents the "all in" cost of producing each MWh of power.	18th out of 20
UCF – Unit Capability Factor	The ratio of available energy generation to the reference energy generation (i.e., energy that could be produced if the unit were operating continuously at full power under normal conditions) over a given time period.	16th out of 16

Source: EB-2010-0008 ExhF5-1-1, p141-145

OPG performed very poorly against all three of the key metrics in 2008. Partially as a result of OPG's poor performance on the key metrics, the Board made cuts to OPG's proposed revenue requirement in the amount of $145M.[113]

The Phase 2 report included ScottMadden's recommendations to OPG to improve both the relative and absolute performance of its nuclear facilities. In conjunction with OPG,

[113] The Board's decision with respect to the disallowance of $145M has been the subject of a number of appeals: first before the Divisional Court (where the Board's decision was upheld), then before the Court of Appeal (where the decision was overturned). The Board has obtained leave to appeal the Court of Appeal's decision to the Supreme Court of Canada, and that appeal will be heard in December 2014. However, the issue on appeal is whether the Board is entitled to use "hindsight" in assessing the reasonableness of what OPG describes as "forecast" O&M costs (in this case OPG's collective agreements, which were in part signed prior to the commencement of the 2011-2012 test period in EB-2010-0008). The Court of Appeal held that the Board cannot use hindsight; however, there was no finding that benchmarking analysis was an improper thing for the Board to consider. On the contrary, the Court held that benchmarking could be used by the Board provided it was on a prospective basis. Therefore, even if the Court of Appeal's decision is upheld by the Supreme Court, the appropriateness of the Board using benchmarking as a basis to make disallowances will be unaffected.

ScottMadden developed action plans and specific targets for the 19 metrics (including the three key metrics) that OPG would attempt to achieve by 2014 to close the gap. The targets were set on a facility by facility basis (i.e. separate targets for Pickering A, Pickering B, and Darlington). OPG agreed to these targets and incorporated them into its 2010-2014 five-year business plan. The targets were agreed to by all of OPG's site and support unit executives.[114] ScottMadden observed: "[w]hile the targets set for 2014 will not achieve 'best quartile' performance in all performance categories for all sites, they represent a significant improvement over current performance. … In our opinion, the targets established by OPG management are fair and reasonable given OPGN's baseline position."[115]

6.4.2 Benchmarking Results

OPG annually prepares a "Nuclear Benchmarking Report". These reports, prepared by OPG since 2009, measure performance in the same manner that ScottMadden did in the Phase 1 report (which presented the data from 2008), subject to some minor differences.[116] For example, the report now includes 20 metrics and Pickering A and B results are shown as one station to reflect amalgamation. The most recent year for which the scorecard has been completed is 2013.

The results of OPG's efforts to date to achieve the targets agreed to by OPG's site and support unit executives, are summarized in a table prepared by Board staff for cross examination and subsequently reviewed by OPG. The reviewed chart was filed as J5.2 and is reproduced below.

[114] Exh K5.5, ScottMadden Phase 2 report, page 31.
[115] Exh K5.5, ScottMadden Phase 2 report, page 31 - OPGN stands for Ontario Power Generation Nuclear.
[116] Exh F2-1-1 page 4

Summary of Nuclear Benchmarking Reports

	---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		

Q1
Q2
Q3
Q4

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 Pla
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)

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

The benchmarking reports reflect rolling averages for UCF and TGC (columns a to f) while the targets are annual targets (columns g to i). Column g are the 2014 targets OPG established with ScottMadden (and incorporated into its 2010-2014 business plan). Column h are OPG's most recent 2014 targets.

Actuals to the end of 2014 are of course not yet available. However, it seems that OPG will likely not meet the targets it established with ScottMadden or OPG's most recent targets for any of the three key metrics at any of its facilities.

For Darlington, the NPI target for 2014 was set at 98.60 by ScottMadden and 97.90 by OPG. The highest result OPG achieved since 2008 was 96.30 (2012); the most recent figure from 2013 is 90.8. The 2 year UCF target for 2014 was set at 93.30% by ScottMadden and 93.50% by OPG. The highest result achieved by Darlington since 2008 was 92%; however the figure from 2013 is 90.44%. Board staff is uncertain how the 90.44% two year rolling average UCF was determined as the 2013 data reported in OPG's financial results was 82.9%.[117] Regardless, it is highly unlikely that OPG will achieve its target of 93.50% or ScottMadden's target of 93.30% in 2014.

All of the value for money metrics, chiefly TGC, are based on data from EUCG. OPG confirmed that, unlike the benchmarking for the hydroelectric business, nuclear cost benchmarking includes corporate costs[118] and some centrally held costs.[119]

The data respecting TGC is puzzling to staff. The target set in conjunction with Scott Madden for 2014 was $36.75/MWh and more recently $36.21/MWh as set by OPG. However, Darlington had already handily exceeded this target by 2008 (for when OPG reports a TGC of $30.08/MWh), the year before the target was actually set. The $30.08/MWh figure does not appear in the Phase 2 report; however ScottMadden's forecast for 2009 was $36.48/MWh, which is significantly different from the actual figure later reported by OPG: $32.77/MWh. Given OPG's very poor overall performance on the TGC metric (16 out of 16 in 2008 and 12 out of 14 in 2011), it is not clear to staff why ScottMadden would set a target significantly *higher* than the results already achieved by OPG for Darlington. Considering the significant differences between ScottMadden's forecast of 2009 (which appears to have been prepared sometime in

[117] Exh L-2.1-ED-3, Attachment 1 page 5
[118] Oral Hearing Tr Vol 5 page 105
[119] J5.3

2009) and OPG's actual reported number for 2009, Board staff is having difficulty reconciling these data.

The analysis for Pickering is complicated somewhat by the fact that OPG now reports Pickering A and B as a single facility, whereas the ScottMadden targets were set for the facilities individually. Regardless, it is clear that the targets set in conjunction with ScottMadden for 2014 for NPI and UCF will not be achieved. For NPI, the targets set by ScottMadden for 2014 for Pickering A and B were 70.9 and 81.3 respectively. As of 2013 (the last year for which actuals are available), the combined result for the two facilities was 67.52 – significantly below the target that had been set for either facility. For UCF, the targets set by ScottMadden for 2014 for Pickering A and B were 84.3 and 81.0 respectively. The actual results for the combined facilities for 2013 was 75.77 – again significantly below the target for either facility.

Rather than setting aspirational targets that would drive towards top quartile, the 2015 targets are in fact lower for Darlington than 2014, and stable for Pickering. The benchmarking reports also summarize OPG's nuclear performance against its peers with colour coding for quartile performance. It is clear that TGC is deteriorating for Darlington and consistently in the fourth quartile for Pickering.

One of ScottMadden's target setting conclusions was:

> While the targets [agreed to by OPG site and support unit executives and] set for 2014 will not achieve "best quartile" performance in all performance categories for all sites, they represent a significant improvement over current performance.[120]

It is clear that OPG has not achieved the performance set out by ScottMadden. It would appear that the OPG nuclear business no longer considers closing the gap and achieving top quartile to be an objective. In cross examination, the OPG witness stated:

> MS. CARMICHAEL: First, you mention that our memorandum asks us to reach top quartile. I think the memorandum just asks us to benchmark against first quartile. I just want to clarify. Did I hear that incorrectly?[121]

[120] Exh K5.5, ScottMadden Phase 2, page 31
[121] Oral Hearing Tr Vol 5 page 119-120

Board staff does not understand this position. The MOA could require benchmarking without reference to the top quartile. In referring to top quartile in the MOA, it is clearly the shareholder's expectation that OPG would set targets to try to achieve top quartile.

The first decision, EB-2007-0905, noted that OPG did not follow up on Navigant's 2006 benchmarking recommendations and directed OPG to produce further benchmarking reports. Board staff submits that OPG has not followed up on the numerous recommendations developed to assist OPG in approaching top quartile performance as set out in ScottMadden's 2009 reports. In staff's view, it is clear that the Board directed OPG to produce further benchmarking as a means to improve performance and to achieve an enduring level of high performance.

6.4.3 Conclusion

OPG's nuclear benchmarking performance has been disappointing. As detailed above, OPG has made little progress in improving its overall nuclear performance relative to its peers. OPG is nowhere near the top quartile performance that its shareholder requires it to target through the MOA, and OPG stated that it does not target the top quartile. With respect to the three key metrics, OPG's nuclear business remains near the bottom of the rankings. Many of the targets OPG has set in the 2015 Business Plan are in fact lower than the targets that were originally set for 2014 in conjunction with Scott Madden, which does not appear to represent "continuous improvement" as mandated by the MOA. The poor benchmarking results speak to OPG's poor efficiency and level of productivity.

It must be stressed that OPG's poor nuclear performance directly impacts the costs imposed on ratepayers. In particular, OPG's poor performance in the three key metrics directly impact the revenue requirement. If OPG had a lower TGC and better UCF, for example, its revenue requirement would be lower. Using the most recent data available in the 2012 Benchmarking Report,[122] for example, OPG's overall nuclear TGC is \$46.92/MWh. The comparable figure for the generator at the TGC midpoint is \$40.50/MWh. If OPG's TGC were \$40.50/MWh, its costs would be reduced by approximately \$300M per year (TGC Differential x production forecast). If OPG were to actually achieve top quartile, the savings would be \$725M per year.

[122] Exh F2-1-1 Attachment 1 page 80

Board staff recognizes that the TGC includes OM&A, fuel and some capital costs. So this of course is a rough calculation and comparison, and Board staff is not suggesting disallowances even close to this magnitude. It does demonstrate, however, the very significant costs that are imposed on ratepayers as a result of OPG's inefficiency and poor productivity. It is reasonable for the Board to expect that OPG's efficiency and productivity should be improving.

OPG, its shareholder (through the MOA), and its benchmarking expert (from the previous proceeding) all accept that benchmarking is an appropriate tool to use to assess the efficiency of OPG's nuclear operations. The evidence is clear that OPG's cost and reliability performance has historically been poor, and remains poor. OPG accepts that there is much room for improvement.[123] However, OPG does not appear to accept that there should be any repercussions for its poor performance. Although nuclear performance is the responsibility of OPG's management, OPG proposes to pass all of the costs resulting from its poor performance to ratepayers. In Board staff's submission, this is not reasonable.

There is no "line item" for benchmarking in the revenue requirement, and the costs related to poor benchmarking performance cannot be directly tracked on a dollar for dollar basis to discrete budget items. Staff is proposing disallowances related to nuclear benchmarking; however those requests show up chiefly in in the compensation section of this submission (section 6.7) and the corporate cost section of this submission (section 6.9).

6.5 Nuclear Fuel

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

Nuclear fuel costs include the cost of fuel bundles, used fuel storage cost and fuel oil for standby generators. As updated in Exh N2-1-1, OPG has forecast an amount of $266.5M for nuclear fuel procurement for 2014 and $260.5M for 2015.

[123] Oral Hearing Tr Vol 5 page 96.

OPG filed the Uranium Procurement Program Assessment Study prepared by Longenecker and Associates ("L&A") at Exh F5-2-1; this study was conducted to comply with the Board's direction in Decision and Order EB-2010-0008. Based on its review of the fuel procurement policies and practices of nuclear power generators that it surveyed in Canada and the United States, L&A concluded that OPG has optimized its contract portfolio to achieve protection from supply and price disruptions.[124] L&A provided a number of recommendations, including one related to optimizing inventory. OPG accepted all of L&A's recommendations regarding uranium procurement except for exploration of "off-market" negotiated transactions. With respect to this latter matter of "off-market" negotiated transactions, OPG stated that L&A's recommendation is inconsistent with the Province's procurement guidelines.

Board staff does not take issue with the analysis and findings of the L&A study. Further, Board staff takes no issue with OPG's responses to the recommendations of L&A, including its position that "off-market" negotiated transactions are not preferred.

Since 2007, OPG's uranium concentrate target inventory has been 385,000 kgU (equivalent to 1.0M pounds U308). In response to L&A recommendations about evaluations of inventory levels, OPG has recently adopted a uranium concentrate target inventory of 288,000 kgU (equivalent to 0.75M pounds U308). In the AIC on page 81, OPG states that the new target will be achieved by the end of 2015.

The following chart is reproduced from the evidence at Exh B1-1-1 page 9 (rate base and working capital).

Chart 2
Summary of Year End Fuel Inventory - 2010 through 2015

Line No.	Type	units	2010 Actuals (a)	2011 Actuals (b)	2012 Actuals (c)	2013 Budget (d)	2014 Plan (e)	2015 Plan (f)
1	Uranium Concentrate[1]	K$	97,332	95,556	70,402	55,634	45,370	44,957
2		MgU	509	530	435	344	288	288
3		$/KgU	191.29	180.18	162.03	161.85	157.28	155.85

[124] L&A and OPG both note the differences in the nuclear generator technology between American generators and Canadian CANDU technologies, and how these result in differences in the fuel requirements and procurement approaches between generators in the two countries.

Board staff observes that this chart indicates the 288,000 kgU target being achieved in 2014. OPG is requested to clarify the information at Exh B1-1-1 and the AIC and to advise if there is any revenue requirement impact.

Board staff observes that the actual inventories of uranium concentrate were much higher than 385,000 kgU prior to 2013. As the targets were established in 2007, it took more than 5 years to achieve them. While the L&A study was available in April 2012, OPG has only recently proposed to reduce uranium concentrate inventory to 288,000 kgU. Further, Board staff questions whether now is the time to also reduce inventory related to closure of Pickering which is 2020 or earlier.

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 both appropriate strategies for balancing costs and risks, based on the approaches that OPG has found appropriate and that L&A found to be “good utility practice” in its study, as well as planning for lower nuclear fuel inventory requirements for when Pickering will cease operations.

Subject to the above, Board staff submits that the nuclear fuel costs are appropriate, but that the final costs are subject to OPG’s response to the revenue requirement impact question above and the determination of production forecast.

6.6 Pickering Continued Operations

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

In 2010, OPG decided to pursue continued operations of Pickering units 5 to 8 rather than refurbishment. The project would extend life from 2015/2016 to 2020. The previous cost of service decision approved $84.1M in expenses in the 2011-2012 test period for Pickering continued operations.

The 2014 cost of the incremental operating and maintenance work, including additional inspections, is $38.9M. There is an additional expense of $1.8M related to the Pickering continued operations share of the Fuel Channel Life Cycle Management project. No project costs are forecast for 2015. OPG also seeks capacity refurbishment account recovery related to Pickering continued operations 2013 costs. Board staff takes no issue with these costs.

The original design life of the pressure tubes/fuel channels was 210,000 effective full power hours ("EFPH"). Based on work done in the Fuel Channel Life Management project, OPG has high confidence that fuel channels can achieve 247,000 EFPH. The CNSC has renewed Pickering's operating licence to August 31, 2018 but required OPG to make submissions in June 2014 on operating beyond 210,000 EFPH.

OPG has filed an updated business case for the project. OPG reports that the net system benefit of Pickering continued operations vs gas plant operation is $520M. An OPA letter filed with the application suggests that the cost advantage of Pickering continued operations is $100M. This is lower than the $1.1 billion benefit reported in the last cost of service proceeding.

Several intervenors have questioned the economic merits of continued operations of Pickering. Board staff submits that, for the test period, the Board should rely on the Long Term Energy Plan:

> 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.[125]

Board staff therefore supports the cost levels proposed for the 2014 and 2015 test years, subject to any impacts resulting from its submissions on other issues,

6.7 Compensation

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

[125] Exh KT2.2, page 30

Compensation costs are a major component of OPG's revenue requirement. OPG's forecast regulated compensation costs are $1,604.2M for 2014, and $1,618.1M for 2015.[126] The pension component of these compensation costs are the current service costs only, and additional pension costs are also held in "centrally held" costs.

Compensation costs are a function of the number of staff and the wages and benefits paid to/for these staff. Although OPG has made significant reductions to its overall headcount since 2010,[127] its overall compensation levels have continued to climb: from $1,581M in 2010 to a forecast of $1,618.1M in 2015. From 2010 actuals to 2015 forecast, average compensation per employee has risen 1.82% for Management, 10.35% for Society of Energy Professionals ("SEP") employees, and 19.73% for Power Workers' Union ("PWU") employees.[128]

6.7.1 The Regulatory Framework: OPG, Collective Bargaining and the Board

The majority of OPG's staff are unionized, either in the PWU or SEP. For 2014, OPG forecasts it will have headcount numbers of 4,986 from the PWU, 2,995 from the SEP, and 1,084 from Management.[129] Of OPG's forecast 2014 compensation costs of $1,604.2M, $845.5M is for the PWU (53%), $527.1M is for the SEP (33%), and $225.5M is for Management (14%).[130] Approximately 86% of OPG's forecast compensation costs, therefore, are dedicated to its unionized employees.

The application notes that the PWU collective agreement was negotiated in early 2012 and it covers the period from April 1, 2012 to March 31, 2015. The wage increases negotiated under the agreement for 2012, 2013 and 2014 are 2.75% for each year. OPG stated that the agreement was achieved under a net zero regime – meaning any increase in compensation had to be offset by corresponding savings elsewhere in the collective agreement.

The application also notes a negotiated agreement with the SEP could not be achieved and it was submitted to interest arbitration, with the Interest Arbitrator awarding

[126] J9.7 Attachment 1

[127] Regular staff headcount was 9,786 in 2010, and is forecast to be 8,475 in 2015. JT2.33 page 2

[128] J9.7

[129] These numbers exclude 464 "non-regular" employees. Note that "Management" includes all non-unionized employees. Most (but not all) of these employees have management roles. JT2.33 page 2

[130] A further $6.2M is for the EPSCA. J9.7 Attachment 1

increases for 2013, 2014 and 2015 of 0.75%, 1.75% and 1.75%, respectively. The Interest Arbitrator also ordered a temporary freeze on pay progression through the established pay grid for SEP employees during the test years (2014 and 2015).

OPG is required to collectively bargain with its unionized employees and, as discussed in further detail below, this places restrictions on its ability to manage its compensation costs. OPG has more flexibility with respect to compensation for its non-unionized employees.

OPG is an *Ontario Business Corporations Act* corporation. Its sole shareholder is the Province of Ontario. In 2005, OPG entered into a Memorandum of Agreement (the “MOA”) with its shareholder. The MOA stipulates: “OPG will operate as a commercial enterprise with an independent Board or Directors, which will at all times exercise its fiduciary responsibility and a duty of care to act in the best interests of OPG.”

In collective bargaining, OPG is represented by members of its management team. The union is represented by its negotiating team. OPG is responsible for representing the interests of its shareholder, and the union representatives are responsible for representing the interests of the union.[131]

The bargaining is done entirely between the two parties; no ratepayer groups are involved, and OPG does not consult with any ratepayer groups prior to entering into collective bargaining.[132] OPG has further stated that it is also OPG’s role to represent the interests of ratepayers in collective bargaining.[133] Unlike its responsibility to represent the interests of its shareholder (as set out, for example, in the MOA), OPG does not have a specific mandate to represent ratepayers. Board staff observes the interests of OPG’s shareholder and ratepayers will not always be perfectly aligned. In cases of conflict, it appears that OPG’s primary responsibility is to its shareholder.

Collective bargaining is done privately between OPG and its unions. Neither the Board, nor any other party (other than possibly a mediator or arbitrator) is privy to any of the details of the negotiations. OPG accepts that, in assessing the reasonableness of OPG’s unionized labour costs, the Board must look at the final result (i.e. the collective

[131] Oral Hearing Tr Vol 8 page 61.
[132] Oral Hearing Tr Vol 8 page 63.
[133] Oral Hearing Tr Vol 8 page 61.

agreement). OPG also accepts that the Board is not in a position to offer a critique on any specific negotiating strategies.[134]

One of the chief roles of the Board is to act as a proxy for the market to prevent the abuse of monopoly power. In the private (unionized) sector, there is a very strong incentive for companies to bargain aggressively with their unions and attempt to limit increases, or even secure compensation decreases. Where a company in a competitive environment pays more for labour than its competitors, all else being equal it will suffer negative repercussions. For example, it may lose market share and consequently make less money (or even lose money).[135] Companies operating in a market environment must rigorously control their costs or run the risk of bankruptcy.

As a regulated, monopoly service provider, OPG is in a different position. It seeks to recover all of its compensation costs as part of its revenue requirement. It is the Board's role to ensure that OPG is only able to actually recover the costs it would be able to recover if it were operating in a competitive (i.e. market) environment. OPG in fact accepts that it should not pay more than market rates for labour.[136] This does not mean, of course, that the Board can ignore the real constraints that are placed on OPG through the collective bargaining regime. Collective bargaining is also a challenge in a market environment, and indeed many businesses in competitive industry face similar restraints. However, the Board must maintain stringent oversight of OPG's compensation costs to ensure it pays no more than it needs to for labour.

It should also be noted that a significant portion of OPG's compensation costs are not directly related to its collective agreements. Management employees (which include some non-management but non-unionized employees) are not covered by collective agreements. The collective agreements do not set the number of staff OPG must have, and indeed OPG was very successful in reducing its compensation costs to match the disallowances the Board imposed in the previous payments proceeding by reducing its staff numbers.[137] The collective agreements also do not determine the amount of overtime that OPG must pay for.[138]

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[134] Oral Hearing Tr Vol 8 page 64.
[135] Oral Hearing Tr Vol 8 page 65-66.
[136] Oral Hearing Tr Vol 8 page 40.
[137] OPG's Business Transformation initiative realized savings for the regulated business of $27M in 2011, $75M in 2012 and $114M in 2013. This exceeds the disallowance of $145M the Board related to

OPG filed a report, "An Assessment of the Industrial Relations Context and Outcomes at OPG" to support its position on the labour relations context at OPG.[139] The report's author, Dr. Richard Chaykowski, also appeared as a witness.

Dr. Chaykowski's evidence suggests OPG has little wiggle room with respect to its collective agreements. Absent a negotiated agreement, the matter will end up before an arbitrator, and traditionally arbitrators have been friendly to the unions. Board staff accepts that OPG has to bargain within the confines of the collective bargaining regime, and that this is a significant constraint on its ability to reduce costs. While the Towers Perrin salary survey filed in EB-2010-0008 and the AON Hewitt salary survey filed in the current proceeding provide data at the 50th and 75th percentile, Board staff accepts that it would not be realistic to expect OPG to get to the 50th percentile in the near term.

That said, Board staff observes that the collective bargaining regime appears to pay scant attention to the reasonableness of costs or the interests of ratepayers. In arbitration proceedings, it was Dr. Chaykowski evidence that "[arbitrators] do not tend to take into account ability to pay", and "I think it is absolutely the case that interest arbitrators do not want to apply the ability to pay criterion." The ability of a consumer to pay for a service is of course a key factor in the setting of a market price. This places the Board in a difficult position, because its very role is to ensure that ratepayers are protected from unreasonable – i.e. above market – costs.[140]

This is troubling, and raises questions about how the Board is supposed to ensure that ratepayers are protected from unreasonable costs.

6.7.2 OPG's Compensation and Benchmarking

OPG's compensation package includes base salary, incentives, pensions and benefits. OPG's forecast total average compensation per employee for 2015 is $205,914 for Management, $176,508 for SEP employees, and $163,458 for PWU employees.[141]

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excessive compensation costs in EB-2010-0008. Oral Hearing Tr Vol 3, page 68-69 and JT2.10 (June 11, 2014)

[138] Oral Hearing Tr Vol 8 page 42-46

[139] Exh F4-3-1 Attachment 1

[140] Oral Hearing Vol 8 page 156

[141] J9.7 Attachment 1

In its decision in the last payments case (EB-2010-0008), the Board required OPG to prepare and file a full compensation benchmarking study. OPG retained AON Hewitt for this task, and a report was prepared and filed in this proceeding (the "AON Report").[142]

The study was conducted in the fall of 2011, and the data were subsequently aged in 2013. The survey considered 3 comparator groups. Bruce Power was one of the comparators:

1. Power Generation, Electric Utilities, Nuclear R&D
2. Nuclear Power Generation and Electric Utilities
3. General Industry (AON Hewitt Total Compensation Measurement Survey and Mercer Benchmark Database).

The following table summarizes the results for Total Cash Compensation (base salary and short term incentive). The results show that OPG's PWU employees are compensated well above their comparators in all three groups, while SEP and Management staff are at market for power generation and nuclear power generation, but well above market for non-generation specific positions when compared with the general industry comparator group.

Table 23
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

The AON Report is not the first report to show that OPG's compensation levels are generally significantly higher than its comparators. In the previous payments case, for example, OPG filed data obtained from Towers Perrin which showed similar results. In this regard, OPG stated that it was not surprised by the findings of the AON Report.[143]

[142] Exh F5-4-1
[143] Oral Hearing Tr Vol 8 page 74-75.

OPG's argument with respect to the AON Report is that it is not relevant. OPG argues that it must bargain within the confines of Ontario's collective bargaining regime, and the fact that other companies (many of which operate in other jurisdictions) pay less than they do does not assist OPG in its collective bargaining. If OPG is unable to reach an agreement with its unions, there will be a work stoppage and in all likelihood a quick move to binding arbitration mandated by the government. According to Dr. Chaykowski, arbitrators are generally not interested in broader market data, and have focused on "patterning" OPG after Ontario Hydro successor companies, chiefly Bruce Power and Hydro One.

Board staff accepts that a broad compensation study such as the AON Report cannot be used as a blunt tool to automatically set OPG's compensation levels at the 50^{th} percentile. Board staff understands that different jurisdictions and industries will have differing circumstances, and that this will result in some measure of variation amongst their compensation structures. Board staff therefore accepts that it would not be reasonable to expect OPG to achieve the 50^{th} percentile as presented in the AON Report.

The AON Report is a valuable tool, however. The Group 2 comparators (Nuclear Power Generation and Electric Utilities), in particular, are very similar to OPG. Of the 5 comparators in that group, all five are unionized and nuclear related (although Hydro Quebec has recently shut down the Gentilly facility), and three are based in Ontario. One of them is Bruce Power, the chief comparator preferred by OPG. Although OPG pays its SEP and Management employees slightly less than the 50^{th} percentile when compared to Group 2, for the PWU it pays 19.1% above the 50^{th} percentile.

The Board cannot of course be privy to how these comparators were on average able to secure a better result than OPG for many of the positions surveyed. As OPG indicated, collective bargaining negotiations are private discussions between the employer and the unions. The Board is, however, in a position to judge the final result. One way or another the Group 2 comparators achieved a better result than OPG. This is strong evidence that OPG's compensation costs (at least with respect to the PWU, which comprises 53% of OPG's overall compensation) are not reasonable.

The Auditor General's Report references the AON Report in support of its conclusion that OPG should measure its salary levels against similar organizations to ensure that they are reasonable.[144] In addition, the Auditor General compared the total average earnings for selected OPG positions with the total maximum earnings for the same positions in the Ontario Public Service ("OPS") generally. OPG's average compensation is in many cases greatly in excess of the average compensation for the comparable position in the OPS. While many of the positions are unionized positions at OPG (as they are in the OPS), the witnesses identified that 4 of the positions are not unionized.[145] The Auditor General commented that OPG should be looking to compensation levels in the broader public sector to ensure that its own salaries are reasonable.[146]

OPG's position is that the most appropriate comparators for it are not the comparators used in the AON Report, but the successor Ontario Hydro companies. OPG presented several tables that suggest its salary levels compare favourably with these companies.

The data in this regard were prepared by OPG. OPG conceded, however, that some of the comparisons it did against Bruce Power did not account for the fact that OPG pays approximately 1,200 employees in excess of the maximum set in their respective salary bands.[147] In undertaking J8.1, OPG explained that in 2002 and 2006 the top bands of union wage schedules were reduced, but that a number of employees have base wages that exceed the revised top bands. OPG reports that the number over band is now 972 and that the annualized impact is $5.6M. OPG states that if the salary bands were adjusted to account for overband employees, the comparison with Bruce Power would still be favourable.

OPG accepted that there are a number of different ways that the data can be looked at, and that Hydro One was able to file evidence in a different proceeding which appeared to show that it had done quite well in controlling its labour costs in comparison with OPG.[148]

[144] Exh KT2.4 Report of the Auditor General page 165 and 170.
[145] Oral Hearing Tr Vol 8 page 120
[146] Exh KT2.4 Report of the Auditor General page 166 and 170.
[147] Oral Hearing Tr Vol 8 page 78-80
[148] Oral Hearing Tr Vol 8 page 83-84.

Board staff notes that Dr. Chaykowski did not provide an opinion on OPG's actual compensation levels.

For the PWU, OPG states that its application is based on the collective agreement up to March 31, 2015, and no increase in base wages and a 1% step progression for the remaining test period. For the SEP, OPG states that its application is based on 0% increase in the test period and a 1% step progression.[149] Board staff acknowledges these efforts, however, the impacts are not significant with respect to the compensation envelope. Undertaking J9.5 states that the test period revenue requirement of the SEP increase of 1.75% awarded in the arbitration instead of the 1% progression assumed in the application would be an increase of $5.0M.[150]

6.7.3 Staffing Levels

OPG also filed a report on its nuclear staffing levels in response to direction from the Board in EB-2010-0008. Goodnight Consulting Inc. ("Goodnight") conducted a nuclear staffing study in July 2011 (Exh F5-1-1 part a). Those results were subsequently updated/aged in February 2013 (Exh F5-1-1 part b). Goodnight compared OPG nuclear staffing with 16 large stations in the United States. The comparison was done on an adjusted basis so that activities specific to CANDU design were excluded, e.g. staff necessary for heavy water management, and for OPG's 35 hour work week vs 40 hours for comparators.

The July 2011 results indicated that OPG nuclear staffing is 17% (866 FTE) above the comparable benchmark. The February 2013 results indicated that the gap had dropped to 8% (430 FTE) above the benchmark. (Although this was subsequently amended to 7.6% (394 FTE)).[151] As of March 1, 2014, the overstaffing situation is 4.7% (244 FTE).

The Goodnight results are consistent with the 2006 Navigant report (12% nuclear overstaffing) and the 2009 ScottMadden Phase 1 report in which ScottMadden compared OPG nuclear staffing with EUCG data as well as Bruce Power. ScottMadden reported that OPG's nuclear staffing exceeded both the industry median and Bruce

[149] AIC page 92
[150] Exh F4-3-1 section 6.3
[151] JT1.13

Power levels.[152] OPG has achieved significant staff reductions through Business Transformation, however Board staff notes that this initiative is not responsive to benchmarking but is an initiative to align costs with future revenue/generation.

Goodnight found that 23 functional areas (e.g. administration/clerical, budget/finance, human resources) were staffed above benchmark while 14 functional areas (e.g. plant operations, plant engineering, technical engineering) were staffed below benchmark. The Auditor General reproduced some of the 2011 and 2013 Goodnight study results in its December 10, 2013 report.[153]

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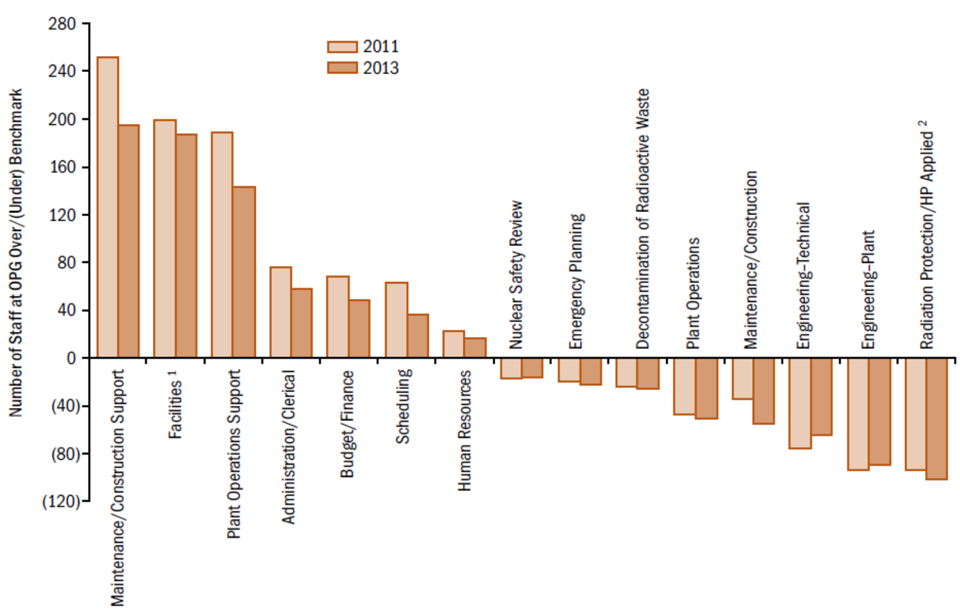
Figure 5: Selected Areas Identified as Overstaffed/Understaffed at OPG by Nuclear Benchmarking Studies
Source of data: Ontario Power Generation



1. "Facilities" refers to general maintenance and custodial services, such as cleaning and changing light bulbs.
2. "HP" is an acronym for health physics, the physics of radiation protection.

The Auditor General noted that several operational functions were understaffed while the associated support functions were overstaffed. The Auditor General also observed that one of the most overstaffed areas, facilities (general maintenance, janitorial and custodial services) improved only slightly from 173% to 170% over benchmark. Board staff observes that many of the overstaffed functions also align with those functions in

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[152] Exh K5.5 ScottMadden Phase 2 page 26
[153] Exh KT2.4 Report of the Auditor General, page 160

group 3 of the AON Hewitt study and which are compensated at 20% to 29% above P50.

6.7.4 Management Staffing

The following table summarizes staffing by employee group for the period 2010 to 2015.[154] The final column is the change in FTE from 2010 to 2015. The final row is the % of management staff vs total.

Table 24

FTE	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan	2010 vs 2015
Management	1,101.7	1,099.2	1,095.6	1,091.0	1,101.0	1,076.3	25.4
Society	3,269.0	3,254.6	3,112.6	2,909.2	3,043.3	2,965.6	303.4
PWU	6,012.9	5,840.7	5,711.0	5,542.0	5,371.7	5,300.3	712.6
EPSCA	97.2	79.8	86.3	60.2	50.1	53.4	43.8
TOTAL	**10,480.8**	**10,274.3**	**10,005.5**	**9,602.4**	**9,566.1**	**9,395.6**	1,085.2
%Management	10.5%	10.7%	10.9%	11.4%	11.5%	11.5%	

OPG's non-unionized staff were subject to the *Public Sector Compensation Restraint To Protect Public Services Act* in 2010. The Auditor General observed that a form of salary adjustment for non-unionized staff was pay increases resulting from promotions,[155] and also observed a significant increase in the management staffing levels, while unionized staffing levels have decreased.[156] The Auditor General noted that in 2012, 17 employees were promoted to VPs and 50 to directors.

At the oral hearing OPG's witnesses attributed the increases in management staffing levels to the Business Transformation initiative and Darlington Refurbishment. The response to undertakings J9.1 and J9.2 indicate that there were 5 Business Transformation Directors and 13 Darlington Refurbishment Directors in 2013. This does not explain the high level of senior management staffing. Further, at the technical conference and oral hearing, Board staff queried the increasing number of vice-presidents and directors who had no specific titles or job descriptions; there were 40 in 2012. The OPG witness replied that, in the absence of a job description, accountability

[154] JT2.33
[155] Exh KT2.4 Report of the Auditor General, page 163
[156] Exh KT2.4 Report of the Auditor General, page 159

would have been passed on by the supervisor. Board staff submits that this is not a satisfactory answer.

The Auditor General also observed that the total earnings for most OPG senior vice presidents significantly exceeded those for most deputy ministers in the Ontario Public Service.

6.7.5 Overtime

The EB-2010-0008 Board decision directed OPG to file an analysis of overtime. Goodnight concluded that OPG overtime levels of 6 to 7% was not unusual compared with 5 to 6% at US plants. OPG has stated that overtime is economical, particularly in certain functions where certain qualifications are necessary for the jobs. Goodnight's analysis excluded outage overtime. In response to undertaking J11.2, OPG has provided overtime analysis for the period 2010 to 2013. For the nuclear business, overtime is in the 12% range at an expense of $140 to $160M annually. For the test period OPG proposes nuclear overtime of $109.1M in 2014 and $122.1M in 2015.

Board staff questions whether the Goodnight selective review met the Board's direction as only half the OPG nuclear overtime was reviewed.

6.7.6 Submission

Hydroelectric Facilities

Board staff has submitted that reductions to test period OM&A are appropriate under section 6.1 above. Board staff does not propose any further compensation related reductions as most of the impacts arising from staff's concerns on compensation are based on staff's analysis of the nuclear business.

Nuclear Facilities

Board staff submits that a disallowance of $100M to test period OM&A related to nuclear compensation is warranted for the following reasons:

- Overstaffing, as confirmed by Navigant (2006), ScottMadden (2009) and Goodnight (2011 and 2013). OPG should be commended for its Business

Transformation initiative, which has significantly reduced the amount of overstaffing in the nuclear division. However, nuclear remains overstaffed and will likely remain overstaffed until at least the very end of the test period. In the absence of the Business Transformation initiative, Board staff's submission would seek a larger reduction in nuclear compensation and OM&A.

- Poor benchmarking performance of both Pickering and Darlington. If OPG's performance as measured against its peers were even average then the revenue requirement would be reduced by hundreds of millions of dollars over the test period. The costs of inefficiency cannot be tracked directly to any particular budget item, however compensation costs are certainly a major driver.
- PWU compensation well above market comparators as detailed by the AON Report and the Report of the Auditor General. Although Board staff accepts that achieving the 50^{th} percentile is not realistic in the near term on account of Ontario's collective bargaining regime, many similar organizations have been able to achieve better results than OPG.
- Management top heavy organization as confirmed by the evidence and as reported by the Auditor General. Board staff estimates that if nuclear management levels were at 2010 levels on a % of total staff basis, the test period revenue requirement would be $20M lower. Based on the evidence from the AON Report, however, it does not appear that OPG's management is in general overpaid on a per employee basis.
- Reductions of $50M in the test period for nuclear corporate services, as submitted under section 6.9 of this submission.

6.8 Pension and Other Post-Employment Benefits ("OPEBs")

Issue 6.8 (Oral Hearing) - Are the 2014 and 2015 human resource related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate?
Issue 6.10 (Oral Hearing) - Are the centrally held costs allocated to the regulated hydroelectric business and nuclear business appropriate?

The current service cost of pensions and OPEB are included in the compensation component of OM&A for the hydroelectric and nuclear businesses. The remainder of pension and OPEB costs, which includes interest costs on the obligations, the expected return on pension plan assets, amounts for past service costs and actuarial gains and losses, and any current service cost variance from the estimate reflected in the standard labour rates, continue to be recorded as a centrally-held cost.

Board staff's proposal on compensation in section 6.7.6 of this submission is generally inclusive of the impacts of pensions and OPEBs. This section of Board staff's submission is separated into two parts. The first part reviews the sustainability of the current pension and OPEB plans and contains the reasons for Board staff's overall position on OPG's compensation envelope as it relates to the pension and OPEB plans. Board staff concludes that there are serious concerns with the sustainability of the plan and proposes that a reduction to the overall compensation envelope is warranted due to the richness of the plans which OPG has not addressed for this test period despite having knowledge of such an assessment from an independent source. Board staff submits that OPG should review the design and construct of their plans going forward beyond this test period.

Board staff also concludes that the accrual basis for accounting for pension and OPEB costs places an unnecessary burden on today's ratepayer and Board staff proposes that the best approach to mitigate the impact on ratepayers for the test period is to move to the cash basis for ratemaking purposes. Accordingly, Board staff discusses the accounting and rate recovery issues regarding pensions and OPEBs affecting this test period in the second part of this section.

It should be noted that any reduction in the compensation envelope may affect the quantum of the impact on revenue requirement from any move to the cash basis of accounting for pensions and OPEBs. Current service costs for pensions and OPEBs form part of the standard labour rates. There is no easy way for Board staff to extrapolate the reduction in standard labour costs related to the cash basis.

However, by way of illustration, Board staff observes that $1,294M of test period OM&A is related to pensions and OPEBs. The total nuclear and hydroelectric OM&A for the test period is $5,591M of which 23% is related to pensions and OPEBs. Earlier in this submission, Board staff argued for a $100M reduction on nuclear OM&A and a $70M reduction in hydroelectric OM&A (most of which is related to compensation, including pensions). Therefore, if the Board was to approve the cash basis for accounting for pensions and OPEBs, Board staff submits the above OM&A reductions could be reduced by $23M for nuclear and $16M for hydroelectric.

6.8.1 Financial Sustainability of the Current Pension and OPEB Plans

OPG seeks $1.3 billion for pension and OPEBs in the test period as summarized below:

Table 25

$million	2014 Plan	2015 Plan
Total Regulated		
Pension	471.3	405.3
OPEB	204.6	212.8

The total unfunded liabilities at December 31, 2013 for the pension plan, supplementary pension plan and OPEB was $5.469 billion.

In 2011, Towers Watson was retained by OPG to assist with the analysis of the financial sustainability of OPG pension and benefits programs. In the report,[157] Towers Watson states that its "analysis confirms the belief and quantifies the extent to which OPG's P&B plans are unsustainable." The report also states that, "Consistent with prior [OPG Compensation and Human Resources Committee] discussions, significant changes to P&B design and program management will be required to improve sustainability." This is a very significant finding, which OPG appears to agree with.

The Towers Watson report was available to OPG when negotiating the PWU collective agreement that is in place for this application. The OPG witness stated that pension and benefit plan sustainability was part of the negotiation agenda, but that the outcome was status quo.[158] The OPG witness also confirmed that the Towers Watson report was not filed as part of the record for the SEP arbitration.[159] In other words, despite the fact that OPG was aware at the time of negotiations that its pensions and benefits plans are unsustainable, no changes have been made to these plans in the most recent collective agreements.

There are external drivers for the level of pension and OPEB in the revenue requirement, e.g. discount rates. However, there are also "internal" drivers, e.g.

[157] JT2.12
[158] Oral Hearing Tr Vol 8 page 154
[159] Oral Hearing Tr Vol 8 page 155

Employer:Employee contribution ratios. Appendix B of the Towers Watson report listed nine pension design interventions, with contribution ratios as one of the high benefit interventions.

The following is one example of a component of OPG's pension plan that could be addressed to reduce the cost of the overall plan, and the overall burden to ratepayers.

OPG's pension plan requires contributions from employees and from the company. The Ontario Public Service has a 1:1 ratio for employee and employer pension contributions as well as funding pension shortfalls. By contrast, OPG pays substantially more for current service costs than employees. The ratio is approximately 3:1.[160] If the special payments are included, the ratio is close to 5:1.[161] OPG will implement changes to reduce the cost of the health and dental benefit plan effective January 1, 2016 for management employees.

OPG has indicated that if the pension contribution ratio of 1:1 was applied, the regulated business would save approximately $60 M annually.[162] Board staff has calculated that if the special payments were included in the total amount to be shared on a 1:1 basis, the company theoretically could save approximately $140 M annually.[163]

OPG has estimated the impacts of most of the pension design interventions listed in Appendix B of the Towers Watson report. However, OPG concluded that significant reductions in pension costs can only result from:

- An increase in actual discount rates
- Higher mortality rates
- Significant legislative amendments[164].

While Board staff does not disagree with OPG on this point, there is no doubt in Board staff's view that OPG can control some of the costs related to various components and features of the plans such as employee contributions, indexing, spousal plans, etc.

[160] Exh L-6.8-Staff-121
[161] Exh KT2.4 Report of the Auditor General, page 165-167
[162] Exh L-6.8-Staff-121
[163] J9.6, page 19-21: 2014 Normal cost $300,085, plus special payments $130,848 = $430,933 /2 minus $358,237 minimum company contribution = $142,771.
[164] J9.10

In cross examination, Board staff summarized three potential scenarios to deal with the sustainability issue: bankruptcy, higher contributions from OPG employees or a bailout from ratepayers.[165] The OPG witness confirmed that the company expects ratepayers to fund the high cost of pension and benefits.

> MS. LADAK: If we can demonstrate that we have incurred costs, prudently incurred costs, and it makes sense, then we would bring those costs to the Board for approval.

Setting aside the actuarial assumptions and related variables in calculating the plan's valuations, in Board staff's view the evidence adduced in this proceeding does not support a finding of prudence with respect to the controllable features when one compares the pension plan for example, to the broader public service. There is no persuasive evidence on the record that would justify the richness of the plan. For example, OPG has not demonstrated that they will not be able to successfully attract the skill sets and talent required to operate the company with a plan that is more in line with other public service entities.

In the 2013 budget, the government announced that it would establish a working group to address pension issues associated with the pension plans at OPG, Hydro One, IESO and the Electrical Safety Authority. On August 1, 2014, the Government of Ontario posted the *Report on the Sustainability of Electricity Sector Pension Plans* concluding among other things that pension benefits in Ontario's electricity sector pension plans are "richer" than most of the province's broader public service plans and that employee contributions are also lower than broader public service plans. The Report notes that, "[a]s a result of generous benefits and larger employer contributions these plans are expensive".[166] In addition, the Report concludes that the four plans for OPG, Hydro One, the IESO and the ESA aren't sustainable over the long term in their current form and recommended structural changes to the plans such as moving to an Employer: Employee contribution target of 50:50.

Board staff shares the concerns regarding the sustainability of OPG's pension plan and has proposed in this submission a reduction to the overall compensation envelope partly based on Board staff's observations in this section. In Board staff's view, the proposed reduction should not make OPG's sustainability issues worse as the reduction

[165] Oral Hearing Vol 8 page 161
[166] Report on the Sustainability of Electricity Section Pension Plans, page 17

is modest compared to the quantum of the overall compensation envelope, but rather, is intended to address the prudence of the pension costs as they impact the test period.

Although OPG recognized that its pension plan is not sustainable, and that without some changes OPG's very solvency is at risk, it does not appear to have any internal plans to remedy the situation (other than perhaps seeking more money from ratepayers). It appears to be placing most of its hopes in a possible government plan to tackle public sector pension plans. Board staff encourages OPG to continue to review the design and construct of its plans to address the sustainability issues identified in this proceeding, and in the broader public domain.

6.8.2 Pension and OPEBs Accounting

Board staff is of the view that there are compelling reasons why the Board should consider changing its approach to how pension and OPEB costs are treated for regulatory purposes. OPG's current payment amounts reflect the accounting (or accrual) method for determining the quanta of the costs to be recovered from ratepayers. The reasons for moving to the cash basis are set out below in the various sections on this topic.

Board staff understands that there have been discussions in this and other recent proceedings of a potential generic proceeding on the regulatory treatment of pension and OPEB costs. Board staff makes the following submissions on this topic within the context of a possible future consultation. Board staff believes that the Board can make a decision in this case with respect to the cash basis of recovery in light of the extensive evidence on the record and considering the magnitude of OPG's pensions and OPEB expense in the test period.

Set-aside mechanism, Segregated Fund or Irrevocable Trust

OPG has a pension fund, the operation of which is regulated under the *Pension Benefits Act*. OPG makes contributions to the pension fund based on actuarial valuations which are prepared every three years at present. The supplementary pension plan is backed by letters of credit. For OPEBs, OPG does not have a fund.

OPG defines its pension and OPEB costs to be those calculated for accounting purposes. These costs are determined by independent actuaries with input from OPG's management. OPG prepares its financial statements in accordance with United States generally accepted accounting principles ("USGAAP").

Under USGAAP, there are standards that apply to the recognition of regulatory assets and liabilities. USGAAP generally requires the use of accrual accounting for pensions and OPEBs. OPG relies in part on the USGAAP accounting standards that deal with regulated operations, specifically ASC-980-715 for compensation and retirement benefits.[167] OPG not only has approved amounts, but also has amounts related to pensions and OPEBs recorded as regulatory assets not yet approved by the Board.[168] OPG also has a Board-approved variance account in which it has recorded the differences between forecast costs included in payment amounts and the year-end accounting expense for pensions and OPEBs . This variance account and a proposed variance account which relates to the cash payment basis of rate recovery, are discussed under Issues 9.1 and 9.5 later in this submission.

In its cross examination, Board staff explored the possibility of establishing a set-aside mechanism for OPEB costs that are calculated and recovered from ratepayers on the accounting basis. In response to that notion, OPG in its AIC[169] stated the following:

> Staff's suggestion that the OEB order OPG to set aside certain funds for the purpose of meeting future supplemental pension plan and OPEB obligations would take the Board beyond its jurisdiction. The Board's jurisdiction to set payment amounts does not include the power to manage OPG, such as by ordering it to set aside, through the establishment of a segregated fund, an irrevocable trust or some other such mechanism that OPG would not control, a portion of its revenues for a specific purpose. The Board itself has stated in its recent submission to the Supreme Court of Canada that the "Board's mandate is to determine a reasonable revenue requirement; it is for OPG's management to decide how that revenue is ultimately spent." (see: Factum of the OEB in Supreme Court of Canada, File No. 35506, para. 97).

[167] Oral Hearing Tr Vol 13, page 59.
[168] Exh K13.1, Board Staff Compendium, Panel 7, page 36, columns 2 & 8.
[169] AIC page 99

OPG believes there is no need to deposit the money recovered for OPEBs in a segregated fund. OPG has stated that the Board would err in law if the Board required OPG to set aside certain funds for the apparent purpose of OPG meeting future employee benefit obligations. OPG has stated that it will manage its future cash flows to ensure that it has sufficient funds available to meet future benefit obligations.

Board staff disagrees with OPG's interpretation of the Board's jurisdiction. The Board's jurisdiction to set just and reasonable rates is very broad. Section 2 of the Act states that the Board is to be guided by the objective of "protect[ing] the interest of consumers with respect to prices and the adequacy, reliability and quality of electricity service."

Section 23 of the Act further allows the Board to impose conditions to its orders: "The Board in making an order may impose such conditions as it considers proper, and an order may be general or particular in its application." The Ontario Court of Appeal has confirmed that this is a broad power, though any condition imposed by the Board must be guided by the Board's objectives as set out in section 1(1).[170] The Court in that case confirmed that the Board has the power to require that any dividends issued by a utility must be approved by a majority of the independent members of the board of directors.

In the current case, a condition requiring OPG to set aside the amounts that it is collecting on an accrual basis to actually pay its future obligations would clearly be directly related to the Board's duty to set just and reasonable rates and protect the interests of ratepayers. For the two test years alone, OPG is recovering $240M more from ratepayers for OPEBs than it will actually be spending on OPEBs. From 2008 to 2015, it will have recovered almost a billion dollars more for OPEBs then it will actually have spent.[171]

Although OPG is using the accrual accounting method for purposes of presentation and disclosure in its financial statements, it is not actually "accruing" any of this money in practice. The over-collection is not being set aside and is in fact being spent for general corporate purposes. In other words, the money being collected today to fund liabilities tomorrow is already gone, and will not be available to actually fund those liabilities. The money being collected from ratepayers for the purpose of funding OPEBs is not being

[170] *Toronto Hydro-Electric System Ltd. v. Ontario Energy Board*, 2010 ONCA 284, para. 33
[171] JT2.40 page 2.

used to fund OPEBs. OPG does not appear to have any clear plan, other than "managing its cash flows" on where it will get the money to fund these liabilities.[172]

Under these circumstances, a condition requiring OPG to set aside the money it is collecting to fund future OPEB liabilities for the purpose of actually funding future OPEB liabilities would be more than reasonable.

If the Board is concerned about its jurisdiction to impose such a condition, then it could consider simply not allowing OPG to collect money from ratepayers for OPEBs that is not being used to fund OPEBs. OPG would no doubt agree that the Board should not allow it to recover $240M in the test year that is not assigned to any purpose (i.e. the OPEB over-recovery that OPG appears to use for general corporate purposes). Allowing OPG to recover for OPEBs on a cash basis would ensure that OPG recovers its actual costs for OPEBs – no more and no less, if combined with a variance account.

Finally, OPG stated that a generic proceeding would be more appropriate to examine the complex legal, tax and accounting issues associated with the set-aside mechanism proposed by Board staff.

Board staff agrees with OPG that there are complex, legal, tax and accounting issues to consider. Board staff agrees with OPG that a generic proceeding may be an appropriate way to look at issues associated with the set-aside mechanism. However, there is one other option. In cross examination, Board staff referred to a Federal Energy Regulatory Commission Statement of Policy ("FERC61").[173] Board staff notes that FERC did not order utilities to set up irrevocable trusts. FERC offered the utilities the choice to elect to comply with FERC's policy statement as discussed in FERC61 in exchange for being allowed to recover OPEBs based on Statement of Financial Accounting Standards No. 106[174] (in other words, on an accounting basis).

Board staff submits that the Board could make similar conditions available for OPG's consideration. Board staff re-iterates that a set-aside mechanism would not be required for the test period if pensions and OPEBs were to be recovered on a cash payment basis.

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[172] AIC page 100.

[173] Exh K13.2 FERC Docket No. PL93-1-000

[174] Exh K13.1, Board Staff Compendium, Panel 7 pages 10-11.

Recovery Mechanism for Pensions and OPEBs

From April 1, 2008 to the end of 2015, OPG has, or will have, recovered more from ratepayers than it will have paid for pensions and OPEBs. From April 1, 2008 to the end of 2013 the actual recovered amount greater than the actual OPEB payments is $752M[175], plus an additional $232.0M[176] in the test period. For pensions during the same period 2008-2015, $113.8 more than the cash payments is the result.[177] There are some amounts in the variance account as at December 31, 2012 being collected over a 12-year period and some further amounts in the variance account as at December 31, 2013 that have been approved for tracking and will be disposed in a future proceeding. Applying the test period excess OPEB amount of $232.0M and using this as a proxy for the future, OPG will recover additional excess amounts of approximately $1.2 billion every ten (10) years.

Staff provided a calculation at the Technical Conference that if one divides the total excess payments (disclosed as $993.3Min JT2.40) by the expected benefit payments for 2015 ($71.3M), OPG will have already recovered enough from ratepayers to make benefit payments for over 13 future years.[178]

Board staff submits that should the Board approve the cash basis of recovery for OPEBs for the test period 2014-2015, OPG will still have this excess amount of $752M already recovered from ratepayers for the period up to December 31, 2013.

Board staff submits that the $752M recovered from ratepayers is a compelling reason why the Board should consider moving to a cash basis for OPEBs.

OPG has stated that there is no direct connection with recovery of pensions and OPEB costs from ratepayers and the ultimate use of the money recovered in payment amounts.[179] OPG has stated that the accounting costs for pensions and OPEBs form

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[175] JT2.40
[176] J13.7
[177] AIC page 105, chart 4 – 2015 projected cash payment amount calculated by staff but to be corrected in final evidence by OPG.
[178] Technical Conference Tr April 23, 2014, page 200-201.
[179] Oral Hearing Tr Vol 13, pages 17-18.

part of revenue requirement in its application, and once the Board approves the payment amounts the disposition of the money collected from ratepayers rests with management[180].

Board staff does not agree with this view. Board staff submits that there is in fact a direct link between the costs that the Board approves for recovery in an application and what the applicant has stated is the purpose of the costs. For example, forecast payroll costs for the test period are reasonably expected to be paid in the test period. Pensions and OPEBs calculated on an accrual accounting basis will not be fully paid in the test period.

In addition, the accrual and cash amount curves will likely not cross in the foreseeable future unless the company ceases to be a going concern.

In its AIC, OPG stated:

> There is no evidence to support the conclusion that the cash basis for pensions produces more favourable impacts over the long-run. OPG is of the view that a cost recovery methodology should be established with a long-term perspective. It would be inappropriate to change a cost recovery methodology to chase short-term financial impacts.[181]

However, at the oral hearing, OPG's witness stated that for at least the next 10 years, OPG would likely be over recovering based on the accrual method:

> MS. HARE: Mr. Mauti, I just want to go back to something that you said in answering Ms. Long's question. You said it would not be within the next ten years when the actual cash payment would be larger than the accrual expense. Does that mean that for at least the next ten years you will be over-collecting?
>
> MR. MAUTI: Based on the current accounting estimates and things like discount rates as they exist today, if you extrapolate that and use that set of assumptions forward for the next ten years, the accrual expense will be higher than the cash, yes.[182]

[180] Oral Hearing Tr Vol 13, pages 17-18.
[181] AIC page 105
[182] Oral Hearing Tr Vol13, page 139

To the extent that the underlying assumptions and variables change that may lead to a significant reduction in the accrual result going forward, ratepayers would be protected from having moved to the cash basis by the use of a variance account. And staff notes that if discount rates for example rise, the cash amounts would be affected in the same direction, in any event given that the discount rates would also affect the actuaries' valuations establishing the minimum contributions.

Board staff is of the view that a careful consideration of the approach to OPEBs is necessary since there are no fund assets similar to a pension fund to offset the liability. OPG has stated that O.Reg. 53/05 (sections 6(2)5 and 6(2)11ii) requires the Board to accept asset and liability values related to pension and OPEBs for the newly regulated facilities [183] Yet, the liability for OPEBs that is disclosed in the financial statements is overstated for regulatory purposes because it is unfunded and is not offset by amounts already recovered from ratepayers.[184] In any event, it is important to note that whatever the liability is at any given point in time, OPG will have already recovered $752M (for OPEBs alone) as of December 31, 2013.

OPG prepares its general purpose financial statements following USGAAP. Board staff will address OPG's claim of potential harm as a result of moving to the cash basis for pensions and OPEBs later in this submission.

Given this over-collection, the Board may wish to consider three options.

First, the Board can approve the cash basis for regulatory purposes and approve $0 in revenue requirement for OPEBs. It can be argued that this would be the appropriate number related to OPEBs for the subject test period. This is supported by the fact that the liability for future post-retirement benefit payments for regulatory purposes should be reduced by $752M already collected from ratepayers. Board staff does not consider this option as violating the principle of final payment amounts as there is no explicit claw-back of the $752M but rather, the Board would be considering amounts that OPG has already over-collected in determining what would be reasonable as the amount for OPEB payments for the test period. Forecast cash pension costs to be included in revenue requirement are $321.9M for 2014 and $329.6M for 2015.[185]

[183] AIC pages 102-104.
[184] Oral Hearing Tr Vol 13, pages 15-17.
[185] J9.6

Second, the Board can approve the cash basis for regulatory purposes but can also approve the forecast pension and OPEB cash payment amounts as a transitional measure, pending the outcome of any generic consultation. Accordingly, for this option the Board may wish to approve the forecast OPEB payments of $89.6M for 2014 and $95.8M for 2015 to be included in revenue requirement for the test period.[186] For pensions, the forecast cash payment amounts noted above would be included under this option also. Later in this submission, Board staff will argue for the establishment of a new variance account in the event the Board moves to the cash basis, to track the difference between the approved pension and OPEB payment amounts in rates and the actual contributions and payments. Option 2 should be combined with the suggested variance account so that the treatment of the resulting variance can be considered in the future.

In corrected Exh JT2.40 filed on June 11, 2014, OPG disclosed OPEB cash payments as $64.9M and $71.3M. However, these numbers do not agree with the cash benefit payment numbers shown in Exh J13.7 of $89.6M and $95.8M which OPG filed on July 28, 2014. The accrual numbers for 2014 and 2015 have also been amended. Staff requests OPG to clarify the evidence with supporting actuarial calculations and to make corrections where necessary.

Third, the Board may wish to retain the status quo in terms of using the accrual method for this application and any changes that may result from any Board consultation can be implemented on a going forward basis. With this option, staff notes that the Board will be approving over $300M (including tax effects) in OPEBs, and $300M (including tax effects) for pensions, in the test period over and above what is being forecast as the required payments.

The above-noted variance account would not be required with this option as the Board has an established variance account to track the variance between the amount of pensions and OPEBs in rates (on an accrual basis) and the actuals (on an accrual basis). Interest carrying charges on this account are discussed under Issues 9.1 and 9.5 which follow.

[186] J13.7

Board staff notes that in the last cost of service proceeding, OPG argued that there was a lack of evidence on the impacts of moving from the accrual to the cash method. Given the extensive evidence in the current proceeding, Board staff recommends Option 2 as the most appropriate recovery mechanism for pension and OPEBs in this proceeding.

Finally, it should be noted that if the Board were to approve an effective date for all payment amounts of July 1, 2014, as will be argued by Board staff later in this submission, it is Board staff's understanding that the current variance account (based on the accrual method) will continue from January 1, 2014 to June 30, 2014, even in the event the Board decides to move to the cash basis for this test period. As a result, while the revenue requirement for the complete two year test period may be reduced in theory by as much as $600M as a result of the change to the cash method, this will be partially offset by an over recovery of approximately $176M[187] given that current payment amounts (reflecting the accrual method for accounting for pensions and OPEBs) will continue until June 30, 2014.

The Stability of the Cash Method - Pension Contributions Forecast for the Test Period

OPG Inc. and its employees contribute to the pension plan based on actuarial valuations. The recommended minimum pension contribution amount includes an estimate for current service costs and minimum special payments for solvency and going-concern issues. It is possible for OPG to contribute more than the minimum amounts calculated by the actuary if management chooses. The deduction for income tax purposes is based on specific rules and increases with higher contribution amounts. Board staff has provided in the table below the actuaries' recommendations for the minimum employer's payments after deduction of the employees' contributions. These recommended amounts were taken from the funding valuations filed by OPG in its applications.[188] The paid amounts were taken from OPG Inc.'s audited financial statements for the years shown.

[187] J13.7 identifies a revenue requirement decrease of $352.5M for 2014 as a result of moving the cash basis effective January 1, 2014.

[188] Mercer January 1, 2005/ EB-2007-0905/ L-14-73; Mercer January 1, 2008/ EB-2010-0008/ L-01-084; Mercer January 1, 2011/ EB-2012-0002/ Exh H2-1-3; AON Hewitt January 1, 2014/ EB-2013-0321/ J9.6

Table 26

Taken From OPG Inc.'s Funding Valuations Filed in Applications				Actual Payments taken from Audited Financial Statements $000s
Year Ending	Current Service Cost $000s	Minimum Special Payments $000s	Minimum Employer's Contribution $000s	
December 31, 2005	186,510	47,316	233,826	254,000
December 31, 2006	193,504	47,316	240,820	261,000
December 31, 2007	200,761	47,316	248,077	268,000
December 31, 2008	205,319	27,726	233,045	253,000
December 31, 2009	211,992	27,726	239,718	271,000
December 31, 2010	218,882	27,726	246,608	272,000
December 31, 2011	217,621	64,837	282,458	302,000
December 31, 2012	224,864	64,837	289,701	375,000
December 31, 2013	232,734	64,837	297,571	306,000
December 31, 2014	227,389	130,848	358,237	
December 31, 2015	233,074	130,848	363,922	
December 31, 2016	238,900	130,848	369,748	

From the chart above it can be seen that OPG has made payments that were higher than those minimum amounts recommend by its actuary. AON Hewitt has calculated that the maximum deductible company contribution for 2014 is $7,261,860,000 ($7.3 billion) but cautions OPG on page 19 of J9.6 (Actuarial Valuation as at January 1, 2014) concerning making such a payment.

However, the minimum contribution amounts shown in the above chart recommended by the actuary do exhibit a fairly stable trend. The actual cash payments differ as shown based on management's past choices, but in general, also demonstrate low volatility.

OPG has provided a table (Chart 4, page 105) in its AIC that shows accrual numbers and allocated cash numbers for regulatory pension costs from 2008 through 2015. OPG did not submit this evidence during discovery and Board staff wishes to correct what appears to be an error.

OPG has entered a cash projection for 2015 of $407.6M. In J9.6 on line 35, OPG indicated that the number was $329.6M. The actuary recommends a total minimum payment of $363.922M for 2015 for OPG Inc. The $407.6M figure seems to have been taken from Exh N2-2-1, Chart 2, line 4, rather than from the AON Hewitt funding valuation filed with J9.6. After making the correction in Chart 4, Board staff has calculated the net total excess amount for the entire period to be $113.8M, rather than $35.8M as shown by OPG and requests OPG to confirm the calculations.

Board staff submits that the minimum required company contribution amount recommended by the actuary provides a stable cost trend. Board staff submits that should the Board decide that the cash basis of recovery of pensions is appropriate, the actuary's recommended minimum contribution should be used to calculate the allocated regulated amounts to be included in revenue requirement for the test period, as this trend appears to be even more stable than the increased contributions. The minimum contribution for OPG Inc. for 2014 is $358.237M, and for 2015 it is $363.922M.[189]

Volatility Caused by the Selection of Discount Rates

USGAAP requires OPG to select a AA bond yield at each year end to calculate pensions and post-retirement benefits obligations that are disclosed in its financial statements under the accounting method. In pre-filed evidence filed on September 27, 2013, OPG provided its first forecast of test year pension and post-retirement benefit costs.[190] Pensions and OPEB costs and obligations for accounting purposes are determined annually by independent actuaries using management's best estimate assumptions.

In Impact Statement Exh N1-1-1 filed on December 6, 2013, OPG introduced new evidence that reflected higher forecast costs resulting from changes in mortality assumptions, plan membership data (census), higher discount rates, lower forecast health care benefits and the related income tax. In the Second Impact Statement Exh N2-1-1 filed on May 16, 2014, OPG reduced its test period forecast pension and post-retirement costs primarily due to higher discount rates and the adoption of a new scale for future mortality improvement. In response to an undertaking J9.6, OPG filed its pension funding valuation dated January 1, 2014 prepared by its actuary. The actuary used 5.6% as the discount rate. In J13.2 OPG replied that an equivalent discount rate for the pension calculations as at June 30, 2014 is 4.3% per annum.

[189] J9.6, Valuation, page 19.
[190] Exh F4-3-1

Table 27

Discount Rates For USGAAP	Pensions	Post-retirement Benefits	Long-term Disability
Exh F4-3-1	4.30%	4.40%	3.50%
Exh N1-1-1	4.70%	4.70%	4.00%
Exh N2-1-1	4.90%	5.00%	4.10%

The dollar results of the changes in assumptions are shown in J12.1 and J12.2 both filed on July 21, 2014. When comparing the impact of discount rates between pre-filed and N2-1-1 evidence, Exh J12.2 shows a cost reduction of $313.8M.

OPG has stated that the primary drivers of change are discount rates and mortality assumptions recommended by OPG's actuaries. The actuaries prepare the very complicated calculations based on established actuarial techniques using high level mathematics.

However, Board staff notes that the results are just mathematics. The results based on one point-in-time set of assumptions are just related to that point in time. OPG and its actuary cannot smooth the discount rates over the calendar year. They cannot smooth the forecast discount rates over the test period. If the financial markets change two weeks after the assumptions are chosen and the calculations are made for year-end accounting, OPG cannot use more recent data for accounting purposes. OPG has to follow USGAAP and choose calendar year-end data.

The actual discount rate used by the actuary to calculate the expected return on pension plan assets is another source of volatility. OPG's current investment policy was used by the actuary to forecast the expected long-term rate of return in the calculation of pension obligations. From OPG's audited financial statements in 2000, the actuary used an expected rate of return of 7.75%. The percentage declined to 7% in 2003 and remained at that rate until 2011 when it declined to 6.5%. For 2013 the rate was 6.25%.[191]

[191] OPG Inc.'s audited financial statements for the years indicated.

OPG's pension fund earned a return of 9.2% in 2013 compared with management's benchmark of 8.5%.[192] OPG's management calculates the benchmark percentage after the year is over. OPG determines the asset mix of the portfolio at the beginning of the year. OPG has not set the benchmark return yet for 2014.[193] The fund's performance for 2014 up to the end of June was 10.6%.[194] For comparison purposes, Hydro One's pension plan earned a return of 17.91% in 2013 and 6.18% for the first five months of 2014.[195]

The discount rates used in the actuarial funding valuations also vary as shown in the table below.[196]

Table 28

Per Cent	2011	2014
Overall expected return	6.60	6.40
Non-investment expenses	-0.00	-0.20
Investment expenses	-0.30	-0.16
Additional returns	0.00	0.00
Margin for adverse deviations	-0.00	-0.44
Discount Rate	6.30	5.60

By contrast, the Board has to approve rates or payment amounts that are just and reasonable for future forecast test years. The Board is not constrained by a year-end date prescribed by accounting or actuarial standards.

OPG filed undertaking J13.7 on July 28, 2014. This undertaking has calculated the difference between cost recovery on an accrual basis compared to the cash basis. The cash pension amount shown in 2015 appears to reflect the same error as in AIC Chart 4 page 105. Board staff has recalculated the correct amounts based on the evidence provided in J9.6. Board staff believes that the correct total should be $609.4M reduction in revenue requirement using the cash basis and staff requests OPG to confirm the numbers in J13.7. However, Board staff has noted that the evidence in JT2.40,

[192] Exh L-6.8-Staff-116
[193] Oral Hearing Tr Vol 13, page 29.
[194] J13.1
[195] EB-2013-0416/ Exh.I/Tab4.03/Sch.1/Staff72.
[196] Mercer January 1, 2011/ EB-2012-0002/ Exh H2-1-3, page 31; AON Hewitt January 1, 2014/ EB-2013-0321/ J9.6, page 44.

corrected and filed on June 11, 2014, shows different accrual and cash numbers for OPEBs than OPG has shown on J13.7. OPG should clarify its evidence in its reply.

Board staff submits that OPG's evidence as submitted in this proceeding demonstrates how volatile and sensitive the forecast accrual accounting test year costs are to changes in discount rates. These forecast costs are not as stable and predictable as the cash payment costs for pensions and post-retirement benefits.

> MR. MILLAR: Any of them. If you did this on a cash basis -- let's just look at other post-employment benefits. If you did this on a cash basis, you're only forecasting for one or two years or something like that. You don't have to worry about the obligation way off into the future.
> It seems to me it is unlikely to be as large a variance as when you do the accrual method.
>
> MR. KOGAN: I would generally agree that the forecast projected payments for the post-retirement benefits are more predictable.[197]

Board staff submits that the evidence in this case presents compelling reasons for the Board to reconsider the cash payment basis of recovery of pensions and post-retirement costs in the determination of just and reasonable payment amounts for OPG.

USGAAP - Impacts Arising from Adopting the Cash Basis of Recovery

OPG applied in EB-2012-0002 to adopt USGAAP. OPG made this choice voluntarily. IFRS at the time did not allow the recognition of regulatory assets and liabilities whereas USGAAP does. OPG settled with parties in the proceeding.

The Board accepted the settlement proposal but made no comments on how OPG's adoption of USGAAP would affect the Board's deliberations in approving just and reasonable rates in future proceedings. However, staff notes that the burden of proof always rests with the applicant.

During cross-examination an OPG witness referred to the Board's authority for rate-setting.

[197] Oral Hearing Tr Vol 13, page 53.

> MR. KOGAN: USGAAP governs accounting for your financial reporting. I understand this Board sets how the amounts are included in the requirement.[198]

The following comments were made with respect to nuclear liabilities and contracts and not directly with respect to USGAAP, but also highlight the Board's authority.

> MR. BARRETT: I think as a general proposition the Board is free to establish methodologies, but ultimately we have to recover our nuclear liabilities costs.[199]

Board staff submits that the Board should not be constrained by USGAAP accounting technicalities in its determination of just and reasonable rates or payment amounts.

In its AIC on pages 105-106 and in undertaking J13.7, OPG introduced new information that it did not provide during discovery. OPG indicated that it has consulted with its external accounting advisors and they have indicated that OPG may *[emphasis added]* have to reverse the USGAAP recognition of some regulatory asset amounts.

During cross-examination, OPG's witness stated that there is a prohibition under USGAAP regarding the cash basis of rate recovery for OPEBs and the recognition of an associated regulatory asset.[200] However, in J13.7 and in its AIC, OPG now states that it may have to reverse recognition of some of the regulatory assets.

Board staff submits that there is some leeway in USGAAP not identified by OPG for the Board's consideration that will allow the cash basis of recovery for pensions and OPEBs.

One possible outcome of not adhering to USGAAP is that OPG's auditor might have to qualify the audit opinion. However, OPG did not discuss this possibility in its AIC nor what the consequences could be.

For example, Hydro One reports following USGAAP, yet it recovers pensions on a cash basis and its auditors have not qualified the audit opinion. In addition, the Board does

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[198] Oral Hearing Tr Vol 9, page 128.
[199] Oral Hearing Tr Vol 13, page 83.
[200] Oral Hearing Tr Vol 13, page 57.

not allow recovery of deferred taxes in rates, yet auditors for OPG, Hydro One, Union and Enbridge have not qualified their audit opinions because of this departure from USGAAP.

OPG has not provided an opinion from its auditor, Ernst & Young LLP, that Ernst & Young LLP will have to qualify the audit opinions associated with 2014 and 2015 financial statements if the Board imposes the cash payment basis of recovery for pensions and OPEBs. In addition, OPG has not provided evidence concerning what the impacts of a qualified audit opinion might be.

Intergenerational Equity

In its AIC, OPG states that the accrual method avoids intergeneration equity issues. Yet as will be explained below, inequity exists in many forms and partly because OPG has not been rate regulated by the Board since its inception.

The number of members of OPG's pension plan at January 1, 2014 was 22,093. Of these members, there are 10,271 active members who are currently working and making pension contributions.[201] At December 31, 2007 the total number of members was 21,705 and the active members numbered 11,603.[202] Having less than 50% of OPG's plan members currently working is a major source of considerable inequity for today's ratepayers to fund.

Up to April 1, 2008 when the Board became responsible for regulation, OPG does not know the specific amounts assumed by the Province for recovery of pensions and OPEBs when interim payment amounts were approved.[203] From the date of OPG's early adoption in 1999 of the CICA accounting standard for pensions and OPEBs, and up to April 1, 2008, OPG was not fully recovering the accrual accounting amounts in revenue that it was recognizing in its income statements.[204] OPG applied to the Board to be allowed to include the accrual accounting expense in payment amounts. The Board approved recovery in the absence of sufficient evidence to the support the cash basis.

[201] J9.6, Actuarial Valuation, page 31.
[202] EB-2010-0008, L-01-084, Attachment 1, Mercer Actuarial Valuation, January 1, 2008, page 38.
[203] Exh L-6.8-Staff-124 page 1.
[204] OPG's audited financial statements.

The issue of intergenerational equity arose in the first application to the Board. Prior to the Board's first decision, ratepayers paid whatever the charge that was levied, whether through market mechanisms or government decisions. Ratepayers today are paying OPG's pension and OPEB costs that have arisen over the last several decades. In addition to paying for OPG's retirees, today's ratepayers are paying for OPG's employees who will retire some decades in the future.

OPG has stated that the accrual method of cost recovery provides the appropriate matching of cost incurrence and inclusion in rates and thereby avoids intergenerational equity issues[205] and that OPG will manage its cash flow in order to fund its future liabilities. In Board staff's view, it is inequitable for today's ratepayers to pay for pension and OPEB costs that OPG will have to find the cash to pay for decades in the future. Some of the amounts that ratepayers have paid for OPG's pension costs are secure in the registered pension plan. However, no segregated fund exists for the excess recoveries for OPEBs. This issue is discussed elsewhere in this submission. Exposing ratepayers to future risks for amounts already paid now seems to staff to be inequitable.

6.8.3 Conclusion and Submission

On an accrual accounting basis, pension and OPEBs are incurred and recognized when the related employee service is considered to be rendered and the benefit is considered to be earned, not when the actual benefit payments are made to retirees. OPG states that it is the earning of the benefit which results in the cost being incurred, not its payment and that reflecting these costs in payment amounts at the time the costs arise results in the appropriate matching of costs and benefits, thereby avoiding intergenerational equity issues.

However, it is Board staff's view that while this is a sensible approach to quantifying a liability for the readers of financial statements, it is not a sensible approach to rate recovery. If we take an example of an employee who is now 30 years of age that will live until the age of 90, and retire at the age of 60, the accrual approach would require that the costs associated with supporting that employee during years 60 to 90, to be paid by rate payers during the years 30 to 60. While there is no doubt that all costs associated with the accrual method will be paid eventually, there is no compelling reason it seems to Board staff why ratepayers should pay such a significant amount earlier than they have to. If OPG was in danger of ceasing operations in the short to

[205] AIC, pages 105-106

mid-term, and the shareholder maintained that ratepayers should pay for the remainder of the liability, then staff would agree that the accrual method would be preferred to smooth out the rate impact. But the underlying assumption is that OPG is a going concern; and that is a major assumption in the actuarial valuations filed in evidence.

In addition, accrual accounting requires OPG to select a discount rate at the end of the year. OPG cannot smooth the discount rate for the whole historical year, nor can OPG make an estimate of the coming year's bond yields. The employee data is generally taken at the beginning of the same year. OPG's staff reductions during the year may not be included. The staff reductions related to closure of Pickering in 2020 have not been included in the forecasts for test period costs even though the future staff reductions will impact the current discounted cash flow calculations.

OPG has acknowledged that the challenges associated with pension funding are not unique to OPG. OPG has stated that the primary drivers of the increased costs are historically low discount rates and updated mortality assumptions recommended by OPG's actuaries. These factors are not within its control, and OPG therefore concludes that the Board should accept the rate impacts. Yet, OPG's management has the discretion for matters such as contributing more than the minimum contribution recommended by its actuary for pensions.

The Board has the authority to allow recovery of pension and OPEB costs in payment amounts using the cash payment basis or the accrual accounting method. The Board assessed the evidence submitted by OPG in prior applications and concluded that the accrual accounting basis provided more stable rates during the test period.

OPG's latest evidence in this application demonstrates how stable the cash method can be for determination of costs to be included in test period payment amounts and how these are the only types of costs that are not aligned with actual expenditures in the test period if the accrual method is used. The Board has few levers at its disposal to smooth OPG's proposed rate impacts. According to OPG, the Board must also accept the constraints imposed by USGAAP. Board staff does not agree. It is not clear to Board staff that any constraints that may exist are not unmanageable. And, it is not clear to Board staff that the adverse impacts to the company (whatever they may be) of setting its payment amounts on the cash basis, outweigh the benefits to ratepayers.

Board staff submits that the Board may wish to consider whether this is the appropriate time to move to the cash basis for determining the amounts to be included in the revenue requirement for pensions and OPEBs for the 2014-2015 test period. Should the Board decide to move to the cash basis, the revenue requirement for each of the test years, based on Option 2 above, will be reduced by $352.5M for 2014 and $256.9M for 2015. The total reduction in revenue requirement will be $609.4M including the income tax PILs impact.[206]

6.8.4 Current Pension and OPEB Cost Variance Account and Interest Carrying Charges – Accrual Method

Issues 9.1 and 9.5 Deferral and Variance Accounts

The balance in this account as at December 31, 2013 for both hydroelectric and nuclear is $667.1M. OPG has riders approved by the Board to clear the balance related to the period up to December 31, 2012 of $264.8 M. OPG has not applied to clear the variances which arose in 2013 of $402.3 M.[207]

In EB-2012-0002, the Board accepted a settlement proposal on March 25, 2013, in which OPG agreed that no interest would apply to the variances or balance in the account from January 1, 2013 through December 31, 2014. OPG proposes that interest will resume on January 1, 2015.

During cross-examination, OPG's witnesses stated that the accrual accounting numbers determined in accordance with USGAAP (and prepared by actuaries) are non-cash amounts.[208] In cross examination, Board staff referred to findings (dated 2012) out of several decisions of the Board that denied interest carrying charges on pensions and OPEB variances that are non-cash actuarially determined amounts.[209]

[206] J13.7, Chart 1, Recalculated by Board staff for the errors previously identified.
[207] Exh L-9.1-SEC-132 Attachment 1 Table 1.
[208] Oral Hearing Tr Vol 9, Mr. Kogan, pages 103, 107, 121-122, 126; Ms. Ladak, page 119.
[209] Exh K13.1 Staff Compendium, Panel 7, pages 30-33/ Enersource, EB-2012-0033, December 13, 2012, page 59; Staff Compendium, Panel 7, page 34/ Enbridge EB-2011-0354, October 3, 2012, Settlement Proposal, page23.

Board staff submits that the variances recorded by OPG have been actuarially determined as described in this submission and that interest carrying charges should not apply to be consistent with other decisions of the Board.

Should the Board decide that the cash payment basis will apply to the recovery of pensions and post-retirement benefits in payment amounts for the test period, the existing variance account will have to be continued until the balance is drawn down. OPG has not applied for disposition of the variances that arose in 2013. Part of the 2012 balance is being recovered over 12 years.

6.8.5 New Variance Account if Cash Basis of Recovery is Approved

There will be differences between the cash payment amounts included in revenue requirement for pensions and OPEBs and the actual cash payments. The Board approved a variance account for Hydro One to record the differences related to pension cash payments.[210]

However as discussed earlier in this submission, OPG's management has the discretion to contribute more than the minimum pension contribution recommended by its actuary. AON Hewitt in J9.6 has calculated that the maximum deductible company contribution for 2014 is $7,261,860,000 ($7.3 billion) while the minimum amount recommended is $358,237,000.

Board staff submits 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.

Since OPG's management has discretion over the amount to be paid beyond the minimum contribution recommendations of its actuary, Board staff submits that the Board must be careful in describing how the variance must be calculated and any limits to be imposed on the excess amount paid beyond the forecast payments included in revenue requirement. In the event the Board approves the cash basis going forward, OPG should file a draft accounting order as part of the draft Payments Amount Order so that the parties can review the mechanics of the account.

[210] EB-2013-0416/Exh.F1/Tab1/Sch.2/page 3/ Continuation of the Board's approval in EB-2009-0096.

6.9 Corporate Costs

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

Support service groups (Business and Administrative Services, Finance, People & Culture, Commercial Operations & Environment and Corporate Centre) provide services and incur costs in support of the nuclear and regulated hydroelectric businesses. The costs are allocated to the business units and the allocation methodology is unchanged from EB-2010-0008.

As part of the Business Transformation initiative, OPG has moved to a centre-led model to "use resources more efficiently and avoid duplication of work"[211] and "consolidating staff that perform similar work, streamlining processes, and eliminating lower value work."[212] Board staff submits that many of the corporate functions are what AON Hewitt would compare with "general industry". OPG's witnesses have described engineering and operators as the critical job families.[213] The AON Hewitt National Utility Survey has indicated that the general industry comparable jobs are significantly overpaid by OPG vs P50. The Auditor General's analysis of administration, finance and human resources jobs indicated that the majority of these jobs are overpaid at OPG with respect to the Ontario Public Service. And as noted previously, the Auditor General also observed that the Goodnight benchmarking found that support functions were overstaffed while operational functions were understaffed.

One of Dr. Chaykowski's conclusions is that "unions disproportionately increase the wages of lower-skilled workers at the bottom of the wage distribution within a firm."[214] Staff submits that this applies to OPG, where "lower-skilled" is synonymous with "general industry" or "non-critical job family".

[211] Exh A4-1-1, page 1
[212] Exh F3-1-1, page 4
[213] Oral Hearing Tr Vol 6, page 20
[214] Exh F4-3-1, Attachment 1 section 1

In the last 6 years, OPG has completed some benchmarking for the IT, HR and Finance corporate functions, and has filed the results of that benchmarking in the previous proceeding, EB-2010-0008, and the current proceeding.

6.9.1 Information Technology

IT services are provided through a combination of OPG resources and contracted service with New Horizon System Solutions ("NHSS"). The forecast NHSS base costs for the regulated business total $65.3M for 2014 and $62.1M for 2015. The forecast OPG IT support costs for the regulated business are $32.0M and $30.9M.[215]

The Auditor General noted that in 2009 OPG renewed its contract at $635M with NHSS for a term of six years ending December 31, 2016 without competition, commenting that OPG did not take advantage of the benefits of open competition to ensure value for money. OPG responded that before the current contract expires, it plans an open competitive process that is consistent with the recommendation of the Auditor General.

Similar to the hydroelectric and nuclear businesses, OPG has access to EUCG cost data for the IT function. The 2011 results indicate that OPG is in the second quartile for IT spending/employee and is in the third quartile for IT spending/GWh.[216]

In response to a technical conference undertaking, OPG filed a report that summarized IT performance for the period 2007–2010. The report was prepared by OPG staff. Similar to hydroelectric benchmarking, the report notes that OPG has excluded some of raw data for its analysis. For the 2007-2010 period, OPG's IT spending metrics were in the second and third quartiles, which is consistent with 2011 results indicating no improvement over the 5 year period.

In interrogatory response Exh L6.9-Staff-130, OPG indicated that test period IT costs would be reduced by $21.9M to $23.5M per year if IT spending/employee were in the top quartile. IT costs would be reduced by $24.4M to $28.3M per year if IT spending/GWh were in the top quartile.

[215] Exh F3-1-1 Tables 6 and 7
[216] Exh F3-1-1, page 6

6.9.2 Human Resources

The forecast People & Culture costs for the regulated business for 2014 are $104.8M and for 2015 are $101.9M. Similar to hydroelectric benchmarking and IT benchmarking, there is no independent benchmarking analysis. OPG receives raw data from the Electric Utility HR Metrics Group and determines benchmarking results. For 2012, OPG's HR Expense Factor (total HR expense divided by the number of regular HR employees) was between the median and bottom quartile. OPG's Employee Ratio which compares HR FTE's with all regular FTE's is in the bottom quartile.

In interrogatory response Exh L6.9-Staff-131, OPG indicated that 2012 HR expenses would be reduced by $14.9M if OPG were in the top quartile for both HR metrics. OPG noted that no utilities achieve top quartile for both metrics.

6.9.3 Finance

The forecast Finance costs for the regulated business for 2014 are $53.6M and for 2015 are $51.0M. The last Finance benchmarking study was conducted in 2010 based on 2008 data.

6.9.4 Submission

Board staff submits that independent benchmarking of the corporate function is required given the significant changes resulting from Business Transformation. The analysis would need to be normalized and reflect the period before BT and after BT.

In light of the most recent corporate function benchmarking results, Board staff submits that OM&A reductions are appropriate.

Hydroelectric Facilities

Board staff has submitted that reductions to test period OM&A are appropriate under section 6.1 above. Board staff does not propose any further corporate cost related reductions.

Nuclear Facilities

The following table summarizes corporate costs for the period 2010 to 2015.

Table 29

$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
Total Variance		-23.2		-18.9		-46.4		-29.9		
Nuclear Variance		-20.5		-16.1		-41.9		-22.7		
Source: Exh F3-1-2 Tables 1,2,3 Exh F3-1-1 page 2 and 3, Exh L-1-Staff-2										

For the historical period, actual costs have consistently been lower than approved/plan. For the nuclear business, the average variance is $25.3M. Board staff submits that a disallowance to nuclear test period OM&A of $25M per year related to corporate costs is warranted based on benchmarking results and historical spending.

6.10 Depreciation

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

The following table summarizes the historical and test period depreciation and amortization expense.

Table 30

$million	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
Previously Regulated Hydroelectic	63.5	65.6	70.0	80.5	82.1	81.9
Newly Regulated Hydroelectric	58.3	58.0	58.6	59.0	62.2	63.1
Nuclear	231.1	228.6	341.9	270.1	273.7	288.5
Source: Exh L-1-Staff-2 Table15, 16 19						

In 2013, the previously regulated hydroelectric expense increased due to NTP coming into service in March. The nuclear depreciation expense increased in 2012 as a result of changes arising from the ONFA Reference Plan.

6.10.1 Depreciation Study

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

In the EB-2010-0008 cost of service decision, the Board directed OPG to conduct an independent depreciation study. OPG engaged Gannett Fleming Inc. ("Gannett Fleming") in 2011 to provide an independent review and assessment of the asset service life estimates and nuclear station end-of-life ("EOL") dates for OPG's regulated assets based on the net book values as at December 31, 2010. Subsequent to the completion of the 2011 Depreciation Study,[217] OPG determined that it would update the study based on December 31, 2012 net book values and changes made to the EOL dates for Pickering effective December 31, 2012.[218] Given its significance, the Niagara Tunnel, placed in-service in 2013, was included in the scope of the updated study. OPG incorporated all recommendations made by Gannett Fleming in these studies to depreciation and amortization expenses for the test period.

In interrogatory Exh L-6.12-Staff-147, staff asked whether the equal life group ("ELG") method provides a better matching of depreciation than the average life group ("ALG") method which is used by OPG. For the ELG method, each ELG includes that portion of property which experiences the service life of that specific group. For the ALG method, the rate of annual depreciation is based on the average life of the property group.

OPG stated that Gannet Fleming acknowledged that the ELG method is superior and provides a better matching of depreciation than the ALG method. However, it did not have the data required to use the ELG method due to a change in asset revaluation in 1999 upon the changeover of assets from the former Ontario Hydro to OPG. At the technical conference in April 2014, Board staff requested an undertaking for OPG to provide the useful lives of major asset classes as at the pre-1999 OPG changeover (Mar 31/1999) and as at the post 1999 OPG changeover (Apr 1/1999). The request was refused. As such, Board staff is unable to assess the impacts of the changeover on estimated service lives of assets. Staff is of the view that the "revaluation" of assets process also included extending the service lives for many of OPG's major assets.

[217] Exh F4-1-1 Attachment 1
[218] Exh F5-3-1

Staff submits that the Board should direct OPG to retain an independent expert to conduct a statistical retirement analysis of OPG's hydroelectric assets (previously and newly regulated) for the purposes of determining asset service lives/depreciation rates based upon the ELG method which segregates assets into groups of assets with the same life expectancy (or using a procedure that yields asset service lives at more granular levels compared to the ALG method used by OPG). This should be a vigorous and objective review to ascertain asset service lives at more granular levels.

While there may be some constraints due to the asset revaluation in 1999, this in itself should not constitute a limiting factor as not to be able to perform such a study. There are various statistical techniques that can be used to address the pre-1999 data including normalizing the data for purposes of the study. This depreciation study should be required to be filed in the next payment amounts proceeding subject to the Board's determination on OPG's incentive payment-setting plan going forward.

6.10.2 Niagara Tunnel Project

With respect to the NTP, Gannett Fleming agreed with OPG's selection of its useful life for the newly competed tunnel. Specifically, Gannett Fleming stated: "Based on its review of the NTP, it is the view of Gannett Fleming that the tunnel excavation investment would have a similar life of 100 years as expected for the existing two Niagara tunnels and other hydroelectric excavation. However, Gannett Fleming's review also specifically noted that the NTP tunnel lining material installation procedures, were specifically designed and the tunnel was specifically constructed for a service life of 90 years. In fact, the 90-year design life was a specific requirement of the NTP to be considered by contractors working on this project."

It would be reasonable to assume that the NTP is far superior to the existing two Niagara tunnels which were completed in 1955.[219] The end of life of the NTP would be more than 90 years given that advanced technology and materials were used in its construction including tunnel construction boring machine, invert membrane and concrete, arch membrane and concrete, profile restoration and liner grouting lining, etc. The NTP was reinforced with a combination of steel ribs, wire mesh, rock bolts and concrete that varied with the actual rock conditions encountered along the tunnel route,

[219] Exh L-6.12-Staff-160

and finally, a waterproof membrane was applied and the final concrete liner was constructed.

While Gannett Fleming claims that the expected service lives for the existing two Niagara tunnels is 100 years, OPG has indicated they are about 120 years (in response to Exh L-6.12-Staff-160 e). The two original tunnels have been in service since 1955. In 1999, their useful lives were extended to 2074 (i.e., 75 years). Thus from 1955 to 2074, their services lives would be about 120 years. In addition, OPG indicated that the two tunnels are operating as designed with no significant changes in water flow capability over almost 60 years since the original in-service date.

Staff submits the NTP should be expected to have a service life in the range of 125 to 150 years given that the two original tunnels have useful lives of about 120 years and since the NTP is a far superior structure. Staff submits the mid-point in this range of 135 years provides a reasonable estimate for the service life.

6.11 Income and Property Taxes

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

6.11.1 Loss Carry-Forward

OPG filed its calculation of 2013 regulatory income tax for the prescribed facilities in response to interrogatories.[220] In 2013, OPG disclosed that there was a regulatory tax loss of $153.8M (updated to $211.6M per J13.4) which OPG states was caused by a shortfall in nuclear production. OPG has not used the 2013 regulatory tax loss as a carry-forward into 2014 to offset part of the 2014 regulatory taxable income of $924.1M[221] which has been subsequently adjusted by two impact statements to $793.5M.[222]

OPG has stated that it had to bear the operating loss and is entitled to receive the benefit of the 2013 regulatory tax loss. OPG relies on the Board's decision in EB-2007-

[220] Exh L-1-Staff-2 Attachment 1 Table 29
[221] Exh F4-2-1 Table 5
[222] Exh N1-1-1 and Exh N2-1-1

0905 in which OPG states the Board established the principle of attributing tax costs and benefits.[223]

OPG chose not to file an application for 2013 payment amounts. OPG relied on the payment amounts that the Board approved for the 2011-2012 test periods for the 2013 calendar year. The payment amounts effect in 2013 included an amount for income tax PILs which was the same amount that was included for PILs in the 2011-2012 test periods. Income tax amounts of $60.9 M and 91.1M were approved for the 2011 and 2012 test years, respectively, which were included in revenue requirement.[224]

In EB-2007-0905, the Board wrote the following comments in its Decision with Reasons.[225]

> The Board also expects OPG to file an analysis of its prior period tax returns that identifies all items (income inclusions, deductions, losses) in those returns that should be taken into account in the tax provision for the prescribed facilities. That analysis should be based on the principle that if OPG is proposing that electricity consumers should bear a cost (or should benefit from revenues) they will receive the related tax benefit (or will be charged the related income taxes).

Ratepayers have paid for the PILs provision included in 2013 revenue requirement. Since ratepayers have borne the costs associated with 2013 PILs as part of the payments amounts, Board staff submits that the 2013 regulatory tax loss calculated by OPG should be used to reduce regulatory taxable income in 2014.

6.11.2 Board Policy for Electricity Distributors

In its 2006 Electricity Distribution Rate Handbook, the Board established its policy with respect to tax loss carry-forwards. Any tax losses that existed at the end of the 2005 tax year were used in the calculation of the 2006 PILs provision that was included in revenue requirement.[226]

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[223] AIC page 118.
[224] Payment Amounts Order EB-2010-0008, Appendix A, Tables 6 and 7
[225] Decision with Reasons, EB-2007-0905, page 171
[226] 2006 Electricity Distribution Rate Handbook, Chapter 7, section 7.2.3 Loss carry-forwards

The Board's filing requirements for 2014 and 2015 continue the requirement for loss carry-forwards to be utilized in the calculation of the test period PILs provision. The Board has provided an Excel PILs model to guide the applicants in the required calculations.[227]

Board staff submits that the Board has a long-established policy with respect to tax loss carry-forwards for the utilities that it regulates. OPG has been regulated by the Board since 2008. The Board approved the PILs amounts that were included in OPG's revenue requirement for the test years 2011 and 2012. Ratepayers have paid PILs costs in 2013 payment amounts. Board staff submits that ratepayers have borne the regulatory 2013 PILs costs which were not incurred by OPG due to the regulatory tax loss, and therefore, ratepayers should benefit by a reduction of the PILs provision in 2014 revenue requirement.

7. OTHER REVENUES

7.1 Regulated Hydroelectric Other Revenues

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

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

Table 31

$million	2010 Actual	2011 Actual	2012 Acutal	2013 Actual	2014 Plan	2015 Plan
Ancillary Services	26.2	22.2	20.8	37.1	18.1	18.5
Seg Mode of Operation	-0.9	1.7	-0.8	4.1	0.0	0.0
Water Transactions	5.5	7.5	1.6	1.0	1.7	1.7
HIM Adjustment				6.5		
Total	**30.8**	**31.4**	**21.6**	**48.7**	**19.8**	**20.2**
Exhibit N1 Update					33.9	34.6

[227] Filing Requirements for Electricity Distribution Rate Applications, Chapter 2, section 2.7.5.

The HIM adjustment in 2013 was required as a proxy to account for the revenue requirement offset ordered by the Board for 2011 and 2012. The Exh N1-1-1 update is the result of higher forecast revenue for operation reserve and a new contract for regulation service – resulting in an increase in ancillary services revenue.

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

Table 32

$million	2010 Actual	2011 Actual	2012 Acutal	2013 Actual	2014 Plan	2015 Plan
Ancillary Services	26.4	26.1	25.9	35.7	22.7	23.1
Seg Mode of Operation	0.0	0.0	0.0	0.0	0.0	0.0
Total	**26.4**	**26.1**	**25.9**	**35.7**	**22.7**	**23.1**

The analysis of variances of other revenues is complicated by redacted data for the 2011 and 2012 period for both hydroelectric and nuclear. Board staff observes that the ancillary services revenues result in the largest variances for the previously and newly regulated hydroelectric facilities. As the Exh N1-1-1 update has revised the previously regulated hydroelectric other revenue for ancillary services, and as there is a variance account for ancillary services, Board staff submits that the test period other revenues are appropriate.

7.2 Nuclear Other Revenues

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

The historical and forecast other revenues for the previously regulated hydroelectric facilities are summarized in the following table. All of the data are from the public record of this proceeding.

Table 33

$million	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2013 Actual	2014 Plan	2015 Plan
Heavy Water Sales	26.7	80.9	55.1	18.9	34.8	26.3	20.4
Isotope Sales	10.1	4.8	11.5	11.1	7.0	11.6	11.9
Inspection & Maintenance Services	36.0	7.1	4.1	0.0	0.0	0.0	0.0
Helium 3 Sales	0.0	0.0	0.0	0.0	0.0	0.0	4.0
Costs	-31.5	-10.7	-8.7	-7.2	-5.9	-6.8	-7.8
Net NGD Contribution	41.3	82.1	62.0	22.8	35.9	31.1	28.5
Ancillary Services	2.6	2.4	1.8	1.9	1.7	1.9	1.9
Third Party Training	0.8	0.6	0.1	0.1	0.0	0.1	0.1
Total	**44.7**	**85.1**	**63.9**	**24.8**	**37.6**	**33.1**	**30.5**
Source: Exh G2-1-1 Table 1, Exh L-1-Staff-2 Table 35							

OPG proposes to continue the sharing of 50% of net revenues from sales of heavy water as set out in EB-2010-0008.

Other revenues from Inspection & Maintenance Services have declined as OPG exited from provision of services to external customers in 2011. The analysis of variances of other revenues is complicated by redacted data for the 2011 and 2012 period for both hydroelectric and nuclear. Board staff observes that the heavy water sales are highly variable. In the application at Exh G2-1-2, the 2013 budget "reflects a return to more normal conditions for sales of heavy water, heavy water detritiation services and isotope sales." However, the 2013 actual total other revenue was $12.8M or 51% higher than 2013 budget. The AIC describes the test period forecast as "a return to a more normal level of revenues for heavy water sales and processing."[228]

Board staff submits that the Board should consider the 2013 actual nuclear other revenue as the normal level for the test period, i.e. $37.6M for both 2014 and 2015.

7.3 Bruce Nuclear Generating Station

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

[228] AIC page 122

The historical and forecast Bruce Lease Net Revenues are summarized in the following table.

Table 34

$million	2010 Actual	2011 Actual	2011 Approved	2012 Actual	2012 Approved	2013 Budget	2014 Plan	2015 Plan
Non-Derivative Lease	241.2	251.4	254.4	248.9	268.7	275.6	274.6	281.2
Derivative Lease	-45.0	-23.5	0	-283.5	0.0	0.0	0.0	0.0
Lease Revenue	196.2	227.9	254.4	-34.6	268.7	275.6	274.6	281.2
Costs	18.6	161.4	126.3	84.9	125.7	233.3	235.0	240.6
Lease Net Revenues	177.6	66.5	128.1	-119.5	143.0	42.3	39.6	40.6

The Bruce Lease Net Revenues were reviewed in the EB-2012-0002 proceeding. Board staff has reviewed the current application to ensure consistency with the approach set out in the approved settlement proposal from the EB-20102-0002 proceeding. Board staff submits that the test period forecast is appropriate.

8. NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING LIABILITIES

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

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

OPG is seeking recovery of $847.5M over the 2014-2015 test period in respect of liabilities for nuclear waste management and decommissioning for both prescribed nuclear and Bruce facilities. This amount includes the revenue requirement impacts of the current (2012) approved ONFA Reference Plan, which total $442.3M over the test period. These impacts relate primarily to increases in depreciation expense, variable used fuel storage and disposal expenses, and increases in accretion expense.

The 2013 revenue requirement impacts of the current approved ONFA Reference Plan were recorded as additions to the Nuclear Liability Deferral Account and Bruce Lease Net Revenues Variance Account and are $122.7M and $110M respectively.

Staff is satisfied that the financial impacts (i.e., types and amounts) provided in this application are consistent with the ones used, reviewed and approved in the last payments proceeding and the financial impacts recorded in the Nuclear Liability Deferral Account as of December 31, 2012 arising from the new approved ONFA Reference Plan which were reviewed and approved for clearance of the account balance in the EB-2012-2002 proceeding.

In relation to “Due to Province” amounts included in the 2013 decommissioning and used fuel funds balances, some intervenors questioned whether the inclusion of the due to province amounts in the funds balances would result in lower cost impacts under the Board’s prescribed nuclear liability recovery calculation methodology. Based on the cross examination, undertaking responses and AIC, Board staff has no concerns with the determination of nuclear liabilities for the test period.

9. DEFERRAL AND VARIANCE ACCOUNTS

9.1 Nature or Type of Costs Recorded

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

The audited 2013 year end balances for all the accounts was provided in interrogatory response Exh L-9.1-SEC-132. The previously regulated hydroelectric facilities balance is $217.3M and the nuclear facilities balance is $1,478.4M.

Board staff has no concerns with the nature of the costs recorded in the approved accounts as they are consistent with the purpose for the accounts. Board staff reserves the right to re-examine the accounts that are not being disposed in this proceeding in greater detail in the future application that will dispose of them.

9.2 Account Balances and Disposition

Issue 9.2 (Secondary) - Are the balances for recovery in each of the deferral and variance accounts appropriate?
Issue 9.3 (Secondary) - Are the proposed disposition amounts appropriate?
Issue 9.4 (Secondary) - Is the disposition methodology appropriate?

The EB-2012-0002 Settlement Agreement filed on September 24, 2012 states:

> OPG applied to the OEB pursuant to 78.1 of the *Ontario Energy Board Act, 1998*, for an order or orders approving the disposition of the audited actual balances as of December 31, 2012 in its deferral and variance accounts, except for the balances in the Hydroelectric Incentive Mechanism Variance Account and Hydroelectric Surplus Baseload Generation Variance Account of ($2.4M)1 and $4.1M2 respectively, and a portion of the Capacity Refurbishment Variance Account of $2.4M3.
>
> For purposes of settlement, the Parties agreed to defer the consideration of the balance of $30.2M in the Nuclear Development Variance Account until OPG's next Nuclear cost of service application and to forego the recovery of interest charges for certain 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.

In the current proceeding, OPG seeks clearance of the 2013 year end balances for the

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

Board staff has no concern with the balances proposed for disposition. The proposed riders as updated in Exh N2-1-1, $3.36/MWh for the previously regulated hydroelectric facilities and $1.35/MWh for the nuclear facilities, would be effective January 1, 2015. The proposed recovery period is 12 months for all of the accounts, except for the Capacity Refurbishment Variance Account – Hydroelectric, for which OPG seeks a 24 month recovery period.

Board staff has no concerns with the determination of the payment riders for these four accounts, subject to the Board's final decision on production forecast and number of accounts to be cleared in this proceeding.

This 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. This was done previously in EB-2010-0008 and EB-2012-0002. It is Board staff's understanding that no other utilities do this, and certainly not on a regular basis. This type of filing means that the bill impacts for notice are based on estimates. Further, this type of filing creates inefficiency.

OPG plans to seek clearance of the December 31, 2014 balances in all its deferral and variance account balances through a separate application to be filed in 2014. Board staff submits that the Board may wish to consider whether it will permit OPG to continue to file on the basis of estimates. It is not apparent to Board staff that the advantages of disposing of a further year of transactions, outweighs the inefficiencies of assessing forecast balances and repeating that assessment once updates are provided.

9.3 Continuation of Accounts

Issue 9.5 (Secondary) - Is the proposed continuation of deferral and variance accounts appropriate?
Issue 9.8 (Secondary) - Is the proposal to discontinue the Hydroelectric Incentive Mechanism Variance Account appropriate?

The Tax Loss Variance Account and the Impact for USGAAP Deferral Account will be terminated on December 31, 2014. Board staff has no concerns with this proposal.

As noted in the Pension Accounting section 6.8.4, Board staff submits that the variances recorded by OPG have been actuarially determined as described in this submission and that interest carrying charges should not apply to be consistent with other decisions of the Board.

OPG has proposed an eHIM in its application that eliminates the need for additions to the Hydroelectric Incentive Mechanism Variance Account in the future. OPG proposes to retain the account for the purposes of amortization and recording of interest only. As noted in the submission in section 5.3, Board staff submits that the account should be continued and operate as it operates now. The account should also function for the incentive mechanism revenue related to the newly regulated hydroelectric facilities.

9.4 Clearance of Only Four Accounts

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

Utilities typically file most recently audited balances for all deferral and variance accounts as part of a cost of service application. Rationale is provided for the clearance of all or some of the accounts in the application.

OPG has filed its application seeking clearance of 2013 audited balances for 4 accounts. It did not provide a rationale for limiting the clearance to the 4 accounts. In response to undertaking J13.8, OPG determined that the impact of clearing all account balances in 2015 would result in significant payment riders: $8.42/MWh for the previously regulated hydroelectric facilities and $27.47/MWh for the nuclear facilities. Board staff submits that this kind of analysis and a rationale for selective clearance must be provided in future applications.

As noted above, OPG plans to seek clearance of the December 31, 2014 balances in all its deferral and variance account balances through a separate application to be filed in 2014. OPG appears to have the understanding that separate applications for disposition of deferral and variance accounts is the norm.

> MS. LADAK: Yes. The variance account is recovered -- we have separate hearings for these variance accounts, typically.[229]

Board staff submits that this is not the norm and 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. This is the reason in Board staff's view why the Board requires electricity distributors to bring forward for review and disposition all of a distributor's applicable deferral and variance accounts at the time of a cost of service application. Not all deferral and variance accounts are completely exogenous to the revenue requirement, and even if they were, it is simply not efficient for the Board to deal with a standalone application when the balances can

[229] Oral Hearing Tr Vol 8 page 129

be reviewed in a single application. Any concern regarding bill impacts can be addressed in a cost of service proceeding.

9.5 Accounts for Newly Regulated Hydroelectric Facilities

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

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 subsumed as subaccounts of existing accounts. Entries to the accounts would commence on the effective date of the payment amounts. The accounts are:

- Hydroelectric Water Conditions Variance Account (for the 21 facilities for which production forecast is based on computer modeling)
- Ancillary Services Net Revenue Variance Account
- Hydroelectric Surplus Baseload Generation Variance Account
- Capacity Refurbishment Variance Account
- Income and Other Taxes Variance Account
- Pension and OPEB Cost Variance Account
- Hydroelectric Deferral and Variance Over/Under Recovery Variance Account

And as noted in section 5.3 of this submission, Board staff submits that the Hydroelectric Incentive Mechanism Variance Account should also apply to the incentive mechanism revenue related to the newly regulated hydroelectric facilities.

9.6 Other Deferral and Variance Accounts

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

OPG has not proposed any new deferral and variance accounts in its application.

As noted in section 6.8.5 of this submission, if the Board approves a cash basis for pension and OPEB, Board staff submits 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.

While part of the analysis of the Niagara Tunnel Project reflects a 10 year GRC payment holiday, OPG is only in the preparation stages of that application to the Ministry of Natural Resources (JT1.8). The potential holiday is not reflected in the GRC costs. OPG does not anticipate MNR response in the test period.

As MNR approval is highly likely, Board staff submits that an account should be set up to capture the GRC costs for return to ratepayers.

If the Board were to approve these two new accounts, OPG should file a draft accounting order as part of its draft Payments Order, explaining the mechanics of each account.

10. METHODOLOGIES FOR SETTING PAYMENT AMOUNTS

10.1 Methodologies

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

Even prior to OPG's first payments application EB-2007-0905, the Board has expressed its preference for the adoption of a form of incentive regulation for setting payments for OPG's prescribed assets.[230]

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[230] Decision with Reasons EB-2010-0008, at page 153:
The Board prepared a report in 2006 establishing the methodology to be used for setting payment amounts for OPG. 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, stated that, "The Board will implement an incentive regulation formula when it is satisfied that the base payment provides a robust starting point for that formula."

At the same time, it is recognized that there is limited comparable generation-only utilities for which benchmarking data or experience under incentive regulation is available.

Nevertheless, the Board has consistently signaled its interest that some form of incentive regulation could be appropriate for the setting of payments for the prescribed assets. The formulaic setting or adjustments to the payments should result in a less onerous review than occurs in a traditional cost of service, of which the three OPG payments applications to date have been examples. Incentive regulation should also provide OPG with the opportunities and incentives to pursue more productive operations, with a sharing of the benefits to both OPG's shareholders and to Ontario electricity consumers.[231]

The EB-2010-0008 proceeding (for 2011-2012 test period) anticipated a 2013-2014 cost of service application. The Board concluded that incentive regulation in 2015 should be considered. The process would commence with a Board review. The Board also expected OPG to provide a proposed work plan and status report for an independent productivity study as part of the 2013-2014 application.

The Board conducted a consultative process, which resulted in the *Report of the Board on Incentive Rate-making for Ontario Power Generation's Prescribed Generation Assets EB-2012-0340*, (March 28, 2013).[232] The Board report set out a timeline to establish IRM for hydroelectric and multi-year cost of service for nuclear assuming a 2014-2015 cost of service application filing in mid-2013. On May 10, 2013, OPG filed a proposed updated timeline in a letter,[233] reflecting an application date of September 2013 and a decision in June 2014. OPG projected work commencing in July 2014 on multi-year cost of service for nuclear and September 2014 on hydroelectric incentive regulation. The Board's report and OPG's application for incentive regulation would be expected to occur in 2015.

OPG's evidence in the current application is found in Exh A3-1-1. OPG has asked London Economics Inc. ("LEI") to conduct the independent hydroelectric productivity study requested by the Board in EB-2010-0008. OPG has filed the LEI work plan for

[231] Decision with Reasons EB-2010-0008 pages 153-156
[232] Exh K2.3 (section 2)
[233] http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/396098/view/

the independent productivity study for the previously regulated and newly regulated hydroelectric facilities to be completed in time to support the working group. The work plan indicates that the report will be completed Q4 2014.

The issue of incentive regulation for OPG's prescribed generation assets was first raised in 2006. As OPG did not file a cost of service application for 2013, the planned incentive regulation implementation contemplated by the EB-2010-0008 decision would be 2016 instead of 2015.

Board staff's main concern is with respect to the timing. OPG's application was filed in September 2013, and the Board will still be processing the application in the fourth quarter of 2014. There has been little progress on incentive regulation. The delays are for various reasons, but it is also clear that no work can or should proceed until this proceeding is completed.

Board staff estimates that no work will commence until early 2015, at the earliest. Taking into account the above timelines and updating, Board staff estimates that, following a decision and the initiation of a working group, it would be many months before a Board report based on the working group's analysis and recommendations could be issued. Then, based on OPG filing an application which would have to be adjudicated by the Board, it is likely that incentive regulation will not be implemented prior to the filing of an application for 2016 payment amounts.

To assist the Board in initiating any incentive working groups as quickly as possible following a decision with this application, Board staff submits that OPG be directed to file publicly with the Board the LEI report and that this be done no later than the end of 2014. The Board could then take this information into account in establishing the work plan for any Working Groups.

10.2 Mitigation

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

In the AIC at page 145, OPG states that the total bill impact of its application has not exceeded 10% - the threshold the Board typically applies for triggering mitigation and therefore mitigation is not required. While OPG has correctly noted the Board's typical approach, Board staff is of the view that restricting the analysis to an estimated total bill impact is not sufficient in OPG's case. OPG is Ontario's largest electricity generator, affecting all customers in the province. As noted in Exh N2-1-1 Attachment 5, the OPG proportion of consumer usage electricity is 48.06%. Board staff also notes that OPG made a similar argument during the development of the Issues List and the Board decided to include this issue on the list nonetheless.

This is the third OPG cost of service proceeding. The payment amount increase sought in the first case was 14.8%. The payment amount increase sought in second case would have been 9.6%, but was changed to 6.2% prior to filing. In the current proceeding, the increase sought is 23.4% including the newly regulated hydroelectric facilities. Excluding the newly regulated hydroelectric facilities, the increase sought would exceed that sought in the previous applications.

Board staff submits that the large increase warrants some consideration of mitigation, notwithstanding the total bill impact analysis, especially given that 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.

In this proceeding, the newly regulated hydroelectric facilities have been added to the regulated facilities. These facilities currently receive payment for generation based entirely on HOEP. For this application, OPG has indicated that $30/MWh (J3.10) is the proxy for HOEP it is receiving for generation. As noted in Exh N2-1-1, the payment amount that OPG seeks is $47.57/MWh – a significant increase of 59%. Board staff observes that OPG as a whole was not experiencing financial difficulty while it operated these facilities under HOEP. And more specifically, the regulation that prescribed the new facilities did not change the costs of operating these assets. Despite this, OPG will be recovering significantly more money from the production of these assets.

In cross examination about the level of HOEP vs the cost of the newly regulated hydroelectric facilities,[234] OPG's witness stated that:

[234] Oral Hearing Tr Vol 3 page 98

> MR. BARRETT: It's certainly in the last few years there has been very low market prices. I don't know if during that entire period whether the market price was below the cost of owning and operating these facilities.

The annual HOEP from the IESO data is summarized below.[235]

Average Hourly Prices for each month since market opening on May 1, 2002. Averages are weighted by the amount of electricity used throughout the province within each hour.

Average Weighted Hourly Price (¢/kWh)

Year	Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2014	5.32	6.54	8.18	8.04	3.33	1.79	2.98						
2013	2.65	3.16	2.93	2.93	2.83	2.54	2.38	3.16	2.38	2.23	2.24	1.61	3.13
2012	2.41	2.56	2.23	1.55	1.72	2.01	2.19	3.37	2.93	2.61	2.24	2.66	2.55
2011	3.15	3.30	3.37	3.16	2.97	2.59	3.46	3.71	3.45	3.19	2.94	2.88	2.58
2010	3.79	3.83	3.64	2.88	3.17	4.04	4.16	5.43	4.68	3.43	3.02	3.25	3.48
2009	3.16	5.48	4.86	3.06	1.96	2.91	2.48	2.01	2.84	2.21	3.03	2.76	3.60
2008	5.17	4.25	5.44	5.82	5.14	3.65	6.23	6.23	5.00	5.23	4.71	5.36	4.83
2007	5.05	4.62	6.08	5.69	4.80	4.11	4.80	4.72	5.73	4.76	5.12	4.85	5.18
2006	4.88	5.71	4.90	5.01	4.54	4.96	4.82	5.43	5.67	3.68	4.17	5.14	4.17
2005	7.21	5.98	5.05	6.10	6.36	5.47	7.12	8.20	9.52	9.97	8.02	6.07	8.39
2004	5.22	6.95	5.43	5.02	4.73	5.05	4.94	4.78	4.55	5.13	5.04	5.38	5.28
2003	5.71	6.23	8.86	8.48	6.16	4.51	4.53	4.27	5.15	5.05	5.90	4.19	4.68
2002	5.59	-	-	-	-	3.00	3.71	6.20	6.94	8.31	5.09	5.12	5.93

Board staff submits that the Board could consider mitigation measures with respect to newly regulated hydro-electric if it chooses to do so. Although the regulation which requires the Board to set payment amounts for the newly regulated hydro-electric facilities requires the Board to accept the assets and liabilities from OPG's most recent audited financial statements, it is otherwise silent on how the Board should set these payment amounts. OPG's operations costs, for example, are not assets or liabilities.

[235] http://www.ieso.ca/Pages/Power-Data/Price.aspx

The Board may wish to consider the following option. For the purposes of this submission, the $47.57/MWh has not been adjusted for other factors, e.g. OM&A reductions (including moving to the cash basis for pensions and OPEBs).

If the Board were to consider a payment amount of $38.79/MWh (i.e. half way between the proxy HOEP and the proposed $47.57/MWh) for the six month period in 2014 and a payment amount of $47.57/MWh for 2015, this would result in an 18 month payment amount of $44.64/MWh. This would be well above the historical HOEP 2009 to 2013 paid to OPG. Board staff submits that phasing in the significant increase is an appropriate mitigation measure to consider. Board staff estimates that OPG would forgo $52.7M in revenue requirement if the Board were to approve this option based on the proposed revenue requirement envelope.

In this submission, Board staff has proposed a number of mitigation options for the Board to consider. Board staff submits that some mitigation measures in addition to a delay in disposing of the remaining deferral and variance accounts are appropriate for the Board to consider.

11. IMPLEMENTATION

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

OPG has requested payment amounts effective January 1, 2014 for the previously regulated hydroelectric facilities and nuclear facilities and July 1, 2014 for the newly regulated hydroelectric facilities.

The following submission relates to the previously regulated hydroelectric facilities and nuclear facilities as the Board is required to set an effective date of July 1, 2014 for the newly regulated facilities.[236]

The application was filed on September 27, 2013. The Board's processing standards for a proceeding with an oral hearing is 235 days, i.e. a decision on May 20, 2014. This metric would be difficult to meet for a proceeding as complex as OPG, and has not been met in the two previous cases. OPG explained that the timing of the application was

[236] O.Reg. 53/05 as amended, section 6(2)11

related to the September 13, 2013 posting of the revision to O.Reg. 53/05 relating to the newly regulated hydroelectric facilities. OPG states that it did not expect a decision by January 1, 2014.[237] Board staff notes that when the EB-2010-0008 application was delayed from mid-April to end of May, 2010, OPG adjusted its requested effective date from January 1 to March 1, 2011.

The application as filed on September 27, 2013 was incomplete and confidential documents were incorrectly filed. The Board typically will not process an incomplete application and will "stop the clock". In this proceeding, however, the Board permitted the application to proceed.

The first update, Exh N1-1-1, resulted in a significant increase in bill impact and required additional notice. The filing of additional evidence in July 2014, Exh D2-2-2, required a technical conference, further prolonging the proceeding.

In the AIC at page 146, OPG states that the time taken to process the application is irrelevant as the Board is required to set just and reasonable rates and the Board has declared payment amounts interim. OPG has referred to the Supreme Court of Canada's decision in *Bell Canada v Canada (Canadian Radio-Television and Telecommunication Commission)*, [1989] 1. SCR. 1772, in support of its position regarding interim payment amounts.

Board staff notes that the Board stated the following in the interim payment order issued on December 17, 2013.

> This determination 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.

Board staff also notes the following Board decision (RP-2005-0020, EB-2005-0361, EB-2006-0197, EB-2007-0016) that addresses the same Supreme Court of Canada decision.

> Having declared the rates interim as of May 1, 2006, the Board's jurisdiction to make the final rate order effective as of that date is not questioned by

[237] Oral Hearing Tr Vol 2 page 171

> Board staff or any party. However, as Counsel to Board Staff argued, ETPC is confusing the Board's <u>ability</u> to retroactively change rates with the <u>requirement</u> to do so.
>
> Once the rates were made interim, the requirement is that in the determination of final rates the Board must consider on what date the rates should take effect. The Board has the legal authority to set the effective date at any time from the date rates were set interim forward. The effective date that the Board selects will be determined after a consideration of all the relevant circumstances. The original panel discharged the requirement that it consider the appropriate effective date and used its discretionary powers to rule, with reasons, that the final rates should not be applied retroactively.
>
> Counsel to EPTC relied in part on the Supreme Court's decision in *Bell Canada v. Canada (Canadian Radio-Television and Telecommunications Commission)*, [1989] S.C.J. No. 68. In that case, the Court held that the tribunal had the power to carry final rates back to the time at which interim rates had been set. The case does not, however, state that the tribunal is *required* to adjust the interim rates retroactively. It is also important to note the full context behind the Bell decision. In the Bell case, the final rates were in fact lower than the interim rates. The purpose of adjusting the rates retroactively, therefore, was to protect the ratepayers who have little or no control over the timing of either the interim [or] final order. This is not to say that the Board could never adjust rates retroactively where the final order was higher than the interim order.
>
> The determination of an effective date is inextricably linked with a rates proceeding. The Board has no requirement to give notice of its intention to consider retroactivity as it has no requirement to give notice of the fact that it will set rates based on what it finds to be just and reasonable. In any event, the fact that the Board had set interim rates constitutes in effect notice that the effective date would be an issue.

Board staff submits that the Board is not required to set payment amounts effective January 1, 2014 because payment amounts were declared interim. The Board has a legitimate interest in attempting to ensure that applications are filed in a timely manner, and there is nothing improper in setting an effective date later than the date of an interim order if the delay is the result of the utility's actions. Applications that are not filed with enough lead time to allow completion of the hearing prior to the proposed effective date can unnecessarily increase the requested payment amount, as the utility will be recovering the same amount of money over a shorter period of time. It can also give rise to issues of inter-generational inequity.

Board staff observes that in the Bell case, the determination that the effective date would match the interim order date resulted in a significant refund to consumers. Consumers, of course, have no control over the timing of a utility's application.

Board staff submits that it is appropriate to set payment amounts effective July 1, 2014 as that is the earliest possible date that a decision and payment order could have been completed based on a September 27, 2013 filing. Board staff notes that it is not proposing that the Board penalize OPG for the additional filings and updates that caused delays in this proceeding. If the Board were to take these delays into account, an effective date of the first of the month following the issuance of the Board's decision would be consistent with prior decisions of the Board. Board staff does not support this outcome given the mitigation measures proposed in this submission.

12. GENERAL

The record for this proceeding is more than 20,000 pages and there are a large number of confidential documents. Board staff submits that OPG can and should review the record of this proceeding and consider how to improve the pre-filed evidence for future applications. For example, Board staff submitted under issue 5.3 and issue 5.4 that there has been lack of clarity on the hydroelectric incentive mechanism in all three cost of service proceedings. Board staff submits that this lack of clarity creates an unnecessary volume of interrogatories, technical conference questioning and oral hearing cross examination.

The application is based on the 2013-2015 business plan. The Exh N1-1-1 update was a selective update for 3 areas of the application based on the 2014-2016 business plan. Updates, in particular selective updates, create confusion and inefficiency. For example, there was questioning about the in-service additions related to the DRP. Board staff submits that OPG should be focused on making one comprehensive update for each application, if required. And if OPG is anticipating significant changes prior to filing an application, e.g. a new business plan or new pension mortality assumptions, it should refrain from filing the application prematurely.

\- All of which is respectfully submitted -