ONTARIO POWER GENERATION

Colin Anderson
Director

Ontario Regulatory Affairs

700 University Avenue, Toronto, Ontario M5G 1X6

Tel: 416-592-3326 Fax: 416-592-8519
colin.anderson@opg.com

July 28, 2014

VIA RESS AND COURIER

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

Dear Ms. Walli:

Re: EB-2013-0321 – 2014/15 Payment Amounts Application – OPG Argument-in-Chief

Please find attached OPG's Argument-in-Chief for its application for payment amounts for its prescribed generation facilities.

Best Regards,

[Original signed by]

Colin Anderson

Attach

cc:	Charles Keizer (Torys)	via email
	Crawford Smith (Torys)	via email
	Carlton Mathias	via email
	Intervenors of record	(letter only)

EB-2013-0321

OEB Application

for

Payment Amounts for OPG's Prescribed Facilities

Argument-in-Chief

Ontario Power Generation Inc.

July 28, 2014

This page has been left blank intentionally.

TABLE OF CONTENTS

1.0 OVERVIEW

This is OPG's third Application for payment amounts for the generating facilities prescribed under Section 78.1 of the Ontario Energy Board Act, 1998. In the three years since OPG's last Application, the company has focused on cost control and on performance improvement while maintaining its commitment to safety and reliability.

OPG has a single shareholder – the Province of Ontario. OPG is incorporated under the Ontario Business Corporations Act and OPG's Board of Directors is appointed by the Province with a mandate to operate the company as a commercial enterprise. To do that, OPG must receive just and reasonable payment amounts for its prescribed facilities that cover the costs of operating and maintaining these assets and making new investments in them, and allow the company to earn a fair return on invested capital.

OPG's prescribed facilities are forecast to produce approximately 154 TWh over the test period. This includes generation from the 48 newly regulated hydroelectric facilities which are included in this Application. The prescribed facilities are among the lowest cost generation sources available to Ontario consumers.

Cost control features prominently in OPG's business planning and this Application. OPG's evidence demonstrates the significant cost control that the company has successfully undertaken over the past few years. Through the use of benchmarking, OPG has initiated activities to continue controlling cost and improving performance at its nuclear facilities in the test period and beyond as discussed in Ex. F2-1-1. OPG's hydroelectric facilities continue to benchmark well overall on both cost and performance as discussed in Ex. F1-1-1. OPG proposes to continue the reinvestment and OM&A expenditures necessary to maintain this high level of performance.

OPG also presents new initiatives in this Application to ensure that the prescribed facilities continue to supply reliable and affordable power into the future. The decision to continue with the Darlington Refurbishment Project and to continue moving through the project's Definition Phase toward the Execution Phase will allow Darlington to operate for an additional 30 years as discussed in Ex. D2-2-1. Continuing to operate Pickering for an additional four years will provide additional baseload generation during a period of intensive nuclear refurbishment at a cost lower than other generation sources (Ex. F2-2-3).

The Niagara Tunnel Project ("NTP"), which began operation on March 9, 2013, was an extremely large, complex and challenging construction project that OPG completed safely and cost effectively given the conditions encountered. The emissions free electricity produced from the water flowing through the NTP will benefit the people of Ontario into the next century. Information contained within Ex. D1-2-1 supports the inclusion of the approximately $1,472M of capital costs associated with the NTP into regulated hydroelectric rate base.

As discussed in Ex. A4-1-1 and elsewhere in the evidence as appropriate, OPG has also undertaken a Business Transformation initiative to support the alignment of OPG's costs with its declining generation capacity and OPG's mission to be Ontario's low cost generator of choice.

OPG proposes to clear the audited, year-end 2013 balances only for those four deferral and variance accounts where review was deferred to a future proceeding in EB-2012-0002. These are the: 1) Hydroelectric Incentive Mechanism Variance Account, 2) Hydroelectric Surplus Baseload Generation Variance Account, 3) Capacity Refurbishment Variance Account, and 4) Nuclear Development Variance Account.

Details regarding the calculations of the rate riders are presented in Ex. H1-2-1 as updated in Ex. N2-1-1, and details regarding the continuation of accounts are found in Ex. H1-3-1. OPG intends to seek review and clearance of the audited year-end December 31, 2014 balances in all of its deferral and variance accounts through a separate application to be filed later in 2014.

OPG is seeking an overall increase of approximately 23.4 per cent on its payment amounts (Tr. Vol. 3, p. 137, line 21), including the newly regulated hydroelectric facilities. In terms of consumer impact, this increase would result in an estimated increase of $5.31 per month on the bill of a typical residential consumer (Ex. N2-1-1, p. 2).

The main drivers of the proposed rate increase are set out in the Drivers of Deficiency exhibit (Ex. A1-3-2, as updated in Ex. J3.3 for the Second Impact Statement). This exhibit shows that the main drivers of the increase are; (i) pension and OPEB costs, driven primarily by discount rate changes and mortality improvements; (ii) the inclusion of the NTP in rate base, (iii) lower nuclear production, and (iv) higher nuclear liability costs reflecting the new Ontario Nuclear Funds Agreement ("ONFA").

During the 2011 to 2013 period when current rates were in place, OPG earned significantly less than its allowed return on equity (Ex. C1-1-1, p. 3), including an actual loss on its overall regulated operations in 2013 of -0.66 per cent (-$22.1M) (Ex. L-1.0-1 Staff-002, Attachment 1, Table 5, line 5).

It is also important to consider OPG's payment amounts within the context of the Ontario electricity industry as a whole. For the first six months of 2013, OPG's average revenue was 5.6 cents per kilowatt hour, whereas the average revenue for all other electricity generators[1] was 10.1 cents per kilowatt hour. For the three months ending June 30, 2013, the 10.1 figure jumped to 11.1 cents per kilowatt hour, while OPG's average revenue stayed at 5.6 cents per kilowatt hour. OPG provides a moderating effect on Ontario electricity prices. Further, when one considers that OPG has not had an increase in its base payment amounts for its regulated assets since April 1, 2008, the need for the proposed increases becomes even more apparent.

2.0 GENERAL

2.1 ISSUE 1.1

Primary - Has OPG responded appropriately to all relevant Board directions from previous proceedings?

In Ex. A1-11-1, OPG has provided a table that identifies the OEB directives from prior proceedings and the exhibit number(s) in this Application where OPG's evidence discusses the responses to the directives. As can be seen in that table and the referenced exhibits, and in the sections below, OPG has responded to all relevant Board directions from previous proceedings.

[1] Revenues for other electricity generators are calculated as the sum of hourly Ontario demand multiplied by the Hourly Ontario Energy Price ("HOEP"), plus total global adjustment payments, plus the sum of hourly net exports multiplied by the HOEP, less OPG's generation revenue.

2.2 ISSUE 1.2

Primary - Are OPG's economic and business planning assumptions for 2014-2015 appropriate?

2.2.1 Introduction

The revenue requirement requested in this Application is based on the forecast costs for the January 1, 2014 through December 31, 2015 test period (Ex. A1-3-1), as updated by OPG's First and Second Impact Statements (Ex. N1-1-1 and Ex. N2-1-1).

These forecast costs are based on OPG's 2013-2015 Business Plan. This business plan was approved by OPG's Board of Directors in May 2013 and concurred by the Province. In OPG's submission, it reflects appropriate economic and planning assumptions, as set out in OPG's business planning instructions (Ex. A2-2-1, Attachment 2).

Cost control features prominently in OPG's business planning and this Application. OPG's evidence demonstrates the significant cost controls that the company has successfully undertaken over the past few years. The payment amounts and riders resulting from this Application are necessary for OPG to meet its obligation to operate the prescribed assets safely, reliably and efficiently for the benefit of the people of Ontario (Ex. A1-3-1).

2.2.2 2014 - 2015 Business Planning and Budgeting

The revenue requirement requested for the regulated hydroelectric and nuclear facilities is based on OPG's 2013-2015 Business Plan, as updated for material changes by Ex. N1-1-1 and Ex. N2-1-1. The 2013-2015 Business Plan is focused on the prudent management of OPG's costs, ensuring the efficient use of existing generation assets and improving the company's financial outlook (Ex. A2-2-1, Ex. L-1.4-2 AMPCO-008, Ex. L-1.0-4 CCC-004(d)).

OPG's financial priority, as a commercial enterprise, is to consistently achieve a level of financial performance that will ensure its long-term financial sustainability and increase the value of its assets for its Shareholder – the Province of Ontario. Inherent in this priority are three objectives (Ex. A2-1-1, Attachment 1, p. 23):

- Enhancing profitability by increasing revenue.

- Improving efficiency and reducing costs.
- Ensuring a strong financial position that enhances OPG's ability to finance its operations and projects.

In 2012, OPG began implementing a Business Transformation ("BT") initiative to drive efficiencies in its operations to enable it to achieve and maintain staff reductions. Reducing staff levels, which represent a majority of OPG's OM&A expense, is key to managing costs. As a first step in the implementation process, OPG adopted a new organizational structure in May 2012. This new structure is based on a "centre-led" model that will allow OPG to use resources more efficiently. Most staff transfers to this new structure took place in 2012. The remaining transfers will occur in 2013/2014 using the processes set out in OPG's collective agreements. By the end of 2015, OPG projects to have achieved approximately 2,000 staff reductions since 2011 (Ex. A2-2-1, p. 2).

OPG considers leading practice in business planning to be an effective, integrated process that aligns business plans and budgets with corporate strategy and presents the appropriate level of detail. The key attributes of an effective business planning process are timeliness, efficiency, accuracy, transparency, depth, insight and clarity (Ex. L-1.2-2 AMPCO-004).

2.2.3 Planning Guidelines

In establishing guidelines for the 2013-2015 business planning process, OPG is primarily focused on finding efficiencies and managing its costs, consistent with BT principles.

To implement planned workforce reductions, OPG is taking advantage of its demographic profile that includes an aging workforce that is nearing retirement age. This creates an opportunity to use natural attrition, and to restrict any re-hiring to critical areas only, to reduce staff levels. The result will be a smaller organization without the need for corporate wide severance programs, and their associated costs. This approach was selected as the most cost effective method of restructuring the organization (Ex. A2-2-1).

With a cost management focus from BT and the explicit goals of reducing staff levels, business planning guidelines (in the areas of capital, OM&A and staff levels) that drive staff reductions were developed. The 2013-2015 guidelines also challenged the business units to absorb inflationary cost pressures, particularly on labour. Other than the increases mandated by existing collective agreements, budget guidelines did not include additional inflationary assumptions on labour (Ex. A2-2-1).[2]

As a result, for Power Workers' Union ("PWU") employees, the 2013-2015 Business Plan assumes wage escalation for the period covered by the collective agreement (up to March 31, 2015) consistent with that agreement (i.e., 2.75 per cent) and no increase for the period beginning April 1, 2015 other than a one per cent increase for step progression. For Society of Energy Professionals ("Society") represented employees, the 2013-2015 Business Plan assumes a zero per cent increase over the test period, again with a one per cent increase for step progression (Tr. Vol. 9, pp. 91-93 and Ex. J9.5).

OPG sets three year business plan targets on an annual basis. Given the company's focus on reducing headcount, OPG has been setting headcount targets, in addition to financial and operational targets. The 2012-2014 Business Plan had headcount targets for each business unit for 2012, 2013, and 2014. In the 2013-2015 Business Plan, OPG set more aggressive targets for 2013 and 2014 by advancing to 2013 the headcount targets it was initially planning to use for 2015, and making further reductions in 2014 and 2015. OM&A targets were also adjusted to reflect the headcount targets (Ex. L-1.2-2 AMPCO-004).

Business unit plans are reviewed by the CEO and CFO and are subject to challenge at the Executive Level. Within each business unit, tradeoffs are also required in terms of work prioritization to manage within operating OM&A budgets as well as project budgets. Benchmark investment levels as well as plant condition and lifecycle plans, if available, are all utilized (Ex. L 1.2-2 AMPCO-004).

2.2.4 Business Transformation

2.2.4.1 Overview

Business Transformation supports the alignment of OPG's costs with its declining generation capacity and OPG's mission to be Ontario's low cost generator of choice. Under BT, OPG will use attrition to reduce its year-end 2015 staff level by 2,000 employees with the potential for further reductions in later years. This decreased staff level is expected to reduce OPG's

[2] See further discussion at 7.11.2 regarding the increases included in the 2013-2015 Business Plan and the revenue requirement in relation to these collective agreements.

OM&A by $700M between 2011 and 2015 (Ex. A4-1-1). Approximately 1,300 staff and $550M are attributable to regulated operations, including the newly regulated hydroelectric facilities (Ex. A4-1-1 and Ex. L-1.2-2 AMPCO-006). As noted in the evidence, the BT headcount reduction target excludes the Darlington Refurbishment and Nuclear New Build projects (Ex. L-6.8-1 Staff-100).

To sustain these staff reductions, OPG has moved to a centre-led model to use resources more efficiently. Each business unit has launched a number of initiatives to improve efficiencies and reduce work through process streamlining. These initiatives will drive sustainable change in the business, while ensuring that changes do not impact the safety, reliability and environmental sustainability of OPG's operations (Ex. A4-1-1). Key BT initiatives are listed at Ex. A4-1-1, Attachment 1.

In 2012, the Ministry of Energy announced an Efficiency Review of OPG and engaged KMPG to perform the review. As part of that process, KMPG was asked to identify organizational and structural opportunities for efficiency improvements. KMPG reviewed key aspects of the BT project and reached the following conclusion:

> "Based on observations from management interviews, business plans and project plans, KPMG believe that OPG has employed a systematic and structured approach to developing a company-wide transformation plan. OPG has incorporated many leading practices for implementing a large business transformation such as assigning dedicated staff to implement the transformation, establishing a program management office, incorporating change management with a focus of cultural change and incorporating business transformation milestones into executive performance plans." (Ex. A4-1-1).

2.2.4.2 Integration with OPG's Business Plan

Reducing staff levels by 2,000 employees by the end of 2015 represents close to a 20 per cent reduction in OPG's headcount. The magnitude of these reductions required a significant focus on streamlining and transforming the way OPG does things in order to be able to operate sustainably at these lower staffing levels (Ex. L-1.2-2 AMPCO-004). To achieve the work reductions required, each business unit identified areas where work could be streamlined or eliminated and developed initiatives to achieve these changes.

Given OPG's workforce demographics, attrition is the most cost effective way to meet the targeted headcount reductions. However, attrition does not always take place in the areas of the company where work has been eliminated. To align the staff and the work, OPG plans to move resources from areas where the work was eliminated to areas where attrition may have outpaced work elimination. About 90 per cent of OPG's workforce is unionized and organizational changes must be managed through specific processes in OPG's collective agreements (Ex. L-1.2-2 AMPCO-006).

2.2.4.3 Costs

BT has been undertaken primarily by internal staff with some expert consulting assistance in organizational design and change management. OPG expects total BT-related costs of $6.0M in 2013, $3.7M in 2014, and $1.4M in 2015, which include internal staffing costs supplemented by some external assistance. Of these amounts, the costs allocated to the regulated business are $5.4M in 2013, $3.3M in 2014 and $1.3M in 2015 (Ex. A4-1-1). OPG submits that the costs for BT are reasonable and necessary to continue this important initiative.

2.3 ISSUE 1.3

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

OPG submits that it has appropriately applied Generally Accepted Accounting Principles of the United States of America ("USGAAP"). OPG's consolidated financial statements are prepared in accordance with USGAAP and, as such, recognize regulatory assets and liabilities, including those for the deferral and variance accounts authorized by the OEB.

The information provided in this Application reflects the application of regulatory constructs (e.g., rate base) to the financial information for OPG's prescribed facilities. The application of regulatory constructs is highlighted in the various sections of the Application. As required by the OEB's Decision with Reasons in EB-2007-0905, financial information related to the Bruce assets is presented in this Application on an accounting basis.

Unless specifically stated otherwise, for the 2011-2015 period, financial information is prepared on a USGAAP basis, reflecting OPG's implementation of USGAAP for financial accounting and regulatory purposes effective January 1, 2012. As part of the adoption of USGAAP, OPG was required to re-state its 2011 comparative financial information on a USGAAP basis and to prepare a USGAAP opening balance sheet as at January 1, 2011. This USGAAP balance sheet was used as the reference point for determining the financial impacts from the adoption of USGAAP. This revised financial information in 2011 also formed the starting point for USGAAP reporting in OPG's 2012 financial statements.

For 2010, financial information for OPG's prescribed facilities is based on Canadian Generally Accepted Accounting Principles ("CGAAP").[3] As noted in EB-2012-0002 with respect to 2011 and 2012, amounts being recorded in approved deferral and variance accounts in 2013 are also determined on a CGAAP basis, as that is the basis upon which OPG's payment amounts were established in EB-2010-0008.

The OEB approved the use of USGAAP by OPG for regulatory accounting, reporting and rate-making purposes in EB-2012-0002. The few differences impacting OPG's regulatory accounting that exist between CGAAP and USGAAP requirements were discussed in EB-2012-0002. The impact on the prescribed facilities is described in Section 4.0 of Ex. A2-1-1.

As discussed in EB-2012-0002, Ex. A3-1-2 Section 2.0, a difference in the accounting treatment of long-term disability benefit costs was the only difference between CGAAP and USGAAP that had a financial impact on OPG's regulated operations effective January 1, 2012. The financial impact of this change was supported by actuarial reports, and the portion of the impact attributable to the regulated operations was recorded in the Impact for USGAAP Deferral Account. The December 31, 2012 balance in this account was approved for recovery by the OEB in EB-2012-0002. As this was the only financial impact on the prescribed facilities associated with OPG's adoption of USGAAP and as the impact was previously reported to and accepted by the OEB, no reconciliation between CGAAP and USGAAP is necessary in this Application.

[3] References to CGAAP throughout this application are to Part V of the Canadian Institute of Chartered Accountants Handbook – Accounting.

2.4 ISSUE 1.4

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

As set out in the OEB's Decision with Reasons in EB-2010-0008 (p. 13), in respect of business planning, OPG's "…obligation is to plan taking account of the requirements of its business and to propose payment amounts which represent recovery of an efficient and reasonable level of costs." And this is exactly what OPG has done in developing its 2013-2015 Business Plan and this Application (Ex. L-1.4-2 AMPCO-008).

During the test period, OPG continues to be the low cost generator of electricity in the Province. When setting business plan targets, OPG's drive to improve efficiency and maintain a focus on cost control demonstrates its understanding of the economic climate in which it operates and the customer impacts of its application. While economic and demographic factors have impacted OPG's labour costs, it has been successful in reducing its overall workforce in order to gain efficiencies that assist in the management of electricity consumer's bills (Ex. L-1.4-2 AMPCO-008 and Ex. A2-2-1).

OPG submits that the overall increase in the test period revenue requirement is reasonable given the steps that it has taken to control its costs, including reducing its headcount by 2000 staff under BT, that it has not had an increase in its base rates since 2008, and that the main drivers of the increase are factors largely beyond the control of OPG.

3.0 RATE BASE

3.1 ISSUE 2.1

Primary - Are the amounts proposed for rate base appropriate?

OPG requests approval of the rate base forecasts set out in Exhibit B of the pre-filed evidence. These forecasts were not updated in either the First or Second Impact Statements and they are based on the same methodology accepted by the OEB in EB-2007-0905 and EB-2010-0008.

From Exhibit B, the forecast of rate base for the previously regulated hydroelectric facilities is $5,128.0M in 2014 and $5,084.6M in 2015 (Ex. B1-1-1, Table 1). The forecast of rate base for the newly regulated hydroelectric facilities is $2,511.5M in 2014 and $2,528.2M in 2015 (Ex. B1-1-1, Table 1).

The rate base for the newly regulated hydroelectric facilities is calculated in the same manner as for the previously regulated hydroelectric facilities. The opening rate base values for the newly regulated hydroelectric facilities are consistent with the audited values provided in Ex. A2-1-1, Attachment 6 and are required to be accepted by the OEB under the terms of O.Reg. 53/05 as discussed further at Section 7.11.7 below.

Also from Exhibit B, the forecast of rate base for the nuclear facilities is $3,706.7M in 2014 and $3,659.0M in 2015 (Ex. B1-1-1, Table 2).

OPG's forecast of rate base for the test period is based on a forecast of net fixed/intangible in-service assets (including nuclear asset retirement costs or "ARC") and working capital associated with the regulated facilities. As in OPG's prior rate cases, the net fixed/intangible asset portion of rate base is determined using a mid-year average methodology. For large in-service additions or adjustments, where the in-service addition amount or the amount of an adjustment exceeds $50M, the specific time in which the addition or adjustment is reflected is used, instead of a mid-year average, to improve accuracy.

As in EB-2010-0008 and EB-2007-0905, fixed and intangible assets used by both the regulated and unregulated generating business units continue to be held centrally. These assets are not included in rate base. Instead, all generating business units are charged an asset service fee for the use of these assets, as discussed in Ex. F3-2-1.

The working capital included in rate base consists of cash working capital, fuel inventory and materials and supplies. The fuel inventory and materials and supplies values for rate base continue to be determined using a mid-year average of opening and closing balances during the period. Cash working capital continues to be determined using a lead/lag analysis. All of these approaches are consistent with the methodologies previously approved by the OEB.

Fuel inventory continues to be valued using the weighted average costing method. Fuel purchases reflect OPG's current target levels for the inventory. This methodology is unchanged from EB-2010-0008. OPG's target level for uranium concentrate inventory has been reduced consistent with changes in uranium market conditions and recommendations from the report of Longenecker & Associates on OPG's uranium procurement program (Ex. F5-2-1).

Consistent with regulatory and accounting requirements, OPG has appropriately recorded opening balances, forecast in-service additions, depreciation and other adjustments to its net fixed assets in its forecast of rate base for the test period. Similarly, OPG has calculated the working capital component of rate base appropriately, including use of a lead/lag study and forecasts of fuel inventory, materials and supplies. As a result, OPG submits the rate base forecasts for the test period should be accepted by the OEB.

4.0 CAPITAL STRUCTURE AND COST OF CAPITAL

4.1 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?

OPG submits that its proposed capital structure and rates of return on equity for the currently regulated and newly regulated facilities should be accepted by the OEB.

4.1.1 Continuance of the Historical Capital Structure

OPG has applied for payment amounts based on the deemed capital structure of 47 per cent equity and 53 per cent debt approved by the OEB in EB-2007-0905 and EB-2010-0008.

OPG is not proposing any changes to its capital structure as there have been no significant changes in the risks faced by OPG's regulated asset portfolio that are not otherwise addressed by proposals to establish new variance and/or deferral accounts as described in Ex. H1-3-1.

OPG engaged Foster Associates Inc. to provide an analysis and expert opinion on whether the cost of capital approved in OPG's last application (EB-2010-0008) was appropriate for the test period, given the completion of the NTP and the inclusion of additional hydroelectric assets in OPG's regulated rate base. The Foster Associates Inc. report was filed as Ex. L-3.1-17 SEC-24, Attachment 1.

The analysis and expert opinion was provided by Ms. Kathleen McShane, who was accepted by the OEB as a cost of capital expert (Tr. Vol. 10, p. 6). Ms. McShane was the only cost of capital expert to testify in the proceeding.

Ms. McShane concluded that OPG's deemed common equity should, at a minimum, remain at 47 per cent for the reasons set out at pages 2 and 3 of her report. These reasons included her views that:

1. The business risks specific to OPG's regulated hydroelectric generation operations, including the newly regulated facilities, are somewhat higher than when the OEB issued its Decision in EB-2010-0008, due largely to the higher operating risks of the newly regulated facilities.

2. The fundamental business risks of the nuclear generation operations have not changed materially. However, the operating leverage has continued to rise, leading to higher potential volatility in earnings for the nuclear generation operations. All other things equal, a thicker equity component would be required to dampen the volatility.

3. The lower end of a reasonable range of equity ratios for the regulated hydroelectric generation operations, including the newly regulated generation, consistent with their relative business risks and the fair return standard is, conservatively, 45 per cent. As such, a 47 per cent common equity ratio for OPG's combined hydroelectric and nuclear operations, given the latter's higher operating risks and increased operating leverage, remains reasonable even with the higher proportion of regulated hydroelectric generation rate base during the test period.

4. The Darlington Refurbishment Project, due to its size, will reverse the relative proportions of the test period hydroelectric and nuclear generation rate base. Capital structure decisions reflect longer-term, not test period, business risks. As the Darlington Refurbishment Project investment is more than double the combined rate base additions from the NTP and newly regulated hydro facilities, maintaining the approved 47 per cent common equity ratio is a conservative approach that OPG should revisit once a decision on the Darlington Refurbishment Project has been reached.

5. The Darlington Refurbishment Project will require significant capital investment, including approximately $1.5B during the test period. With no additional cash flows to service the corresponding debt financing, credit metrics will be weaker, putting downward pressure on debt ratings. At a minimum, OPG's allowed common equity ratio should remain at the previously approved 47 per cent to avoid further weakening of credit metrics.

6. The Board is committed to the implementation of incentive regulation for both the regulated hydroelectric and nuclear operations. Although the specifics of the plans have yet to be developed, the characteristics of incentive regulation expose regulated companies to higher risk than cost of service regulation. The higher business risk of the regulated operations under incentive regulation provides support for, at a minimum, maintaining the approved 47 per cent common equity ratio.

OPG agrees with Ms. McShane's analysis and opinion and submits that the proposed capital structure of 47 per cent equity and 53 per cent debt should not be changed as a result of the newly regulated hydroelectric assets becoming prescribed facilities and the inclusion of the NTP into rate base.

OPG has applied this capitalization to the rate base described in Exhibit B, as adjusted to reflect the application of the "lesser of Asset Retirement Costs and Unfunded Nuclear Liabilities" provision applied by the OEB in EB-2007-0905 and in EB-2010-0008. The rate base for the 2014-2015 test period includes the hydroelectric facilities that were prescribed as of July 1, 2014.

4.1.2 Rate of Return on Equity

OPG proposes to use the same methodology approved by the OEB in EB-2010-0008 (Decision with Reasons, pp. 122-123) to establish the return on equity ("ROE") for 2014 and 2015. As updated in the Second Impact Statement (Ex. N2-1-1, p. 8 and Attachments 3 and 4), OPG is proposing an ROE of 9.36 per cent for 2014 and 9.53 per cent for 2015.

The proposed ROE for 2014 is in accordance with the latest cost of Capital Parameters published by the OEB on November 25, 2013 pursuant to the ROE formula set out in the Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 2009, EB-2009-0084 ("Cost of Capital Report") (see Ex. K13.1, pp. 37-38 and Ex. N2-1-1, Attachment 3). The proposed ROE for 2015 is set using the OEB's approved ROE formula and data from Global Insight, a third party independent market source (see calculation at Ex. N2-1-1, Attachment 4).

OPG submits that its proposed rates of return on equity are reasonable, consistent with the OEB's approved practice for OPG and should be approved.

4.2 ISSUE 3.2

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

OPG's proposed long-term and short-term debt components for the test period have been determined using the methodologies approved by the OEB in EB-2007-0905 and EB-2010-0008. These are described in Ex. C1-1-2 and Ex. C1-1-3 for long and short term debt, respectively. OPG submits that its cost of debt is appropriate and reasonable, and should be approved.

4.2.1 Long-Term Debt

The long-term debt supporting OPG's regulated operations is comprised of existing and planned long-term debt issues plus a long-term debt provision required to reconcile OPG's regulated debt to its OEB-approved capital structure.

OPG has applied for the cost of long-term debt as shown below in Table A (Ex. C1-1-1, Tables 1 and 2):

Table A: Cost of Long-term Debt

	2014	**2015**
Existing/Planned Long-Term Debt	4.85%	4.86%
Other Long-Term Debt	4.85%	4.86%

These amounts were not updated in either of OPG's First or Second Impact Statements.

Existing/Planned Long-Term Debt

OPG assigns all existing and planned project-related financing to its regulated or unregulated operations based on whether the project is related to its regulated assets. All project-related financing that is not associated with OPG's regulated assets is assigned to unregulated operations. OPG also forecasts its financing requirements for projects that are still in the design/assessment phase; however these financing requirements are not assigned to OPG's regulated operations unless, and until, they are specifically identified as a project in OPG's capital budget for its regulated operations.

The portfolio of long-term debt remaining after project-related financing has been directly assigned must be allocated to regulated and unregulated operations. For the test period, OPG has applied the allocation methodology approved by the OEB in EB-2007-0905 and EB-02010-0008.

The rate of interest on OPG's debt is determined using the same methodology as described in EB-2007-0905 and EB-2010-0008. It is based on the prevailing benchmark Government of Canada bond for the corresponding term of the debt, as published by a verifiable market monitoring service on the day prior to the date funds are advanced, plus a credit margin determined five business days before the date funds are advanced. The credit margin is determined based on a sample of quotes for OPG's credit margin as provided by a selected group of Canadian banks. The credit margin will be the same for corporate and project-related debt as the credit margin evaluates OPG as a borrowing entity rather than the project. The interest rate for project-related debt will be the same as the interest rate for corporate debt issued on the same date for the same terms and conditions.

The cost of planned new and refinanced corporate debt and project-related debt for 2014 and 2015 is based on a forecast of the 10-year Long Canada Bond as published in April 2013 by Global Insight.

A credit risk spread for OPG of 132 basis points is added to the Global Insight rates to determine the forecast rate for OPG's OEFC debt in 2014 and 2015. Overall, OPG forecasts its cost of existing and planned long-term debt at \$163.6M for 2014 and \$169.2M for 2015 (see Ex. C1-1-1, Tables 1 and 2).

Other Long-Term Debt

Consistent with the methodology approved in EB-2007-0905 and EB-2010-0008, OPG has used a provision for long-term debt to reconcile the debt component of its regulated capital structure with the proposed rate base that financing supports.

Consistent with the OEB's findings in EB-2010-0008, OPG has applied the rate for its existing and planned long-term debt to the other long term debt provision (see Ex. C1-1-1, Tables 1 and 2).

4.2.2 Short-Term Debt

OPG's cost of short-term debt for the test period was determined using the methodology approved by the OEB in EB-2007-0905 and in EB-2010-0008. The short-term debt component of OPG's capital structure reflects its forecast amount of short-term borrowings, and the cost of short-term debt reflects its forecast short-term borrowing cost.

OPG's short-term debt is comprised of a commercial paper program and an accounts receivable securitization program (Ex. C1-1-3, p. 1).

OPG's commercial paper program is used to fund intra-month working capital requirements. OPG forecasts that a daily average borrowing of $20M is required to finance OPG's normalized intra-month working capital requirements in the test period (Ex. C1-1-3, p. 1). OPG's borrowing rate under the commercial paper program is market-based, comprised of a 10 basis point dealer fee and a corporate spread over the bankers' acceptances rate for OPG. The corporate spread forecast over the test period is based on the current corporate spread of five basis points.

In addition, a bank credit facility continues to be used as the backstop to the commercial paper program (Ex. C1-1-3, p. 1). The bank credit facility also provides liquidity support in the event that OPG is unable to issue commercial paper as OPG would be able to borrow by way of bankers' acceptances under the bank credit facility. Access to adequate liquidity is an important element that credit rating agencies consider when reviewing credit ratings. The bank facility is $1B in size, comprised of two $500M multi-year tranches. In May 2013, OPG extended both tranches to May 2018. The bank credit facility is forecast to cost $3.6M in each of 2014 and 2015, which is equal to the actual cost in 2012.

OPG's other primary source of short-term financing is its accounts receivable securitization program with the Royal Bank of Canada (Ex. C1-1-3, pp. 1-2). This facility is $250M in size. OPG forecasts continued borrowing of $195M under this program throughout the 2014-2015 test period. The cost of the accounts receivable securitization program, consisting of the banker's acceptance rate for the securitization program plus a program fee of 0.6 per cent, is forecast to be $3.7M in 2014 and $5.7M in 2015. Although the accounts receivable securitization program is slightly more expensive than OPG's commercial paper program, it represents an alternative form of financing, and is a more permanent component of OPG's short-term debt.

From a liquidity perspective, the availability of different sources of financing provides flexibility in managing short term funding by allowing the borrower to manage the use of their various facilities.

OPG has forecast its short term cost of debt allocated to the regulated facilities at $192.2M for both 2014 and 2015, resulting in a forecast short-term debt cost of $7M in 2014 and $9M in 2015 (Ex. C1-1-3, Table 2).

5.0 CAPITAL PROJECTS

5.1 REGULATED HYDROELECTRIC

5.2 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?

Capital projects that are subject to Section 6(2)4, O. Reg. 53/05 that are already in-service or are coming into service during the test period include the NTP (see Section 5.6 below), the Sir Adam Beck I GS Unit 7 Frequency Conversion project ($32M - see Ex. D1-1-2, pp. 12-13); the Sir Adam Beck I GS Unit 3 Upgrade project ($23M - see Ex. D1-1-2, p. 3); the Sir Adam Beck 1 GA Unit 10 Upgrade project ($25.6M - see Ex. D1-1-2, p. 4) and the Sir Adam Beck I GS Unit 9 Upgrade project ($30M - see Ex. D1-1-2, p. 12).

OPG's expenditures on these projects increase their output, refurbish them and/or add to their operating capacity. These expenditures are prudent as can be seen by their various business cases (see Niagara Tunnel Project (Ex. D1-2-1, Attachments 5 and 8); Sir Adam Beck I GS Unit 3 Upgrade project (Ex. D1-1-2, Attachment 1, Tab 2); Sir Adam Beck I GS Unit 7 Frequency Conversion project (Ex. D1-1-2, Attachment 1, Tab 3); Sir Adam Beck I GS Unit 9 Upgrade (Ex. D1-1-2, Attachment 1, Tab 4); and Sir Adam Beck I GS Unit 10 Upgrade (Ex. D1-1-2, Attachment 1, Tab 5).

On this basis, OPG submits that the in-service additions associated with these projects should be included in rate base.

5.3 ISSUE 4.2

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

Capital expenditures for the previously regulated hydroelectric facilities (excluding the NTP) are forecast to be $34.5M and $38.2M in 2014 and 2015, respectively (Ex. D1-1-1, Table 1). Capital expenditures for the newly regulated hydroelectric facilities are forecast to be $91.0M and $100.0M in 2014 and 2015, respectively (Ex. D1-1-1, Table 1).

OPG submits that its proposed hydroelectric capital expenditures and/or financial commitments are reasonable. OPG's hydroelectric business unit uses a structured portfolio approach to identify and prioritize projects (Ex. F1-1-1, p. 23, Appendix A). Ultimately, the project portfolio is approved through OPG's business planning process (discussed under Issue 1.2), which includes approval of the capital project budget (as well as the project OM&A budget) by OPG's Board of Directors. Prior to beginning work on a project, funds are released through approval of a business case summary ("BCS"). These business cases provide the justification for the proposed capital expenditures in the test period.

OPG's project management and capital budgeting processes are substantially the same as those reviewed and accepted in EB-2010-0008 (Ex. D1-1-1, p. 15). For the previously regulated facilities, the annual level of capital expenditures (excluding the NTP) proposed for the test period is entirely consistent with the annual levels during the historic period (Ex. D1-1-1, Table 1). For the newly regulated facilities, the level of proposed capital expenditures is higher during the test period than in the historical period, however this higher level is driven by a few large new projects that will be underway during the test period (Ex. D1-1-1, pp. 3-7).

OPG's planned capital expenditures for the previously regulated hydroelectric facilities during the test period are dominated by the Sir Adam Beck I GS G10 Upgrade and DeCew Falls I GS Station Upgrade projects at Niagara, and the powerhouse crane and station service equipment replacements at Saunders (Ex. D1-1-1, p. 3). OPG's planned capital expenditures for newly regulated hydroelectric facilities during the test period are dominated by three projects: Chenaux GS Protections Upgrade, New Ottawa – St. Lawrence Plant Group Headquarters Building, and Otto Holden GS Sluicegates and Headgates Replacements (Ex. D1-1-1, pp. 3-4).

Comprehensive descriptions and listings of previously regulated and newly regulated hydroelectric capital projects over the test period can be found at Ex. D1-1-2. This exhibit also presents in-service additions for the bridge year and test period, and explains changes from OPG's EB-2010-0008 application.

OPG submits that the OEB should find that the proposed hydroelectric capital expenditures are reasonable.

5.4 ISSUE 4.3

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

Through its requested approval of rate base, OPG is seeking approval for previously regulated and newly regulated hydroelectric in-service additions under this Issue 4.3 except for the NTP, which is addressed under Issue 4.5. The proposed in-service additions are summarized in Table B below (Ex. D1-1-2, Tables 1-5 and Ex. L-1.0-1 Staff-002, Table 2).

Table B: Proposed Hydroelectric In-Service Additions (excluding Niagara Tunnel)

	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**

The largest test period in-service addition for OPG's previously regulated hydroelectric facilities is for the Sir Adam Beck I G10 Unit Rehabilitation. The project is expected to increase the turbine output by about 10 MW and close to rate base in 2015 (Ex. D1-1-2, p. 4).

Significant test period in-service additions for newly regulated hydroelectric facilities include:

- Lower Notch G1 Capital Upgrade. It is expected $14.3M will close to rate base in 2014.
- Lower Notch G2 Capital Upgrade. It is expected $14.2M will close to rate base in 2015.
- New Ottawa-St. Lawrence Plant Group Headquarters. It is expected $12.1M will close to rate base in 2015.
- Stewartville GS Protections and Controls Upgrade. It is expected $9.1M will close to rate base in 2015.
- Nipissing Penstock Replacement. It is expected $8.0M will close to rate base in 2015.
- Des Joachims AC Station Service Replacement. It is expected $5.6M will close to rate base in 2014.

OPG submits that its capital spending has been prudent and the in-service additions to rate base should be approved.

5.5 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?

5.5.1 Introduction

This section discusses the Niagara Tunnel Project ("NTP"), which came into service on March 9, 2013. The NTP was an extremely large, complex and challenging construction project that OPG completed safely and cost effectively given the conditions encountered. The 10.2 kilometre tunnel with interior diameter of 12.7 metres will allow OPG to make better use of the available water flow from the Niagara River to produce on average an additional 1.5 TWh per year from the Sir Adam Beck ("SAB") Generating Stations 1 and 2. The emissions free electricity produced from the water flowing through the NTP will benefit the people of Ontario into the next century. A comprehensive summary of OPG's actions and associated costs to construct the NTP can be found at Ex. D1-2-1.

The NTP's original budget of $985.2M, approved by the OPG Board of Directors in 2005, was a realistic estimate of the project's cost based on extensive geotechnical investigations including consultation with recognized professional and academic experts (Ex. D1-2-1, p. 136, Appendix B) and the costs proposed by the international tunneling consortia that responded to OPG's competitive solicitation. The extremely difficult rock conditions encountered during tunneling necessitated the revised project schedule and cost forecast of $1,600M contained in the 2009 Superseding Business Case Summary approved by the OPG Board of Directors. OPG ultimately completed the project some $123M below the approved funding with commercial service beginning nine months sooner than the approved completion date in the Superseding BCS. The amount OPG spent on the NTP represents the true cost of completing the project given the subsurface conditions actually encountered (Ex. L-4.4-2 AMPCO-016 and Tr. Vol. 2, pp. 85-89).

The issue before the OEB is whether the $491.4M in cost beyond the budget originally approved by OPG's Board of Directors prior to OEB regulation was prudently incurred.[4]

The OEB's prudence review standard is set out in RP-2001-0032. There the OEB defined the standard at paragraph 3.12.2 in the following way:

- Decisions made by the utility's management should generally be presumed to be prudent unless challenged on reasonable grounds.
- To be prudent, a decision must have been reasonable under the circumstances that were known or ought to have been known to the utility at the time the decision was made.
- Hindsight should not be used in determining prudence, although consideration of the outcome of the decision may legitimately be used to overcome the presumption of prudence.
- Prudence must be determined in a retrospective factual inquiry, in that the evidence must be concerned with the time the decision was made and must be based on facts about the elements that could or did enter into the decision at the time.

[4] O. Reg. 53/05, section 6(2)4 requires the OEB to ensure that OPG recovers the capital and non-capital costs of the NTP approved by OPG Board of Directors prior to the first payment amounts order and to determine the prudence of any expenditures beyond the OPG Board approved amount. The originally approved budget was $985.2M. The estimated total costs to completion are $1,476.6M ($1,472M capital + $4.6M expense), which leaves $491.4M as the amount subject to OEB approval (see Ex L-4.5-1 Staff-025).

This approach to prudence reviews was affirmed by the Ontario Divisional Court and the Court of Appeal in *Enbridge Gas Distribution Inc. v. Ontario Energy Board* (2005), 75 O.R. (3d) 72 (Div. Ct.); rev'd on other grounds, (2006), 41 Admin L.R. (4th) 69.

OPG submits that applying this standard can only lead to one conclusion – OPG's decisions with respect to the NTP and its management of the project were prudent. The costs above the original budget arose entirely from the fact that the rock conditions encountered were substantially worse than OPG reasonably anticipated based on the extensive geotechnical investigations that it conducted prior to beginning the project. These investigations were conducted by highly qualified professionals and academics over a period of more than ten years (Ex. D1-2-1, p. 136, Appendix B). OPG's experienced tunneling contractor, Strabag AG of Austria, reviewed the results of these investigations and used them as the basis for designing the tunnel including the necessary rock support (See Ex. F5-6-1, pp. 16-20). This information was presented in a Geotechnical Data Report, that Mr. Roger Ilsley, an independent expert on tunnel design and construction, described as "comprehensive" (Ex. F5-6-1, p. 15). His opinion concluded that the geotechnical investigations for the NTP, "were professionally completed and met or exceeded in some cases, the professional standards for work of similar type and magnitude" (Ex. F5-6-1, p. 29 and Tr. Vol. 1, p. 42).

The sections that follow will demonstrate that OPG acted prudently in planning, contracting for, resolving disputes related to this project and ultimately bringing it into service. In light of the actual conditions encountered during tunneling, the project was completed efficiently and cost effectively. It will provide clean, renewable electricity into the next century. As a result, the full cost associated with the NTP should be approved for inclusion in OPG's regulated hydroelectric rate base.

5.5.2 Project Description

The scope of the NTP includes the design, construction and commissioning of a diversion tunnel from a new intake under the International Niagara Control Works structure in the upper Niagara River above Niagara Falls to a new outlet canal feeding into the existing Pump Generating Station ("PGS") canal. The project also includes all required ancillary and enabling works.

This third tunnel supplements the diversion capacity of the two tunnels and one open channel that deliver water from the Niagara River to the SAB generating stations. The new diversion tunnel and related works were delivered under a Design-Build Agreement ("DBA") with Strabag AG of Austria and its wholly owned subsidiary Strabag Inc. ("Strabag"). Strabag was the successful pre-qualified proponent in an international competitive request for proposal ("RFP") process. The tunnel was excavated using a tunnel boring machine ("TBM") as required by the project approvals contained in the Environmental Assessment ("EA").

5.5.3 Risk Mitigation and Assessment

5.5.3.1 Extensive Geotechnical Studies

The preparation for a new Niagara tunnel commenced over 30 years ago, in 1982, when Ontario Hydro (the predecessor company of OPG) began to study the possible expansion of its hydroelectric facilities on the Niagara River.

Beginning in 1983, extensive geotechnical investigations were undertaken during concept and definition phases for the expansion of OPG's Niagara hydroelectric facilities.[5] These investigations were heavily focused on the Queenston shale formation because drilling in this formation was required by the plans to excavate the new tunnels underneath the two existing SAB No. 2 tunnels to allow for the continued use of the existing rights of way. Because the plan also involved tunneling under the buried St. Davids Gorge (to reduce excavated material disposal relative to an open canal) and constructing the planned underground powerhouse, the investigations also focused on the buried St. Davids Gorge area and the planned powerhouse area. The geology in the area of the NTP is further described in Section 2.4 of Ex. D1-2-1.

As described in Ex. D1-2-1, Appendix B, the geotechnical investigations were carried out in stages and included a total of 59 boreholes and a geotechnical test adit (small test tunnel). Rock cores were retrieved from the boreholes to determine physical and engineering properties (chemical composition, strength, in-situ stress, joints, swelling potential, etc.). Besides core retrieval for testing, in-situ stress measurements were conducted in some boreholes to assess the magnitude and orientation of the horizontal stress regime. Piezometers were also installed in many of the boreholes to assess groundwater conditions. This investigative work involved

[5] The facilities contemplated at that time were two additional tunnels, a new underground generating station and extensive transmission reinforcements (collectively known as the "Niagara River Hydroelectric Development").

internal staff, experienced engineering consultants, geotechnical engineering faculty from the University of Western Ontario, University of Toronto, Laurentian University, University of Michigan, and other international geotechnical engineering and tunneling experts from universities in Florida and Germany who participated through technical review panels.

The geotechnical adit was an exploratory tunnel constructed to provide additional insight into the geotechnical conditions in the Queenston Shale (Tr. Vol. 1, p. 107). It was originally 580 metres long and three metres in diameter and was subsequently enlarged to 12 metres in diameter over its last 30 metres (Ex. D1-2-1, p. 136, Appendix B). The adit was tested and observed during construction and monitoring continued after construction. Construction of a geotechnical adit is not typically done for tunnel projects because of the associated time and cost. The trial enlargement was specifically designed and constructed to simulate the excavation of the planned diversion tunnels in the Queenston shale formation using a full-face tunnel boring machine. The adit helped OPG conclude, in consultation with engaged experts on the Geotechnical Specialist Consulting Board, that rapid, full-face tunnel excavation in the Queenston shale formation on the planned scale was technically feasible and cost-effective.

After contract award, Strabag also drilled seven additional boreholes to verify the rock conditions in the vicinity of the buried St. Davids Gorge. These boreholes confirmed that the Queenston shale was intact and that Strabag's proposed alignment (which was higher than the concept alignment originally presented in the RFP) was feasible.

Mr. Roger Ilsley reviewed all pertinent geotechnical investigations conducted and reports prepared for the design and construction of the NTP. In his opinion, "these site investigations addressed the appropriate design and construction issues and that the studies undertaken were completed to professional standards and exceeded those standards in some cases" (Ex. F5-6-1, p. 3). He noted, in particular, that, "In my review, I have focused on the site investigations related to the diversion tunnels which remained within a defined corridor from the start of the studies. The number of borings was appropriate given the relative uniformity of the Queenston." (Ex. F5-6-1, p. 15).

Early in February 1998, in anticipation of receiving EA approval, Ontario Hydro initiated a review of the viability of proceeding with the first phase of the Niagara River Hydroelectric Development (i.e. the construction of a single additional 500 m^3/s tunnel). This review included the solicitation and evaluation of bids for the construction of the tunnel during the summer and fall of 1998 using a design-build approach. In the fall of 1998, the bids were reviewed and a recommended bidder was identified, but the contract was never awarded. In late June 1999, OPG announced that it had decided to defer construction of the tunnel indefinitely.

OPG's expenditures on engineering studies for the 1998/99 tender developed information that was subsequently used in the preparation and conduct of the 2004/05 RFP process. In consideration that rock characteristics take millions of years to change, OPG did not see any need to conduct further geotechnical investigations for the NTP prior to the 2004/05 RFP process (Ex. L-4.5-17 SEC-044 and Tr. Vol. 2, p. 63).

OPG submits that both the scope and quality of the geotechnical studies conducted for the NTP were appropriate for a project of this magnitude and complexity, and OPG's pre-project investigations should be found to be prudent by the Board.

5.5.3.2 Contracting Process

On June 24, 2004, the OPG Board of Directors approved the recommendation to proceed with the NTP including a preliminary release of $10M for the RFP process and other necessary pre-construction activities. On June 25, 2004, the Province of Ontario endorsed the decision by OPG's Board to proceed with the NTP. Based on the OPG Board approval, OPG commenced a RFP process in July 2004 by inviting submission of expressions of interest for pre-qualification. Seven submissions were received, evaluated and ranked following which OPG invited the five highest ranked firms to meet. Proponents were encouraged to give candid feedback on various aspects of OPG's proposed project and contracting approach (Ex. D1-2-1, pp. 23-26).

Invitations to respond to the RFP were sent to four of the five firms that submitted expressions of interest for pre-qualification. Three of the four invitees indicated that they would submit a proposal. In January 2005, these three proponents participated in a mandatory site visit. In association with the visit, the proponents also reviewed background documents in a data room that had been established by OPG near the project site.

OPG prepared a detailed evaluation process under which it evaluated the proposals received and negotiated with the various proponents (Ex. D1-2-1, pp. 29-33 and Ex. L-4.5-17 SEC-034).

Ultimately, the Evaluation Team recommended that Strabag be awarded the contract for the NTP. The OPG Steering Committee concurred as did the Major Projects Committee ("MPC") of the OPG Board of Directors.

Based on the MPC recommendation, the OPG Board approved the award of the contract to Strabag subject to financing. OPG then proceeded to enter into contract negotiations with Strabag. Once the Minister of Finance issued a Directive to the Ontario Electricity Financing Corporation to lend OPG up to $1B for construction of the NTP, the DBA with Strabag was signed on August 18, 2005.

5.5.3.3 Risk Assessment

OPG retained URS Corporation ("URS") to help perform both qualitative and quantitative risk assessments of the NTP (Ex. D1-2-1, Attachments 1 and 3). The scope of the URS work included identification, assessment and presentation of NTP risks in a way that provided the groundwork for the risk management methods used as the NTP proceeded. URS analyzed the NTP within an overall risk management framework provided by the Code of Practice for Risk Management of Tunnel Works (Ex. D1-2-1, p. 26).[6] URS assembled the resulting information into an initial high-level risk register, which collected and organized the risks identified, discussed their potential consequences and identified mitigation measures to reduce them.

As both the qualitative and quantitative risk evaluations undertaken by URS were done prior to completing the solicitation for a design-build contractor, OPG recognized the need to update the quantitative risk evaluation once the final proposals were received from the design-build proponents. This update was undertaken by an expert panel of NTP team members consisting of personnel from OPG, OPG's owner's representative, Hatch Mott MacDonald (the "OR"), and Torys LLP, OPG's external legal counsel.

In the OPG update (Ex. D1-2-1, Attachment 4), the top two contributors to potential cost increases were: 1) "Dispute Review Board interpretation of Agreement unfavourable" and 2) "DSC [Differing Subsurface Conditions] claim due to rock strength." These same two factors, in

[6] As Ex. D1-2-1, p. 26, states: "This code was issued by The International Tunneling Insurance Group "to promote and secure best practice for the minimisation and management of risks associated with the design and construction of tunnels. It can be found at http://www.imia.com/downloads/external_papers/EP24_2006.pdf.""

reverse order, were also identified as the top two contributors to potential schedule delay for which OPG, rather than the contractor, would be responsible. Based on the results of the updated quantitative risk assessment model, OPG estimated that for the tunnel construction portion of Strabag's winning proposal, a $96M cost contingency and a 36 week schedule contingency were required to achieve a 90 per cent probability that the project would remain within its budget and schedule. OPG then determined the overall cost contingency for the project as a whole to be $112M.

5.5.4 Tunnel Construction: Difficulties Encountered by Strabag

Due to the rock conditions encountered being significantly more challenging than expected, constructing the tunnel was more costly and took longer than initially anticipated. This section discusses the factors that necessitated the additional expenditures and time required to complete the tunnel.

Strabag's successful proposal featured a cast-in-place concrete lining with an impermeable waterproof membrane (Ex. D1-2-1, p. 82, Figure 9). OPG evaluated this proposal as most likely to provide superior tunnel performance (less friction due to fewer joints) and the 90 year maintenance free design life specified in the RFP (Ex. D1-2-1, p. 67). Strabag determined that an open TBM was the appropriate tunnel boring technology for the anticipated rock conditions and proposed lining design.[7] Use of an open TBM requires an initial lining of rock bolts, friction anchors, wire mesh, steel channels, and shotcrete to support the rock until the waterproof membrane is placed and the final concrete lining is cast in-place. The TBM was configured to permit initial support adjustments as required during construction based on the rock conditions encountered.

One overriding and recurring issue experienced by Strabag was overbreak in the tunnel crown. Overbreak is the cracking and loosening of rocks above the TBM cutterhead, which has the effect of distorting the circular profile created by the TBM. Substantial overbreak was

[7] The cast-in-place grouted unreinforced concrete lining and waterproof membrane require the complete elimination of voids between the liner and the surrounding rock to ensure structural stability and impermeability. With a closed (shielded) TBM, ensuring that no voids remain is extremely difficult because the shield prevents direct examination of the rock above the lining (Ex. D1-2-1, p. 67).

encountered as soon as the TBM reached the Queenston shale.[8] Strabag modified the TBM to enable the installation of additional rock support closer to the excavation, and when overbreak increased substantially, Strabag began installing forward raking pipe spiles ("spiles") in an effort to limit the amount of the overbreak and to safely advance the TBM.

In some parts of the tunnel, overbreak in the arch along the tunnel's top significantly altered the circular shape produced by the TBM, creating gaps some of which were over four metres high (Ex. D1-2-1, p. 84, Photo 13). This required Strabag to undertake an additional step in the tunnel construction process to restore the circular profile prior to installing the lining. Profile restoration on the scale required for the NTP is not typical in tunnel construction. As neither party anticipated this scale of restoration work, it was not included in the DBA. The amount of restoration work required the development of specialized equipment during the execution of the project. Ultimately, of the $687.2M in costs directly attributable to the diversion tunnel (see Ex. L-4.5-1, Staff-028), the portion of the total project cost related to profile restoration was $92M (Ex. J2.1).

As a result of difficulties encountered during tunneling, in autumn of 2007 the parties began discussions regarding realigning the tunnel to exit the Queenston shale sooner and thereby increase the boring rate. In May 2008, OPG and Strabag agreed on horizontal realignment; vertical realignment began in December 2008, after the horizontal realignment took the NTP out from beneath the SAB No. 2 tunnels (Ex. D1-2-1, pp. 76-77).

On September 11, 2009, about 100 cubic metres of Queenston shale and temporary tunnel lining (shotcrete, wire mesh and steel channels) fell from the right side of the tunnel between 3,605 metres and 3,625 metres, about two kilometres behind where the TBM was then located. Work was stopped immediately. There were no injuries and all workers were safely evacuated from the tunnel. The Ministry of Labour ("MOL") subsequently issued a Stop-Work Order stopping all tunnel work beyond 3,500 metres pending an investigation, remedial work and verification of the adequacy of the tunnel crown support.

[8] Soon after the TBM began mining in the Queenston shale, a large block of rock weighing about 30 tonnes fell on the TBM delaying mining by more than three weeks (Ex. D1-2-1, p. 71).

A full investigation of this fall of ground was conducted by Strabag and the OR. The investigations concluded that a loosening of the rock support dowels put more pressure on the face plates for the dowels than they could hold, which led to the fall. The investigations also concluded ungrouted boreholes contributed to the loosening of the dowels by allowing relatively fresh water to penetrate and degrade the rock surrounding the dowels. Owing to the horizontal realignment, the tunnel excavation had intersected with the boreholes on February 27, 2009, allowing groundwater inflow until they were plugged with grout in March 2009.

Prior to this incident, it had been Strabag's practice to grout open boreholes located in close proximity to the tunnel alignment following TBM excavation. This was done without incident for Borehole NF39, which had previously been intersected by the TBM excavation in the Queenston shale (Ex. JT1.2). Ultimately, the final impact of the 2009 fall of ground was an increase to the target schedule by 17 days and an increase to the Target Cost by $2M.

On July 2, 2011, another portion of the tunnel roof partially collapsed between 6,033 metres and 6,080 metres, resulting in about 1,200 cubic metres of fallen rock and initial lining and rock support materials. No one was injured. The tunnel was initially shutdown from 5,933 metres to 6,130 metres to prevent access to the area. Following an MOL inspection, a Stop-Work Order was issued for the area surrounding the fall pending Strabag's submission of its engineering assessment and plans for safe remediation of the area. The Stop-Work Order for this area of the tunnel was in effect from July 5 to September 27, 2011. Strabag's consulting engineer cited the overload of the initial support systems caused by horizontal stresses in the Grimsby formation as the primary cause of this fall of ground.

Ultimately, a $12M insurance claim was submitted under the Builder's All Risk policy to recover the cost of remedial work associated with the July 2011 fall of ground. The claim was subject to a $2M deductible and a $10M limit if the length of the fall was less than 100 metres. After some discussions, the insurers invoked the $10M limit and paid this amount. Taking into account the insurance payment, the project cost increased by about $2.4M due to this fall of ground (Ex. D1-2-1, p. 94).

5.5.5 Strabag Claim for Differing Subsurface Conditions

Owing to the rock conditions encountered, in May 2007 Strabag began issuing a number of claims and notices all aimed at recovering additional costs because the subsurface conditions being encountered were significantly more adverse than were contemplated in the DBA (Ex. D1-2-1, pp. 96-97). After months of discussion, in late November 2007, OPG and Strabag senior management agreed to a final three-month effort to resolve their dispute through negotiation prior to submitting it to the Dispute Review Board ("DRB") established in the DBA to address disputes between parties. These negotiations proved unsuccessful, and in February 2008, the parties agreed to present the matter to the DRB.

While Strabag offered a number of reasons in support of its claim for differing subsurface conditions, the essence of its position was that the rock conditions being encountered were significantly more adverse than contemplated in the Geotechnical Baseline Report ("GBR") that formed part of the DBA. Under the agreement, OPG was responsible for the resulting costs if the subsurface conditions actually experienced were more adverse than anticipated.[9]

The DRB hearing was held from June 23 through 26 in Niagara Falls, Ontario. On August 30, 2008, the DRB issued its Report and Recommendations ("DRB Report") (Ex. D1-2-1, Attachment 7). The DRB's conclusions were unanimous. While OPG's position was adopted on most issues, the DRB did find that the excessive overbreak experienced by Strabag constituted a differing subsurface condition and that the Table of Rock Conditions and Rock Characteristics in the GBR was defective. On this basis, the DRB concluded that Strabag had encountered differing subsurface conditions, which under the DBA, were OPG's responsibility. Despite this fact, the DRB recommended that the dispute be resolved on a cost sharing basis, stating that:

> Since the development of the GBR was the mutual responsibility of both Parties, we recommend that the Parties negotiate a reasonable resolution based on a fair and equitable sharing of the cost and time impacts resulting from the overbreak conditions that have been encountered and the support measures that have been employed. Both Parties must accept responsibility for some portion of the additional cost, but at the same time the Contractor

[9] The GBR, which is Appendix 5.4 of the DBA, states at page 5, paragraph 4: "Those consequences associated with subsurface conditions more adverse than the baseline conditions are accepted by OPG" (Ex. D1-2-1, Attachment 6 (PDF p. 1724)).

> must have adequate incentives to complete the Work as soon as possible (Ex. D1-2-1, Attachment 7, pp. 18-19).

At the end of the DRB Report, the DRB added the following additional finding:

> The DRB members have rarely experienced such an excellent, cooperative atmosphere between the Parties on a tunnel project. This is especially impressive considering the pioneering nature of the Work and the problems and issues encountered. The Board is confident that the Parties can negotiate an amendment(s) to the DBA that, while not commercially optimum for either Party, will allow the Project to proceed to optimum completion (Ex. D1-2-1, Attachment 7, p. 19).

Mr. Roger Ilsley, who has served on numerous DRBs, in reviewing OPG's conduct before the DRB, concluded: "it was appropriate to take the dispute before the DRB and further that OPG conducted the hearing in a proper manner" (Ex. F5-6-1, p. 3). It is important to note that throughout the negotiations over the dispute and the entire DRB process, OPG and Strabag continued to work together to complete the NTP safely.

5.5.6 Contract Renegotiation

After receiving the DRB Report, OPG examined a number of potential responses and concluded that negotiating with Strabag based on the DRB recommendations was the path mostly likely to complete the tunnel in the least amount of time and at the lowest cost (Ex. D1-2-1, pp. 102-103). Both OPG and Strabag agreed that their joint focus over the next few months would be on negotiating a mutually satisfactory resolution of their disagreements and a path forward to project completion.

In early October 2008, Strabag submitted two options to OPG for resolving the current dispute and moving forward, which are detailed in Section 8.2 of Ex. D1-2-1. OPG, in consultation with the OR, noted that neither of Strabag's proposals adequately captured the notion of a "fair and equitable sharing of the cost and time impacts" as recommended by the DRB. However, OPG also noted that as Strabag continued to do a good job and work safely on the project despite the difficult rock conditions then being encountered in the tunnel, it was in OPG's interest to attempt to settle with Strabag to allow the project to move forward to completion (Ex. D1-2-1, p. 105).

OPG and Strabag ultimately developed a Principles of Agreement ("Principles") document which was based on a hybrid approach that included resolution of Strabag's past claims for differing subsurface conditions in the Queenston formation and renegotiation of the DBA going forward. In addition, OPG and Strabag developed a Term Sheet and accompanying Memorandums of Understanding to further delineate provisions for amending the DBA. Both parties committed to complete the project in a safe, environmentally sound and expeditious manner and to reflect the DRB recommendations as they worked toward a revised agreement.

After further negotiation the parties agreed to a lump-sum payment for past costs and a new agreement covering future costs. OPG agreed to pay Strabag $40M to resolve all issues through November 30, 2008, which reflected a sharing of Strabag's claimed losses of $90M. The parties negotiated an Amended Design Build Agreement ("ADBA") based on the original DBA (Ex. D1-2-1, Attachment 9). Most DBA provisions were retained unchanged except as necessary to convert the agreement to a target cost contract (Ex. D1-2-1, pp. 106-112).

Under the ADBA, OPG and Strabag agreed that Strabag would complete the project at cost with no profit and only a 5 per cent allowance for corporate overhead (Ex. D1-2-1, p. 106). The agreed Target Cost was $985M and the agreed Substantial Completion date was June 15, 2013. Strabag was entitled to its costs to complete the project and could earn incentives if it completed the project for less than the Target Cost or before the agreed Substantial Completion date. Conversely, disincentives (penalties) applied if the costs exceed the Target Cost or the project was late.

In addition to the payments described above, Strabag received an Interim Completion Fee of $10M upon completion of TBM mining activities on March 30, 2011 and was also entitled to a Substantial Completion Fee of $10M on March 9, 2013 upon achieving Substantial Completion.

Consistent with the original DBA, an incentive or disincentive was to be applied to the extent measured flow deviates from the Guaranteed Flow Amount ("GFA") of 500 cubic metres per second by an amount which exceeds the dead band of plus or minus two per cent. Strabag also continued to provide the warranties and financial guarantees contained in the DBA, including a parental indemnity, a Letter of Credit and a Maintenance Bond (Ex. D1-2-1, p. 111).

5.5.7 OPG Board of Directors Approval: Superseding Business Case Summary

While the ADBA was being finalized, OPG began preparing a Superseding BCS to seek approval from its Board of Directors. OPG management had kept the OPG Board apprised throughout its negotiations with Strabag (Ex. D1-2-1, p. 112). The Superseding BCS (found at Ex. D1-2-1, Attachment 8) was the vehicle to seek formal OPG Board approval of the new contracting approach and the resulting Target Cost and schedule.

The Superseding BCS included a summary of progress on the project and the difficulties encountered in tunneling, leading to the differing subsurface conditions dispute before the DRB and its resolution. It then summarized how the project was to be executed under the ADBA.

The Superseding BCS outlined the forecast cost increases between the DBA and the ADBA. The bulk of the increase was attributable to the tunnel contract (including contingency), but the longer schedule also increased other costs, primarily those associated with maintaining the OR on site and interest cost. It presented three other alternatives besides the recommended alternative of proceeding under the ADBA.

The Superseding BCS updated the financial analysis contained in the original BCS for the project's increased cost and new completion date. The Superseding BCS concluded that the project remained an attractive source of clean electricity. The sensitivity analysis included in the Superseding BCS confirmed that this conclusion is valid across a broad range of scenarios.

Based on the Superseding BCS, the OPG Board approved a revised maximum budget of $1,600M and an in-service date of no later than December 31, 2013 for the project and authorized management to execute the ADBA on behalf of the corporation. The OPG Board also authorized the request for an increase of the credit facility with the Ontario Electricity Financing Corporation to $1,600M to reflect the new project budget (Ex. D1-2-1, p. 115).

5.5.8 Project Completion

Under the ADBA, OPG and Strabag worked together to complete the project in accordance with the revised schedule and budget. The NTP's Substantial Completion occurred on March 9, 2013, well in advance of the target schedule date. OPG paid Strabag the maximum incentive of $40M under Section 8.6 of the ADBA based on the project's Substantial Completion relative to the contract's Substantial Completion date as amended. The project cost was also below the Target Cost as amended, but no additional incentive was paid because of the ADBA's $40M cap on the combined total of cost and schedule performance incentives (Ex. D1-2-1, Attachment 9, PDF p. 115).

5.5.9 Conclusion

As the discussion above demonstrates, numerous challenges emerged during the course of constructing this extremely large and complex project. These challenges derived primarily from tunneling conditions which were substantially more difficult than those reasonably anticipated. Extensive studies and other investigation of geologic conditions were conducted by Ontario Hydro and others well in advance of the NTP. No amount of preparation however, can provide perfect knowledge of subsurface conditions more than 100 metres underground over the course of a tunnel route more than 10 kilometres long. When challenges to the project schedule and cost emerged, OPG addressed them in a prudent manner and, working with Strabag and the OR, ultimately overcame every obstacle to deliver a project that will provide substantial value for the people of Ontario into the next century. The project as completed met all of the performance requirements initially established for it, including those related to workplace safety (Ex. D1-2-1, p. 40).

OPG submits that the cost variance relative to the originally approved budget is entirely due to the more adverse subsurface conditions experienced during the tunnel construction. As fully documented in the evidence, the amount OPG spent on the NTP represents the true cost of completing the project given the subsurface conditions actually encountered:

> MR. RUBENSTEIN: And the question that I want to understand is: If you knew what the actual subsurface conditions were at the time that you -- at the time of the design-build agreement, what do you think the cost would have been?
>
> MR. YOUNG: I believe that the cost would have been ultimately what the cost was. The project involved -- it was a mining project, and it involved removal of a certain amount of material.
>
> It involved lining the tunnel and filling the voids around that lining, and that was effectively what OPG paid for in this case; so the approximately 1.5 billion cost (Tr. Vol. 2, p. 85 and Ex. L-4.4-2 AMPCO-016).

OPG acted prudently in planning and executing this project and in addressing the differing subsurface conditions encountered. On this basis, OPG submits that the entire $491.4M of project costs subject to review was prudently incurred and should be recovered.

5.6 ISSUE 4.5

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

The total in-service additions for the Niagara Tunnel Project through 2013 were $1,439.2M with an additional $13.4M expected during the test period (Ex. L-4.5-1 Staff-025).[10] OPG submits that the proposed 2013 and test period in-service additions are reasonable, as detailed under issue 4.4.

5.7 NUCLEAR

5.8 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?

In EB-2010-0008, the OEB determined that Pickering Continued Operations (including the Fuel Channel Life Cycle Management project) was subject to section 6(2)4 of O. Reg. 53/05 as the program is designed to increase output of the Pickering Generating Station (Decision with Reasons, p. 52). The Darlington Refurbishment Project, which is discussed under Issues 4.9-4.12, is also subject to section 6(2)4 of O. Reg. 53/05 and meets the requirements of that section.

OPG is proposing in this Application that the Fuel Channel Life Extension project also be found to be subject to section 6(2)4 of O.Reg. 53/05, because it will also increase the output of the Pickering and Darlington Generating Stations (Ex. F2-3-3, Tab 11, Project 80014, p. 2, Figure 1). By achieving high confidence in the fitness for service of the Pickering fuel channels operating to 261,000 EFPH (previously 247,000 EFPH), OPG will be able to operate all, not

[10] The total capital cost of the NTP to completion is $1,472M. Of this figure, $19.2M associated with construction of the Accelerating Wall was previously placed into service in 2007 (Ex. D1-2-1, p.4).

just some, of the Pickering units to the end of 2020 without needing a life management outage on any of the units (Ex. L-6.3-1 Staff-077).

OPG submits that these three identified projects and their associated costs meet the requirement of section 6(2)4 of O. Reg. 53/05 since they serve to either increase the output or refurbish a prescribed generation station.

5.9 ISSUE 4.7

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

The annual actual and forecast totals for combined capital and OM&A project expenditures in the nuclear project portfolio are set out in Chart 1 below (Ex. D2-1-1, p. 2 and L-1.0-1 Staff-002, Attachment 1, Tables 10 and 21). These amounts are generally consistent with OPG's target annual re-investment levels of $25M to $30M per nuclear unit for OPG's 10-unit nuclear fleet. OPG submits that they are reasonable and should be approved.

Chart 1

	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
	$M					
Project Portfolio -OM&A	124.8	100.5	96.8	87.3	101.1	105.8
Project Portfolio - Capital	157.0	135.3	145.9	191.0	175.0	122.2
Total Project Portfolio	281.8	235.8	242.7	278.3	276.1	228.0

These target capital and OM&A project portfolio budget levels were developed in consideration of: historical investment patterns, project execution capabilities, the potential beneficial impact of the improved project portfolio management processes, and high level comparative data from other nuclear utilities (Ex. D2-1-1, p. 1). Most of the capital projects in the portfolio in the test period are sustaining projects, or projects to sustain and/or improve plant reliability at both Darlington and Pickering. They include expenditures on systems and components approaching their end of life, or for which replacement parts are no longer readily available. The expenditures also include additional projects required to address regulatory requirements arising from the nuclear accident in March 2011 at the Fukushima Daiichi nuclear plant (Ex. D2-1-2 pp. 2-3).

OPG's cost control and prioritization efforts have allowed OPG to hold nuclear project portfolio capital spending below 2010 levels for both test years despite labour and material cost escalation. Since the last filing, OPG has completed six major projects (cost >$20M), five of which were completed on or under budget (Ex. D2-1-2, p. 1).

In addition to nuclear capital and OM&A project portfolio expenditures, there are other nuclear capital and OM&A project expenditures that are managed and approved outside of the project portfolio, for example, the purchase of minor fixed assets (capitalized in accordance with OPG's capitalization policy) as well as non-portfolio OM&A project expenditures (i.e., test period project costs associated with Pickering Continued Operations and Fuel Channel Life Cycle Management projects) (Ex. D2-1-2, p. 2; Ex. F2-3-1, p. 2).

OPG nuclear projects are developed to meet regulatory commitments (e.g., from the CNSC), decrease future base or outage OM&A expenditures, increase system or unit reliability, address system obsolescence or increase the output of the station (Ex. D2-1-1, p. 2). Projects are categorized by OPG into two categories:

- "**Portfolio Projects (Allocated)**" are projects that have an Asset Investment Screening Committee ("AISC") approved budget and an approved business case summary ("BCS"). This includes major capital spares.
- "**Portfolio Projects (Unallocated)**" is the difference between the total approved capital budget and the amount of capital allocated to projects in the Portfolio Projects (Allocated) category. In effect, it represents the amount of approved capital that remains available to undertake projects that are currently in the project identification or project initiation phases.

Overall, OPG is committed to completing necessary work on prioritized basis up to the total level of the project portfolio (Ex. D2-1-2, p. 2).

The OPG Board of Directors approves the annual nuclear projects portfolio budget during business planning. The annual nuclear projects portfolio budget is administered by the AISC via the portfolio management process, which determines project prioritization and allocates portfolio funding to specific projects (Ex. D2-1-1, p. 3).

OPG's nuclear operations capital expenditures are $196.3M and $143.8M in 2014 and 2015, respectively (Ex. D2-1-2, Table 1). This amount consists of project portfolio capital expenditures ($175.0M and $122.2M in 2014 and 2015 respectively) and minor fixed assets ($21.3M and $21.7M in 2014 and 2015 respectively) (Ex. D2-1-2, Table 2). Planned capital expenditures for the Darlington Refurbishment Project are not included in these figures. Discussion of the Darlington Refurbishment Project is presented in Sections 5.11 to 5.15 below.

There are only two new Tier 1 projects that have been approved since EB-2010-0008 (Ex. D2-1-3, Table 1). Project #46634 (Pickering Fuel Handling Single Point of Vulnerability Equipment Reliability Improvement) will improve fuel handling equipment reliability. Project #49285 (Pickering Modification/Replacement of Fiber Reinforced Plastic ("FRP") Components) will demonstrate the vacuum building FRP components will remain fit for service to 2024, precluding the need for another station wide outage before the planned end of station life.

OPG submits that the level of proposed test period capital expenditures is appropriate, and that the company properly scopes, prioritizes and executes projects. On this basis, the OEB should find that the proposed nuclear test period capital budgets are appropriate.

5.10 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's forecast test period nuclear in-service additions (excluding the Darlington Refurbishment Project) of $158.3M in 2014 and $141.7M in 2015 are appropriate and should be approved by the OEB.

The forecast of in-service amounts was developed through OPG's business planning process and reflects in-service dates of the various projects described in Ex. D2-1-3.

In accordance with the OEB filing guidelines, OPG filed detailed business case summaries for all in-service projects for the test years for all projects with total costs greater than $20M (except for security classified projects) (Ex. D2-1-3, Table 1, with the business case summaries provided as Attachment 1). Also in accordance with the filing guidelines, projects with total project costs between $5M and $20M and contributing to in-service additions in the test years were summarized at Ex. D2-1-3, Tables 2a and 2b, while projects with total costs less than $5M were aggregated at Ex. D2-1-3, Table 3. The remaining amount for in-service additions in the test years is composed of minor fixed assets and supplemental in-service amounts (Ex. D2-1-3, p. 4 and Table 4c).

In-service amounts will vary year-over-year, driven by the level of capital expenditures and the timing of project installations that are frequently tied to specific unit or station outages. In the event a project is cancelled, alternative replacement projects are undertaken from the queue of projects awaiting execution.

OPG submits that the OEB should find that the proposed forecast of nuclear in-service additions is appropriate.

5.11 ISSUES 4.9 THROUGH 4.12

This section will deal with each of the issues noted above related to the Darlington Refurbishment Project (the “DRP”). However, the issues will not be considered in order. As much of the oral hearing focused on the issues related to the reasonableness of OPG’s commercial and contracting strategies (Issue 4.11) and OPG’s adherence to the Long Term Energy Plan’s (“LTEP”) principles applicable to nuclear refurbishment (Issue 4.12), these two issues will be considered first followed by Issues 4.9 and 4.10.

While OPG is not seeking OEB approval of the decision to refurbish Darlington, it is seeking the following findings and approvals associated with the DRP:

- a finding that OPG’s commercial and contracting strategies for the DRP are reasonable;
- a finding that the proposed capital expenditures of $839.9M in 2014 and $842.5M in 2015 are reasonable (Ex. D2-2-2, p. 7);
- approval of OM&A expenditures of $6.6M for 2014 and $18.2M for 2015 (Ex. J7.1, Attachment 1);

- approval of in-service additions to rate base of $5.0M in 2012, $104.2M in 2013, $18.7M in 2014, and $209.4M in 2015 for new facilities and related 2014 and 2015 depreciation expense (Ex. J7.1, Attachment 1); and
- approval to recover the capital portion of the actual audited nuclear balance in the Capacity Refurbishment Variance Account as at December 31, 2013, currently projected at $5.7M (Ex. J7.1, Attachment 1).

5.11.1 The DRP Context

The DRP is a mega project unlike any other considered by the OEB. The DRP, currently in its Definition Phase, will not be fully completed until 2025 and OPG's current medium to very high confidence estimate range is $8B to $10B in 2013 dollars excluding interest and escalation (Ex. J15.2).

The DRP is a multi-phase program comprised of a significant number of individual projects of various scales and levels of complexity. Management and coordination of the DRP has been divided into the following five major project work packages: Re-tube and Feeder Replacement ("RFR"), Turbine Generator, Fuel Handling, Steam Generators, and Balance of Plant.

The RFR work package includes the removal and replacement of pressure tubes, calandria tubes and feeders in each reactor. At approximately 60 per cent of the total DRP costs, the RFR work package is the largest and requires the most tooling, and planning. This work must be properly sequenced and executed as errors in installation can cause significant delays and expense:

> MR. REINER: …So the job itself, what creates the complexity in this job, is that you have 480 fuel channels, 960 end fittings, 960 feeder pipes. If it isn't executed in a very precise sequence or an issue arises that might require you to go back and rework, which was the case at Point Lepreau, you're having to do that 480 times. And if it takes you half a day to do that work, you multiply that by 480, you can see how the schedule overruns arise.
>
> So it becomes a complicated job from the perspective of orchestrating the execution (Tr. Vol. 16, p.19-20).

To avoid these consequences OPG has built a mock-up of the reactor where procedures can be practiced and tools can be tested before work occurs in the reactor, thereby allowing OPG to develop a high degree of certainty before going into the reactor that the project schedule is actually achievable (Tr. Vol. 16, p. 20). This approach will allow OPG to avoid the significant delays that have plagued other refurbishment projects, and reflects the inherent quality of incorporating lessons learned that is key to the DRP's success.

The Turbine Generator work package consists of inspections, repairs and replacements of specific components of the four turbine generator sets and their auxiliaries, and the replacement of analog control systems with digital systems. The Fuel Handling work package involves the defueling of the reactor prior to re-tube and feeder replacement, as well as life cycle repair and replacement work to refurbish the fuel handling equipment. The Steam Generators work package includes mechanical cleaning, water lancing, inspection and maintenance work. The Balance of Plant work package consists of replacement of safety and control system components and repair and replacement of components for systems on the reactor side of the unit (such as heavy water and cooling systems) and for systems on the conventional side of the unit (such as electrical system, piping and valve work).

Because of the DRP's complexity, project management and contractor coordination is key to successfully executing the project. Employing an engineering-procurement-construction ("EPC") approach combined with a multi-prime contractor commercial strategy, OPG will obtain direct visibility into project status, schedule and costs to enable early identification of issues so that corrective action can be undertaken to mitigate risk.

This approach will enable OPG to develop a release quality estimate ("RQE") in 2015. Under OPG's approach, by the time the RQE is developed, OPG will have tested every sequence of work that will take place on the critical path during the unit outages, tested all tools developed, tested the abilities of the workers that will utilize those tools, and will have tested setup, tear down and the execution of work (Tr. Tech. Conf., July 9, 2014, p. 26, lines 12-21).

The DRP is subject to a substantial amount of oversight. The Darlington Refurbishment team ("DR Team") subjects itself to continuous self-assessment. It regularly conducts self-assessments and evaluations of challenging conditions, and has initiated management actions in response to those assessments. The DR Team also actively identifies and incorporates lessons learned from other large nuclear and non-nuclear projects, both internal and external to OPG. Part of its self-assessment includes the work of internal auditors, internal oversight committees, a scope review board, an options review board, a blue ribbon committee on project scope, and the gate review board for project funding releases (Tr. Tech. Conf., July 8, 2014, pp.19-20, lines 46-50).

In addition, the DR Team also incorporates recommendations from external oversight assessments undertaken by Burns & McDonnell/Modus Strategic Solutions ("BMcD/Modus") and Concentric Energy Advisors ("Concentric"). BMcD/Modus is fully integrated into the DRP for the purpose of providing observations and recommendations to management and BMcD/Modus reports regularly to the Nuclear Oversight Committee ("NOC") of OPG's Board of Directors (Tr. Tech. Conf., July 8, 2014, pp. 4-5). Concentric was retained in 2011 and provides advisory services to OPG with respect to contracting strategies, contract negotiations, contract terms and language, and additionally provides opinions to counsel and to the OPG Board of Directors (Tr. Vol. 13, pp. 146-149 and Ex. D2-2-1, Attachments 7-1 to 7-5).

While BMcD/Modus, as demonstrated in its reports and in testimony at the hearing, supports OPG's commercial and contracting strategies and its earlier reports were consistent with the evidence set out in Ex. D2-2-1 (Tr. Vol. 16, p. 147), the BMcD/Modus report dated May 13, 2014 identified deficiencies in and raised serious concerns regarding the execution of the Drum Handling Facility ("D2O Storage") and Auxiliary Heating System ("AHS") projects. It also raised serious concerns about their potential impact on the DRP schedule and costs. In light of BMcD/Modus' findings and in order to independently assess the integrity of the DRP and its progress to RQE, OPG's NOC obtained a fifth report dated June 26, 2014 from BMcD/Modus. This report assesses OPG's corrective actions with respect to the projects in question and assesses the overall health of the DRP as it progresses to RQE.

In its June 26, 2014 report, BMcD/Modus stated the following conclusions regarding the DRP: "The Refurbishment Project is advancing at an appropriate pace toward the RQE milestone. The majority of the contracts for the Definition Phase have been awarded and essential preparatory work is moving forward." (Ex. D2-2-2, Attachment 1, p. 1).

With respect to incorporating lessons learned, BMcD/Modus noted that the DR Team has taken action on many of the items it raised. BMcD/Modus noted that OPG has either: already taken action on the recommendations as written by BMcD/Modus; or, has identified how the DR Team plans to address the recommendations in the future. BMcD/Modus expressed its satisfaction with the DR Team's response to its recommendations (Tr. Vol. 16, p. 149).

In summary, the DRP is not a linear project or like the construction work normally seen by the OEB as part of the leave to construct process in the transmission and distribution context. As a result, the OEB must look at the DRP through the lens of a mega project, taking into account the high degree of complexity, interdependence, project management and commercial and contracting strategies inherent in projects of this nature.

5.12 ISSUE 4.11

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

During the oral proceeding, OPG clarified Issue 4.11 and its request for approval with respect to its commercial and contracting strategies. OPG 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 (Tr. Vol. 16, p. 4).

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:

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 (Tr. Vol. 16, p. 5).

OPG submits that based the aforementioned principles, OPG's commercial and contracting strategies for the DRP are reasonable. Each of these principles and the reasonableness of the commercial and contracting strategy, in general, will be considered below.

5.12.1 Multi-prime Contractor Model

The commercial strategy selected by OPG is a multi-prime contractor model. Under this model, the project work is split up amongst multiple prime contractors. OPG as the owner has a separate contract with each prime contractor. A prime contractor is responsible for the completion of the work under its particular contract, but not for the entire DRP. OPG as the owner is the integrator between the prime contractors and is responsible for the entire DRP.

Under this model OPG retains project management responsibility and design authority for the DRP. The retention of the project management responsibility and design authority for the DRP is a key risk management and mitigation measure that underpins OPG's contracting strategy. By taking an active project management role which includes embedding OPG personnel into the contractor's organization (Tr. Vol. 16, p. 60), OPG obtains direct and clear visibility into the workplan, schedule and cost of each prime contractor. This visibility enables OPG to discern potential risks and issues and to ensure early corrective action, including the requirement that prime contractors implement recovery plans and monitoring of those recovery plans to return work to schedule or to the estimated cost. For example, the DRP Team has required the RFR contractor to develop a recovery plan to restore its progress to plan. The DRP Team has actively held the RFR contractor accountable to its recovery plan and the RFR contractor's performance has since improved (Ex. D2-2-2, Attachment 1, p. 12).

This approach is contrasted with the turnkey contracting approach where one contractor is responsible for delivering to the owner a completed project after taking full responsibility for design and execution. The turnkey contracting approach provides for minimal visibility and limited ability for the owner to monitor risk issues and require corrective action. OPG has incorporated key lessons learned in its multi-prime approach. For example, as indicated by

OPG, this was a key lesson learned from the Point Lepreau project where decisions were made by the contractor without owner involvement that led to significant delays and costs (Ex. D2-2-1, Attachment 7-1, p. 7 and Tr. Vol. 16, p. 45).

OPG considered a number of other potential commercial strategies. These include:

- Partnering – This involves a single agreement with multiple vendors (possibly in a joint venture) for purposes of designing and executing work packages. The goal is to tie vendors' financial reward to the overall project success based on the theory that interests would be aligned and cooperation would be promoted. However, because financial reward is tied to other contractors that are beyond the partnering contractor's control, projects utilizing this model were subject to vendor disputes causing delays and added costs (Ex. D2-2-1, Attachment 7-1, p.7 and Tr. Vol. 16, pp. 43-44).

- Fixed Price Lump Sum Turnkey – As noted above, a fixed price lump sum turnkey model similar to Point Lepreau was also considered. This strategy would have turned over the entire project to a single contractor to complete the entire scope of work and to return the operating unit back to OPG when refurbished. Coupled with a fixed price arrangement, in theory, this model could provide greater price certainty and risk transfer. However, OPG found this model to be unacceptable since: (i) this model would have eliminated OPG's control over the final design, pace and project management, and as OPG ultimately bears the risk of schedule completion (Tr. Vol. 14, p. 55, lines 17-19), OPG would be left with a risk that it could not mitigate (Tr. Vol. 16, p. 45-46); and (ii) although there is a theoretical price risk transfer to the vendor, this is unachievable in the nuclear safety environment due to exclusions and excuses under the contract such that the risk premium paid in the contract by the owner does not match the transfer of risk (Ex. D2-2-1, Attachment 7-1, p. 7). This was the lesson learned from Point Lepreau, identified above. Furthermore, such a contract is not currently feasible in the current market (Ex. D2-2-1, Attachment 7-1, p.8, Tr. Vol. 14, pp. 45-48, and Tr. Vol. 16, p. 45).

- Project Management Organization ("PMO") – This model contemplates a retention of a firm qualified to manage mega projects similar to the DRP. The PMO would be responsible for project planning, negotiation with prime contractors and managing various work packages. However, there is a risk of misalignment between the PMO and the prime contractors that may lead to disputes. This is particularly the case in the nuclear services market where the tight market for nuclear service vendors could require the PMO to also undertake work in respect of the project. Recent experiences of Bruce Power caused that generator to abandon the PMO model in respect of its refurbishment (Ex. D2-2-1, Attachment 7-1, p.8 and Tr. Vol. 16, pp. 47-48).

In September 2011, Concentric was retained to review whether the commercial and contracting strategies for the DRP were reasonable and prudent. In a series of opinions, Concentric considered OPG's overall commercial strategy and contracting strategies for RFR, Turbine Generator, Fuel Handling, Steam Generators and Balance of Plant work packages (Ex. D2-2-1, Attachments 7-1 to 7-5). Concentric provided its assessment based on document review that consisted of thousands of documents and interviews with numerous OPG personnel involved directly with the DRP. As a result of its independent assessment, Concentric concluded that it was reasonable and prudent for OPG to select the multi-prime model under the current market circumstance and to reject the alternatives considered by the company.

5.12.2 Work Packages

Once the decision was made not to use the Fixed Price Lump Sum Turnkey commercial strategy, the division of the necessary work into work packages became the optimal way to proceed. Because of the complexity of the DRP, the sequencing of elements of the project and the specialized nature of various components, OPG divided the DRP into five separate work packages described above. They are the construct within which OPG's commercial and contracting strategies are applied and are delineated based upon the technical parameters of the project and OPG's knowledge of the facilities. Their creation is driven by these technical parameters and not the risk management and pricing considerations underpinning the multi-prime model or the target pricing contract structure adopted by OPG. As such, OPG submits that the use of the prescribed work packages is reasonable (Ex. D2-2-1, Attachment 7-1, pp. 5-6).

5.12.3 EPC Contract Arrangements

With each work package, OPG will enter into contracts with the various prime contractors that fit the engineering, procurement, and construction model or some combination of those three aspects depending on market conditions (Tr. Vol. 16, pp. 6-7). The key rationale for an EPC as the preferred delivery model is that it provides one point of contact for OPG and thereby fewer interfaces and one point of accountability for complete delivery (Ex. D2-2-1, Attachment 6-1). For example, because one contractor is responsible for the key functions of engineering, procurement and construction, there is appropriate coordination of subcontractors to avoid downtime because of independent actions of trades on site (Tr. Vol. 16, p. 45-47).

5.12.4 Target Pricing and Risk Management

As part of its commercial and contracting strategy, OPG has adopted the principle that it would allocate risk to the party best able to manage that risk through a pricing structure tailored to the level of project definition and the level of required owner oversight. For OPG, this means the use of target pricing where the project is less defined and requires more oversight, and fixed pricing where there is greater project definition and less oversight is required.

Risk is inherent in any project. The key to success from OPG's perspective is to establish a commercial strategy that enables OPG to effectively manage the intrinsic risk to the project (Ex. D2-2-1, Attachment 7-1, p. 5). Intrinsic risks are those that are within the control of OPG and largely related to the technical and commercial aspects of the project.

Contractual attempts to fully shift accountability to the contractors may not be achievable or may command too high a risk premium. As noted above, in the nuclear services market, it is virtually impossible to enter into a contract that transfers the intrinsic risk of the project to the contractor at a fixed price. Based upon its own analysis and that of Concentric, OPG has sought the middle ground, which uses a contractual mechanism that aligns the party most capable of managing that risk with accountability for that risk, and includes effective oversight and economic incentive mechanisms (Ex. D2-2-1, Attachment 6-1, p. 9).

At the root of this alignment is project definition. Where there is a high level of design completion and clarity of scope, the contractor is best able to manage that risk (Ex. D2-2-1, Attachment 6-1, p. 9 and Tr. Vol. 16, p. 4). In this circumstance, OPG has established or will establish fixed price provisions in the contractual terms and have less project oversight. An example of this arrangement is the tooling portion of the RFR contract undertaken by the RFR contractor (Tr. Vol. 15, p. 36 and Tr. Vol. 16, p. 21).

Where there is less project definition and risk responsibility rests with both parties, OPG has established a target pricing mechanism tied to a risk register that allocates risk between the parties. This is the case for the actual retube and feeder replacement work under the RFR contract. The conditions that will arise on the actual reactor face are unknown. No contractor in today's market conditions would bear that risk exclusively and OPG as the operator and the owner is best able to manage that risk (Tr. Vol. 14, pp. 45-48 and Tr. Vol. 15, p. 35).

In Undertaking Ex. JT3.17, OPG provided a detailed example of the target pricing mechanism and fixed pricing components and thereby the risk responsibilities for the RFR contract. That undertaking provides an example of the target price model under different cost overrun scenarios using the RFR contract terms.

As the model indicates, if the contractor's direct costs exceed the target price, costs are recovered through a repayment of the fixed fee, which impacts the contractors overhead and profit. In addition to cost disincentives, the RFR contract, which represents a large portion of the DRP's critical path, has schedule disincentives for any delays beyond the approved target schedule. The contractor is accountable for all costs related to rework where the cause of the rework is due to contractor quality. The contractor is also accountable for all costs related to rectifying items that fall under a warranty provision (Tr. Vol. 13, pp. 175-176, Tr. Vol. 14, pp. 53-55).

If the contractor completes the refurbishment for a cost or schedule less than the target price or schedule, they are eligible for incentives equal to a percentage of the amount of the disincentives (Ex. JT3.17).

Through OPG's target pricing mechanism and the recognition for matching risk responsibility to project definition, OPG has established a commercial strategy that reflects both the practical realities of this mega project and the current market conditions.

This model, in whole or in part, has been applied to other major EPC contracts in place including in the Turbine Generator, Steam Generators, and Defueling contracts. Each of these contracts has a combination of fixed price, cost reimbursable, and target price components (Ex. JT3.16; Ex. JT3.17).

The Balance of Plant related work done using the Extended Services Master Services Agreement ("ESMSA") is described in detail in Undertaking Ex. JT3.16. The ESMSA also allows for either fixed price or target price arrangements (Ex. JT3.16). As a result of the foregoing, 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.

5.13 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?

On December 2, 2013, the Ministry of Energy released the LTEP for the Province of Ontario. The LTEP noted that:

The nuclear refurbishment process will adhere to the following principles:

1. minimize commercial risk on the part of ratepayers and government;
2. mitigate reliability risks by developing contingency plans that include alternative supply options if contract and other objectives are at risk of non-fulfillment;
3. entrench appropriate and realistic off-ramps and scoping;
4. hold private sector operator accountable to the nuclear refurbishment schedule and price;
5. require OPG to hold its contractors accountable to the nuclear refurbishment schedule and price;
6. make site, project management, regulatory requirements and supply chain considerations, and cost and risk containment, the primary factors in developing the implementation plan; and
7. take smaller initial steps to ensure there is opportunity to incorporate lessons learned from refurbishment including collaboration by operators.

OPG has demonstrated that its plans for the DRP are consistent with the above principles. In particular, as set out in Ex. L-4.12 Staff-058, OPG has taken a number of specific steps that align with the LTEP principles:

Minimize commercial risk on the part of ratepayers and government

- Locking down project scope well in advance of starting construction.
- Fully developing engineering and planning of the work so that it is 100 per cent complete prior to the start of construction.
- Building a full-scale mock-up of the Darlington Nuclear Generating Station reactor and vault that will be used for training and proving the tools needed for the removal and replacement of the reactor components.
- Developing a RQE in phases that incorporates a high-confidence budget and schedule for the work.
- "Unlapping" Unit 2 from the subsequent units so that the focus can be on the planning and construction of a single unit and so that OPG can gain from the lessons learned in completing the work.
- Utilizing target price contracts for the execution phase that is based on developing cooperation, transparency, and risk sharing with key vendors.
- Utilizing fixed price contracts for certain execution phase scope that is well defined and where risk transfer to a third party is appropriate.
- Negotiating various off-ramps and stages into contracts.
- Establishing a robust risk management process to directly identify and administer commercial risks.

Mitigate reliability risks by developing contingency plans that include alternative supply options if contract and other objectives are at risk of non-fulfillment

- OPG's decision to "unlap" Unit 2 from the other units' refurbishments, which predated the LTEP, was intended to mitigate performance risk and to allow the DRP Team to focus on one unit's refurbishment at a time. If the first unit is not successful, off ramps are in place; the second unit refurbishment will not commence until the first unit is successfully returned to service.
- Risk assessment and appropriate contingency plans/back-out plans for each execution work package will be developed and included in the RQE.
- OPG's investment in the reactor mock-up will be used to perform full integration and commission testing of tools needed for refurbishment; lessons will be learned on the mock-up, not on the unit. The results of the mock-up testing will be incorporated into the tooling performance guarantee, which sets the target schedule and price, with the RFR vendor.

Entrench appropriate and realistic off-ramps and scoping

- OPG has engaged in a structured process with numerous off-ramps for the definition phase including Board of Directors oversight and annual releases of funds.

- Each contract has off-ramp provisions allowing OPG to terminate, with or without cause; OPG would be accountable only to reimburse vendor for any reasonably incurred costs.

- Scope review process in place to minimize scope of work performed in DRP period to things that must be done to extend life or can only be done in drained/defueled state.

- OPG has fully examined the scope of the Unit 2 refurbishment project and optimized the work based on OPG's regulatory commitments and/or on an analysis of the best time to perform the work.

Hold Private sector operator accountable to the nuclear refurbishment schedule and price

- This is accomplished through the steps taken under the first three principles.

Require OPG to hold its contractors accountable to the nuclear refurbishment schedule and price

- OPG, in implementing all of its contracts, is highly focussed on achieving value for money; there are incentives and/or disincentives related to achieving the cost and schedule set out in the contracts.

- Contracts with major vendors are being developed and vetted utilizing a deliberate, staged and gated process with requirements for budget, schedule, scope, and risk identification at each gate.

- Contracts have specific negotiated incentives and disincentives that are calculated toward promoting the contractor's (and OPG's) responsible management of the work.

- OPG is implementing a detailed, integrated Level 3 schedule that will encompass all of the contractors' and OPG's work, as well as a rolled-up Level 2 Control and Coordination Schedule that is used as a higher level interfacing tool.

- OPG has implemented cost control systems that are geared toward holding contractors accountable. These systems include earned value and budget controls through the gate process.

- OPG performs analysis of all pricing and check estimates for contractors' work. These estimates are provided by an independent vendor with experience in the industry.

- OPG's senior management has established separate regular steering committees with each of the major vendors' executives, which provide senior level leadership with a forum to discuss progress, potential and actual issues impacting performance and commercial issues.

Make site, project management, regulatory requirements and supply chain considerations, and cost and risk containment, the primary factors in developing the implementation plan.

- OPG's plan for the RQE assumes that all of the factors listed will be fully considered, planned, and budgeted in advance of execution of the work.

- Taking lessons from Pickering A, the DRP Team has committed to completing the identification of all regulatory requirements well in advance of final design and construction.

- OPG has committed to the completion of the design and proving of the RFR tools and completing procurement of all long lead materials one full year prior to the start of the first unit refurbishment.

- OPG has implemented, in accordance with Project Management Institute standards and Association for Advancement of Cost Engineering ("AACE") best practices, project controls and risk management programs and will continue to refine these tools as the outage nears.

- OPG has retained external oversight and engaged other corporate functions in providing input and assurance that the DRP team is meeting its commitments.

Take smaller initial steps to ensure there is opportunity to incorporate lessons learned from refurbishment including collaboration by operators.

- To fully incorporate lessons learned from the refurbishment of the first unit (Unit 2), the start of refurbishment work on the second unit (Unit 1) has been delayed until the completion of the first unit.

- OPG has filled key positions in its project management team with individuals having direct experience with prior CANDU refurbishments.

- OPG has contracted with SNC/Aecon, whose subsidiary CANDU Energy (formerly AECL) has been associated with each of the prior refurbishments.

- OPG and its contractors are studying lessons learned and OPEX from those prior projects and incorporating those into the DRP.

- OPG routinely collaborates with other CANDU operators directly and/or through the CANDU Owner's Group. OPG has initiated further discussions with Bruce Power to determine additional areas for collaboration.

5.14 ISSUE 4.9

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

OPG's proposed in-service additions are $18.7M in 2014 and $209.4M in 2015 (Ex. D2-2-2, p. 6 and Ex. J7.1, Attachment 1, p. 5).

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 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 in Table C below. 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 Undertaking 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.

Table C: Darlington Refurbishment Test Period Additions

$ 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**

5.15 ISSUE 4.10

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

OPG is forecasting capital expenditures on the DRP of $839.9M in 2014 and $842.5M in 2015, an increase from the amounts included in the pre-filed evidence (Ex. D2-2-2, p. 7).

As indicated above, the DRP is a mega project with a high degree of complexity. To comply with the LTEP, to continue its progress to RQE in the Definition Phase and to be ready to move to the Execution Phase shortly thereafter, capital expenditures are required over the test period. These capital expenditures include the work required in respect of the RFR work package. As noted, the work related to tooling has to be completed and tested in advance of the Execution Phase to minimize any delay during the Execution Phase related to learning and adaption of tools on this critical part of the project. In November 2013, an updated DRP Business Case was presented to OPG's Board of Directors as part of an approval of the planned expenditures in 2014 and 2015 (Ex. D2-2-1, p. 13 and Ex. D2-2-1, Attachment 5). There are also a number of prerequisite projects that must be completed from a nuclear regulatory perspective and also on a support basis. These include the Facilities and Infrastructure or campus plan projects.

OPG carefully plans and manages the work undertaken in the Definition Phase and uses a gated approach for assessing and approving work to be completed. Gated decision making is a way of reducing the level of risk that the project proponent is exposed to by taking individualized decision making steps or decision analysis before the risk becomes too large. The project proponent reduces the risk and exposure to risk by making decisions throughout the project's progression (Tr. Vol. 16, pp. 32-33).

OPG submits that its proposed capital expenditures in the test period are reasonable and should be accepted by the Board (Tr. Vol. 15, pp. 65, 120 and 130).

6.0 PRODUCTION FORECASTS

6.1 REGULATED HYDROELECTRIC

6.2 ISSUE 5.1

Secondary - Is the proposed regulated hydroelectric production forecast appropriate?

6.2.1 Introduction

OPG is seeking approval of a test period hydroelectric forecast of 65.9 TWh (32.4 TWh in 2014 and 33.5 TWh in 2015). Table D below divides the test period forecast hydroelectric production between OPG's previously regulated hydroelectric facilities and OPG's newly regulated hydroelectric facilities.

Table D: Test Period Hydroelectric Production*

	2014	2015
Production Forecast (TWh)		
Previously Regulated	20.1	21.0
Newly Regulated	12.4	12.5
TOTAL	**32.4**	**33.5**

* From Ex. N1-1-1, p. 20, Chart 10 and Ex. E1-1-1, Table 1 (numbers may not add due to rounding).

OPG's production forecast for the previously regulated hydroelectric facilities is based on the methodology approved by the OEB in EB-2010-0008. The production from the 21 largest of the newly regulated hydroelectric facilities, whose production accounts for 95 per cent of the newly regulated facility production, is forecasted using models and an approach similar to those used to forecast production from the previously regulated facilities (Ex. E1-1-1, pp. 4-5). The production forecast for the remaining five per cent of the newly regulated production capacity is calculated based on historical flows. As discussed more fully below, in both cases the production methodologies have been appropriately applied to the test period and the resulting forecasts should be approved by the OEB.

6.2.2 Forecast Methodology

Hydroelectric production forecast is impacted by water availability. OPG seeks to optimize the use of available water while meeting safety, legal, environmental, and operational requirements. The availability of water is affected by meteorological conditions, particularly precipitation and evaporation (Ex. L-5.1-1 Staff-059). The forecast methodology accounts for operational strategies designed to maximize use of available water and minimize spill (unutilized water flow) (Ex. E1-1-1, p. 2).

Computer models are used to derive production forecasts for the previously regulated hydroelectric facilities and the great bulk of the production from the newly regulated hydroelectric facilities (Ex. E1-1-1, Appendix 1). Forecast monthly water flows, generating unit efficiency ratings, and planned outage information are used to convert forecast water availability into forecast energy production (Ex. E1-1-1, pp. 2-5). Within these constraints, the forecast assumes all available water is used for production with no reduction to the forecast production for surplus baseload generation conditions (EB-2010-0008, Tr. Vol. 2, pp. 100).

Production forecasts for the remaining 27 small stations that account for about five per cent of the newly regulated hydroelectric facilities production are based on historical mean monthly production values adjusted for planned outages (Ex. E1-1-1, p. 5 and Appendix 2). Owing to their small contribution to OPG's regulated hydroelectric production (less than two per cent of the total), OPG does not intend to include the twenty-seven small stations in the Hydroelectric Water Conditions Variance Account (Ex. H1-3-1, p. 4).

6.3 ISSUE 5.1(a)

Primary - Could the storage of energy improve the efficiency of hydroelectric generating stations?

Except for pump generation, OPG has not undertaken any technical or economic assessments of new energy storage opportunities that may improve the efficiency of its hydroelectric facilities.

6.4 ISSUE 5.2

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

Surplus baseload generation ("SBG") is a condition that occurs when electricity production from baseload facilities is greater than Ontario demand. During the test period, OPG expects SBG conditions will persist owing to reduced electricity demand and an increase in baseload electricity supply, both of which are outside of OPG's control. OPG's production forecast for the test period does not take into consideration the decreased production attributable to SBG (Ex. E1-1-1, p. 2). Instead, the SBG that actually occurs is addressed through the Hydroelectric Surplus Baseload Generation Variance Account ("SBG Variance Account") (Ex. H1-3-1, p. 5).

While SBG is an Ontario-wide phenomenon that is managed by the IESO, OPG does take certain actions to minimize SBG. To minimize SBG, OPG operates the Sir Adam Beck Pump Generation Station to the maximum extent possible (Ex. E1-2-1, p. 1). Additionally, some of the newly regulated hydroelectric facilities have forebay storage capabilities that can be used to store water when Ontario is experiencing SBG conditions (Tr. Vol. 4, p. 14). Both of these actions will have the added effect of mitigating the cost of SBG, but do not result in entries into the SBG Variance Account (Tr. Vol. 4, p. 15).

The SBG Variance Account records the financial impact of foregone production due to SBG (Ex. H1-1-1, p. 4). In calculating foregone production due to SBG, OPG first subtracts spill associated with market, operational, and production constraints as well as contractual obligations (Ex. E1-2-1, p. 3). The remaining spill volume is potential SBG spill. From the potential SBG volume, OPG excludes spill that occurred when the Ontario market price was above the level of the Gross Revenue Charge, the price which represents the minimum offer price for OPG's hydroelectric facilities. The volume of spill remaining after this exclusion is the foregone production due to SBG and is used to calculate entries into the SBG Variance Account (Ex. E1-2-1, p. 3 and Tr. Vol. 4, p. 13). OPG submits that the OEB should continue this approach because it is reasonable and effectively protects both customers and OPG against the risk of over/under recovery associated with SBG.

6.5 ISSUE 5.3

Secondary - Has the incentive mechanism encouraged appropriate use of the regulated hydroelectric facilities to supply energy in response to market prices?

OPG's decisions to move energy production from periods of low market prices to periods of high market prices are based on the expected price spread between the off-peak and on-peak periods constrained by facility and reservoir availability and hydrologic conditions (Ex. E1-2-1, p. 4). The deployment of the Sir Adam Beck Pump Generating Station ("PGS"), in conjunction with the Sir Adam Beck Generating Stations, can move substantial quantities of energy from periods of low market prices to periods of high market prices. OPG's analysis of the use of the PGS during periods of SBG conditions demonstrates that the company is responding appropriately to market price signals provided by the hydroelectric incentive mechanism ("HIM") and using the PGS to mitigate SBG (Ex. E1-2-1, p. 5). This analysis is confirmed in the report submitted by Cliff Hamal of Navigant Economics (Ex. E1-2-1, Attachment 1).

The use of market signals is important to consumers and all market participants as this facilitates the efficient production and consumption of electricity. In particular, the movement of energy from low value periods (typically off-peak) to high value periods (typically on-peak) reduces overall demand-weighted market prices and hence customer costs. Absent an incentive mechanism, OPG's incentive would not be to follow market price signals, but instead to maximize production at the regulated rate which would result in a flatter production profile and higher revenues.

In EB-2010-0008, the Board held the purpose of the HIM is to provide OPG with incentives to operate the PGS in a way which benefits customers (EB-2010-0008, Decision with Reasons, p. 146). To confirm that this is occurring, the Board directed OPG, among other things, to revisit the structure of the HIM and provide a more comprehensive analysis of the benefits of the HIM for ratepayers (EB-2010-0008, Decision with Reasons, page 148). Allowing for off-setting increases in GRC payments resulting from additional on-peak hydroelectric generation, overall, ratepayers benefit from reduced costs attributable to displacement of more expensive, on-peak generation and increased amounts paid to the IESO for exports (Ex. E1-2-1, p. 7 and Tr. Vol. 4, p. 25). During the test period, OPG forecasts a reduction in customer costs arising from economic time shifting of $36M per year (Ex. E1-2-1, Table 2, p. 7).

Accordingly, OPG submits that the HIM has encouraged the appropriate use of its regulated hydroelectric facilities to supply energy in response to market prices to the benefit of Ontario consumers.

6.6 ISSUE 5.4

Primary - Is the proposed new incentive mechanism appropriate?

In EB-2010-0008, the Board directed OPG to undertake an analysis of the interaction between HIM and SBG and an assessment of alternative approaches in light of expected future conditions in the contracted and traded market (EB-2010-0008, Decision with Reasons, p. 148). OPG's analysis of the interaction between HIM and SBG indicated an unintended consequence arises when SBG spill reduces OPG's monthly production profile thereby generating an unwarranted incentive payment under the HIM (Ex. E1-2-1, p. 8).

Owing to this issue with the current HIM, OPG began examining alternative mechanisms that would continue to properly incent OPG to shift production while addressing this unintended consequence (Ex. E1-2-1, p. 9). The proposed Enhanced Hydroelectric Incentive Mechanism ("eHIM") is essentially identical to the existing HIM payment mechanism with the addition of an adjustment to the incentive mechanism to remove the effects of SBG. Under the proposed adjustment, all induced incentive revenues arising from SBG-related spills would be removed from the SBG Variance Account. As a result, the eHIM will continue to properly incent OPG to shift production while eliminating the unintended incentive payments as a consequence of the interaction between HIM and the SBG Variance Account (Ex. E1-2-1, p. 9).

OPG assessed and compared the HIM to three alternative payment mechanisms – eHIM, the Enhanced Hydroelectric Baseload Forecast ("eHBF") and an Incentive Mechanism ("IM") based on a fixed market price exposure (Ex. E1-2-1, pp. 9-10). Based on this analysis, OPG concluded that eHIM is the most appropriate choice (Ex. E1-2-1, p. 11). The eHIM has a strong positive correlation between the amount of production time-shifted and the level of incentive revenues and lower volatility in incentive payouts. The incentive mechanism should exhibit low volatility to ensure that there is an appropriate balance between ratepayer value and the incentive revenues earned by OPG (Ex. E1-2-1, page 10). The OEB should approve the eHIM, because it will encourage time shifting in response to market prices differentials while addressing the unwarranted incentive that arises from the interaction between the HIM and SBG spill.

6.7 NUCLEAR

6.8 ISSUE 5.5

Primary - Is the proposed nuclear production forecast appropriate?

OPG is seeking approval of nuclear production forecast of 48.5 TWh and 46.1 TWh for 2014 and 2015, respectively (Ex. N2-1-1, p. 9, Chart 6). This section discusses the derivation of OPG's forecast and recent trends in production.

6.8.1 OPG Produces Detailed Forecasts of Nuclear Production

OPG's nuclear production planning process establishes annual production forecasts for its individual nuclear units, an aggregated forecast for each station and an overall corporate forecast. Nuclear facilities are designed to operate continuously at full power as base load generators. Therefore, the annual nuclear production forecast is equal to the sum of the generating units' capacity multiplied by the number of hours in a year, less the number of hours for planned outages and forced production losses (i.e., unplanned outages and derates) as adjusted for sources of generation losses (i.e., lake temperature, grid losses and consumption (station service) (Ex. E2-1-1, p. 4). As such, the production planning process is focused on establishing annual planned outage schedules and on estimating forced production losses. Forced production losses reflect the fact that all generating units face the risk of unscheduled equipment problems that may require unplanned shutdowns or a derating of the generating unit. Accordingly, OPG develops forced loss rate ("FLR") targets that reflect the risk of such forced production losses for all units in the station.

The major factors influencing the test period production forecast are:

- A combined Vacuum Building Outage ("VBO")/Station Containment Outage ("SCO") in 2015 in which all four Darlington units will be shutdown for 157.0 days (3.31 TWh) (Ex. L-5.5-2 AMPCO-030). A 95 day Unit 3 maintenance will be conducted at the same time.
- A mid-cycle planned outage of 20 days on Pickering Units 1 in 2014 to focus on preventative maintenance and lessen the risk of future forced outages.
- The impact on scope and duration of the planned outages at Pickering Units 5-8 in 2014 as a result of the Pickering Continued Operations initiative.
- A forecast Pickering FLR for 2014 of 8.9 per cent and 5.5 per cent in 2015 (Ex. N2-1-1, p. 7 and Ex. E2-1-2, Table 1).
- A forecast Darlington FLR for 2014 of 1.3 per cent in 2014 and 1.0 per cent in 2015 (Ex. E2-1-2, Table1). The targeted reductions in FLR in 2015 reflect expectations of improved performance due to initiatives underway to improve reliability.

There has been an improving trend in OPG's actual nuclear production over the period 2007-2012 (Ex. L-5.5.-13 LPMA-006, Chart 1). Nuclear production was lower in 2013 (44.7 TWh) primarily due to reduced production at its Pickering facilities (Tr. Vol. 5, p. 97). OPG is targeting improved reliability with increased production to achieve 48.5 TWh in 2014 (Ex. N2-1-1, p. 7). In 2015, forecast production declines to 46.1 TWh primarily as a result of the 157 day (3.31 TWh) impact of the four unit VBO/SCO (Ex. N1-1-1, pp. 12-16).

OPG has historically experienced significant revenue shortfalls due to variances between the nuclear production forecasts that underpin OEB approved nuclear rates and actual generation. The negative revenue impact was calculated to be a combined $1,072M over the period 2008-2013, representing an average revenue shortfall of $178.6M (Ex. L-5.5-13 LPMA-006, Chart 2). As a result, Senior Management directed OPG's generation planning staff to review the nuclear production forecast as part of the 2014-2016 Business Plan review process to address the large and persistent gap between forecast and actual production and to ensure that the planned outage days sufficiently recognized the scope and complexity of the planned VBO/SCO in 2015 (Ex. N1-1-1, p. 13).

The decision to bring forward the 2021 VBO and combine it with the 2015 SCO was driven by a desire to reduce the complexity and resource demands in 2021 during the Darlington Refurbishment Project (Tr. Vol. 6, p. 78). OPG saw a significant risk to the successful completion of both the VBO and the DRP if it had to schedule and complete work on a VBO at the same time as when the refurbishment project was underway. This risk would be mitigated by moving the outage to 2015 (Tr. Vol. 6, p. 78). The initiative will eliminate a VBO in 2021 and eliminate all future SCO's, which require a 4-unit outage. OPG prepared a summary economic analysis in 2011 which established a positive NPV of $48.0M for advancing the VBO into 2015 and combining it with the SCO (Ex. J6.2, Attachment 1).

The combined VBO/SCO includes a 100 per cent increase in electrical equipment maintenance, significant emergency service water ("ESW") piping replacement, a 50 per cent increase in emergency coolant injection ("ECI") valve replacement and the first time implementation of pressure relief valve ("PRV") maintenance (Ex. N1-1-1 p. 15 and Ex. L-5.5-17 SEC-078). SCOs in the past have typically been of a shorter duration than a VBO (Tr. Vol. 7, p. 24). However, combining the VBO with the SCO will not result in additional planned outage days because the critical path, which determines the duration of a planned outage, continues to be the ESW piping replacement and ECI valve replacement that was scheduled to be undertaken in conjunction with the SCO (Tr. Vol. 6, p. 33 and Tr. Vol. 6, p. 74). Advancing the VBO will, however, add additional work (Tr. Vol. 6, p. 34) and therefore increase the test period outage costs (see Section 7.5.4 below, Outage OM&A).

In its Decision with Reasons for EB-2007-0905, the Board noted at page 174 that it believes "OPG should be fully incented to produce as accurate a forecast of nuclear production as possible and should be at risk if actual output falls short of forecast." The test period nuclear production plan represents OPG's most complete and accurate forecast for 2014 and 2015 and therefore, consistent with the Board's EB-2007-0905 Decision with Reasons, it should be the basis for deriving rates for 2014 and 2015.

7.0 OPERATING COSTS

7.1 REGULATED HYDROELECTRIC

7.2 ISSUE 6.1

Oral Hearing - Is the test period operations, maintenance and administration budget for the regulated hydroelectric facilities appropriate?

7.2.1 Introduction

The previously regulated and newly regulated hydroelectric operating costs include base and project OM&A, Gross Revenue Charges ("GRC"), the share of corporate support and centrally held costs attributable to the previously regulated hydroelectric and newly regulated hydroelectric facilities, and the asset service fee.

OPG submits that the total hydroelectric OM&A budget for the previously and newly regulated hydroelectric facilities is reasonable and should be approved by the OEB.

OPG's forecast hydroelectric OM&A and GRC costs are shown in Table E below (numbers may not add due to rounding).

Table E: Hydroelectric OM&A and GRC

	2014($M)	2015 ($M)
Base OM&A		
Previously Regulated	$74.6	$68.6
Newly Regulated	$113.4	$113.7
Total Base OM&A	**$188.0**	**$182.3**
Project OM&A		
Previously Regulated	$13.5	$17.9
Newly Regulated	$24.5	$32.1
Total Project OM&A	**$38.0**	**$50.1**
GRC		
Previously Regulated[1]	$267.3	$280.8
Newly Regulated	$75.6	$77.5
Total GRC	**$342.9**	**$358.4**
TOTAL	**$568.9**	**$590.8**

Note 1: Previously regulated amounts include additional GRC costs of $14.0M (2014) and $11.3M (2015) attributable to revised hydroelectric production forecast (Ex. N1-1-1, Chart 9).

7.2.2 Base OM&A

OPG's OM&A budget for its previously regulated and newly regulated hydroelectric facilities is established through the annual business planning process (see Ex. A2-2-1 and Ex. F1-1-1). The 2013-2015 process included a focus on prudent management of costs ensuring the efficient use of existing generation assets, and improving OPG's financial outlook while properly maintaining the hydroelectric assets.

Base OM&A expenditures for OPG's previously and newly regulated hydroelectric facilities are attributed on a work program basis, consistent with how costs are incurred. Base OM&A budgets are attributed to each of the plant groups based on the following work programs: operations, maintenance, and administration support (Ex. F1-2-1, pp. 2-3). Overall, base OM&A expenditures are expected to decline in 2015 to an amount lower than the 2013 budgeted amount (Ex. F1-2-1, Table 1).

In addition to the costs incurred within the plant groups, certain other costs incurred to support the previously regulated and newly regulated hydroelectric facilities are provided on a centralized basis. The support costs included in previously regulated and newly regulated hydroelectric OM&A include directly assigned and allocated costs from OPG's corporate functions, centrally held costs, hydroelectric central support group costs and, for the Saunders facility only, which is part of the Ottawa-St. Lawrence Plant Group, an allocated portion of that plant group's common support costs (Ex. F1-2-1, pp. 8-9).

OPG's forecast hydroelectric base OM&A expenditures represent the funds necessary to operate, maintain and administer the prescribed hydroelectric facilities in the test period and should be approved by the OEB.

7.2.3 Project OM&A

OPG's OM&A projects differ from base OM&A work because they have a non-recurring scope of work, a generally longer timeline and a higher materiality threshold (typically $100K) (Ex. F1-3-1, p. 1). OM&A projects are distinct from capital projects because they do not meet the criteria for capitalization under OPG's capitalization policy (see Ex. D4-1-1). However, the management of OM&A projects is identical to that of capital projects (Ex. D1-1-1). Hydroelectric plant groups manage both capital and OM&A projects in a project listing that forms the basis for budgeting during the annual business planning process (Ex. F1-3-1, p. 1). Projects are identified through routine inspections, engineering reviews and detailed plant condition assessments. The process for identifying and prioritizing hydroelectric projects is described in Ex. F1-1-1, p. 24.

OM&A projects are mainly sustaining expenditures for repairs and maintenance, such as major unit overhauls (Ex. F1-3-1, p. 2). In addition to maintenance projects for production equipment, there are many projects related to aging civil structures. Project OM&A expenditures on production equipment include the unit rehabilitation program at Sir Adam Beck Pump Generating Station, Lower Notch and Otto Holden, with expenditures for each during the test period (Ex. F1-3-1, p. 2).

OPG's forecast of project OM&A spending represents a reasonable level of necessary expenditures in the test period and should be approved.

7.2.4 GRC and Other Water Agreement Costs

Another significant cost for the regulated hydroelectric facilities is the GRC. The GRC is charged to the owners of hydroelectric generating stations under Section 92.1 of the Electricity Act and is comprised of a property tax component payable to the Ministry of Finance or the Ontario Electricity Financial Corporation, as well as a water rental component payable to the Ministry of Finance for holders of water power leases (Ex. F1-4-1, pp. 1-2).

All aspects of GRC payments made by OPG to the Province are governed by legislation or regulation. As such, OPG does not control the GRC charges associated with its hydroelectric facilities (Ex. F1-4-1, p. 1). O. Reg. 124/02 establishes the water rental component at 9.5 per cent, while the property tax component is tiered and dependent on annual production levels (Ex. F1-4-1, p. 2, Chart 1).

OPG also pays water rental charges and other water agreement costs to other governments, agencies, or companies (i.e., Parks Canada, Government of Quebec, St. Lawrence Seaway Management Corporation, Hydro Quebec, H2O Power LP, Lake of the Woods Control Board, and the Ottawa River Regulation Planning Board) (Ex. F1-4-1, pp. 3-6).

OPG has appropriately forecasted these charges and its test period request should be approved by the OEB.

7.3 ISSUE 6.2

Oral Hearing - Is the benchmarking methodology reasonable? Are the benchmarking results and targets flowing from those results for OPG's hydroelectric facilities reasonable?

As part of its overall benchmarking effort, OPG benchmarks the reliability, cost and safety performance of its hydroelectric assets with comparable businesses (Ex. F1-1-1, p. 11). Benchmarking data provides a starting point to compare the costs and reliability of OPG's regulated hydroelectric facilities with those of other hydroelectric facilities. OPG obtains benchmarking data from three main sources: EUCG Inc. ("EUCG"), Navigant Consulting and Canadian Electrical Association ("CEA") (Ex. F1-1-1, p. 11). Because of the differing geographic locations and distribution of the plants, as well as differences in regulatory regimes, absolute comparisons cannot be made between the regulated hydroelectric station costs and other stations.

Overall, OPG's hydroelectric facilities demonstrate strong benchmarking results. The availability and reliability of the previously and newly regulated facilities are generally better than the EUCG and CEA benchmarks (Ex. F1-1-1, pp. 13-14 and 16), while remaining cost competitive (Ex. F1-1-1, p. 18). In fact, from 2009 to 2011, an average of 99 per cent of OPG's Niagara Plant Group and R.H. Saunders GS energy production ranked in the top two EUCG unit energy cost quartiles (Ex. F1-1-1, p. 19).

OPG's hydroelectric business unit reviews the benchmarking results and best practices annually as part of its business planning process and applies new practices and associated cost reductions as appropriate. Examples of best practices that have been implemented over the past ten years are shown at Ex. F1-1-1, page 11.

Based on the evidence presented in Ex. F1-1-1, pages 11-22, the OEB should find that both the methodology and the results of OPG's hydroelectric benchmarking are reasonable.

7.4 NUCLEAR

7.5 ISSUE 6.3

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

7.5.1 Introduction

This section presents OPG's forecast Nuclear OM&A and fuels cost, which constitute the Nuclear expenses necessarily to safely, reliably and efficiently operate and maintain OPG's nuclear stations in the test period. It also addresses Pickering B Continued Operations. The specific subjects covered are:

- Base OM&A
- Project OM&A
- Outage OM&A
- Fuels
- Pickering B Continued Operations

OPG's forecast Nuclear OM&A and fuel spending in millions is shown in Table F below (Ex. F2-2-1, p. 1, Ex. F2-3-1, p. 1, Ex. F2-4-1, p. 1 and Ex. N2-1-1, Attachment 5, p. 5).

Table F: Test Period Nuclear OM&A and Fuel

	2014	**2015**
Base OM&A	$1,151.1	$1,154.0
Project OM&A	$113.9	$106.4
Outage OM&A	$262.7	$330.7
Fuel	$266.6	$260.6
Total	**$1,794.3**	**$1,851.7**

The forecast Nuclear expenses and spending trends discussed in this section are the product of the target setting and cost control initiatives arising from Business Transformation, as discussed in the Benchmarking and Business Planning section.

7.5.2 Base OM&A

Base OM&A provides the main source of funding for operating and maintaining the nuclear facilities to ensure they operate safely, meet all applicable regulatory standards, achieve targeted levels of production, and maintain and improve their reliability (Ex. F2-2-1, p. 2). Base OM&A also funds regular labour for planned outages, the cost of all forced outages and derates and the indirect costs of commercial activities such as the provision of inspection and maintenance services to OPG facilities.

Base OM&A includes incremental short-term labour resources available for operating and maintaining the nuclear stations including overtime, as well as temporary staff (e.g. non-regular staff) and external contractors. OPG uses base OM&A overtime to maintain coverage of key (e.g. authorized nuclear operator) positions and provide backup for absent staff so as to maintain minimum staff complement on shifts. The selection of which incremental labour resource option to employ is an ongoing resource optimization and balancing process and depends on the specific circumstances at the time.

Base OM&A is forecast to increase by 1.55 per cent per year over the period 2012-2015 (Ex. F2-2-2, p. 1). The primary driver of this increase is labour escalation and pension/other post-employment benefits ("OPEB"), which increase base OM&A costs by an average of 2.20 per cent per year (Ex. F2-2-2, p. 1). As part of Business Transformation, OPG is pursuing non-labour cost savings through cost control and work prioritization and labour cost savings through planned staff reductions to help mitigate total base OM&A cost increases due to labour escalation and OPEB, including:

- The continuation of improvement initiatives to achieve the nuclear performance targets set in the business plan. These initiatives, which are focused on achieving safety, reliability, value for money and human performance targets, are largely executed by base OM&A resources (Ex. F2-2-1, p. 5).
- Implementation of new initiatives as part of Business Transformation to gain efficiencies, eliminate duplication of effort, and standardize processes thereby enabling OPG to pursue staff reductions (Ex. F2-2-1, p. 5). In 2012, various Nuclear operating groups were consolidated into centre-led functions at the corporate level in 2012 as part of Business Transformation. This consolidation transferred 1064.7 regular staff FTEs from Nuclear operating groups to corporate support in 2012 (Ex. F2-1-1, Table 3). A further reduction of 292.8 FTEs from Nuclear operating and project staff (excluding Darlington Refurbishment) is forecast to occur over the period from 2012 to 2015.

The results OPG has achieved to date and its commitment to further savings out to 2015 demonstrate that the company has embraced the culture of cost control. OPG's test period Base OM&A forecast reflects this fact and should be approved.

7.5.3 Project OM&A

OPG's corporate policy defines a project (capital or OM&A project) as a temporary, unique endeavor undertaken outside the routine base activities of the normal work program. The final decision on whether work will be classified as a nuclear project is made by the Asset Investment Screening Committee ("AISC") having regard to the complexity and materiality of the work (Ex. F2-3-1, p. 1). Project OM&A funds are expended on activities that meet the criteria for categorization as a project, but do not meet the criteria for capitalization. OPG seeks approval of forecast project OM&A expenses of $113.9M and $106.4M in 2014 and 2015 respectively, as shown in Chart 2 below (Ex. F2-3-1, p. 1). These amounts include the project OM&A component of Pickering Continued Operations and the Fuel Channel Life Cycle Management project discussed in Section 7.8 below.

OPG's process for managing OM&A projects is identical to that described in Section 5.9 above for capital expenditures. Portfolio budgets are established during the business planning process and are based on station reliability needs, benchmarking, new regulatory requirements and ability to execute the projects. As part of the managed portfolio process, new projects are identified and prioritized, and budgets are approved by AISC throughout the year. Once AISC has allocated the project budget, authorization to execute the project is obtained.

The approved project OM&A budget in the 2013-2015 Business Plan includes AISC-approved projects that have an approved business case summary (Ex. F2-3-1, p. 2). It also contains projects ("unallocated projects") representing work that is progressing through the review and approval process but does not have an AISC-approved budget and an approved BCS.

OPG's test period Project OM&A forecast from the 2013-2015 Business Plan is comparable to prior years, but does reflect a targeted reduction by 2015 in spending, as shown in Chart 2 below. This reduced level of Project OM&A in 2015 will be achieved through increased focus on cost control. As well, the 2015 Plan declines due to the completion of the Pickering

Continued Operations project in 2014 and reduced spending on the Fuel Channel Life Cycle Management project.

Chart 2

	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
	$M					
Project Portfolio	124.8	100.5	96.8	84.2	101.1	105.8
P2/P3 Isolation	10.5	0.0	0.0	0.0	0.0	0.0
PN Continued Operations	1.7	1.0	3.5	6.0	6.0	0.0
Fuel Channel Life Management	5.7	10.1	11.3	14.7	6.8	0.6
Total	142.7	111.6	111.5	104.9	113.9	106.4

Two new Tier 1 projects have been undertaken since EB-2010-0008. Project #38933, Primary Heat Transport Liquid Relief Value Modifications to Prevent Water Hammer, is to address valve and piping degradation caused by valve-induced water hammer, to ensure continued relief valve functioning and over-pressure protection (Ex. F2-3-3, Tab 9). Project #62449, Severe Accident Management Guidelines Implementation Improvements, is to improve OPG's Severe Accident Management Program by incorporating the lessons learned from the 2011 Fukushima Daiichi incident (Ex. F2-3-3, Tab 10). More detail on OPG's project prioritization and approval process and the improvements it has made in managing its project portfolio are provided in Section 5.9 above. The evidence in this proceeding clearly demonstrates that OPG has a robust and well managed process for selecting and executing projects. Based on this evidence, OPG's project OM&A budget is reasonable and should be approved.

7.5.4 Outage OM&A

Outage OM&A includes the expenditures on the incremental labour (e.g., overtime, temporary staff and external contractors), services and materials necessary to complete OPG's planned outages along with Inspection and Maintenance Services (“IMS”) regular staff labour (Ex. F2-4-1, pages 1-3). OPG forecasts outage OM&A spending of $262.7M and $330.7M in 2014 and 2015, respectively.

Forecast outage OM&A expenditures depend on the number of outages undertaken each year and the particular tasks to be accomplished in each outage (a combination of “routine” inspection and maintenance and “non-routine” work specific to a particular outage) (Ex. E2-1-1, p. 5). Thus a year-over-year comparison of outage OM&A expenditures to develop a trend is not a meaningful exercise because the yearly expenditures vary with the number and specifics of each year’s outages.

The level of forecast outage OM&A spending in 2015 ($330.7M) compared to 2014 $(262.7M) reflects the intent to complete a lengthy and complex combined 4 unit VBO/SCO at Darlington in 2015. OPG anticipates 25 per cent to 75 per cent more work will be required for this outage depending on the particular area (Ex. L-5.5-17 SEC-074).

Outage OM&A spending at Pickering in 2015 reflect savings compared to 2014 due to the completion of Pickering Continued Operations program at the end of 2014 (Ex. F2-4-2, p. 1).

The reduction in outage OM&A in 2014 compared to 2013 reflects the fact that Darlington had two outages in 2013, compared to one outage in 2014 (Ex. F2-4-2, p. 1).

Outage OM&A expenditures by Nuclear Support Division show an increase trend over the period 2010-2015. However, this reflects a change in the presentation of IMS costs. For 2010 and 2011, Nuclear Station’s Other Purchase Services included the cost of work performed by OPG’s IMS division. For 2012 and thereafter, IMS costs are separately identified as part of services provided by the Nuclear Support Division (Ex. L-6.3-15 PWU-018).

OPG’s forecast Outage OM&A spending is necessary to properly inspect and maintain the prescribed nuclear facilities and should be approved.

7.6 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?

7.6.1 Introduction

This section discusses OPG's nuclear benchmarking and the top-down gap-based nuclear business planning process first implemented in 2009 based on the recommendations of ScottMadden Management Consultants (Ex. F2-1-1 p. 3). OPG submits that its continued reliance on the benchmarking and gap-based nuclear business planning methodology, which consists of four steps (benchmarking, target setting, gap closure and resource planning), is a reasonable method of evaluating nuclear performance against other operators and working to improve it. Furthermore, the benchmarking results and the targets chosen by OPG (and forming part of its nuclear business plan) are appropriate and should be accepted by the OEB. The 2013-2015 Nuclear Business Plan targets achieving a more sustainable cost structure through the implementation of Business Transformation and through other initiatives focused on improving performance while driving cost efficiencies.

OPG filed the 2012 Nuclear Benchmark Report, which benchmarks OPG's performance against industry peers based on 2011 data and uses 20 indicators aligned with the cornerstone values of Safety, Reliability, Value for Money and Human Performance (Ex. F2-1-1, Attachment 1). OPG also engaged a consultant in 2011, Goodnight Consulting Inc. ("Goodnight"), to undertake a Nuclear Staffing Study (Ex. F5-1-1, Part a) in response to the OEB direction in EB-2010-0008 to conduct an examination of its nuclear staffing levels. An update to the initial report was also prepared by Goodnight as of February 2013 (Ex. F5-1-1, Part b). By engaging Goodnight and in addressing the findings in the Nuclear Staffing Study, OPG has responded fully to the OEB's direction in EB-2010-0008.

7.6.2 2012 Benchmarking Report

OPG benchmarks its performance against the performance of the top quartile of electricity generating companies in North America consistent with its mandate under the Memorandum of Agreement (Tr. Vol. 5, p. 62). OPG's 2012 Benchmark Report assesses OPG's 2011 performance using twenty metrics (Ex. F2-1-1, p. 3). The results show that

OPG maintains strong safety performance at both of its nuclear stations. Darlington compares very favourably against top performing plants.

Pickering has improved its performance from 2010 in areas such as Collective Radiation, Fuel Reliability and Value for Money. Pickering has also been able to maintain a stable Total Generation Cost per MWh ("TGC/MWh"), thereby improving its relative performance against the Value for Money benchmark, reflecting the fact that industry costs are escalating as demonstrated by the increase in the top quartile and median TGC/MWh values (Ex. F2-1-1, Attachment 1, pp. 62-63). Pickering's TGC/MWh metric remains in the 4th quartile, reflective of lower capability factors (including 2013 actual results), due to forced outages and longer planned outages, and its smaller unit sizes (Ex. F2-1-1, p. 6).

As Ms. Swami noted in oral testimony, Pickering's performance was "not what we had planned, and certainly is a target by OPG management to make improvements" (Tr. Vol. 5, p. 97). OPG is targeting an overall improvement for the Pickering Generating Station by 2016 (Ex. N1-1-1, Attachment 5).

The Value for Money metric uses data from EUCG, and with the exception of OPG and Bruce Power, all of the comparators are U.S. nuclear pressurized water reactor ("PWR") and boiling water reactor facilities ("BWR") (Ex. F2-1-1, Attachment 1, p. 91). Goodnight's Nuclear Staffing Studies show that technology, design and regulatory differences exist between CANDU and PWR units and that these factors result in higher staffing levels for CANDU plants (Ex. F2-1-1, p. 11). Labour costs (including overtime) represent approximately 75 per cent of Nuclear base OM&A costs (Ex. F2-2-1, Table 2). Darlington's ability to achieve best quartile performance (Ex. F2-01-01, Attachment 1, p. 61) despite the disadvantage of additional CANDU staffing requirements is therefore all the more impressive.

The benchmarking results present a fair and balanced view of OPG's operating and financial performance compared to other operators in the nuclear generation industry. The major operator results indicate that OPG's nuclear business performs well across a broad range of industry operational measures and that some improvement has been achieved to-date. While OPG has shown improvement in performance over time, OPG's performance ranking will be impacted by improvements other electric generator operators may be making at the same time (Tr. Vol. 5, pp. 84-85).

OPG has taken a prudent and reasonable approach in response to the 2012 Benchmarking Report by setting targets in the 2013-2015 Business Plan that will allow OPG to narrow the identified performance gaps at a pace consistent with continuing safe operation.

7.6.3 Response to the OEB's Direction on Staffing

In 2011, OPG retained Goodnight to undertake an analysis of nuclear staffing levels in response to the OEB directive in the EB-2010-0008 Decision with Reasons (p. 45). The terms of reference for this assignment were to:

- benchmark OPG nuclear staffing levels against other North American nuclear operators;
- identify the source of any significant differences in staffing levels including consideration of technology differences between CANDU and PWR/BWR;
- analyze the nature of the differences; and,
- by reference to OPG's Nuclear 2012 Business Plan, compare planned 2014 staffing levels with benchmarks (Ex. F2-1-1, p. 8).

Goodnight's staff benchmarking process consisted of three steps:

- Quantify the number of OPG nuclear staff by functional grouping in order to identify applicable OPG personnel (including base-line contractors) for benchmarking.
- Develop industry benchmark staffing levels by functional grouping by identifying applicable U.S. nuclear plants/nuclear organizations as the benchmarking source.
- Compare OPG Nuclear with industry benchmark staffing levels and identify gaps, adjusted for technology, labour hours and work program differences (Ex. F2-1-1, p. 9).

Goodnight made various adjustments/exclusions to both the OPG and industry benchmark staff levels in order to ensure OPG staffing information was presented on an equivalent basis with the industry benchmark data (Ex. F2-1-1, p. 9). The adjustments/exclusions included OPG employees engaged in specific activities unique to the CANDU design for which there are no comparators in U.S. PWR plants (e.g., heavy water management and the tritium removal facility), staffing for major projects or one time initiatives (e.g. Darlington Refurbishment), outage execution, and certain functions undertaken at both OPG and PWR facilities where the processes are uniquely different and benchmarking was not recommended (e.g. Low and Intermediate Level Radioactive Waste Management) or where staffing information was confidential (e.g. security personnel).

7.6.4 Goodnight Nuclear Staffing Study Results

The main conclusions of the initial Goodnight Nuclear Staffing Study were:

- As of July 2011, OPG Nuclear is above the comparable staffing benchmark by 866 employees or approximately 17 per cent.
- Technology/design/regulatory differences exist between CANDU and PWR units and that such factors drive staffing differences. Goodnight found that OPG's CANDU design requires an additional 82 FTEs for every 2-units in operation (i.e. approximately 400 FTEs for OPG's 10-unit operations) relative to the same functional areas in a PWR (e.g. training, scheduling, and radiation protection) (Ex. F5-1-1, p. 4).
- OPG's use of overtime was not unusual relative to the U.S. PWR comparator group. Average base overtime use at OPG was 7 per cent in 2010 and 6 per cent in 2011, which compared favourably with U.S plants at 5 to 6 per cent (Ex. F5-1-1, p. 20).
- OPG's 2012-2014 Nuclear Business Plan is directionally correct, reducing staff to within 343 FTEs of the benchmark, or 6.7 per cent, by 2014 (Ex. F2-1-1, p. 10).
- OPG should target nuclear staff reductions in appropriate functions, as the Goodnight benchmark analysis indicates plant staffing is already below benchmark for certain functions (e.g. plant and technical engineering) (Ex. F2-1-1, p. 10).

A March 2013 update to the initial study revealed that additional staff reductions had narrowed the previously identified gap to 8 per cent and preliminary results from a 2014 update currently underway indicate the gap has been further reduced to 4.7 per cent (Ex. J6.1). The gap is expected to be further narrowed if not eliminated by the end of 2015 with the full implementation of Business Transformation and other Nuclear initiatives (Tr. Vol. 6, p. 48).

7.6.5 OPG's Response to the Goodnight Nuclear Staffing Studies

In response to the Goodnight study, the 2013-2015 Nuclear business planning guidelines were updated to include staff level adjustments (Ex. F2-1-1, p. 12). For example, additional resources were budgeted for plant and technical engineering, which were significantly below benchmark, while resource budgets were reduced by similar amounts for areas such as Operations and Maintenance support groups, which were over benchmark.

The 2013-2015 Nuclear Business Plan also includes initiatives to reduce staffing for those functional areas which were not benchmarked by Goodnight as part of OPG's focus on cost control and finding efficiencies. While it is not appropriate to extrapolate the staffing results established by Goodnight to those functional areas which Goodnight could not benchmark, Nuclear operations is focused on cost control and finding efficiencies across all aspects of the business (Tr. Vol. 6, p. 106), and has achieved staff reductions in those non-benchmarked groups (Tr. Vol. 6, p. 118-119).

Overall, the 2013-2015 Nuclear Business Plan is targeting to narrow the staffing benchmark gap by managing attrition and implementing Business Transformation initiatives to enable OPG to sustain the reductions over time (Ex. F2-1-1, p.1). Regular staff levels in Nuclear declined by 431 FTEs, or 5.7 per cent (excluding Nuclear transfers to Corporate) from 2010 to 2013. OPG's 2013-2015 Nuclear Business Plan set out further regular staff reductions of 298.3 FTEs or an additional 4.9 per cent reduction over the period of 2013-2015 (Ex. F2-1-1, p. 13-14). The 2013-2015 Nuclear Business Plan is targeting staff reduction through continuous monitoring, controls and initiative development and implementation to streamline processes and find efficiencies. The targeted staff reduction reflects the fact that the nuclear staffing plan is a measured approach and OPG will not compromise safety or the ongoing initiatives to improve reliability and implement industry best practices (Ex. F2-1-1, p. 13).

7.6.6 Gap Based Business Planning: Target Setting

Top-down targets are designed to close performance gaps and significantly drive OPG's Nuclear operations closer to top quartile industry performance over the duration of a business plan. The top-down approach establishes operational, financial, generation and staff targets set by reference to historical performance, targets established in the prior years, and updated benchmarking results.

OPG is targeting improvement in the Value for Money metrics for Pickering. For 2015, OPG is targeting to achieve an annual TGC/MWh target of $60.25/MHz in 2015. This would represent a significant improvement to actual 2013 results of $67.18/MWh (calculated on a 3 year rolling average) (Ex. J5.02). Darlington's 2015 Value for Money metric of $42.78/MWh is impacted by the cost and reduced production due to the 4 unit VBO/SCO (Tr. Vol. 5, p. 91-92), and consequently declines to 2nd quartile (Ex. J5.02).

OPG is also focusing on improved reliability at both Pickering and Darlington by 2015. Average actual FLR from 2005 to 2013 is 2.0 per cent for Darlington and 13.2 per cent for Pickering (Ex. L-5.5-17 SEC-074). For 2015, OPG is targeting to improve to a 1.0 per cent FLR at Darlington and a 5.5 per cent FLR at Pickering (Ex. N1-1-1, pp. 13 and 15).

7.7 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?

7.7.1 Nuclear Fuel

OPG's forecast test period fuel costs are $266.6M and $260.6M for 2014 and 2015, respectively (Ex. N2-1-1, Attachment 5, p. 5). OPG requires a secure supply of high quality fuel to ensure the continued operation of its reactors. OPG's goal is to obtain the necessary fuel at the lowest cost consistent with obtaining a secure supply of high quality fuel (Ex. F2-5-1, p. 3).

OPG's nuclear fuel supply chain has three components: 1) the purchase of uranium concentrate, 2) fuel conversion services that convert uranium concentrate into uranium dioxide, and 3) fuel bundle manufacturing services that take the uranium dioxide and use it to manufacture the specific fuel bundle configuration required by each of OPG's stations (Ex. F2-5-1, p. 1).

OPG's 10-year supply contract with the sole domestic supplier of uranium conversion services expired at the end of 2011. A new agreement was negotiated and will result in higher costs for uranium conversion services (Ex. F2-5-1, p. 8). OPG, as part of its due diligence, confirmed the higher costs was justified based on an obtaining an independent examination of the supplier's costs (Ex. F2-5-1, p. 8).

OPG purchases fuel bundle manufacturing services under a contract with a qualified domestic manufacturer. In 2011, OPG negotiated an extension to the contract through to 2018 in order to secure the supply of a modified fuel design for the Darlington station, which will provide better flow distribution within the fuel elements, increasing the margin of safety and improving fuel cooling (Ex. F2-5-1, p. 9). The base price under this contract extension was improved over previous pricing.

OPG purchases uranium concentrate with the primary objectives of ensuring an adequate supply of uranium is available to meet the operational requirements of OPG's nuclear units, while minimizing the price, market and credit risks associated with this supply (Ex. F2-5-1, p. 5). In addition, OPG also must ensure quality standards are met. OPG has a well functioning procurement program to obtain uranium concentrate via long-term contracts and the spot market (Ex. F2-5-1, p. 6). The procurement program is subject to pre-established physical and financial coverage limits and is designed to maintain a targeted level of inventory (Ex. F2-5-1, p. 5). OPG's standard procurement practice employs competitive processes where available, using pre-determined evaluation criteria that include quality, security of supply and costs (Ex. F2-5-1, p. 6).

As directed by the OEB in EB-2010-0008, Decision with Reasons, p. 55, OPG engaged an external consultant, Longenecker and Associates, ("Longenecker"), with extensive experience in uranium procurement, to conduct a review of OPG's uranium concentrate procurement program. OPG asked Longenecker to:

- Review and assess OPG's physical and financial coverage limits for uranium concentrate procurement, and provide recommendations on potential changes.
- Review and assess OPG's supply risk mitigation strategies and provide recommendations for improvement.
- Review and assess recent OPG's price risk mitigation strategies and provide recommendations on contract improvements.
- Review and assess OPG's inventory targets and provide recommendations on alternative inventory targets, and
- Provide an overall assessment of OPG's uranium procurement program in achieving low cost and meeting OPG's objectives (Ex. F5-2-1, p. 11).

The Longenecker Report (Ex. F5-2-1) found that OPG's uranium procurements have been undertaken in a professional manner, using evaluation criteria that gives appropriate consideration to diversity of supply, the relative capabilities and performance risks of suppliers, and includes an appropriate mix of contracts (spot versus long-term, fixed price versus market-related, etc.) (Ex. F2-5-1, p. 3). They also found that OPG's procurement strategy is prudent in today's market. Longenecker concluded that OPG's uranium procurement program is appropriate and fully inclusive of the various factors that should be considered.

The Longenecker Report contains four main recommendations (Ex. F2-5-1 pp. 12-14). Three of the four recommendations have been accepted by OPG (Ex. F2-5-1 pp.12-14). The exception is the recommendation that OPG explore "off-market" negotiated transactions. OPG did not accept this recommendation as it is inconsistent with OPG's procurement guidelines and those of the Province of Ontario. These guidelines require that OPG provide access for qualified vendors to compete in a fair and transparent procurement process (Ex. F2-5-1, p. 13).

OPG's existing uranium concentrate contracts are a mix of fixed price, market-related (i.e., tied to long term or spot market price indicators) and base price escalated contracts (Ex. F2-5-1, p. 3). Contracts utilizing base price escalated will have a fixed price component (Base Price $ per pound), which is subject to price escalation over the term of the contract based on changes in either CPI or US Gross Domestic Product implicit price deflator, from the base period specified in the contract. Currently, 33 per cent of the purchase volume remaining under OPG's contracts is subject to long term or base price escalated prices with the remainder subject to spot pricing (Ex. L-6.5-1 Staff 094).

Benchmarking results based on EUCG data indicate that the three-year fuel cost per MWh for Darlington and Pickering continue to rank among the top North American EUCG plants in terms of fuel costs mainly due to the CANDU requirement of natural uranium (Ex. F5-T1-S1, p. 10). The escalation trends in OPG's fuel bundle costs are consistent with other North American nuclear operators, based on EUCG data (which includes CANDU, PWR and BWR units) as per the 2012 Benchmark Report (Ex. F2-1-1, Attachment 2, p. 69).

7.7.2 Nuclear Fuel Inventory

OPG's procurement program maintains, as market conditions dictate, a target inventory of uranium concentrate to mitigate the impact of supply disruptions and ensures continuous reactor operations (Ex. F2-5-1, p. 4). Failure to secure sufficient fuel supplies would put OPG at risk of having to attempt to purchase fuel in a volatile and illiquid spot market or idle its reactors. Neither of these risks is acceptable to the company and, OPG submits, to the people of Ontario who depend on a reliable supply of nuclear generation.

One of Longenecker's recommendations is that OPG should perform ongoing evaluations of uranium concentrate inventory levels based on an assessment of potential physical supply disruption risks (Ex. F5-2-1, p. 48). OPG has recently adopted a minimum uranium concentrate inventory of 288,000 KgU, representing a four month supply to feed the production of uranium dioxide based on the recommendations from the Longenecker Report (Ex. F2-5-1, p. 4). OPG's prior inventory target of 385,000 KgU, was put into place in 2007, when OPG made the decision to increase the strategic uranium concentrate inventory target to a six month supply or one million pounds following the run up in uranium prices and a tight supply situation (Ex. L-6.5-1 Staff 090). OPG expects to reach the new target level of 288,000 KgU by end of 2015. This timing reflects existing contractual commitments to purchase uranium concentrate in 2013-2015 as well as consideration of other variables within the procurement plan, such as need for incremental purchases to meet financial and physical risk coverage limits (Ex. L-6.5-3 CME-08).

OPG also maintains a 12-month supply of fuel bundles to allow continued fueling in the event of a disruption in the supply of fuel bundles or uranium conversion due to labour unrest or production issues (Ex. F2-5-1, p. 4). A three-month supply of uranium dioxide is targeted to feed the fuel bundle manufacturing process (Ex. F2-5-1, p. 4). The uranium conversion supplier is also contractually required to maintain an inventory of certified uranium dioxide for OPG's use in the event of a supply interruption at the supplier's facilities.

OPG submits that the Longenecker Report has validated OPG's approach to fuel contracting and inventory management, and that OPG has responded appropriately to the Longenecker Report and the OEB's direction in EB-2010-0008. In these circumstances, the balance that OPG has struck in its fuel procurement strategy, which includes an appropriate mix of indexed and market-related contracts and targeted inventory, should be respected, and its forecast of nuclear fuel expense and the rate base impact of fuel inventory be approved.

7.8 ISSUE 6.6

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

The Pickering Continued Operations program will increase the output of the Pickering units 5-8 by extending their operating lives from 2014-2016 until 2020.[11] The initiative, which was over 75 per cent complete when OPG filed its Application, is on budget and on schedule to be finished by the end of 2014 as originally planned (Ex. F2-2-3, p. 1).

The initial end of life estimate for Pickering units 5-8 was predicated on the assumed design life of the key major component (i.e., the pressure tubes). The design life of the pressure tubes was originally projected to be 210,000 Effective Full Power Hours ("EFPH"), resulting in a projected end of life of 2014-2016. The Continued Operations program consists of incremental maintenance, inspections and analyses in conjunction with the Fuel Channel Life Management project to enable Pickering units 5-8 to achieve additional operating life to 247,000 EFPH (Ex. F2-2-3, p. 1). The Continued Operations program is covered by O. Reg.53/05 section 6(2)4 because it will increase Pickering's output by allowing it to operate for a longer period.

The test period costs for continued operations are \$38.9M (all OM&A), which includes \$1.8M related to Pickering continued operations' share of the Fuel Channel Life Cycle Management ("FCLM") project expenditures (Ex. F2-2-3, p. 4, Chart 1). The nuclear production forecast also reflects the incremental outage days associated with Pickering Continued Operations, which reduce nuclear production by 0.5 TWh in 2014 (Ex. F2-2-3, p. 1).

Prior to moving forward with any expenditure on the Pickering Continued Operations program post 2012, OPG completed an updated Pickering Continued Operations business case in April 2012 (Ex. F2-2-3, Attachment 1). The purpose of the updated business case was to reconfirm the value of extending the operating life of the Pickering B units beyond 2014-2016. OPG's updated analysis reconfirmed a significant economic cost advantage from Pickering Continued Operations with a positive Net Present Value ("NPV") of \$520M (Ex. F2-2-3, p. 1). In addition, through the FCLM project, OPG was able to complete the necessary laboratory testing and technical work allowing OPG to confirm high confidence that the fuel channels for Pickering

[11] OPG expects to operate Unit 7 and Unit 8 into 2020 along with Unit 1 and Unit 4. Unit 5 is assumed to operate until 2018 and Unit 6 until 2019.

Units 5-8 can attain an operational life of 247,000 EFPH. On August 9, 2013, the CNSC announced its decision to renew Pickering's power reactor operating licence for a 5 year period from September 1, 2013 to August 31, 2018, but required OPG to make submissions on operating beyond 210,000 EFPH, which was referred to as the Regulatory Hold Point.

OPG made submissions to the CNSC on this matter and the CNSC released a decision in early June 2014 to remove the Regulatory Hold Point (Tr. Vol. 5, p. 6). This will allow OPG to operate Pickering until essentially the end of 2020, or the equivalent of 247,000 EFPH (Tr. Vol. 5, p. 6).

OPG, seeking independent third party confirmation of OPG's positive assessment, asked the OPA to prepare an analysis of system cost impacts from Pickering Continued Operations. The OPA analysis, which is summarized in their letter dated August 15, 2012 (Ex. F2-2-3, Attachment 2), derived an expected cost advantage to Pickering Continued Operations on the order of approximately $100M. The OPA's continued support for Pickering Continued Operations was reconfirmed in their letter of June 9, 2014 (Ex. K6.1).

In addition to the financial benefits, there are other non-financial benefits for Pickering Continued Operations as highlighted by the OPA's August 15, 2012 letter (Ex. F2-2-3, Attachment 2). These include:

- An approximately 11 megatonne reduction in Ontario CO2 emissions between 2015 and 2020.
- The potential for the deferral of some investments in transmission enhancements.
- The hedge that Pickering Continued Operations could provide against mid-term uncertainties that would otherwise result in additional replacement requirements (i.e. the availability of Pickering's 3000 MW was viewed as insurance during the period 2015 to 2020, when Ontario's electrical system will be subject to significant uncertainties, including multiple concurrent refurbishment outages and restarts, and potential natural gas-fired generator retirements).

The LTEP includes the continued operation of Pickering to facilitate the refurbishment of the first units at Darlington and Bruce by providing replacement capacity and energy without greenhouse gas emissions while managing prices (Ex. KT2.2, p. 30).

Based on OPG's April 2012 economic analysis of a net positive benefit from Pickering Continued Operations (Ex. F2-2-3, Attachment 1), the OPA's August 15, 2012 confirmation letter (Ex. F2-2-3, Attachment 2), the June 9, 2014 letter from the OPA reconfirming their support for expenditures on Pickering Continued Operations (Ex. K6.1), CNSC concurrence with OPG ability to achieve 247,000 EFPH (Tr. Vol. 5, p. 6) and the provisions of the LTEP that contemplate Pickering Continued Operation beyond 2014-2016,[12] OPG believes that its expenditures to-date and projected expenditures are prudent and should continue. For these reasons, the OEB should approve OPG's proposed 2014 expenditures on Pickering Continued Operations and associated impact on the nuclear production forecast.

7.9 ISSUE 6.7

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

The project is primarily a capital project, but does include certain OM&A expenditures for activities such as the Operations Trainee Program, demolition and removal of structures, and certain development work (Ex. F2-7-1). OPG is seeking OEB approval for OM&A expenditures of $6.6M in 2014 and $18.2M in 2015 (Ex. J7.1). All differences between OEB-approved and actual OM&A costs incurred in respect of the DRP are subject to the Capacity Refurbishment Variance Account, which is discussed in Ex. H1-1-1, pp. 6-9 (Ex. L-6.7-1 Staff-098).

The forecast for 2014 includes costs for the Operations Trainee program, and for costs incurred during the Definition Phase that are not eligible for capitalization (Ex. L-6.7-1 Staff-098). For 2015, the forecast includes costs for the Operations Trainee program, and for costs incurred during the Definition Phase that are not eligible for capitalization, as well as for demolition and removal costs. Based on the evidence, OPG submits that the DRP OM&A costs are appropriate and should be accepted.

[12] The Pickering Generating Station is expected to be in service until 2020. The LTEP recognizes that an earlier shutdown of the Pickering units may be possible depending on projected demand going forward, the progress of the fleet refurbishment program, and the timely completion of the Clarington Transformer Station (KT. 2.2, p. 5).

7.10 CORPORATE COSTS

7.11 ISSUE 6.8

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

This section discusses the cost of OPG's wages, pension and other benefits (together "compensation and benefits"). Set out below in Table G is a summary of OPG's historical, bridge year and test period compensation and benefits cost for its regulated facilities.[13]

Table G: OPG Compensation and Benefits[14]

Organization	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2013 Actual	2014 Plan	2015 Plan
Nuclear	1,297.7	1,317.8	1,173.3	1,215.6	1,242.6	1,116.3	1,140.8
Previously Regulated Hydro	50.4	54.5	51.8	57.1	53.7	54.1	55.6
Allocated Corporate Support	135.1	142.2	284.1	315.5	309.1	308.0	297.3
Sub-total	1,483.2	1,514.5	1,509.2	1,588.2	1,605.4	1,478.4	1,493.7
Newly Regulated Hydro	79.2	87.9	91.5	102.1	96.1	99.4	99.1
Allocated Corporate Support	18.6	18.7	23.0	23.6	22.5	26.4	25.3
Sub-total	97.7	106.6	114.4	125.6	118.6	125.8	124.4
TOTAL REGULATED COSTS	1,581.0	1,621.0	1,623.7	1,713.8	1,724.0	1,604.2	1,618.1
Increase in Pension/OPEB Current Service Costs Since 2010	-	68.0	123.2	172.3	154.7	94.1	102.0
TOTAL REGULATED COSTS EXCLUDING INCREASE IN PENSION/OPEB	1,581.0	1,553.0	1,500.5	1,541.6	1,569.3	1,510.1	1,516.1

In OPG's submission its compensation and benefits are appropriate for the scope and complexity of the regulated business.

OPG's compensation and benefits costs are driven by a number of factors. OPG requires highly skilled employees and these employees have high ongoing training needs (Ex. F4-3-1, pp. 3-6). It also has a large proportion of unionized employees (approximately 90 per cent) whose compensation and benefits are set by collective agreements established through

[13] Total regulated costs includes base salary and wages, overtime, incentive pay and total benefits (comprised of statutory benefits, employee health tax, non-statutory benefits, and current pension and other post employment benefits service cost).
[14] Figures for 2013 Actual and 2014 and 2015 Plan are taken from J9.7, Attachment 1; all other figures from F4-3-1, Table 1.

collective bargaining. OPG continues to face significant demographic challenges that place upward pressures on compensation and benefits costs (Ex. F4-3-1, p. 5). OPG is committed to maintaining a competitive, equitable and cost effective compensation and benefits program which will enable OPG to attract, retain and engage employees required to fulfil OPG's goals and objectives.

As the above table demonstrates, OPG's total compensation and benefit costs for its regulated operations are stable and below bridge year levels. For the period 2011 to 2015, the total costs are forecast to grow by just over one per cent per year, or within the rate of inflation. The wages paid by OPG are actually going down over this period as a result of headcount reductions flowing mainly from OPG's Business Transformation program. This has been offset by pension and OPEB costs increases driven primarily by changes in discount rates, and mortality assumptions, which are beyond OPG's control.

Overall, in light of the demands placed on OPG's workforce, the skills, education and training that are required to operate, maintain and renew OPG's prescribed facilities, and the unionized environment in which OPG's operates, its compensation and benefits costs are reasonable, and should be approved by the OEB.

7.11.1 OPG's Workforce

At the end of 2012, OPG had approximately 10,844 employees. Of this total approximately 9,453 employees work directly in or are allocated to OPG's regulated activities. This figure includes some 8,313 employees associated with OPG's nuclear business, 433 employees associated with the previously regulated hydroelectric plants and 707 employees associated with the newly regulated hydroelectric facilities (Ex. F4-3-1, p. 4, corrected June 11, 2014).

In order to operate OPG's mix of generation technologies, staff must be highly skilled, and must possess a wider array of skills and knowledge than employees in many other utilities. In particular, because the vast majority of OPG employees' work is related to nuclear generation, they require extensive knowledge, adherence to very detailed procedures, particular skills and comprehensive training unique to the nuclear industry. OPG's workforce is comprised of engineers, scientists, other professional staff, and skilled trades people. These highly skilled employees are in demand across the country, and OPG must compete for these employees with Bruce Power and other private generators and energy service organizations as well as the general marketplace.

OPG has a mature and experienced workforce. As of year-end 2012, approximately 20 per cent of active employees were eligible to retire with an undiscounted pension. By the end of the test period (year-end 2015) more than 28 per cent of the year-end 2012 employees will be eligible to retire (Ex. F4-3-1, p. 5).

In 2011, OPG began the BT initiative to better align cost with revenue and improve efficiency so as to be able to operate with fewer employees (see Ex. A4-1-1). Through attrition, OPG has a company-wide staff reduction target of 2,000 by the end of 2015.[15] It has already realized three quarters of this target (i.e., a headcount reduction through attrition of approximately 1,500 by year-end 2013) (Ex. L-1.0-3 CME-001, Attachment 1). As discussed elsewhere, Business Transformation focuses on building the framework for long-term sustainable operation at these lower staffing levels by re-engineering programs and restructuring to streamline and simplify processes.[16] Becoming a leaner, more efficient organization will contribute to OPG's financial sustainability, allow the pursuit of opportunities to strengthen and grow the company and deliver on OPG's mission to continue to be Ontario's low-cost electricity generator of choice (Ex. F4-3-1, p. 5).

7.11.2 Compensation for OPG's Unionized Employees

Context and Approach to Collective Bargaining. OPG's regulated staff work in a predominantly unionized environment, with approximately 90 per cent of staff belonging to either the PWU or the Society. Of this 90 per cent, approximately two thirds belong to the PWU and approximately one third belong to the Society. The extent of unionization and the mix of PWU, Society and non-represented staff have generally remained stable (Ex. F4-3-1, p. 4).

Pursuant to the Ontario *Labour Relations Act*, as a successor employer to Ontario Hydro, OPG was required by law to adopt collective agreements covering the employees transferred from Ontario Hydro to OPG when it began operation on April 1, 1999. For the unionized employees

[15] Approximately 1,300 staff out of the target staff reductions of 2,000 are attributable to regulated operations (Ex. A4-1-1, p. 1, ft. nt. 1).

[16] A number of strategies and programs are in place to mitigate the risk of knowledge loss associated with ongoing retirements, including succession planning, training & development programs, knowledge management risk assessments and the development of retention plans where necessary.

within OPG, items such as wages, pensions, and benefits can only be changed through the collective bargaining process or arbitration (if the collective agreement provides for it or the Government imposes it through legislation) (see Ex. L-6.8-2, AMPCO-58(j)). They cannot be changed unilaterally by OPG (Ex. F4-3-1, p. 7).[17]

OPG follows a formal and structured approach to collective bargaining. It begins with a review of the external labour relations landscape. The review focuses on the bargaining results of Ontario Hydro successor companies and other broader public sector employers. Included in the review is an assessment of recent agreements and arbitrated decisions relating to wages, benefits, pensions, contracting out, job security, productivity issues, and other compensation issues (Ex. F4-3-1, p. 7).

Representatives from OPG's business units are selected by business unit leaders to represent OPG in collective bargaining. The individuals selected are senior level, experienced leaders with good insight into the strategic and key operational issues facing the company. The collective bargaining process is directed by an experienced team of labour relations staff who have extensive negotiating experience and frequent dealings with OPG's unions. The bargaining team develops the bargaining agenda based on the company's priorities. OPG's priorities are established by soliciting input from across the company on key issues that should be addressed through the collective bargaining process (Ex. F4-3-1, pp. 7-9). OPG begins each round of bargaining with cost containment as its chief goal (Tr. Vol. 8, p. 51). OPG also engages the unions on a regular basis to discuss the challenges OPG faces as an employer (Tr. Vol. 8, p. 71).

OPG's compensation levels and the terms of the PWU and Society collective agreements also exist within a labour relations context defined by legal requirements and a long history of collective agreements. This context bears directly on the amount of compensation paid by OPG and on the prospects of achieving significantly different labour costs (Tr. Vol. 8, p. 75).

To assist in understanding the labour relations context in which OPG operates, OPG filed the report of Dr. Richard Chaykowski (Ex. F4-3-1, Attachment 1). He is an expert in industrial

[17] As it relates to pension costs, OPG is further restricted by the Pension Benefits Act (Ontario) which precludes any amendment to a pension plan which purports to reduce the value of previously accrued benefits (see, s. 14(1)).

relations and, among other things, contributed to the Drummond Commission. His particular role on that Commission focused on labour relations in the Ontario broader public sector, including wage outcomes and the impact of interest arbitration. Dr. Chaykowski's expertise was not challenged before the OEB and he was qualified to provide opinion evidence in relation to the matters covered in his report (Tr. Vol. 7, pp. 136-141).

Among Dr. Chaykowski's main conclusions were the following:

With respect to unionization and pay determination under collective bargaining:

A main objective of unions is to achieve greater compensation for their members, relative to non-unionized employees; and unions are better able to achieve this, the higher is the union density in an industry, and the lower is the degree of competition (Ex. F4-3-1, Attachment 1, ss. 4.1-4.3).

With respect to the resolution of impasses in collective bargaining, and essential services:

An impasse in negotiations can be resolved through mutual agreement or through binding interest arbitration (whether mandated by a collective agreement or imposed by legislation (Tr. Vol. 9, p. 80). In industries or business lines where services are essential, or where service disruptions impose an undue hardship, as well as in industries where services are not essential, interest arbitration remains a major policy option for dispute resolution. In practice interest arbitration is used extensively to determine wages and other terms and conditions of employment throughout the Ontario broader public sector. This practice can impart an upward bias on wage settlements (Ex. F4-3-1, Attachment 1, ss. 5.1-5.3).

With respect to unionization and pay determination at OPG:

The relevant "comparator" firms for purposes of considering industrial relations outcomes at OPG are those in the same broader industry, which are subject to the same labour market and labour relations regulatory regime, that have inherited the same collective agreements from Ontario Hydro and that have similarly very high levels of unionization (Ex. F4-3-1, Attachment 1, ss. 6.1-6.3).

In his view, the best comparators are Bruce Power and HydroOne (Ex. F4-3-1, Attachment 1, s. 6.3). "Patterning" and the use comparators is not synonymous with benchmarking. As Dr. Chaykowski explained, comparators are the entities used by labour unions to "pattern" their bargaining after and the entities that interest arbitrators rely on in rendering their decisions. As he testified:

> I'm not sure that that's quite accurate. I tend to think of benchmarking as, often, a human resource management compensation-type exercise.
>
> Patterning, really, in this context, is a labour relations term, is the way in which I am using it. And I think it is the way in which it was used on Friday.
>
> It is really looking at a relevant, comparable comparator in the collective bargaining world. And I think I gave the example of the collective bargaining unit across the street kind of thing, with the similar union, similar workers, similar line of business, et cetera. (Tr. Vol. 8, pp. 52-53).

OPG wage settlements tend to track the negotiated increases in the Ontario broader public sector over time and compares well to the comparator firms. OPG's outcome is to be expected given the very high level of unionization across that sector (Ex. F4-3-1, Attachment 1, s. 6.3; Ex. F4-3-1, pp. 11-12).

In view of the industrial relations context and specific industrial relations circumstances at OPG, it can reasonably be expected to make only incremental changes in the terms and conditions of employment negotiated with its unions.

PWU Agreement. The current collective agreement with the PWU covers the period from April 1, 2012 to March 31, 2015. The wage increases provided under agreement are: April 1, 2012 – 2.75 per cent; April 1, 2013 - 2.75 per cent; and April 1, 2014 - 2.75 per cent.

The PWU agreement was negotiated in early 2012. Prior to that time, the Government had passed the Public Sector Compensation Restraint to Public Services Act, 2010 (Compensation Restraint Act) as part of Bill 16. The Compensation Restraint Act included measures to extend controls over management compensation. While its provisions covered only OPG's non-unionized employees, the Government requested that OPG, and other Provincially-owned entities, achieve contracts with net zero compensation increases, meaning any increase in compensation had to be offset by corresponding savings elsewhere in the collective agreement. OPG was successful in this respect and met the Government's expectation; OPG negotiated a number of cost and productivity offsets to the wage increases in the PWU agreement ((Ex. F4-3-1, p. 10; Ex. L-6.8-1 Staff-101, p. 3; see also, Ex. JT2.34).

Compared to other companies that inherited collective agreements from Ontario Hydro, OPG has negotiated increases that have been at or below most of the successor companies in most years since 2001 resulting in cumulative increases that are below most of the successor companies (Ex. F4-3-1, Table 3). A comparison of OPG with Bruce Power LP, considered to be the primary competitor for nuclear jobs represented by the PWU, indicates that overall OPG wages for PWU represented staff are lower than those at Bruce Power LP (Ex. F4-3-1 Table 2). The discussion regarding Society compensation below explains why the fact that some "grandfathered" employees are paid over-band does not alter this conclusion.

Society. The Society of Energy Professionals represents the majority of employees who perform the work of professional engineers, front line managers, and accountants. The current collective agreement with the Society covers the period from January 1, 2013 to December 31, 2015. Pursuant to the Government's direction, OPG attempted to negotiate zero compensation increase in the current collective agreement. When a negotiated agreement was not achieved, the matter was submitted to interest arbitration as the collective agreement requires. The terms of the agreement, including compensation were fixed by binding arbitration conducted within the criteria established by the collective agreement, and the generally established protocol for interest arbitrators. The Interest Arbitrator (Arbitrator Albertyn) awarded annual increases over 2013, 2014 and 2015 of 0.75, 1.75 and 1.75 per cent, respectively, based on his assessment of the criteria and evidence presented by each side. He also ordered a temporary freeze on pay progression through the established pay grid for employees during the 2nd and 3rd years of the collective agreement (2014 and 2015) (Ex. F4-3-1, p. 12).

As is the case with the PWU, OPG's Society negotiated or arbitrated increases have been at or below most of the successor companies in most years since 2001 resulting in cumulative increases that are below most of the successor companies (Ex. F4-3-1, Table 5). A comparison of 2013 pay ranges for the various classifications (bands) of Society represented employees to those of Bruce Power LP indicates that for each band, both the minimum and the maximum weekly salary offered by Bruce Power LP exceed the corresponding salary offered by OPG.

For the highest salary bands (MP5 and MP6), Bruce Power's minimum weekly salary is more than five per cent above OPG (Ex. F4-3-1, Table 4).

During the oral hearing, questions were raised regarding the validity of OPG's comparisons with Bruce Power as a result of some staff being "grandfathered" into rates above the band maximum (Tr. Vol. 8, pp. 76-81). As explained in Ex. J8.1, employees are over-band because OPG successfully negotiated reductions to the top bands of its PWU and Society wage schedules. Employees who were earning more than the newly negotiated maximums were "grandfathered." The fact that some employees are over-band does not in any way invalidate the comparison that OPG made because the maximum bands presented are accurate and adjustments for over-band employees would not change the conclusion that OPG pays less than Bruce Power (Ex. J8.1, p. 2). Furthermore, the number of over-band employees is decreasing rapidly (Ex. J8.1, p. 1).

As a final matter in relation to wages, and as discussed during the hearing, it is important to recognize that OPG's Application is based on its 2013-2015 Business Plan. For PWU represented employees the Plan assumes wage escalation for the period covered by the collective agreement (up to March 31, 2015) consistent with that agreement (i.e., 2.75 per cent). For the period beginning April 1, 2015, however, the Plan assumes no increase in base wages and an increase of just one per cent for step progression. For Society represented employees the Plan assumes a zero per cent increase over the test period, again with a one per cent increase for progression. In other words, notwithstanding (1) the reality that it will be extremely challenging (to say the least) for OPG to negotiate a wage freeze for PWU employees and (2) the binding terms of the Albertyn Arbitration, OPG's Application assumes these lower wage levels (Tr. Vol. 9, pp. 91-93; Ex. J.9.5).

7.11.3 Management Group Compensation

As a result of the Agency Review Panel findings, OPG has adopted a Management Group ("MG") compensation policy of generally paying at the 50th percentile while balancing the need to attract and retain qualified staff.

Each fall, OPG's MG compensation band structure and base pay merit budget are reviewed against external benchmarks to ensure that MG compensation is in line with the 50th percentile.

The MG band structure has been frozen since 2008 and base pay and merit increases have been restricted through numerous constraints that have been self-imposed by OPG or imposed by Government legislation in the form of Bill 16 and Bill 55. These salary restraint measures have contributed to a reduction in OPG's total cost of MG base salaries since 2010 and have reduced management salaries such that they are now generally at or below the 50th percentile relative to the comparator groups (Ex F4-3-1, p.20).

OPG's Annual Incentive Plan ("AIP") for MG employees delivers a portion of compensation on a pay at-risk basis, if key financial and operational objectives of the corporation, business unit and individual are met (Ex F4-3-1, p.23). The AIP program design provides line of sight to corporate objectives and provides control over program costs. Corporate objectives must be met in order for the AIP to payout, as the AIP is not funded if corporate objectives are not met. The AIP envelope for a given year is capped based on corporate performance. In accordance with Bill 55, the AIP envelope is further constrained to ensure the total performance pay envelope is capped at the envelope awarded for 2011 performance (paid in 2012). Corporate, business unit and individual scorecards are established at the beginning of the year, outlining the expectations for performance. The Corporate Scorecard is reviewed by the Compensation and Human Resources Committee and approved by the OPG Board of Directors. There have been no changes to the current AIP Plan design since January 2010 (Ex. F4-3-1, pp. 19-23).

7.11.4 Benefits

All regular employees and pensioners at OPG can receive health, dental and life insurance benefits designed to protect them from undue costs associated with illness and to encourage them to take steps to maintain good health. OPG's programs consist of health, dental, life insurance and other benefits for current employees and their dependants, and other post employment benefits ("OPEB"). OPEB include post-retirement benefits, such as group life insurance and health and dental care for pensioners and their dependants, as well as long-term disability plan ("LTD") benefits for current employees.[18]

OPG has been taking steps to stabilize benefit costs and has implemented a number of changes to better align benefit provisions with those of the external market (Ex. F4-3-1, p. 24).

[18] The term "other post retirement benefits" refers to post employment benefit plans other than the Registered Retirement Plan and LTD benefits.

OPG outsources claims administration to Great-West Life and has a number of plan management and adjudication mechanisms in place to control benefit costs. These include the mandatory substitution of generic drugs, maximizing coordination of benefit opportunities, and a requirement for prior approval for certain drug and treatment therapies. Changes for the employees represented by the Society and the PWU are achieved only through the collective bargaining process and are, therefore, tied to the timelines of the agreements (Ex. F4-3-1, pp. 24-25).

OPG's other cost containment initiatives include:

- Implementation of the 55 and 10 rule for Society represented and Management Group employees
    - Removes the ability to retire with less than 10 years of service and receive post-retirement benefits for life. Provides for lifetime benefits only if, at age 55, the employee has a minimum of 10 years of service with OPG (Ex. F4-3-1, p. 25).
- Outsourcing Benefits/Pension Administration
    - OPG was successful at arbitration in obtaining a Purchased Services Agreement ("PSA") to outsource some incremental Benefits/Pension administrative duties to existing carriers. This eliminates duplication of effort and allows for reassignment of OPG staff currently performing this work (Ex. F4-3-1, p. 25).
- 24 month Health and Dental benefit claim window
    - Requires employees to submit all Health & Dental Benefits claims within a 24 month window of obtaining the service. This lowers administration costs on the adjudication of old claims and is now in place for all employees (Ex. F4-3-1, p. 25).
- Millennium Health & Dental Benefits Plan
    - New externally hired MG employees receive Health & Dental Benefits based on the Management Group Millennium Plan. This plan provides lower coverage levels, both in terms of dollar amounts of coverage and in terms of diversity of coverage,

compared to the Management Group Heritage Plan for legacy staff (Ex. F4-3-1, p. 25).

- Change in the Sick Leave Plan

    - OPG negotiated the ability to require that PWU employees a major medical absence form be completed for any absence of four continuous days/shifts. This was a reduction from the previous requirement of five days/shifts and has resulted in a dramatic drop in the number of absences (Ex. L-6.8-17 SEC-120).

7.11.5 Pension and Other Post Employment Benefits

OPG has a contributory, defined benefit registered pension plan. The plan was introduced by Ontario Hydro. It is incorporated by reference into the PWU and Society collective agreements and has been since OPG's formation. The terms of the plan remain substantially the same across all of the successor companies (Tr. Vol. 8, pp. 19-20). There has been no increase by OPG in the benefits offered under the plan since it was last considered by the OEB.

All OPG employees earn and contribute towards their pension package, although the benefit levels are less for non-unionized employees than for union members. In addition, all employees are eligible to receive benefits from the defined benefit supplementary pension plans should their pension promise exceed the limits under the Income Tax Act for payment from the pension plan. Other post employment benefits ("OPEB") include post-retirement benefits, such as group life insurance and health and dental care for pensioners and their dependants, as well as long-term disability benefits for current employees.

OPG is seeking recovery of test period pension and other post employment benefits costs associated with the regulated operations determined in accordance with USGAAP (Ex. F4-3-1, p. 26). USGAAP requires the use of accrual accounting for pension and OPEB. The OEB approved the accrual-based methodology for determining OPG's pension and OPEB-related costs for setting payment amounts in EB-2007-0905 and EB-2010-0008. The circumstances with respect to OPG's pension and OPEB-related costs and their recovery have not changed since EB-2010-0008.

On an accrual basis, pension and OPEB-related costs are incurred and recognized in accordance with generally accepted accounting principles ("GAAP") 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 in the future. It is the earning of the benefit which results in the cost being incurred, not its payment. 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.

During the course of the hearing, the possibility of recovering these costs on alternative basis, the cash basis, was raised (Tr. Vol. 12, p. 34). The cash basis of cost recovery is discussed in section 7.11.8, below.

Pension and OPEB costs and obligations continue to be determined annually by independent actuaries using management's best estimate assumptions. Both economic (e.g., inflation, salary escalation, and health care cost trends) and demographic (e.g., mortality, termination rates, and retirement rates) assumptions are set in accordance with USGAAP. Specifically, in relation to discount rates, these are based on AA corporate bond yields in Canada for the appropriate duration of the benefit obligations (Ex. F4-3-1, pp. 31-34). The payment amounts established for OPG in EB-2007-0905 and EB-2010-0008, as well as the December 31, 2012 balances in the Pension and OPEB Cost Variance Account and Impact for USGAAP Deferral Account approved in EB-2012-0002, reflected pension and OPEB costs determined using such discount rates. These discount rates are also used to determine pension and OPEB costs for the purposes of OPG's consolidated financial statements as well as the audited financial statements for OPG's prescribed facilities Ex. A2-1-1, Attachment 2).

The pension and OPEB cost assumptions are set out below in Chart 3.

Chart 3: Pension and OPEB Cost Assumptions

	2014 Plan	2015 Plan	Reference
Discount rate for pension	4.90% per annum	4.90% per annum	Ex N2-1-1, Pg 5, lines 9 - 17
Discount rate for other post retirement benefits	5.00% per annum	5.00% per annum	Ex N2-1-1, Pg 5, lines 9 - 17
Discount rate for long-term disability[19]	4.10% per annum	4.10% per annum	Ex N2-1-1, Pg 5, lines 9 - 17
Expected long-term rate of return on pension fund assets	6.25% per annum	6.25% per annum	Ex F4-3-1, Pg 30, Chart 1
Inflation rate	2.0% per annum	2.0% per annum	Ex F4-3-1, Pg 30, Chart 1
Salary schedule escalation rate	2.5% per annum	2.5% per annum	Ex F4-3-1, Pg 30, Chart 1
Rate of return used to project year-end pension fund asset values	N/A	6.25% per annum in 2014	Ex N2-1-1, Pg 4, lines 6 - 8

Pension and OPEB costs have increased compared to the 2010-2013 period, as discussed in Ex. F4-3-1, Section 6.0 and as updated in Ex. N2-1-1. As set out above, the increase is not due to changes in benefit levels or plan provisions. Rather, the primary drivers of the increase are historically low discount rates and the updated mortality assumptions recommended by OPG's actuaries.

The challenges associated with pension funding are not unique to OPG. Rather they are widespread across the Ontario broader public sector. Hydro One, for example, has a funding deficit roughly the same as OPG's. As Dr. Chaykowski commented in relation to pension costs:

[19] In accordance with USGAAP, the discount rates for 2014-2015 are projected (2014-2015) rates at December 31 of those years.

> My observation is that pension issues are critical right across most of the Ontario broader public sector. I realize, from following the discussion here today, that it is obviously a big issue here. But these organizations, the unions and OPG, are not alone and the electricity sector is not alone.
>
> There are some -- and you see evidence of that in the report of Professor Harry Arthurs for the provincial government. You see that in the work of -- the report of Mr. Jim Leech.
>
> So I think it is -- if nothing else is well understood, what is well understood is that there are a great number of pension plans that are in trouble in this province. And that's probably true in the private sector as well as the public sector. And that there is no quick fix. (Tr. Vol. 8, p. 166).

OPG is cognizant of the increase in pension and OPEB costs and is actively taking steps to decrease these costs to the extent it is reasonably capable of doing so. For management employees, OPG has taken steps to increase the pension contributions those employees are required to make and to change their retirement factors from the age and service factor of 84 to the age and service factor of 90 (Ex. L-6.8-1 Staff-120). These changes have been announced to management and will be implemented, having regard to legal advice relating to notice, beginning January 1, 2016. This timing also considers OPG's ability to attract and retain management staff recognizing that a portion of management comes from represented employees (Tr. Vol. 11, pp. 47-48; Ex. L-6.8-1 Staff-120).

For the represented employees which make up the overwhelming majority of OPG's workforce (90 per cent), OPG is constrained in the steps it can take by the fact that pensions and benefits are negotiated terms of employment. While OPG was successfully able to negotiate increases in the contributions made by PWU members in 2002 and 2009 (Tr. Vol. 8, pp. 20-22) further changes have been rejected by the OPG's unions. As Dr. Chaykowski testified, "pensions are extremely important to their [union] members…It is a tough issue to make concessions on for unions, because it is so important. So I wouldn't say that those issues are intractable, but they're amongst the most difficult." (Tr. Vol. 11, p. 53).

To help break this impasse, OPG is actively working with the Government on its initiative to tackle pension and OPEB costs. Ultimately, however, from OPG's perspective, having regard to the committed nature of these costs and the labour relations context, significant reductions in costs can only be achieved through significant legislative amendments or an increase in actual discount rates, both of which are beyond the company's control.

7.11.6 Jurisdiction to Require OPG to Establish a Segregated Fund for Supplemental Pension and Other Post-Employment Benefits

During the Oral Hearing, Board staff probed the nature of accrual accounting as compared to cash accounting and the implications flowing from the use of these accounting methodologies in respect of OPG's pension obligations and the corresponding impacts on payment amounts of those obligations. Staff observed that, under accrual accounting, it is possible for a utility to recover more through rates in a certain period than it is required to actually pay out in that period, but that in other periods the amount recovered could be less than the amount required to be paid (Tr. Vol. 13, p. 12). For the test years 2014 and 2015, on a projected basis, Staff noted that OPG expects to recover more than it expects to pay out as a result of applying the accrual accounting methodology (Tr. Vol. 13, p. 13).[20]

Staff questioned why OPG does not set aside in a segregated fund the excess amounts it recovers in certain years in order to have those funds available to meet its supplemental pension plan and OPEB obligations in future years (Tr. Vol. 13, pp. 16-18). Staff pointed to a 1992 decision from the Federal Energy Regulatory Commission ("FERC") as a precedent for this approach (Tr. Vol. 13, pp. 22-25).

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).

In the 2006 Supreme Court of Canada case of *ATCO Gas & Pipeline Ltd. v. Alberta (Energy & Utilities Board)*, [2006] 1 S.C.R. 140 ("ATCO"), the Supreme Court of Canada stated that, through the payment for regulated services, customers do not acquire ownership or control of

---

[20] As noted in the transcript, the actual recovery of some portion of these amounts may be deferred owing to the operation of the Pension and OPEB Cost Variance Account (Tr. Vol. 13, pp. 9-13).

the utility's assets (at para. 68). The Court also agreed that, absent any ownership interests, any allocation of the proceeds of a sale, thereby affecting the property interests of the utility, would be confiscatory and would require the clear intention of the legislation (at paras. 69 and 79).

It would be an error of law for the OEB to require OPG to set aside certain funds for the apparent purpose of OPG meeting future pension obligations. Section 78.1(4) of the Ontario Energy Board Act, 1998, specifically circumscribes the scope of a payment amounts order under section 78.1.

Moreover, implementing Staff's suggestion to establish a segregated fund would be a highly intrusive and confiscatory 'remedy' to a problem that does not exist. The difference between the amounts recovered by OPG and the amounts paid out by OPG in a given period on account of its supplemental pension and OPEB liabilities is simply the result of the accounting methodology approved by the OEB and properly applied by OPG. While in future years it is expected that OPG will experience periods in which the amounts it recovers will be less than the amounts that it will be required to pay out, OPG will manage its cash flows and plan and forecast its future cash requirements so as to ensure it has sufficient funds available to meet these future obligations.

In accordance with US GAAP, OPG applies the accrual accounting methodology when preparing its financial statements. The Board approved OPG's use of US GAAP (see EB 2012-0002, Tr. Vol. 1, p. 25 (approving a Settlement Agreement authorizing USGAAP)) and has previously approved the recovery of payment amounts based on OPG's prior use of accrual accounting (Tr. Vol. 13, p. 6). In addition, Mr. Barrett testified that nearly all utilities in Ontario use accrual accounting for supplemental pension plans and OPEB (Tr. Vol. 13, p. 20). As such, it remains OPG's submission that if the Board is inclined to consider this complex issue further, with appropriate legal, tax and accounting expertise, it would be most appropriate to do so in a generic proceeding.

With respect to the FERC decision referenced by Board staff, Commission, Docket No. PL93-1-000, Statement of Policy: Post-Employment Benefits Other than Pensions, December 17, 1992, as touched upon by Mr. Kogan, the circumstances of that decision are very different from those in the present proceeding (Tr. Vol. 13, p. 25). FERC issued its decision as a policy statement of broad application to all natural gas pipelines and public utilities under its jurisdiction following a broad public comment period that attracted comments from 77 regulated utilities.

The impetus for the policy statement was a new accounting standard issued by the Financial Accounting Standards Board, which required employers to reflect in current expense an accrual for post-retirement benefits other than pensions during the working lives of covered employees. To manage the broad transition to accrual accounting, FERC established the policy which, among other things, would recognize, as a component of cost-based rates, allowances for prudently incurred costs of post-retirement benefits other than pensions when determined on an accrual basis, if the company agrees to make deposits into an irrevocable external trust fund for amounts equal to the annual test period allowance for the relevant costs.

Notably, the policy indicates that it is merely a statement of intention that will be followed unless particular circumstances demonstrate the policy to be inappropriate and both the validity of the policy and its application to particular facts may be challenged and are subject to further consideration in individual cases (see: FERC policy statement, p. 6). Given the unique circumstances of the FERC policy statement, the significant differences in circumstances relative to the present proceeding, and recognizing that Board staff has not presented any analysis with respect to the subsequent application or experience with the FERC policy, the FERC policy is of extremely limited precedential value in this proceeding.

Finally, there is no legitimate evidentiary basis for the Board to adopt Staff's suggestion. First, there is no evidence to indicate that a requirement to set aside funds for meeting future pension and OPEB obligations would actually further the Board's objectives in respect of either customers or OPG; it is easy to envision how the requirement to establish a segregated fund could work to the detriment of both. Second, OPG also indicated that if it were required to establish a segregated fund there would be significant tax consequences and that the large sums of money that would be set aside would earn less than if they were reinvested into the rate base for the benefit of ratepayers and upon which the company would earn a return (Tr. Vol. 13, p. 21). Without solid evidence in this regard, including a detailed analysis of tax consequences, it would be inappropriate for the Board to implement the suggested regime, even if it were legal to do so.

7.11.7 O.Reg. 53.05 Requires the OEB to Accept Asset and Liability Values Related to Pension and Other Post-Retirement Benefits

During the Oral Hearing, the OEB Panel Chair specifically asked for OPG's "interpretation of what the regulation means with respect to line items such as pension and other post-employment benefits." (Tr. Vol. 13, p. 138). OPG's interpretation is that s. 6(2)11(ii) of O.Reg. 53.05 means exactly what it says, that in setting payment amounts for the newly regulated hydroelectric assets the OEB is required to accept the asset and liability values associated with those assets, which includes the ongoing liabilities with respect to pension and other post-retirement benefit ("OPRB") obligations that are allocated to those assets.[21] It cannot take action that would effectively change those values.

OPG's understanding as to the meaning of s. 6(2)11(ii) is based upon its plain reading of the section within its regulatory context. This interpretation is entirely consistent with the OEB's prior treatment in EB-2007-0905 of a similar requirement under s. 6(2)5 of the regulation, which applied to the making of the OEB's first order under s. 78.1 of the Act, and fundamental principles around the setting of just and reasonable rates.

The values from the financial statements that the OEB is required to accept are defined broadly and, given the language used, the specific items identified in the second sentence of s. 6(2)11(ii) are intended to be illustrative, not an exhaustive list. Notably, the items that are expressly included in the second sentence - income tax effects of timing differences and the revenue requirement impact of accounting and tax policy decisions − are accounting aspects that relate to OPG generally, at the enterprise level, and are not specific to the newly prescribed hydroelectric generation facilities. To establish the revenue requirement these corporate items must be extracted from values that are included in OPG's company-wide financial statements and allocated to or calculated for the prescribed assets using an OEB approved methodology. This is exactly what is done for pensions and other post employment benefits.

[21] The complete wording of section 6(2)11(ii) is:

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

OPG does not have separate pension or benefit plans for different business units. Rather, in developing its proposed revenue requirement, OPG applies a consistent OEB-approved methodology to attribute its company-wide pension and other post-retirement liabilities and costs to each business unit, including the newly prescribed hydroelectric facilities. Estimated pension and OPRB costs for current service are charged directly to business units (Ex. J11.7). All other pension and OPRB costs, which relate to both active and inactive members of the pension plan, are recorded as centrally-held costs and are attributed to business units using a methodology that was approved in EB-2007-0905 and in EB-2010-0008, and verified by an independent cost allocation study in this proceeding (Ex. F5-5-1).

As explained in response to Ex. J11.7, OPG therefore interprets s. 6(2)11(ii) of the regulation to mean that the OEB must ensure recovery of the cost impacts flowing from OPG's pension and OPRB obligations (and the funded status of the pension plan) that initially arose prior to regulation and which are reflected in the financial statement liability values. These obligations cover both active and inactive employees/plan members. The pension and OPRB asset and liability values that OPG has used in applying this methodology are as set out in its 2013 audited financial statements that were approved by its board of directors prior to regulation of the newly prescribed facilities, and which, based on s. 6(2)11(ii), the OEB is required to accept.

In OPG's first payment amounts proceeding, the OEB had an opportunity to consider a rule that is very similar to that in s. 6(2)11(ii) of the regulation. Section 6(2)5 of O. Reg. 53/05 required the OEB, in making its first order under s. 78.1 in respect of OPG, to accept the amounts for OPG's assets and liabilities as set out in OPG's then most recently audited financial statements that were approved by its board of directors. With respect to pension and other post employment benefits, the entire amount of the obligation allocated to the prescribed facilities was accepted (EB-2007-0905, Decision with Reasons, p.60); there was no suggestion that portion of this obligation attributable to retirees could be distinguished from that attributable to current employees.

It is also incumbent upon the OEB in accordance with the "just and reasonable" rates standard to allow recovery of the current cost impacts, which flow from OPG's pension and OPRB obligations that are attributable to these facilities. The current costs of the newly prescribed hydroelectric facilities include the prudently committed pension and OPRB costs incurred in the past by OPG (or Ontario Hydro), a portion of which have been allocated to the newly prescribed hydroelectric facilities using a methodology previously approved by the OEB.

OPG is precluded by law from reducing accrued pension benefits payable to its employees (Pension Benefits Act (Ontario), s.14.1). Identical costs for the previously regulated facilities have been approved in past payment amounts proceedings with no suggestion that they were imprudent or unreasonable.

With respect to pension and other post employment benefits payable to employees or retirees covered by a collective agreement; these are committed costs during the period of the collective agreement. They are subject to reduction only through negotiation and only prospectively with regard to future benefit entitlements.

7.11.8 Cash Basis of Cost Recovery

OPG provided the revenue requirement impact of moving from an accrual basis of cost recovery to a cash basis of cost recovery for pensions and OPEB, including transition costs (Ex. J13.7). The primary motivation for the change in methodology would appear to be to reduce near-term rate impacts (Tr. Vol. 13, p. 85).

With respect to pension, as can be seen from Chart 4 below, for the period beginning with OPG's regulation by the OEB and continuing through the test period, the cash basis would have produced higher rates in six of the eight years and the total difference between the two methods is not large in the context of the amounts involved.

Chart 4 – Differences between Cash and Accrual for Pension Costs
Pension Amounts ($M)[22]

Cost Recovery Basis	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Projection	2015 Projection	Total
Accrual Basis: (Recoverable Costs)[23]	121.4[24]	141.4[25]	150.1[26]	195.0[27]	286.1	383.3	471.3	405.3	2,153.9
Cash Basis: (Actual/Projected Contributions)[28]	198.6	206.1	208.5	235.5	297.1	242.9	321.9[29]	407.6	2,118.1
Accrual Basis less Cash Basis	(77.2)	(64.7)	(58.3)	(40.5)	(10.9)	140.3	149.4	(2.3)	35.8

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. As noted during the hearing, the OEB has already considered and rejected the use of the cash basis for pensions for OPG in EB-2010-0008 (Tr. Vol. 13, p. 85; EB-2010-0008 Decision with Reasons, p. 91).

With respect to OPEB, the cash basis is not appropriate as it does not recognize future OPEB obligations that are being incurred in the present. The accrual method of cost recovery provides the appropriate matching of cost incurrence and inclusion in rates and thereby avoids

[22] Amounts for 2008-2013 exclude those for the newly regulated hydroelectric assets; amounts for 2014 and 2015 include them. Amounts for all years do not include those related to the Nuclear Waste Management Organization.
[23] As per Pension Cost amounts for nuclear, previously regulated hydroelectric and newly regulated hydroelectric (as applicable) for 2012-2015 shown in Ex. L-6.8-1 Staff-114.
[24] Amount for recoverable costs represents 9/12 of the annual amount, as the EB-2007-0905 payment amounts came into effect on April 1, 2008, i.e., ($154.7M for Nuclear plus $7.2M for Previously Regulated Hydro in EB-2007-0905 Ex. F3-4-1, Chart 6) multiplied by 9/12. Amounts for actual contributions are for the full year.
[25] Amount for recoverable costs is calculated as $135.1M for Nuclear plus $6.3M for Previously Regulated Hydro in EB-2007-0905 Ex. F3-4-1, Chart 6.
[26] Represents 12/21 of the sum of 2008 and 2009 amounts, as the EB-2007-0905 payment amounts became effective April 1, 2008 and applied throughout 2010 (i.e., 2008 amount of $121.4M plus 2009 amount of $141.4M) multiplied by 12/21).
[27] Represents 2/21 of the sum of 2008 and 2009 amounts, plus 10/12 of the actual 2011 amount of $204M, as the EB-2010-0008 payment amounts and the pension and OPEB cost variance account as per EB-2011-0090 were effective March 1, 2011.
[28] As per Contributions Other Than Solvency Deficit Payments (except for 2014) for nuclear, previously regulated hydroelectric and newly regulated hydroelectric (as applicable) for each year shown in Ex. L-6.8-1 Staff-114.
[29] Ex. J9.6 line 35.

intergenerational equity issues. Promoting intergenerational equity is consistent with generally accepted regulatory principles (Ex. JT2.40, p. 1). In contrast, the cash method is inconsistent with this matching.

OPG accepts that there are cash flow consequences inherent with the use of the accrual basis of OPEB cost recovery (Tr. Vol. 13, pp. 132-133). As all Ontario utilities use the accrual basis of accounting for recovery of OPEB costs in rates, OPG agrees with the views expressed by Enbridge (see Tech. Conf. Tr. April 23, 2014, p. 198) that if the OEB determines to address this issue, then a generic proceeding involving other Ontario regulated utilities that currently recover pension and OPEB-related costs on an accrual basis would be appropriate given the need for consistent application of this complex, industry-wide issue (Tr. Vol. 13, pp.19-20 and 24-25).

A change to the cash basis of cost recovery will result in a reduction to net income of $379.1M in the test period alone (Ex. J13.7) as OPG's costs would continue to be accounted for on an accrual basis, and its revenues would not reflect those costs. This has implications for OPG's credit metrics and financial risk and would be expected to require an upward adjustment in OPG's equity ratio to ensure a fair return (Ex. J13.7). OPG also may have to reverse its recognition of USGAAP regulatory assets of up to $3 billion, which currently offset unamortized amounts in other comprehensive income (Tr. Vol. 13, pp. 55-58, 102). The $3 billion in regulatory assets was recognized by OPG on the expectation that the cost recovery methodology would remain unchanged.

7.12 ISSUE 6.9

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

7.12.1 Introduction

This section presents OPG's corporate function costs, including the asset service fee, and corporate allocations. Corporate function costs cover the centralized activities necessary to the operation of OPG's regulated hydroelectric and nuclear facilities. The asset service fee is the charge for the use of certain corporate assets required to support OPG's regulated hydroelectric and nuclear facilities. Hydroelectric Central Support Groups costs are included in hydroelectric base OM&A (See Ex. F1-2-1, pp. 10-11).

The hydroelectric and nuclear revenue requirements include OM&A costs directly assigned and allocated from OPG's corporate groups and asset service fees (Ex. F3-1-1, Tables 2 and 3; Ex. F3-2-1, Tables 1 and 2). The test period assigned and allocated corporate OM&A costs are:

- Previously Regulated Hydroelectric - $29.8M in 2014 and $26.9M in 2015
- Newly Regulated Hydroelectric - $42.1M in 2014 and $39.6M in 2015, and
- Nuclear - $433.9M in 2014 and $417.4M in 2015.

The test-period asset service fees are:

- Previously Regulated Hydroelectric - $1.5M and $1.7M in 2014 and 2015 respectively,
- Newly Regulated Hydroelectric - $2.9M and $3.0M in 2014 and 2015 respectively, and
- Nuclear - $23.3M and $26.8M in 2014 and 2015, respectively.

As a result of Business Transformation in 2012, 1,064 staff and $198.0M of OM&A were transferred from Nuclear Operations and Nuclear Projects to corporate functions (otherwise referred to as "Support Services"). Similarly, 61 staff and $14.6M in OM&A was transferred from the Hydro-Thermal business to the corporate functions. Refer to Ex. A4-1-1 for list of BT related organizational changes. The tables provided in Ex. F3-1-1, pages 2 and 3 reflect the impact on the 2012 Board Approved values due to the BT transfers from the nuclear and hydroelectric businesses to the Support Services groups.

Exhibit F3-1-1, Table 1 summarizes OPG's total Support Services OM&A. These costs increased over the 2011-2013 period mainly due to implementation of a new centre-led organization driven by the BT initiative. Support Services costs decrease over the 2013-2015 periods mainly due to attrition, economies of scale from consolidating staff performing similar work, streamlining processes, and eliminating lower value work. In addition, the execution of the Enterprise System Consolidation Project in Business and Administrative Services will enable streamlining/standardization of processes in other Support Services groups and reduce IT costs.

OPG submits that the overall level of corporate support costs and asset service fees allocated to the regulated business units is appropriate and should be approved. OPG's cost allocation methodology was reviewed in 2013 by independent cost allocation experts HSG Group Inc.

(Ex. F5-5-1). HSG concluded that the methodology to assign and allocate costs meets best practices and is consistent with cost allocation precedents established by the OEB, and that the allocated costs meet the requirements of the OEB's "3-prong test" (Ex. F5-5-1, pp. 18-24). The methodology is consistent with the methodology that was reviewed and accepted in the EB-2010-0008 Decision with Reasons (p. 94).

7.12.2 OPG's Corporate Function Costs

OPG is structured such that certain corporate groups provide services and incur costs, which are necessary to support the operation of the prescribed hydroelectric and nuclear facilities (Ex. F3-1-1, p. 1). Corporate support groups include Business and Administrative Services (includes Information Technology, Real Estate and Supply Chain), Finance, People & Culture, Commercial Operations & Environment (includes Commercial Contracts, Environment, Regulatory Affairs, Electricity Sales & Trading, and Integrated Revenue Planning), and Corporate Centre (includes Executive Office, Corporate Executive Operations, Law, Corporate Relations and Communications, and Corporate Business Development & Enterprise Risk Management).

The budgets for OPG's corporate groups are established through the corporate business planning process. OPG benchmarks the costs of its largest corporate functions, specifically, Information Technology, Finance and Human Resources, as a tool to support its annual business planning process and to help establish performance targets. The results of corporate function benchmarking show that OPG delivers cost-effective corporate services. The overall level of Support Services costs allocated to the regulated businesses decrease over the bridge year and test period.

OPG's Information Technology function continues to use the benchmarking data services of EUCG, a non-profit association with membership from North America and international utilities. 2011 EUCG data was used by IT to compare OPG against ten North America electric utilities' IT spending per employee and IT spending per GWh. The 2011 results for the two metrics are provided in the table at Ex. F3-1-1, page 6, and indicate the OPG's IT costs were within the second quartile for IT spending per employee and within the third quartile for IT spending per GWh. The IT group has committed to further cost reductions over the 2013-2015 business planning period through a series of cost saving initiatives by improving demand management, leveraging existing applications, storage reduction and re-tiering, data centre and server optimization, increased standardization and simplification of the information technology environments, and negotiated savings in software maintenance contracts and outsourced services (Ex. F3-1-1, p. 6; Ex. L-6.9-2 AMPCO-64).

OPG's Finance department implemented a number of improvement initiatives based on the 2009 benchmarking report prepared by the Hackett Group, filed in EB-2010-0008. These changes include standardized financial reporting and modified budgeting practices to ensure financial targets are held at an appropriate level of detail in the organization. As part of BT, Finance will continue to pursue cost efficiencies by investing in a new standardized management reporting system and leveraging a shared service delivery model by centralizing or consolidating similar transactional based activities (Ex. F3-1-1, p. 12).

OPG continues to participate in a benchmarking group called the Electric Utility HR Metrics Group ("EU-HRMG") to compare the performance of its People & Culture function to other organizations (Ex. F3-1-1, p. 14). This group benchmarks performance on a cross-section of HR metrics annually across 42 member utilities. This information is used to analyze performance and trends.

OPG's HR Expense Factor in 2012 was $172 k / HR Employee (Ex. F3-1-1, pp. 14-15). This is lower than the median for all benchmarked utilities ($194 k). OPG's HR FTE/Employee ratio improved modestly since 2009. When OPG completes the BT process and initiatives, further improvements in the HR FTE/Employee ratio are anticipated (Ex. F3-1-1, p. 15).

7.12.3 Corporate Cost Allocation

The cost allocation methodology is the same as was previously evaluated and accepted by the OEB as part of EB-2010-0008 (Decision with Reasons, p. 94) and EB-2007-0905 (Decision with Reasons, p. 60).

In addition, Support Services costs attributed to the newly regulated hydroelectric plant groups are subsequently assigned and allocated between newly regulated hydro stations and unregulated stations as discussed in Ex. F1-2-1. OPG uses a standardized allocation methodology for attributing costs within plant groups that include newly regulated and unregulated hydroelectric stations.

In 2012, staff were transferred from Operating business units to Support Services groups as part of BT. This resulted in costs increasing in Support Services groups and costs decreasing in Operating groups by an equal amount. The existing cost allocation methodology continues to be used as it appropriately reflects the work that was transferred from the operating groups to the Support Service groups. In 2013, OPG's allocation methodology was also independently evaluated by HSG Group Inc. (Ex. F5-5-1).

OPG's allocation methodology distributes shared costs among the business units by direct assignment and allocation. Direct assignment is used when OPG can reasonably establish the use of specific employees and other cost items by a particular business unit. Allocations are used when more than one business unit uses an employee or cost item, but the portions used by each cannot be directly established. In these cases, a cost driver is used to allocate the costs. A cost driver is a formula for sharing the cost of a resource among those who caused the cost to be incurred.

7.13 ISSUE 6.10

Oral Hearing - Are the centrally held costs allocated to the regulated hydroelectric business and nuclear business appropriate?

Centrally-held costs are an integral part of the costs of operating OPG's generation facilities. They are company-wide costs that are recorded centrally for a variety of reasons, such as achieving record-keeping efficiency and maintaining proper oversight. They are not support services costs (Ex. F4-4-1, p. 1).

The amounts included in revenue requirement for the 2014-2015 test period are $927.7M[30] comprised of $50.7M for the previously regulated hydroelectric facilities, $100.9M for the newly regulated hydroelectric facilities, and $776.1M for the nuclear facilities.[31] Pension and OPEB related costs comprise the majority of these amounts. OPG submits that these amounts are reasonable and should be approved.

[30] Centrally Held costs per 2013-2015 Business plan of $582.4M (2014) and $574.5M (2015) per Ex F4-4-1, Table 1 plus an increase of $146.2M per Ex N1-1-1, p. 4, Chart 2 less a decrease of $206.9M per Ex N2-1-1, p. 3, Chart 1.

[31] The increase in pension/OPEB costs was allocated to nuclear and previously and newly regulated hydroelectric operations using the factors accepted by HSG Group, Inc. in its Review of Cost Allocation Methodology for Centralized Services and Common Costs Report (Ex F5-5-1).

Centrally-held costs are directly assigned or allocated to OPG's regulated operations using the same methodology as in EB-2010-0008. The methodology was previously reviewed and found to be appropriate in EB-2010-0008 (see Decision with Reasons, pp. 94-96). The methodology was similarly found to be appropriate as part of the independent review of OPG's cost allocation methodology provided in Ex. F5-5-1.

7.13.1 Pension and OPEB-related Costs

Certain components of pension and OPEB-related costs for all of OPG's employees and retirees continue to be included in centrally-held costs (F4-4-1, pp. 3-4). These cost components continue to include interest costs on the obligations, the expected return on pension plan assets, amounts in respect of past service costs, actuarial gains and losses, and variances from the forecast current service costs reflected in the standard labour rates.

As in EB-2010-0008, the pension and OPEB-related costs that are centrally-held are directly assigned and allocated to business units in proportion to the pension and OPEB costs directly charged to the business units. The amounts included in revenue requirement for the 2014-2015 test period are $608.1M[32] comprised of $30.3M for the previously regulated hydroelectric facilities, $58.7M for the newly regulated hydroelectric facilities, and $519.1M for the nuclear facilities. Section 7.11.5 above and Ex. F4-3-1, Section 6 provide further information on OPG's pension and OPEB plans and costs.

7.13.2 Insurance

OPG's insurance costs include the cost of the company-wide insurance program and the additional nuclear-specific insurance program. The company-wide program covers commercial general liability, directors and officers and fiduciary liability, all risk property, boiler and machinery breakdown, including statutory boiler and pressure vessel inspections, and business interruption (Ex. F4-4-1, pp. 4-5).

---

[32] Centrally Held costs per 2013-2015 Business plan of $16.0M (2014) and $15.7M (2015) for previously regulated hydroelectric facilities per Ex F4-4-1, Table 2 plus $28.6M (2014) and $27.5M (2015)for newly regulated hydroelectric facilities per Ex F4-4-1, Table 3 plus $292.6M (2014) and $288.4M (2015) for nuclear facilities per Ex F4-4-1, Table 1 plus an increase of $146.2M per Ex N1-1-1, p. 4, Chart 2 less a decrease of $206.9M per Ex N2-1-1, p. 3, Chart 1.

As in EB-2010-0008, the costs of this program are primarily directly assigned to the business units based on the applicability of each type of insurance coverage and the asset replacement cost of the generation facilities.

The nuclear-specific insurance program relates to liability insurance associated with nuclear operations and additional property insurance for damage to the nuclear portions of OPG's nuclear generating stations, which complements the conventional property insurance program. This portion of insurance costs continues to be directly assigned to the nuclear facilities.

The forecast increases in nuclear insurance costs in 2014 and 2015 primarily reflect increased premiums due to expected higher statutory nuclear liability insurance limits to be phased-in over several years. Higher limits are forecast to result from the proposed federal legislation replacing the 1976 Nuclear Liability Act (Ex. L-6.10-1 Staff-138).

7.13.3 Performance Incentives

These costs include performance incentives for OPG's employees. Performance incentive costs continue to be attributed to the business units based on the distribution of past performance incentive payments.

Performance incentive costs are stable over the test period. Performance incentive plans are discussed in Ex. F4-3-1, pp. 19-23.

7.13.4 IESO Non-Energy Charges

IESO non-energy costs are charges that are applied to withdrawals of energy from the IESO controlled grid. These charges are not discretionary and apply to all energy withdrawals from the IESO-controlled grid. These charges are directly assigned to the specific regulated facilities (Ex. F4-4-1, pp. 5-6).

7.13.5 Other Centrally Held Costs

Other centrally-held costs consist of a number of relatively smaller items. In the test period, close to 75 per cent of Other costs is comprised of labour-related costs (such as the fiscal calendar and labour balancing adjustments and vacation accrual) and the annual Ontario Nuclear Funds Agreement ("ONFA") guarantee fee (Ex. F4-4-1, pp. 7-8).

As required by the terms of the ONFA, the Province has provided a Provincial Guarantee to the CNSC since 2003 on behalf of OPG. The Nuclear Safety and Control Act (Canada) requires OPG to have sufficient funds available to discharge the current nuclear decommissioning and waste management liabilities. The Provincial Guarantee provides for any shortfall between these long-term liabilities and the current market value of the Used Fuel Fund and the Decommissioning Fund (together, the “Segregated Funds”), up to the value of the Provincial Guarantee. OPG pays the Province an annual guarantee fee of 0.5 per cent of the amount of the Provincial Guarantee, which is currently $1,551M (Ex. F4-4-1, p. 8).

OPG submits that its centrally held and other costs are reasonable and should be approved.

7.14 DEPRECIATION

7.15 ISSUE 6.11

Secondary - Is the proposed test period depreciation expense appropriate?

OPG is seeking approval of a test period revenue requirement that includes depreciation and amortization expense of $82.1M in 2014 and $81.9M in 2015 for the previously regulated hydroelectric facilities, $62.2M in 2014 and $63.1M in 2015 for the newly regulated hydroelectric facilities, and $273.7M in 2014 and $288.5M in 2015 for the nuclear facilities, as shown in Ex. F4-1-1 Tables 1 and 2, respectively. OPG submits that these amounts are reasonable and should be approved.

The depreciation and amortization expense for the regulated hydroelectric facilities to increases in 2014, reflecting the full-year impact of the depreciation on the Niagara Tunnel. The expense then stabilizes in 2015. Regulated hydroelectric in-service additions are discussed in Ex. D1-1-2 and the Niagara Tunnel is discussed in Ex. D1-2-1.

The depreciation and amortization expense for the newly regulated hydroelectric facilities is largely stable over the test period.

In 2014, the nuclear depreciation and amortization expense increases moderately mainly due to the impact of in-service additions, which are discussed in Ex. D2-1-2 and Ex. D2-2-1. There is a similar increase in 2015.

Allocation is not required to attribute depreciation and amortization expense to the regulated facilities as approximately 99 per cent of OPG's in-service fixed and intangible assets are associated with specific generation facilities or plant groups. The remaining in-service fixed and intangible assets continue to be either directly associated with a business unit, or be held centrally for use by both regulated and unregulated generation business units. The assets held centrally are not allocated to regulated facilities; instead the generating business units (both regulated and unregulated) are charged an asset service fee for the use of these assets. This charge is reported as an OM&A cost. The asset service fees are described in Ex. F3-2-1.

With the exception of the treatment of gains and losses on asset retirements and the re-classification of certain other components of expense to OM&A, OPG's depreciation and amortization expense is determined in the same manner as was presented in EB-2010-0008. In addition, the expense is determined in the same manner for both newly and previously regulated hydroelectric assets.

Depreciation and amortization rates for the various classes of OPG's in-service fixed and intangible assets continue to be based on their estimated service lives. The service life of an asset class continues to be limited by the service life of the station(s) to which it relates. A single end-of-life ("EOL") date is established for depreciation purposes for all units at a particular station, which is typically based on an average of estimated EOL dates of each unit. The determination of these station EOL dates for depreciation purposes involves an assessment of the condition of and expected remaining life of certain key components (referred to as life limiting components), in conjunction with an estimate of the expected operation of the station, which includes economic viability considerations. For the nuclear stations, the life-limiting components are: steam generators, pressure tubes, feeders and reactor components. For hydroelectric stations, dams are considered to be the life-limiting component (Ex. F4-1-1, p. 3).

As part of its due diligence process, OPG convenes an internal Depreciation Review Committee ("DRC") to examine the service lives of fixed and intangible assets and ultimately the calculation of depreciation and amortization expense (Ex. F4-1-1, pp. 7-9). The DRC is comprised of business unit representatives as well as staff from the Finance and Regulatory

Affairs functions. The DRC considers available engineering, technical, operational and financial assessments/information as part of its review.

The DRC conducts a regular review of the service lives of generating stations, including the Bruce stations, and a selection of asset classes with the general objective of reviewing all significant asset classes for the regulated assets over a five-year cycle. Periodic independent reviews of the service life estimates of significant asset classes for the regulated assets are also performed over a five-year period, as recommended by Gannett Fleming Inc. ("Gannett Fleming"). The DRC's scope and recommendations are submitted for approval to the Chief Financial Officer, the Chief Nuclear Officer, Senior Vice President, Hydro-Thermal, and Senior Vice President, Commercial Operations and Environment (the "Approvals Committee"). Approved DRC recommendations are used to calculate the depreciation and amortization expense that is reflected in OPG's financial statements and business plan. OPG's DRC review process was found by Gannett Fleming to be procedurally sound and meeting generally accepted regulatory objectives regarding depreciation (Ex. F4-1-1, Attachment 1, p. 1-4).

7.16 ISSUE 6.12

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

In its EB-2010-0008 Decision with Reasons (p. 97), the OEB directed OPG to conduct an independent depreciation study. In response, OPG engaged Gannett Fleming in 2011 to provide an independent review and assessment of the asset service life estimates and nuclear station EOL dates for OPG's regulated assets based on the net book values as at December 31, 2010 (the "2011 Depreciation Study"). The depreciation and amortization expense for the test period incorporates all recommendations made by Gannett Fleming in their study. The 2011 Depreciation Study is provided in Ex. F4-1-1 Attachment 1.

Subsequent to the completion of the 2011 Depreciation Study, OPG determined that it would update the study based on December 31, 2012 net book values and changes made to the end of life dates for Pickering GS. Given its significance, the Niagara Tunnel, placed in-service in 2013, was included in the scope of the updated study. The 2013 Depreciation Study was filed as Ex. F5-3-1.

The 2013 Depreciation Study recommended the continued use of the currently approved average service life estimates, as modified for the six exceptions included in the results of the study (Ex. F5-3-1, Part III: Results of Study). As noted in the 2013 DRC Report, the DRC accepted these six exceptions, the impact of which is a $1M reduction in depreciation expense for hydroelectric assets and a minimal annual depreciation impact on nuclear due to minimal carrying value of the assets (Ex. L6.11- 1 Staff-142, Attachment 2, pp. 2-3).

Gannett Fleming stated that the hydroelectric account recommendations applied to both previously and newly regulated hydroelectric assets and that it is appropriate for OPG to categorize the assets making up both the newly and previously regulated hydroelectric facilities into the same plant accounts with the same average service lives. Gannett Fleming also agreed with the 2012 DRC recommendation that a new, separate hydroelectric plant account with an average service life of 90 years be established for the tunnel lining of the new Niagara Tunnel (Ex. F5-3-1, Part III: Results of Study).

OPG did not amend its revenue requirement to reflect the updated depreciation study since the revenue requirement impact of the updated depreciation study fell below OPG's materiality threshold.

OPG submits that test period depreciation expense is reasonable, consistent with the recommendations of Gannett Fleming and should be adopted by the OEB.

7.17 INCOME AND PROPERTY TAXES

7.18 ISSUE 6.13

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

7.18.1 Income Taxes

OPG seeks approval of the 2014 and 2015 income tax expense of $49.7M and $64.2M for the previously regulated hydroelectric facilities, $29.9M and $42.7M for the newly regulated hydroelectric facilities, and $108.3M and $16.8M for the nuclear facilities, respectively, as presented in Ex. N2-1-1, Table 1. OPG submits that these amounts are reasonable and should be approved.

OPG continues to use the taxes payable method for determining regulatory income taxes for its prescribed assets, as it did in EB-2010-0008 and EB-2007-0905 (Ex. F4-2-1, p. 2). Under the taxes payable method, only the current income tax expense is reflected in the revenue requirement.

The methodology for determining the regulatory income tax expense starts with the determination of taxable income in accordance with the requirements of the tax legislation. This involves adjusting (through additions and deductions) regulatory earnings before tax to address differences between accounting and tax treatments. In most cases, these additions and deductions are commonly used by regulated utilities in their tax calculations; however, in some cases they result from items unique to OPG. To evaluate the appropriate amounts attributable to ratepayers for regulatory income tax purposes, OPG has continued to apply the principles as established by the OEB in EB-2007-0905 and applied in EB-2010-0008, namely:

- The party that bears a cost should be entitled to any related tax savings or benefits; and
- Only the prescribed assets are to be considered in the evaluation.

Regulatory income taxes for the prescribed facilities are determined by applying the statutory tax rates to the regulatory taxable income of the combined prescribed nuclear and hydroelectric facilities and reducing the resulting amount by recognized investment tax credits ("ITCs") for qualifying Scientific Research and Experimental Development ("SR&ED") expenditures (Ex. F4-2-1, pp. 2-3).

For the purpose of determining payment amounts for each regulated business, total income taxes, before SR&ED ITCs, determined for OPG's prescribed facilities are allocated based on each business's regulatory taxable income. SR&ED ITCs are primarily directly attributed to each business unit based on underlying SR&ED expenditures that give rise to the ITCs. This approach is the same as that applied and approved in EB-2010-0008 and EB-2007-0905.

As noted above, regulatory taxable income is computed by making additions and deductions to the regulatory earnings before tax for items affected by different regulatory accounting and tax treatment, applying the same principles used for the calculation of actual income taxes under applicable legislation as well as regulatory principles. Additions and deductions are described in detail at Ex. N2-1-1, Attachment 5, p. 9.

The newly regulated hydroelectric assets are considered in the calculation of the income tax expense starting in the test period, as the facilities are regulated in 2014.

In 2013, there was a regulatory tax loss of $153.8M, due to a shortfall in nuclear production, as shown at Ex. L-1.0-1 Staff-002, Table 29, line 21. The 2013 regulatory tax loss is not applied to reduce the forecast 2014 regulatory taxable income because the loss arose as a result of a 2013 nuclear operating loss. As OPG and its shareholder had to bear the operating loss and not ratepayers, it is entitled to receive the benefit of the associated tax loss (Ex. L-6.13-1 Staff-166). This principle of attributing the tax cost or benefit between the ratepayers and OPG's Shareholder was established by the Board in EB-2007-0905 (Decision with Reasons, p. 170) and applied in OPG's analysis of tax losses reflected in the balance of the Tax Loss Variance Account approved by the Board in EB-2010-0008 (EB-2010-0008, Ex. F4-2-1, pp. 17-19).

7.18.2 Property Taxes

The nature, basis and components of OPG's property tax expense are unchanged from the evidence presented in EB-2010-0008 (Ex. F4-2-1, p. 14). OPG remains responsible for both the payment of municipal property taxes and a payment in lieu of property tax to the Province of Ontario.

OPG's property tax expense for the previously regulated hydroelectric facilities, the newly regulated hydroelectric facilities and the nuclear facilities is presented in Ex. F4-2-1 Tables 1, 2 and 3, respectively, for the test period. Municipal property taxes paid by OPG for properties that are not directly associated with specific generation business units and are held centrally form part of the asset service fees as discussed in Ex. F3-2-1. Property taxes associated with the Bruce assets are presented separately in Ex. G2-2-1.

OPG seeks approval of the 2014 and 2015 property tax expense of $0.3M and $0.3M for the regulated hydroelectric facilities, $0.2M and $0.2M for the newly regulated hydroelectric facilities, and $15.9M and $16.4M for the nuclear facilities, respectively, as presented in Ex. F4-2-1 Tables 1 to 3. OPG submits that these amounts are reasonable and should be approved.

7.19 OTHER COSTS

7.20 ISSUE 6.14

Secondary - Are the asset service fee amounts charged to the regulated hydroelectric business and nuclear business appropriate?

Approximately 99 per cent of OPG's in-service fixed assets are directly associated with specific generation facilities (Ex. F3-2-1, p. 1). The remaining assets are either directly associated with a business unit, or are common assets used by both regulated and unregulated generation facilities.

The assets held centrally are not included in rate base and the depreciation and amortization expense in this rate submission does not include any depreciation or amortization related to these assets. Instead, the regulated facilities (as well as unregulated facilities) are charged a service fee for the use of these assets, which is included in their respective OM&A expenses (Ex. F3-2-1, p. 1).

The service fee methodology used in this Application is the same as that accepted by the OEB in EB-2010-0008 (Decision with Reasons, p. 94) and EB-2007-0905 (Decision with Reasons, p. 60). Exhibit F3-2-1 Tables 1 and 2 present asset service fee amounts expected to be charged to hydroelectric and nuclear facilities for the test period. OPG seeks approval of the 2014 and 2015 asset service fee amounts of $1.5M and $1.7M for the regulated hydroelectric facilities, $2.9M and $3.0M for the newly regulated hydroelectric facilities, and $23.3M and $26.8M for the nuclear facilities, respectively.

The asset service fee increases over the test period, due to higher IT in-service additions and depreciation expense.

Asset service fees are computed in a cost-based manner. The costs included in the computation of the service fees are depreciation expense, certain operating costs, property taxes, and a tax-adjusted return earned on these assets.

The costs of these assets are allocated to the regulated hydroelectric and nuclear businesses using the cost allocation approach and methodology discussed in Ex. F3-2-1. OPG submits that the cost-based asset service fees it has proposed have been appropriately allocated to the regulated hydroelectric and nuclear businesses and should be approved.

7.21 ISSUE 6.15

Secondary - Are the amounts proposed to be included in the test period revenue requirement for other operating cost items appropriate?

There are no additional operating cost items that are not already covered under other issues.

8.0 OTHER REVENUES

8.1 REGULATED HYDROELECTRIC

8.2 ISSUE 7.1

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

OPG earns other, non-energy revenues from its prescribed hydroelectric facilities (Ex. G1-1-1, p. 1). Consistent with the treatment approved by the OEB in EB-2010-0008, OPG proposes that revenues (less costs) from ancillary services, segregated mode of operation ("SMO"), and water transactions be applied as an offset to OPG's revenue requirement.

The provision of ancillary services is integral to the operation of OPG's prescribed assets. A forecast of these other revenues for the test period is included in the calculation of the revenue requirement for the previously and newly regulated hydroelectric facilities. Differences between this forecast and actual revenues are recorded in the Ancillary Service Net Revenue Variance Account - Hydroelectric Sub Account, as approved by the OEB (Ex. H1-1-1, pp. 3-4).

As updated in the First Impact Statement, the forecast of other revenues associated with OPG's previously regulated hydroelectric facilities is $34M in 2014 and $34.6M in 2015 and for the newly regulated hydroelectric facilities it is $22.7M in 2014 and $23.1M in 2015 (Ex. N1-1-1, page 17 and Table 1, line 21). The forecast reflects a slight increase compared to the previous test period owing primarily to higher forecasted revenues for operating reserve and a new contract for regulation service that compensates OPG at regulated rates instead of HOEP. OPG's updated forecast for the test period is reasonable and should be adopted by the OEB.

8.2.1 Segregated Mode of Operation

Segregated mode of operation transactions occur at R.H. Saunders Generating Station and Chats Falls and are accommodated by segregating units from OPG's facilities to Hydro-Québec's control area. Prior to entering into a SMO configuration, OPG must seek approval from the IESO, which can be refused or revoked at any time (Ex. G-1-1, pp. 7-8).

SMO is conducted by OPG when it identifies economic opportunities in neighbouring markets. These transactions are arranged in advance with counterparties and are typically conducted in off-peak periods.

For the test period, OPG proposes to use the revenue offset mechanism established by the Board in EB-2007-0905, which is an average of the previous three historical years' actual net revenue values. Accordingly, OPG's forecast of SMO for the test period is based on the average actual net revenues over 2010, 2011 and 2012 (Ex. G1-1-1, pp. 1-2).

8.2.2 Water Transactions

OPG proposes to change how it calculates the revenue offset associated with water transactions between the New York Power Authority ("NYPA") and OPG to reflect the significant decrease in water transactions owing to the Niagara Tunnel coming into service (Ex. G1-1-1, pp. 4-7).

Water Transactions provide an opportunity to maximize use of the available water by allowing either OPG or NYPA to use a portion of the other's share for power generation (Ex. G1-1-1, p. 4). In return, the entity that uses the water provides the revenues resulting from the water transactions, minus an accommodation charge, to the other entity.

The OEB's decisions in EB-2007-0905 and EB-2010-0008 specified that the average of the previous three historical years of actual net water transactions revenues be applied as an offset against OPG's revenue requirement. However, with the Niagara Tunnel coming into service, OPG is able to use significantly more of its Niagara River water entitlement (Ex. G1-1-1, p. 5).

Accordingly, OPG has proposed a reduction of 65 per cent to the historical Water Transaction volume (Ex. G1-1-1, p. 7; Ex. L-7.1-1 Staff-175). The start of operations for the Niagara Tunnel represents a structural change to the Water Transaction market not unlike how the DC intertie affected the SMO market (Ex. G-1-1, p. 2). As a result, the use of the three year historical average would significantly overstate the value of Water Transaction revenues in the test period. The revenue offset forecast for 2014 and 2015 based on OPG's proposal is $1.7M per year.

8.2.3 HIM Revenue Requirement

Under OPG's modified incentive mechanism, eHIM, the 50 per cent sharing of HIM revenues with customers is achieved through the monthly settlement process with the IESO via the application of the 'X'-factor (Ex. E1-2-1, p. 13). In this way, the generation of incentive payments for OPG, and the attendant value delivered to the customer, occur simultaneously. As a result, there is no need for an additional revenue requirement adjustment related to the hydroelectric incentive revenues (Ex. E1-2-1, p. 13).

8.3 NUCLEAR

8.4 ISSUE 7.2

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

OPG earns nuclear non-energy revenues from ancillary service revenues, Heavy Water Sales, Heavy Water Services and Isotope Sales (Ex. G2-1-1, p. 1). Consistent with the treatment approved by the OEB in EB-2010-0008, OPG proposes to continue treating revenues (less costs) from nuclear non-energy revenues as an offset to OPG's revenue requirement.

The amounts of the proposed revenue offsets attributable to nuclear non-energy revenues are $33.2M and $30.5M for 2014 and 2015, respectively (Ex. G2-1-1, Table 1). This is a decrease from the previous test period and reflects a return to a more normal level of revenues for heavy water and sales and processing (Ex. G2-1-1, Table 1). OPG submits that these forecasts are appropriate and should be accepted by the Board.

8.4.1 Ancillary Services

Provision of ancillary services is integral to the operation of OPG's prescribed assets (Ex. G1-1-1, pp. 2-4). A forecast of these other revenues for the test period is included in the calculation of the revenue requirement for OPG's nuclear facilities (Ex. G2-1-1, Table 1). Differences between this forecast and actual revenues are recorded in the Ancillary Service Net Revenue Variance Account - Nuclear Sub Account, as approved by the OEB (Ex. H1-1-1, pp. 3-4).

8.4.2 Heavy Water Sales

OPG seeks opportunities to sell surplus quantities of heavy water from its heavy water inventory. Surplus quantities are defined as those quantities of heavy water not required to meet OPG's current and future needs. As determined by the Board in EB-2010-0008, revenues (less costs) from sales of heavy water are to be shared on a 50/50 basis with ratepayers. OPG does not propose any change to this treatment during the test period (Ex. G2-1-1, p. 2).

8.4.3 Heavy Water Services

OPG's Heavy Water Services business consists of the provision of tritium removal (detritiation) services at the Darlington Tritium Removal Facility. Revenues during the previous test period were high relative to previous and following years and were the result of significantly higher demand arising from two Bruce Nuclear units returning to service and work associated with New Brunswick Power's Point Lepreau (Ex. G2-1-1, p. 2). Demand for heavy water services has since returned to more normal levels.

8.4.4 Isotope Sales

OPG Isotope sales business is comprised of the sale of Cobalt-60 and Tritium. OPG sells Cobalt 60 under an exclusive long term agreement with a third party. OPG's revenues from Cobalt 60 sales remain relatively consistent as a result. OPG tritium sales have also been relatively stable with the only notable exception occurring in 2012 due to a temporary reduction of operations by one of OPG's customers (Ex. G2-1-1, p. 3).

8.5 BRUCE NUCLEAR GENERATING STATION

8.6 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?

OPG has leased its Bruce A and Bruce B Generating Stations and associated lands and facilities to Bruce Power (Ex. G2-2-1, pp. 1-2). The Bruce Lease sets out the main terms and conditions of the lease arrangement between OPG and Bruce Power (including lease payments). In association with the Bruce Lease, OPG and Bruce Power have entered into a number of agreements in regard to the provision of services by OPG to Bruce Power, or by Bruce Power to OPG.

As in EB-2012-0002 and EB 2010-0008, the treatment of revenues and costs associated with the Bruce Lease agreement and associated agreements are based on the OEB's decision in EB-2007-0905. This decision held that the revenues and costs associated with the Bruce Lease must be calculated in accordance with GAAP.

The methodology for assigning and allocating revenues and costs to the Bruce facilities and under the Bruce Lease is also unchanged from that presented in EB-2010-0008 and reflected in EB-2012-0002. In 2010, Black & Veatch Corporation Inc. ("Black & Veatch") reviewed this allocation methodology and found it appropriate. The methodology was initially accepted by the OEB in EB-2010-0008, and was subsequently applied in EB-2012-0002 through the disposition of the balance in the Bruce Lease Net Revenues Variance Account.

For the test period, the net amounts of Bruce Lease revenues and costs are forecast to be $39.7M for 2014 and $40.6M for 2015 as shown in Ex. G2-2-1, Table 1. These net amounts are an offset to the nuclear revenue requirement.

OPG submits that these net revenue amounts are the appropriate forecast for the test period, but, in any event, these forecast amounts will be tracked against actual revenues and costs and trued up via the Bruce Lease Net Revenues Variance Account as discussed below in Section 10.3.13.

9.0 NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING LIABILITIES

9.1 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?

This section discusses OPG's forecast of nuclear liabilities and how the treatment of those liabilities impacts OPG's revenue requirement. OPG is seeking recovery of $847.5M over the test period in respect of liabilities for nuclear waste management and decommissioning for both prescribed and Bruce facilities (Ex. C2-1-1, Table 1). This amount includes the financial impacts of the current approved Ontario Nuclear Fund Agreement Reference Plan. These impacts relate primarily to increases in depreciation expense and variable used fuel storage and disposal expenses and, for the Bruce facilities, increases in accretion expense. The current approved ONFA Reference Plan covers the 2012-2016 periods. The ONFA was approved by the Province effective January 1, 2012, as discussed in EB-2012-0002.

OPG's nuclear liabilities represent the present value of the lifecycle cost of decommissioning and nuclear waste management programs. These lifecycle costs include the fixed cost components of each program as well as the lifetime variable costs for waste already generated. The present value of the committed costs is recorded as an Asset Retirement Obligation ("ARO") on the balance sheet of OPG (Ex. L-2.1-6 ED 003, Attachment 1, p. 46).

To the extent that the ARO increases or decreases from changes in the approved ONFA Reference Plan or a change in accounting estimates, an equal amount must be recorded as an increase or decrease in the net book value of the assets to which the retirement obligation relates. This change in net book value is known as an Asset Retirement Cost ("ARC"). One exception is the annual incremental waste cost, which increases the ARO, but does not impact the ARC because it is expensed in the year generated.

For the test period, OPG proposes to maintain the revenue requirement treatment for nuclear liabilities approved by the OEB in EB-2007-0905 and EB-2010-0008 for Pickering, Darlington and the Bruce facilities. OPG, as the owner of the Bruce facilities, is responsible for the management of all levels of nuclear waste generated at the Bruce facilities and for decommissioning. However, the revenue requirement treatment approved for the Bruce facilities in EB-2007-0905 and EB-2010-0008 differs from that approved for Pickering and Darlington.

Under the methodology applicable to the prescribed nuclear facilities, the depreciation expense resulting from the amortization of the ARC over the life of the nuclear facilities, variable incremental used fuel costs and variable incremental low and intermediate level waste ("L&ILW") costs are determined in accordance with GAAP for regulated entities. The approved methodology also requires that the return on a portion of the rate base equal to the lesser of the unfunded nuclear liabilities (i.e., the ARO less the segregated funds balance) and the unamortized ARC be limited to the average accretion rate. OPG is able to earn a return on the excess of the unamortized ARC over the unfunded nuclear liability at the weighted average cost of capital for the prescribed facilities (EB-2007-0905 Decision with Reasons, pp, 88-91).

For the Bruce facilities, the OEB approved an approach based on GAAP for unregulated firms to determine the net revenue impact for the nuclear liabilities. In summary, the difference is that for Bruce facilities the OEB substitutes the net income determinants of accretion expense and earnings on segregated funds in lieu of a return on the unamortized ARC (rate base) used in determining the revenue requirement for prescribed facilities (EB-2007-0905 Decision with Reasons, p. 110).

The ARO is allocated at the station level based on each of the five programs involved in retiring nuclear stations and managing nuclear waste. These five programs are: decommissioning; used fuel storage; used fuel disposal; L&ILW storage and L&ILW disposal. The ARC is recorded at the station level using the methodologies that are used for the ARO. The allocation of the ARC and ARO for both the prescribed facilities and Bruce facilities is shown in Ex. C2-1-1, Tables 1 and 2, respectively.

OPG's costs associated with the decommissioning, used fuel disposal and L&ILW disposal programs are long-term in nature and are paid out of the segregated funds, as per ONFA. OPG's costs associated with used fuel storage and L&ILW storage programs prior to permanent station shut down are short-term in nature and are funded through cash flow from OPG's operations (Ex. L8.1-2 AMPCO-82).

9.2 ISSUE 8.2

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

The components of the revenue requirement impact from the nuclear liabilities associated with prescribed and Bruce facilities are detailed at Ex. C2-1-1, Table 1. OPG submits that the amounts proposed are reasonable and should be approved.

For the prescribed facilities, OPG is seeking recovery of a total pre-tax test period amount of $427.8M in respect of the liabilities for nuclear waste management and decommissioning, consisting of $214.6M for 2014 and $213.2M for 2015 (Ex. C2-1-1, Table 1, line 6). The associated income tax impacts are $14.8M for 2014 and $13.5M for 2015 (Ex. C2-1-1, Table 1, line 7).

For the Bruce facilities, OPG is seeking recovery of a total pre-tax test period amount in respect of the liabilities for nuclear waste management and decommissioning of $293.6M as a reduction to Bruce Lease net revenues, consisting of $144.9M for 2014 and $148.7M for 2015 (Ex. C2-1-1, Table 1, line 15). The associated income tax impacts are $48.3M for 2014 and $49.6M for 2015 (Ex. C2-1-1, Table 1, line 16).

Some intervenors questioned the “Due to Province” amounts included in the segregated fund balances on OPG’s December 31, 2013 consolidated financial statements. In accordance with generally accepted accounting principles, each Due to Province amount is treated as a liability in OPG’s financial statements for each segregated fund.

Although a Due to Province amount exists for both the Decommissioning Fund and the Used Fuel Fund, only the Decommissioning Fund is overfunded as of December 31, 2013. Since the Decommissioning Fund is overfunded, OPG limits the earnings it recognizes in its consolidated financial statements by recording a payable to the Province for the excess (i.e. “Due to Province” amount), which is $624M as of December 31, 2013.

For the Used Fuel Fund, the Province guarantees a return of 3.25 per cent plus Ontario CPI for funding related to the first 2.23 million of used fuel bundles (“Committed Return”). Since the difference between the Committed Return and the actual market return is positive as of December 31, 2013, the difference of $990M is recorded as a Due to Province amount. While the Used Fuel Fund has a Due to Province amount in respect of the Committed Return, the Used Fuel Fund as a whole is underfunded by approximately $2.4B as of December 31, 2013.

As indicated in O. Reg. 53/05, the Board shall ensure that OPG recovers all the costs it incurs in connection with the ONFA. Due to Province amounts cannot be removed from segregated fund balances because, in accordance with ONFA provisions, OPG does not have the right or access to these amounts, which accrues to the benefit of the Province, as explained in Ex. J11.8. Specifically:

1) ONFA Section 2.2 restricts access to and use of the nuclear segregated funds to circumstances required or permitted by the ONFA, as follows: "The assets of the Segregated Funds may not be held, used, paid, distributed, disbursed, managed, encumbered in any way or transferred except as required or expressly permitted by the terms of this Agreement…"

2) ONFA Section 4.7.3 stipulates that, only in circumstances where the market value of the Decommissioning Fund is more than 120 per cent of the Decommissioning Balance to Complete Cost Estimate, OPG has the right to direct 50 per cent of the amount in excess of the 120 per cent of the Decommissioning Balance to Complete Cost Estimate to be transferred to the Used Fuel Fund.[33] This was explained by the OPG witness at the Technical Conference (Tr. Vol. 2, p. 158). This is also described in OPG's audited consolidated financial statements (for example, Ex. L-2.1-6 ED-003, Attachment 1, p. 36). The OPG witness also stated that the 120 per cent threshold is not expected to be reached during the test period (Tr. Vol. 11, p. 110).

3) ONFA Section 8.2 stipulates that, upon termination of the ONFA, the Province "shall then have the right to requisition a Disbursement to it and/or to OEFC (as the Province may determine)" for the amount by which the market value of the Decommissioning Segregated Fund exceeds the Decommissioning Balance to Complete Cost Estimate.[34]

4) ONFA Section 3.7.1(b)(i) stipulates that "the Province may direct the Used Fuel Fund Custodian to make a Disbursement to the Province in any amount up to the amount, if any, by which the Actual Used Fuel Fund Value exceeds the Fixed Used Fuel Fund Value" in respect of the Used Fuel Fund. Under the ONFA, the Actual Used Fuel Fund Value exceeds the Fixed Used Fuel Fund Value when the actual market return related to the first 2.23 million of used fuel bundles is greater than the Committed Return. This results in the Province's claim on the Used Fuel Fund amount above the Committed Return. The Province may exercise this claim after receipt of an OPG report containing

[33] Section 4.7.3 refers to the term Surplus. At paragraph 1.117 of the ONFA, Surplus is specifically defined as the amount by which the market value of the Decommissioning Fund exceeds 120 per cent of the Decommissioning Balance to Complete Cost Estimate.

[34] Section 8.1 of the ONFA stipulates that the agreement may be terminated only at the earlier of: a written agreement of both OPG and the Province to this effect; or when substantially all of the costs for the nuclear waste management and decommissioning programs covered by the ONFA have been discharged.

an estimate of the amount of the Actual Used Fuel Fund Value and the Fixed Used Fuel Fund Value. OPG shall submit such a report to the Province after a Triggering Event, as specified in ONFA section 3.6.1 (e.g., when a new or amended Reference Plan becomes an Approved Reference Plan).

Notwithstanding OPG's objection to the feasibility of eliminating the Due to Province amount from the segregated fund balances, doing so would increase OPG's revenue requirement because eliminating the Due to Province Amount would increase each segregated fund balance, which would reduce unfunded nuclear liabilities. As per the Board's nuclear liability cost recovery methodology for prescribed facilities this would have the effect of decreasing the rate base amount that attracts a lower rate of return (i.e., the lesser of the unfunded nuclear liabilities and the unamortized ARC, which attracts a rate of return limited to the average accretion rate, would be lower) and increasing the rate base amount that attracts a higher rate of return (i.e., the difference between the unamortized ARC and the unfunded nuclear liability, which receives the weighted average cost of capital, would be higher). A hypothetical illustrative calculation showing how the revenue requirement would increase by eliminating the Due to Province amount is reflected in Ex. J13.6.

10.0 DEFERRAL AND VARIANCE ACCOUNTS

10.1 ISSUE 9.1

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

OPG submits that the nature and type of costs recorded in the deferral and variance accounts are appropriate. OPG's deferral and variance accounts were established pursuant to O. Reg. 53/05 and the OEB's decisions in EB-2007-0905, EB-2009-0038, EB-2009-0174, EB-2010-0008, EB-2011-0090, EB-2011-0432 and EB-2012-0002.

The balances in all accounts, including additions to accounts during 2013, are shown in Ex. L-9.1-17 SEC-132, Attachment 1, Table 1 (Updated version of Ex. H1-1-1, Table 1). The total year-end 2013 debit balance is $217.3M for the previously regulated hydroelectric facilities and $1,478.4M for the nuclear facilities.

Entries into these accounts for 2013 have been calculated in accordance with the applicable OEB decisions and orders. The December 31, 2012 balances in all authorized accounts were approved by the OEB for recovery in EB-2012-0002, with the exception of the four accounts brought forward for recovery in this proceeding.

OPG is not proposing any new deferral or variance accounts in this Application. OPG proposes to continue all existing deferral and variance accounts except the Tax Loss Variance Account and the Impact for US GAAP Deferral Account (see Section 10.3, below).

10.2 ISSUES 9.2 - 9.4

9.2 Secondary - Are the balances for recovery in each of the deferral and variance accounts appropriate?

9.3 Secondary - Are the proposed disposition amounts appropriate?

9.4 Secondary - Is the disposition methodology appropriate?

In its Application, OPG proposes to clear the audited December 31, 2013 balances in the four accounts that were deferred from the EB-2012-0002 proceeding.

The four accounts are: 1) the Hydroelectric Incentive Mechanism Variance Account, 2) the Hydroelectric Surplus Baseload Generation Variance Account, 3) portions of the Capacity Refurbishment Variance Account, and 4) the Nuclear Development Variance Account (collectively, the “brought forward accounts”). These accounts were deferred to this proceeding from EB-2012-0002 (Ex. H1-1-1, p. 1).

The total year-end audited 2013 debit balance in these four accounts is $126.9M for the previously regulated hydroelectric facilities and $62.2M for the nuclear facilities (Ex. N2-1-1, Tables 9 and 10). A detailed explanation of the proposed account clearance and calculation of riders is presented in Ex. H1-2-1 and Ex. N2-1-1, Tables 9 and 10.

OPG submits that the proposed disposition methodology is appropriate. OPG proposes to calculate separate hydroelectric and nuclear payment riders for the period from January 1, 2015 to December 31, 2015 in the form of $/MWh rates consistent with the OEB’s decisions and Payment Amounts Orders in EB-2012-0002 and EB-2010-0008.

The hydroelectric and nuclear payment riders are calculated separately using the following three steps. First, a recovery period is determined for each account to be cleared. Second, based on each account's recovery period and the audited balance in the account, the amount to be amortized over the period is determined. Finally, since the proposal is to clear these balances during 2015, the total amount to be amortized for all accounts to be cleared during the period is divided by the forecast energy production in 2015 to determine the payment rider (Ex. H1-2-1, p. 2).

OPG is requesting recovery of the audited December 31, 2013 balances in the Hydroelectric Incentive Mechanism Variance Account, Hydroelectric Surplus Baseload Generation Variance Account, and the hydroelectric portion of the Capacity Refurbishment Variance Account through hydroelectric payment rider to come into effect on January 1, 2015 and calculated using the forecast 2015 output from the previously regulated hydroelectric facilities.

OPG is also requesting recovery of the audited December 31, 2013 balances in the Nuclear Development Variance Account and the capital cost portion of the nuclear balance in the Capacity Refurbishment Variance Account through a nuclear payment rider to come into effect on January 1, 2015 and calculated using the forecast 2015 output from the nuclear facilities.

The resulting proposed riders are $1.35/MWh for nuclear and $3.36/MWh for the previously regulated hydroelectric (Ex. N2-1-1, Table 6 and 8).

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 (Ex. H1-1-1, p. 1, and Tr. Vol. 13, pp. 88-89).

10.3 ISSUE 9.5

Secondary - Is the proposed continuation of deferral and variance accounts appropriate?

OPG submits that the proposed continuation of existing deferral and variance accounts is appropriate.

Two accounts, the Tax Loss Variance Account and the Impact for US GAAP Deferral Account, are proposed to be terminated effective December 31, 2014 with any remaining balances transferred to the Nuclear and Hydroelectric Over/Under Variance Accounts. These two accounts can be terminated on this date because the need for these accounts is ending as explained for each account in the discussion below.

OPG proposes to continue the following existing deferral and variance accounts:

- Hydroelectric Water Conditions Variance Account
- Ancillary Services Net Revenue Variance Account – Hydroelectric and Nuclear Sub-Accounts
- Hydroelectric Incentive Mechanism Variance Account
- Hydroelectric Surplus Baseload Generation Variance Account
- Income and Other Taxes Variance Account
- Tax Loss Variance Account (to be terminated on December 31, 2014 pursuant to the EB-2012-0002 Payment Amounts Order)
- Capacity Refurbishment Variance Account
- Pension and OPEB Cost Variance Account
- Impact for USGAAP Deferral Account (to be terminated on December 31, 2014 pursuant to the EB-2012-0002 Payment Amounts Order)
- Hydroelectric Deferral and Variance Over/Under Recovery Variance Account
- Nuclear Liability Deferral Account
- Nuclear Development Variance Account
- Bruce Lease Net Revenues Variance Account – Derivative and Non-Derivative Sub-Accounts
- Pickering Life Extension Depreciation Variance Account
- Nuclear Deferral and Variance Over/Under Recovery Variance Account

The justification for continuing or ending each of these accounts, on an account by account basis, is set out in Ex. H1-3-1. The justifications are summarized below.

10.3.1 Hydroelectric Water Conditions Variance Account

The Hydroelectric Water Conditions Variance Account was originally established by O. Reg. 53/05 and subsequently approved by the OEB in EB-2007-0905 in recognition of the fact that water conditions are subject to a high degree of forecast risk due to factors that are beyond OPG's ability to manage or control, such as weather. This account should continue to record the financial impact of differences between forecast and actual water conditions for the previously regulated hydroelectric facilities. Due to similar forecast risk for the 21 largest newly regulated hydroelectric facilities, whose production is forecasted using models similar to those used to forecast production from the previously regulated facilities, OPG proposes to extend this account to include their production. Together they account for about 95 per cent of production from the newly regulated facilities (Ex. E1-1-1, pp. 4-5; Ex. H1-3-1, pp. 3-4).

10.3.2 Ancillary Services Net Revenue Variance Account

The Ancillary Services Net Revenue Variance Account was originally established by O. Reg. 53/05 and subsequently approved by the OEB in EB-2007-0905. This account recognizes that ancillary services revenues are difficult to forecast accurately, with variances between forecast and actual ancillary revenues reflecting changing demand and system/grid operating requirements. For the same reasons, OPG proposes that the account be extended to the newly regulated facilities.

The account also needs to continue in order to record the amortization of the year-end 2012 account balance approved in EB-2012-0002 and interest.

10.3.3 Hydroelectric Incentive Mechanism Variance Account

The Hydroelectric Incentive Mechanism Variance Account was originally approved in EB-2010-0008 to record a credit to ratepayers of 50 per cent of HIM net revenues above a specific threshold. In this Application, OPG is proposing a change to the operation of the HIM that eliminates the need for additions to the account in the future. The proposed mechanism is discussed in Ex. E1-2-1. The variance account needs to continue in order to record interest and amortization of the year-end 2013 account balance as proposed in this Application.

10.3.4 Hydroelectric Surplus Baseload Generation Variance Account

The Hydroelectric Surplus Baseload Generation Variance Account was originally approved in EB-2010-0008. This account should continue in order to record the financial impact of foregone production at the previously regulated hydroelectric facilities due to SBG conditions, with the enhancements described in Ex. E1-2-1, pp. 11-14. For the same reasons this account was originally established for the previously regulated hydroelectric facilities, OPG proposes to include the 21 largest newly regulated hydroelectric facilities (listed in Ex. E1-1-1, Appendix 1) in this account (Ex. H1-3-1, pp. 3, 5-6).

No forecast of foregone production due to SBG conditions has been applied to reduce the hydroelectric production forecasts proposed for establishing new payment amounts for the previously and newly regulated hydroelectric output.

OPG will also continue to record in the account changes in the GRC costs, as a result of SBG, from those reflected in the revenue requirement approved by the OEB. The amounts to be recorded will be calculated by multiplying the foregone production volume at the prescribed hydroelectric facilities due to SBG conditions by the applicable gross revenue charge rates. OPG will also continue to record in the Previously Regulated Sub-Account any variances in the amounts payable to the St. Lawrence Seaway Management Corporation for the conveyance of water in the Welland Ship Canal as a result of foregone production due to SBG. OPG also proposes to record in the Newly Regulated Sub-Account any related variances in the amounts payable to Government of Quebec (see Ex. F1-4-1, pp. 4-5) as a result of foregone production due to SBG.

The variance account also needs to continue in order to record interest and amortization of the year-end 2013 account balance as proposed in this Application.

10.3.5 Income and Other Taxes Variance Account

The Income and Other Taxes Variance Account was originally approved in EB-2007-0905. A similar account is available to electricity distributors.

The account also needs to continue in order to record the amortization of the year-end 2012 account balance approved in EB-2012-0002 and interest.

For the same reasons as it applies to OPG's other regulated facilities, OPG proposes that this account should apply to the newly regulated hydroelectric facilities starting on the effective date of the payment amounts for these facilities.

10.3.6 Tax Loss Variance Account

The Tax Loss Variance Account was originally approved in EB-2009-0038. OPG ceased recording additions to the account effective March 1, 2011. OPG will continue to record only interest and amortization in the account. Pursuant to the EB-2012-0002 Payment Amounts Order, the regulated hydroelectric and nuclear portions of the remaining account balance as at December 31, 2014 will be transferred to the Hydroelectric and Nuclear Deferral and Variance Over/Under Recovery Variance Accounts, respectively. Following this transfer, the Tax Loss Variance Account will be terminated on December 31, 2014.

10.3.7 Capacity Refurbishment Variance Account

The Capacity Refurbishment Variance Account was originally approved in EB-2007-0905 pursuant to Section 6(2)4 of O. Reg. 53/05. This account will continue to record variances between the actual capital and non-capital costs and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to a prescribed generation facility listed in O. Reg. 53/05, Section 2 and those forecast costs and firm financial commitments reflected in the revenue requirement approved by the OEB. The prescribed generation facilities include all newly regulated hydroelectric facilities. As required by O. Reg. 53/05, Section 6(2)4, this account will continue to include assessment costs and pre-engineering costs and commitments.

The account will also continue in order to record the amortization of the portion of the year-end 2012 account balance approved in EB-2012-0002 and interest. The account will also record the amortization of the portion of the year-end 2013 account balance proposed to be cleared in this Application.

10.3.8 Pension and OPEB Cost Variance Account

The Pension and OPEB Cost Variance Account was originally approved in EB-2011-0090 and subsequently continued in EB-2012-0002. As reflected in the approved Settlement Agreement in EB-2012-0002, this account will continue to record the difference between: (i) the pension and OPEB costs, plus related income tax PILs, reflected in the current revenue requirement approved by the OEB, and (ii) OPG's actual pension and OPEB costs, and associated tax impacts, for the prescribed generation facilities.

The account is required because pension and OPEB costs can vary significantly from forecast as a result of factors beyond management's control such as changes in discount rates, mortality and pension fund performance.

The differences between the forecast and actual amounts will continue to be calculated and recorded in a manner consistent with that underpinning the approved account balance as at December 31, 2012. Actual pension and OPEB costs used in the calculation of the difference will be calculated using the same accounting standards as those used to derive the OEB-approved forecast amounts.

The account also needs to continue in order to record the amortization of the year-end 2012 account balance approved in EB-2012-0002.

Effective January 1, 2015, OPG will resume the application of interest to the opening monthly balance of the remaining balance of the Future Recovery component and all additions recorded after December 31, 2012. The rationale for applying interest to other deferral and variance accounts also applies to the Pension and OPEB Cost Variance Account. An interest cost on the account balance is borne by OPG or ratepayers as a result of the accumulation, for future recovery from, or refund to, ratepayers, of amounts related to a current period. The application of interest on the balance recognizes the time value of money associated with the lag between the period in which amounts recorded in the account arise and the period in which they are settled between ratepayers and OPG.

OPG proposes that the variance account apply to the newly regulated facilities starting on the effective date of the payment amounts for these facilities, as the same factors resulting in differences between actual and forecast pension and OPEB costs equally affect both the newly and previously regulated facilities.

10.3.9 Impact for USGAAP Deferral Account

The Impact for USGAAP Deferral Account was originally approved in EB-2011-0432. This account captured the financial impacts of OPG's transition to and implementation of USGAAP. Effective January 1, 2013, pursuant to the EB-2012-0002 Payment Amounts Order, OPG ceased recording additions to the account. OPG will continue to record only interest and amortization in the deferral account. Pursuant to EB-2012-0002 Payment Amounts Order, the regulated hydroelectric and nuclear portions of the remaining account balance as at December 31, 2014 will be transferred to the Hydroelectric and Nuclear Deferral and Variance Over/Under Recovery Variance Accounts, respectively. Following this transfer, the Impact for USGAAP Deferral Account will be terminated on December 31, 2014.

10.3.10 Hydroelectric Deferral and Variance Over/Under Recovery Variance Account

The Hydroelectric Deferral and Variance Over/Under Recovery Variance Account was originally approved in EB-2009-0174. This account should continue in order to record the differences between the amounts approved for recovery in the hydroelectric deferral and variance accounts and the actual amounts recovered based on actual regulated hydroelectric production and approved riders. While there are currently no deferral or variance account balances for the newly regulated hydroelectric facilities, such balances are anticipated in the future, as OPG proposes to extend existing accounts to include these facilities. As such, this account is also proposed to be extended to include the newly regulated hydroelectric facilities.

The account also should continue in order to capture the transfer of the hydroelectric portion of the balances remaining in the Tax Loss Variance Account and the Impact for USGAAP Deferral Account as at December 31, 2014, and, as ordered by the OEB, other accounts as they may expire from time to time.

The account also needs to continue in order to record the amortization of the year-end 2012 account balance approved in EB-2012-0002 and interest.

10.3.11 Nuclear Liability Deferral Account

The Nuclear Liability Deferral Account was originally approved in EB-2007-0905 pursuant to O. Reg. 53/05. Pursuant to O. Reg. 53/05, this account will continue to record the revenue requirement impact of any change in OPG's nuclear decommissioning liability arising from an approved reference plan measured against the forecast impact reflected in the revenue requirement approved by the OEB. OPG will continue to record the return on rate base in the account using the weighted average accretion rate on its nuclear liabilities of 5.37 per cent.

The account will also continue to record the amortization of the year-end 2012 account balance, as approved in EB-2012-0002. Pursuant to the terms of the approved Settlement Agreement, as stipulated in the EB-2012-0002 Payment Amounts Order, no interest will be recorded on the balance of the Nuclear Liability Deferral Account**.**

10.3.12 Nuclear Development Variance Account

The Nuclear Development Variance Account was originally approved in EB-2007-0905 as mandated in O. Reg. 53/05. This account will continue to record variances between the actual non-capital costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities and those forecast costs and firm financial commitments reflected in the revenue requirement approved by the OEB. As noted in Ex. F2-8-1, OPG does not propose to include a forecast of these costs in the test period revenue requirement.

The account will also record interest and amortization of the year-end 2013 account balance as proposed in this Application.

10.3.13 Bruce Lease Net Revenues Variance Account

The Bruce Lease Net Revenues Variance Account was originally approved by the OEB in EB-2007-0905 in order to ensure that OPG recovers its actual costs associated with the Bruce facilities and that the regulated payment amounts are adjusted to reflect the actual revenues net of costs earned from the Bruce lease. This account should continue in order to capture differences between (i) the forecast revenues and costs related to the Bruce lease that are factored into the nuclear revenue requirement approved by the OEB, and (ii) OPG's actual revenues and costs in respect of the Bruce facilities. These revenues and costs are discussed in Ex. G2-2-1.

The variance recorded in this account will continue to be measured by comparing the Bruce lease revenues net of costs credited to customers monthly through the approved nuclear payment amount to the actual monthly Bruce lease revenues net of costs realized by OPG (Ex. H1-3-1, pp. 12-13). The monthly Bruce lease revenues net of costs credited to customers will continue to be equal to the rate of recovery reflected in the nuclear revenue requirement approved by the OEB multiplied by OPG's actual nuclear production. The rate of recovery will continue to be calculated by dividing the forecast Bruce lease revenues net of costs reflected in the OEB-approved nuclear revenue requirement by the OEB-approved nuclear production forecast.

As contemplated in EB-2012-0002, this account will continue be divided into two sub-accounts as follows:

Derivative Sub-Account: The Derivative Sub-Account will continue to record the following additions as determined in accordance with generally accepted accounting principles for unregulated entities: changes in the fair value of the derivative liability for the conditional supplemental rent rebate provision of the Bruce lease (recognized as change in accounting income) and associated income tax impacts on Bruce lease net revenues, and income tax impacts on Bruce lease net revenues of rent rebates resulting from the above provision.

Non-Derivative Sub-Account: The Non-Derivative Sub-Account will continue to record variances related to all non-derivative aspects of Bruce lease revenues net of costs.

The cost impact of any changes in OPG's liability for decommissioning the Bruce nuclear generating facilities and the management of nuclear waste and nuclear fuel related to the Bruce stations will also continue to be recorded in this account and will be reflected in the Non-Derivative Sub-Account.

The two sub-accounts will also continue in order to record the amortization of the applicable portions of the year-end 2012 account balance approved in EB-2012-0002.

To the extent that the actual supplemental rent rebate amounts paid to Bruce Power differ from the approved forecast amounts, such differences will be reflected in the Derivative Sub-Account in order to be carried forward to adjust amortization amounts the next time the account balance is cleared.

The terms of the approved Settlement Agreement reflected in the EB-2012-0002 Payment Amounts Order specified that no interest is to be recorded on the balance of either sub-account during the period from January 1, 2013 to December 31, 2014. Additionally, during this period, OPG is not recording interest on additions to either sub-account arising during 2013 or 2014.

Effective January 1, 2015, OPG will resume the application of interest to the opening monthly balances in the account, including all additions recorded after December 31, 2012.

10.3.14 Pickering Life Extension Depreciation Variance Account

As discussed in Ex. H1-1-1, Section 4.14, pursuant to the EB-2012-0002 Payment Amounts Order, this variance account was established in order to record a credit amount of $3.9M per month for the period from January 1, 2013 until the effective date of new nuclear payment amounts (excluding payment riders), reflecting the revised service lives, for depreciation purposes, of the Pickering stations. The nuclear payment riders established for 2013 and 2014 were reduced by an equivalent amount, resulting in an amortization debit entry being recorded in this account starting in 2013.

As the proposed revenue requirement reflects the revised Pickering service lives, starting on the effective date of the new payment amounts, the account will no longer record a credit addition. As the EB-2012-0002 payment rider continues until December 31, 2014, the account will continue to record an amortization debit entry during 2014 as approved in the EB-2012-0002 Payment Amounts Order. This will result in an accumulation, by December 31, 2014, of a balance to be recovered from ratepayers. This operation of the account is outlined in the approved EB-2012-0002 Settlement Agreement (Ex. M1-1, p. 30) and avoids the double-counting of the impact of the revised service lives that would otherwise result once new payment amounts are effective.

As per the EB-2012-0002 Payment Amounts Order, the account balance will continue not to attract interest.

10.3.15 Nuclear Deferral and Variance Over/Under Recovery Variance Account

The Nuclear Deferral and Variance Over/Under Recovery Variance Account was originally approved in EB-2009-0174. This account should continue in order to record the differences between the amounts approved for recovery in the nuclear deferral and variance accounts and the actual amounts recovered based on actual nuclear production and approved riders. The account also should continue in order to capture the transfer of the nuclear portion of the balances remaining in the Tax Loss Variance Account and the Impact for USGAAP Deferral Account as at December 31, 2014, and, as ordered by the OEB, other accounts as they may expire from time to time.

The account also needs to continue in order to record the amortization of the year-end 2012 account balance approved in EB-2012-0002 and interest.

10.4 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?

OPG submits that its proposal to not clear deferral and variance account balances in this proceeding other than the four accounts directed for clearance in EB-2012-0002 is appropriate. 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.

The reasons for clearing the balances in only these four accounts are discussed in Ex. H1-1-1, Sections 4.3, 4.4, 4.7 and 4.12 and in Ex. L-9.6-1 Staff-191. OPG chose to clear all accounts other than the four required by the decision and order in EB-2012-0002 through a separate application to be filed later in 2014 because: (i) these accounts had recently been reviewed (i.e., during 2013) and a rate rider for these accounts had already been established for 2014; and, (ii) it decreased the scope of the current case, making it somewhat more manageable (Tr. Vol. 13, pp. 88-92).

10.5 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 submits that its proposal to make existing hydroelectric variance accounts applicable to the newly regulated hydroelectric generation facilities is appropriate.

The newly regulated assets are subject to the same, or more, level of variability and uncertainty in respect to the cost and revenue items covered by these accounts as the previously regulated hydroelectric assets, as discussed in Ex. L-3.1-1 Staff 14 and Ex. L-9.7-1 Staff 193. Accordingly, for the same reasons as the existing hydroelectric variance accounts were established for OPG's currently regulated hydroelectric facilities, OPG proposes that these accounts should apply to the newly regulated hydroelectric facilities (Ex. L-9.7-1 Staff 193). Entries into the accounts in respect of the newly regulated hydroelectric facilities will commence on the effective date of the payment amounts for these facilities, proposed as July 1, 2014.

Where applicable, for ease of record keeping and tracking, OPG has proposed that separate sub-accounts will be used to distinguish between account entries for the previously and newly regulated facilities for the Hydroelectric Water Conditions Variance Account, the Ancillary Services Net Revenue Variance Account, the Hydroelectric Surplus Baseload Generation Variance Account and the Capacity Refurbishment Variance Account (Ex. H1-3-1).

10.6 ISSUE 9.8

Secondary - Is the proposal to discontinue the Hydroelectric Incentive Mechanism Variance Account appropriate?

The Hydroelectric Incentive Mechanism Variance Account was originally approved in EB-2010-0008 to record a credit to ratepayers of 50 per cent of hydroelectric incentive mechanism net revenues above a specific threshold.

In this Application, OPG is proposing an enhancement to the operation of the HIM that eliminates the need for additions to the account in the future (See eHIM proposal discussed in Ex. E1-2-1). Therefore, OPG submits that it is appropriate to discontinue the account once the current balance in the account, along with recorded interest, is disposed.

10.7 ISSUE 9.9

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

OPG is not proposing any new deferral or variance accounts in this Application and no new accounts were proposed by other parties during the proceeding.

11.0 REPORTING AND RECORD KEEPING REQUIREMENTS

11.1 ISSUE 10.1

Secondary - What additional reporting and record keeping requirements should be established for OPG?

OPG submits that no additional reporting or record keeping requirements are necessary. OPG did not propose any such requirements in its Application and the issue was not raised during the proceeding.

12.0 METHODOLOGIES FOR SETTING PAYMENT AMOUNTS

12.1 ISSUE 11.1

Oral Hearing - Has OPG responded appropriately to Board direction on establishing incentive regulation?

OPG submits that is has responded appropriately to the OEB's directions on establishing incentive regulation.

On March 28, 2013, the OEB issued its EB-2012-0340 Report of the Board on Incentive Rate-making for Ontario Power Generation's Prescribed Assets (the "Report"). This Report sets out the Board's expectations regarding incentive regulation ("IR") for OPG's prescribed generation assets (Ex. A3-1-1).

Importantly, the Report indicates that after this proceeding is concluded, the OEB intends to strike a working group to develop recommendations on the details of the IR mechanism for OPG's hydroelectric assets. A second working group will be established by the OEB to propose a methodology for setting OPG's nuclear payment amounts based on a multi-year cost of service approach. OPG anticipates that a nuclear IR mechanism will be established after the Darlington Refurbishment Project is complete, or upon achieving operational stability in this line of business in order to allow for an effective incentive rate making ("IRM") regime (Tr. Vol. 2, pp. 159-160).

The Report required OPG to file a proposed work plan and status report for the independent productivity study with the Application. The proposed work plan and status report was filed at Ex. A3-1-1, Attachment 1 (the "Work Plan").

OPG has engaged a consultant, London Economics International ("LEI"), to undertake the independent productivity study for OPG's prescribed hydroelectric facilities (Ex. A3-1-1). This study will be completed in time for the working group activities.

As noted during the proceeding, OPG is open to including the newly regulated hydroelectric assets in an IRM mechanism that covers all of OPG's hydroelectric assets for reasons of consistency and regulatory efficiency. In this Application, OPG has proposed that all of the regulatory treatments that apply to the previously regulated hydroelectric assets also be applied to the newly regulated assets. OPG would have to assess the Board's decision in this Application before finalizing its proposals for a comprehensive hydroelectric IRM (Ex. L-11.1-1 Staff 200).

12.2 ISSUE 11.2

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

OPG submits that the design of the proposed regulated hydroelectric and nuclear payment amounts is appropriate and should be accepted by the OEB.

The design is the same as that approved in OPG's two previous payment amounts cases. It was not challenged by any party during the proceeding.

As discussed under Issue 9.4, OPG is proposes separate per MWh riders for regulated hydroelectric and nuclear to clear the approved deferral and variance account balances. These riders would be determined based on the actual audited balances as at December 31, 2013 (provided in Ex. L-9.1-17 SEC-132).

Interim Period Shortfall Riders, determined as described in Ex. J3.10, would be appropriate to address the gap between effective date and implementation date, following the pattern set in EB-2007-0905 and EB-2012-002.

12.3 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?

As in the past, cost control is a prominent element of OPG's business planning process (see Section 2.2, above). Moreover according to the OEB's existing mitigation approach for transmitters and distributors, the threshold for considering mitigation is a 10 per cent total bill impact to customers. That threshold has not been reached in this Application (Ex. N2-1-1, p. 11). Based on the impact of OPG's proposed increase and its ongoing cost control efforts documented in its Application, OPG is not proposing to mitigate its proposed rate increases.

13.0 IMPLEMENTATION

13.1 ISSUE 12.1

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

OPG has requested an effective date of January 1, 2014 in respect of the previously prescribed hydroelectric and nuclear facilities, and an effective date of July 1, 2014 in respect of the newly prescribed hydroelectric facilities (Ex. A1-2-2, p. 2). Moreover, OPG requests recovery of the deficiency back to the applicable effective date over the balance of the test period by way of a rate rider.

In May of 2013, the OPG Board of Directors approved the 2013-15 Business Plan (Ex. A2-2-1, Attachment 1), which forms the basis of this Application. Both the business plan and the Application include OEB regulation of an additional 48 hydroelectric facilities. The timing of the Application was primarily driven by the time required to incorporate the requisite information on the newly regulated hydroelectric facilities and by the timing of the amendment posting.

The proposed amendments to O. Reg. 53/05 prescribing the additional hydroelectric facilities were posted for public review on September 13, 2013. Immediately thereafter, OPG finalized the Application and filed it on September 27, 2013 requesting payment amounts effective on January 1, 2014 (Ex. L-12.1-17 SEC-140).

The analysis of the proper effective date(s) is governed by (1) the legal requirement that payment amounts ordered by the Board must at all times be just and reasonable and (2) the fact that the OEB issued an Interim Payment Amounts Order declaring the currently approved payment amounts for the previously prescribed hydroelectric and nuclear facilities interim as of

January 1, 2014, and the current payment amounts for the newly prescribed hydroelectric facilities interim as of July 1, 2014.

In OPG's submission, having declared current payment amounts interim as of the dates set out above, the OEB is obliged to make the payments amounts it determines to be just and reasonable after review of the application effective from those dates. The time taken to process and review OPG's Application is legally irrelevant.

The Supreme Court of Canada's decision in *Bell Canada v. Canada (Canadian Radio-Television and Telecommunications Commission),* [1989] 1. S.C.R. 1722 is directly applicable. In that case, Bell had filed an application for a general rate increase and was granted an interim rate increase. Nearly two years later, in dealing with its final order, the CRTC determined that Bell had earned excessive revenues (just over $200M) in the interim period and ordered these excessive revenues to be credited back to customers.

The Supreme Court of Canada upheld the CRTC's jurisdiction to order the credit from the time rates were interim be returned to customers. The Supreme Court held that the CRTC had the power to revisit the period during which interim rates were in force and that this power was necessary to discharge the CRTC's primary obligation of ensuring that rates, at all times, during this period were just and reasonable.

As the Supreme Court of Canada explained:

> [T]he appellant [CRTC] has been given broad powers for the purpose of ensuring that telephone rates and tariffs are, at all times, just and reasonable. The appellant may revise rates at any time, either of its own motion or in the context of an application made by an interested party….<u>Were it not for the fact that the appellant has the power to make interim orders, one might say that the appellant's powers in this area are limited only by the time it takes to process applications, prepare for hearings and analyse all the evidence. However, the appellant does have the power to make interim orders and this power must be interpreted in light of the legislator's intention to provide the appellant with flexible and versatile powers for the purpose of ensuring that telephone rates are always just and reasonable</u>. [Emphasis added.]

And later, as the Court concluded:

> However, the power to make interim orders necessarily implies the power to modify in its entirety the rate structure previously established by final order. As a result, it cannot be said that the rate review process begins at the date of the final hearing; instead, the rate review begins when the appellant sets interim rates pending a final decision on the merits. (emphasis added.)

As set out above, here, the OEB set payment amounts on an interim basis from January 1 and July 1, 2014. In the Supreme Court's words, those are the dates on which the rate review process must begin. From those dates, it is incumbent on the OEB, under Section 78.1 of the Act to set payment amounts that are just and reasonable. The OEB cannot avoid this obligation by reference to the time taken to process the application.

If the Board were to establish effective dates that were later than the dates that the payment amounts were deemed interim, OPG would recover less than its full cost of service over the test period. This under-recovery would breach the just and reasonable rate standard. The costs underlying the Application are OPG's costs for the 2014 and 2015 period, which costs OPG needs to recover in order to operate its business in a safe and reliable manner.

In any event, even if other factors were relevant to the setting of an effective date, in OPG's submission, here those factors support OPG's request. Throughout the proceeding, OPG has been responsive to the Board, staff and intervenors. OPG has participated diligently, responsibly and with due regard for the procedural timelines that the Board has established and for the administrative procedures governing the proceeding.

Given the filing date for the Application, OPG acknowledges that it would have been unlikely the Board could have completed the proceeding prior to January 1, 2014. However, as indicated by Mr. Barrett during the Oral Hearing, the date of the filing of the Application was driven by the Government's consideration of whether or not to regulate the newly prescribed hydroelectric facilities. OPG first became aware of this possibility in the spring of 2013, in response to which OPG developed a business plan revenue forecast and commenced gathering the information needed to support such a filing. This work continued into the summer of 2013. However, OPG was not in a position to file its Application, and OPG did not believe the OEB would have been in a position to receive the Application, until the Government signaled publicly that it was actually going to prescribe the relevant facilities. This occurred on September 13, 2013 when the government posted its proposed amendment to the regulation.

Once this happened, OPG proceeded expeditiously and the Application was filed two weeks later (Tr. Vol. 2, pp. 169-172).