ONTARIO POWER GENERATION

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February 20, 2015

VIA RESS AND COURIER

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

Dear Ms. Walli:

Re: EB-2014-0370 – Clearance of Deferral and Variance Account Balances – Evidence Update

Please find attached updates to evidence to incorporate audited actual December 31, 2014 balances in OPG's deferral and variance accounts. In its December 18, 2014 filing, OPG indicated its intent to file actual audited balances in February, 2015. This package includes:

- A New Exhibit, H1-1-2 which contains tables setting out and supporting audited actual December 31, 2014 account balances, as well as the associated rider and impact calculations. This exhibit describes reasons for differences between actual balances and projected balances originally filed where those differences are material. This exhibit also contains, as attachments, auditor's and independent actuary's reports as supporting material.

- Updated administrative documents, updated as required to give effect to proposed riders resulting from audited actual December 31, 2014 account balances.

A list of the amended evidence is provided below:

Exhibit	**Description**
A1-1-1	Updated page 1
A1-1-2	Updated page 2
A1-1-3	Updated page 3
H1-1-2	A new evidence schedule that provides audited actual December 31, 2014 account balances and the resulting riders and estimated impacts.

Regards,

[Original signed by]

Garry M. Hendel

cc:	Charles Keizer	Tory’s LLP
	Carlton Mathias	OPG
	EB-2014-0370 Intervenors	

EXHIBIT LIST

EX	TAB	SCH	CONTENTS
A			ADMINISTRATIVE DOCUMENTS
A1	1	1	Exhibit List
		2	Application
		3	Approvals
		4	Draft Issues List
A2	1	1	Stakeholder Information Session
		2	Procedural Orders / Correspondence / Notices
		3	List of Witnesses
		4	Curricula Vitae of Witnesses
H			DEFERRAL AND VARIANCE ACCOUNTS
H1	1	1	Overview of Deferral and Variance Accounts
	1	2	Update for Audited Actual Balances for Deferral and Variance Accounts Attachment 1: Independent Auditors' Report on OPG's Deferral and Variance Account Balances as at December 31, 2014 and Accompanying Schedule of Regulatory Balances Attachment 2: Report on the Accounting Cost for Post Employment Benefit Plans in Support of Pension and OPEB Cost Variance Calculations for Fiscal Year 2013 and the Period from January 1 to October 31, 2014
	2	1	Clearance of Deferral and Variance Accounts
	3	1	Continuation of Existing Deferral and Variance Accounts
I			DETERMINATION OF RIDERS
I1	1	1	Regulated Hydroelectric and Nuclear Riders
		2	Rate and Consumer Impact
		3	IESO Settlement Process

5. For the Bruce Lease Net Revenues Variance Account – Derivative Sub-Account, OPG proposes to clear the balance using the method as per the terms of the OEB-approved settlement in EB-2012-0002.

6. To achieve the requested disposition of the balances in the deferral and variance accounts (as described in paragraphs 2 and 3 above), OPG is seeking payment riders of \$3.55/MWh and \$15.57/MWh for the output of its prescribed Hydroelectric and Nuclear facilities, respectively, effective July 1, 2015.

7. The Application will be supported by written evidence. The written evidence filed by OPG may be supplemented or amended from time to time by OPG prior to the OEB's final decision on the Application.

8. OPG requests that pursuant to section 32.01 of the OEB Rules of Practice and Procedure, this proceeding be conducted by way of a written hearing.

9. OPG further applies to the OEB pursuant to the provisions of the Act and the OEB Rules of Practice and Procedure for such orders and directions as may be necessary in relation to the Application and the proper conduct of this proceeding.

10. The persons affected by this Application are all electricity consumers in Ontario. It is impractical to set out the names and addresses of the consumers because they are too numerous.

11. OPG requests that copies of all documents filed with the OEB by each party to this Application along with copies of all comments filed with the OEB in accordance with Rule 9 of the OEB Rules of Practice and Procedure be served on the applicant and the applicant's counsel as follows:

- Approval to clear the approved balances in the above referenced accounts, except for the post 2012 additions to the Pension and OPEB Cost Variance Account and the derivative portion of the Bruce Lease Net Revenues Variance Account, over 18 months (July 1, 2015 through December 31, 2016).

- Approval to clear the approved balance in the Pension and OPEB Cost Variance Account attributable to the 2013 and 2014 Additions over 24 months (July 1, 2015 through June 30, 2017).

- Approval to clear the Bruce Lease Net Revenues Variance Account – Derivative Sub Account over 18 months (July 1, 2015 through December 31, 2016) using the method which was approved in EB-2012-0002. That method requires the amount cleared each year to be equal to the amount of the supplemental rent rebate forecast to be payable to Bruce Power for that year by OPG and associated income tax impacts, less the difference between amounts previously recovered in respect of this sub-account and actual rent rebates paid to Bruce Power by OPG and associated income taxes.

- Approval of the following payment riders effective July 1, 2015 through December 31, 2016: Regulated Hydroelectric $3.55/MWh and Nuclear $15.57/MWh.

UPDATE FOR AUDITED ACTUAL BALANCES FOR DEFERRAL AND VARIANCE ACCOUNTS

1.0 PURPOSE

The purpose of this exhibit is to provide the audited actual deferral and variance account balances at December 31, 2014 and to update OPG's calculation of payment riders proposed for the clearance of these account balances and resulting consumer impacts.

2.0 SUMMARY OF BALANCES, PAYMENT RIDERS AND CONSUMER IMPACT

The tables accompanying this exhibit reproduce those originally filed in Ex. H1-1-1, Ex. H1-2-1 and Ex. I1-1-2. The tables have been updated to reflect audited actual balances and related information.

Audited actual deferral and variance account balances at December 31, 2014 are presented in Ex. H1-1-2, Table 1, col. (d). Continuity schedules showing actual additions, amortization and interest for each account during 2014 are provided at Ex. H1-1-2, Table 1b for January to October 2014 and Table 1c for November and December 2014. Exhibit H1-1-2, Tables 2 through 14 provide supporting calculations showing the derivation of additions into the accounts.

Overall, the total audited actual December 31, 2014 balances for recovery are debit balances of $190.6M for regulated hydroelectric and $1,557.8M for nuclear, as shown in col. (c) of Ex. H1-1-2, Tables 15 and 16, respectively.[1] Compared to the projected balances originally filed, the total regulated hydroelectric debit balance for recovery has decreased by $11.2M from the projection of $201.8M. The total nuclear debit balance for recovery has increased by $9.2M from the projection of $1,548.5M.

Actual account balances as at December 31, 2014 have been audited by OPG's auditor, Ernst & Young LLP. The unqualified auditors' report and the accompanying schedule of the

[1] A debit entry or balance is an amount to be collected from ratepayers. A credit entry or balance is an amount to be returned to ratepayers.

audited balances are provided as Attachment 1 to this exhibit. In addition, an independent actuary's report from Aon Hewitt, in support of the January 2013 through October 2014 pension and other post-employment benefits ("OPEB") amounts underpinning the actual additions recorded in the Pension and OPEB Cost Variance Account during this period, is included as Attachment 2 to this exhibit. The additions to the Pension and OPEB Cost Variance Account from January 2013 through October 2014 are unchanged from those presented in the original filing (see Ex. H1-1-1, section 5.8).

Section 3 discusses the actual audited 2014 account balances and entries for the deferral and variance accounts with the largest differences in the December 31, 2014 balances from the projections originally filed on December 18, 2014.

The lower December 31, 2014 total regulated hydroelectric debit balance for recovery is primarily driven by the change from a debit to a credit balance in the Hydroelectric Water Conditions Variance Account and a higher credit balance in the Ancillary Services Net Revenue Variance Account, partially offset by a higher debit balance in the Hydroelectric Surplus Baseload Generation Variance Account. The main driver of the increase in the December 31, 2014 total nuclear debit balance for recovery is the higher debit balance of the derivative sub-account of the Bruce Lease Net Revenues Variance Account, partially offset by the lower debit balance of the non-capital portion of the Capacity Refurbishment Variance Account and the higher credit balance in the Income and Other Taxes Variance Account.

There are no changes to OPG's clearance proposal for any of the accounts, including amortization periods and methods for calculating the payment riders. The calculation of the payment riders, proposed to be effective July 1, 2015, is shown in Ex. H1-1-2 Table 15 for regulated hydroelectric and Table 16 for nuclear. The resulting riders are $3.55/MWh for regulated hydroelectric and $15.57/MWh for nuclear.

The bill impact for a typical residential consumer of the above riders is estimated to be $3.00 per month on a typical monthly bill, as shown in Ex. H1-1-2 Table 17. This impact is slightly lower than the increase of $3.08 per month originally filed based on projected account balances.

3.0 DISCUSSION OF VARIANCES FROM YEAR-END 2014 PROJECTED BALANCES

This section discusses the actual audited 2014 account balances and entries for the deferral and variance accounts with the largest differences in the December 31, 2014 balances for recovery from the projections originally filed on December 18, 2014.
The main reasons for the differences from the December 18, 2014 projections of year-end 2014 balances for these accounts are discussed below.

3.1 Hydroelectric Water Conditions Variance Account

The 2014 year-end audited credit balance in the Hydroelectric Water Conditions Variance Account is $8.5M, compared to the originally filed projected debit balance of $12.7M, as shown in Ex. H1-1-2, Table 1, due to higher-than-forecast credit additions to the account during the November 1, 2014 to December 31, 2014 period. The higher credit additions, the calculation of which is shown in Ex. H1-1-2, Table 2, were due to actual water flows in 2014 being higher than originally projected.

3.2 Bruce Lease Net Revenues Variance Account – Derivative Sub-Account

The 2014 year-end audited debit balance in the Derivative Sub-Account of the Bruce Lease Net Revenues Variance Account is $153.8M, compared to the projected balance of $129.9M, The actual debit additions during November and December 2014 are as a result of an increase in the fair value of the derivative liability related to the Bruce lease agreement. The increase in the fair value is due to an increased expectation that the annual arithmetic average of the HOEP will fall below $30/MWh in the future. The actual account additions, revenues earned by OPG under the Bruce lease and associated agreements in 2014 and the related costs incurred by OPG with respect to the Bruce Nuclear Generating Stations are presented in Ex. H1-1-2 Tables 13 and 13a.

As noted in Ex. H1-1-1, section 5.13, pursuant the approved EB-2012-0002 Settlement Agreement, the 2013 and 2014 amortization of the Derivative Sub-Account is equal to the amount of the supplemental rent rebate forecast to be payable to Bruce Power by OPG for each year and associated income tax impacts, adjusted by the difference between amounts previously recovered for the derivative, and the actual rent rebates paid by OPG to Bruce Power and associated income taxes. OPG has proposed to continue with this recovery methodology as discussed in Ex. H1-2-1. As such, the higher debit balance in the Derivative Sub-Account as at December 31, 2014 does not impact the proposed amortization amounts and payment riders.

3.3 Hydroelectric Surplus Baseload Generation Account

The 2014 year-end audited debit balance in the Hydroelectric Surplus Baseload Generation Account is $67.1M, compared to the originally filed projection of $52.0M. This is due to a higher than expected volume of foregone production at OPG's regulated hydroelectric facilities during November and December 2014 as a result of surplus baseload generation ("SBG") conditions. The higher SBG spill during November and December 2014 reflected weaker than expected electricity demand and higher than expected water flows. Ex. H1-1-2, Table 5 details the account additions.

3.4 Ancillary Services Net Revenue Variance Account – Hydroelectric

The 2014 year-end audited credit balance in the Ancillary Services Net Revenue Variance Account – Hydroelectric is $16.5M, compared to the originally filed projected credit balance of $10.6M. The higher actual credit balance reflects actual ancillary services revenues for operating reserve ("OR") and regulation service (formerly automatic generation control) being higher than forecasted for this period. The higher OR revenues were a result of higher than expected OR prices during the last two months of 2014, while the higher regulation service revenues reflected the newly negotiated contract between OPG and the IESO. Ex. H1-1-2, Table 3 details the account additions.

3.5 Capacity Refurbishment Variance Account – Nuclear – Non-Capital Portion

The 2014 year-end audited debit balance of the nuclear non-capital portion of the Capacity Refurbishment Variance Account is $1.3M, which is lower than the $6.7M originally projected. This is primarily due to actual non-capital costs incurred for the Darlington Refurbishment project and Pickering Continued Operations in November and December 2014 being lower than forecast.

Actual non-capital Darlington Refurbishment project costs for November and December 2014 were lower than expected primarily due to a reduction in removal costs charged to the project. Actual Pickering Continued Operations costs for November and December 2014 were lower than projected primarily due to delays in execution of maintenance and repairs activities, partially offset by higher than planned expenditures related to project work. Ex. H1-1-2, Table 12 details the account additions.

3.6 Income and Other Taxes Variance Account - Nuclear

The total 2014 year-end audited balance in the Income and Other Taxes – Nuclear Variance Account is a credit of $13.2M, compared to the originally filed projected credit balance of $8.5M. The higher credit balance reflects an additional 25 per cent of the benefit of the Scientific Research & Experimental Development investment tax credits for 2010 that were previously credited to ratepayers at 75 per cent. The additional credit is based on the completion of the audit of OPG’s 2010 taxation year in late 2014. This credit addition, shown at Ex. H1-1-2 Table 6, is the same in nature and calculation as the equivalent additions for the 2008 and 2009 taxation years recorded in the variance account in 2013 and earlier in 2014.

LIST OF ATTACHMENTS

Attachment 1:	Independent Auditors' Report on OPG's Deferral and Variance Account Balances as at December 31, 2014 and Accompanying Schedule of Regulatory Balances
Attachment 2:	Aon Hewitt's Report on the Accounting Cost for Post Employment Benefit Plans in Support of Pension and OPEB Cost Variance Calculations for Fiscal Year 2013 and the Period from January 1 to October 31, 2014

INDEPENDENT AUDITORS' REPORT

To the management of **Ontario Power Generation Inc.**

We have audited the accompanying schedule of regulatory balances of **Ontario Power Generation Inc.** as at December 31, 2014 (the "Schedule"). The Schedule has been prepared by management to present the balances of the variance and deferral accounts of **Ontario Power Generation Inc.** authorized for **Ontario Power Generation Inc.** by the decisions and orders of the Ontario Energy Board, in accordance with United States generally accepted accounting principles, as modified to include a return on equity amount as part of cost of capital additions recorded in the accounts for recovery from, or refund to, ratepayers, as described in Note 1 to the Schedule.

Management's responsibility for the schedule of regulatory balances
Management is responsible for the preparation and the fair presentation of this Schedule in accordance with United States generally accepted accounting principles, as modified to include a return on equity amount as part of cost of capital additions recorded in the accounts for recovery from, or refund to, ratepayers, as described in Note 1 to the Schedule, and for such internal control as management determines is necessary to enable the preparation of the Schedule that is free from material misstatement, whether due to fraud or error.

Auditors' responsibility
Our responsibility is to express an opinion on the Schedule based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the Schedule is free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the Schedule. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the Schedule, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the Schedule in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the Schedule.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the Schedule presents fairly, in all material respects, the balances of the variances and deferral accounts of **Ontario Power Generation Inc.** as at December 31, 2014 authorized for **Ontario Power Generation Inc**. by the decisions and orders of the Ontario Energy Board, in accordance with United States generally accepted accounting principles, as modified to include a return on equity amount as part of cost of capital additions recorded in the accounts for recovery from, or refund to, ratepayers, as described in Note 1 to the Schedule.

Basis of accounting and restriction on distribution
Without modifying our opinion, we draw attention to Note 1 to the Schedule, which describes the basis of accounting. The Schedule is prepared solely for the use of **Ontario Power Generation Inc.** and for filing with the Ontario Energy Board as part of the regulatory process. As a result, the Schedule may not be suitable for another purpose.

Our auditors' report is intended solely for **Ontario Power Generation Inc.** and for filing with the Ontario Energy Board as part of the regulatory process and should not be used for any other purpose.

[Original Signed by]

TORONTO, CANADA
February 18, 2015

ERNST & YOUNG LLP
Chartered Professional Accountants
Licensed Public Accountants

SCHEDULE OF REGULATORY BALANCES
AS AT DECEMBER 31, 2014

The *Ontario Energy Board Act, 1998* and *Ontario Regulation 53/05* provide that Ontario Power Generation Inc. (“OPG”) receives regulated prices for electricity generated from most of its hydroelectric generating facilities and all of the nuclear generating facilities that it operates. OPG’s regulated prices for the generation from these facilities are determined by the Ontario Energy Board (“OEB”). Forty-eight of the regulated hydroelectric facilities were prescribed for regulation effective in 2014, pursuant to a November 2013 amendment to *Ontario Regulation 53/05*.

The OEB’s decisions and orders have authorized OPG to establish certain variance and deferral accounts, including those authorized pursuant to *Ontario Regulation 53/05*. The balances in these accounts are calculated in accordance with the OEB’s decisions and orders and *Ontario Regulation 53/05*. In accordance with United Stated generally accepted accounting principles (“US GAAP”), OPG’s consolidated financial statements recognize regulatory assets and liabilities for balances in the variance and deferral accounts.

In its March 2013 decision approving a settlement agreement between OPG and intervenors on all aspects of OPG’s application under case number EB-2012-0002, the OEB approved the December 31, 2012 balances in most of OPG’s variance and deferral accounts. To effect the recovery of the approved balances, the OEB established rate riders for the period from January 1, 2013 to December 31, 2014. During 2013 and 2014, OPG recorded additions to the variance and deferral accounts and amortized the approved December 31, 2012 balances as authorized by the OEB. In December 2014, under case number EB-2014-0370, OPG filed an application requesting the OEB’s approval for disposition of the balances as at December 31, 2014 in most of the variance and deferral accounts, through new rate riders effective July 1, 2015. During 2013 and 2014, where authorized by the OEB, OPG recorded interest on the unamortized balances in the applicable variance and deferral accounts at the OEB-prescribed rate of 1.47 percent per annum.

As at December 31, 2014, the balances to be recovered from (refunded to) ratepayers in the variance and deferral accounts authorized for OPG were as follows:

(millions of dollars)	**2014**
Regulated Hydroelectric	
Capacity Refurbishment Variance Account – Hydroelectric	**233**
Hydroelectric Surplus Baseload Generation Variance Account	**67**
Pension and OPEB Cost Variance Account – Hydroelectric – Future Recovery Component	**10**
Pension and OPEB Cost Variance Account – Hydroelectric – Post 2012 Additions	**35**
Pension & OPEB Cash Versus Accrual Differential Deferral Account – Hydroelectric	**5**
Hydroelectric Deferral and Variance Over/Under Recovery Variance Account	**5**
Pension & OPEB Cash Payment Variance Account – Hydroelectric[1]	**-**
Income and Other Taxes Variance Account – Hydroelectric[1]	**-**
Hydroelectric Incentive Mechanism Variance Account	**(7)**
Hydroelectric Water Conditions Variance Account	**(8)**
Ancillary Services Net Revenue Variance Account – Hydroelectric	**(17)**
Total – Regulated Hydroelectric	**323**
Nuclear	
Pension and OPEB Cost Variance Account – Nuclear – Future Recovery Component	**215**
Pension and OPEB Cost Variance Account – Nuclear – Post 2012 Additions	**679**
Nuclear Liability Deferral Account	**286**
Bruce Lease Net Revenues Variance Account – Derivative Sub-Account	**154**
Bruce Lease Net Revenues Variance Account – Non-Derivative Sub-Account – EB-2012-0002 Approved	**37**
Bruce Lease Net Revenues Variance Account – Non-Derivative Sub-Account – Post 2012 Additions	**124**
Nuclear Development Variance Account	**59**
Nuclear Deferral and Variance Over/Under Recovery Variance Account	**56**
Pension & OPEB Cash Versus Accrual Differential Deferral Account – Nuclear	**31**
Capacity Refurbishment Variance Account – Nuclear – Capital Portion	**13**
Capacity Refurbishment Variance Account – Nuclear – Non-Capital Portion	**1**
Pickering Life Extension Depreciation Variance Account	**8**
Pension & OPEB Cash Payment Variance Account – Nuclear	**6**
Ancillary Services Net Revenue Variance Account – Nuclear	**2**
Income and Other Taxes Variance Account – Nuclear	**(13)**
Total – Nuclear	**1,658**

[1] The account balance is less than $0.5 million, which rounds to nil million.

This schedule of regulatory balances has been prepared solely for the use of OPG's management and for filing with the OEB, and is considered by OPG's management to be a fair and reasonable representation of the balances in the authorized variance and deferral accounts as at December 31, 2014. These balances have been determined in accordance with the basis of accounting described in Note 1 to this schedule.

On behalf of Ontario Power Generation Inc.

[Original signed by]

Beth Summers
Chief Financial Officer
February 18, 2015

See accompanying note to the schedule

NOTE TO THE SCHEDULE OF REGULATORY BALANCES
AS AT DECEMBER 31, 2014

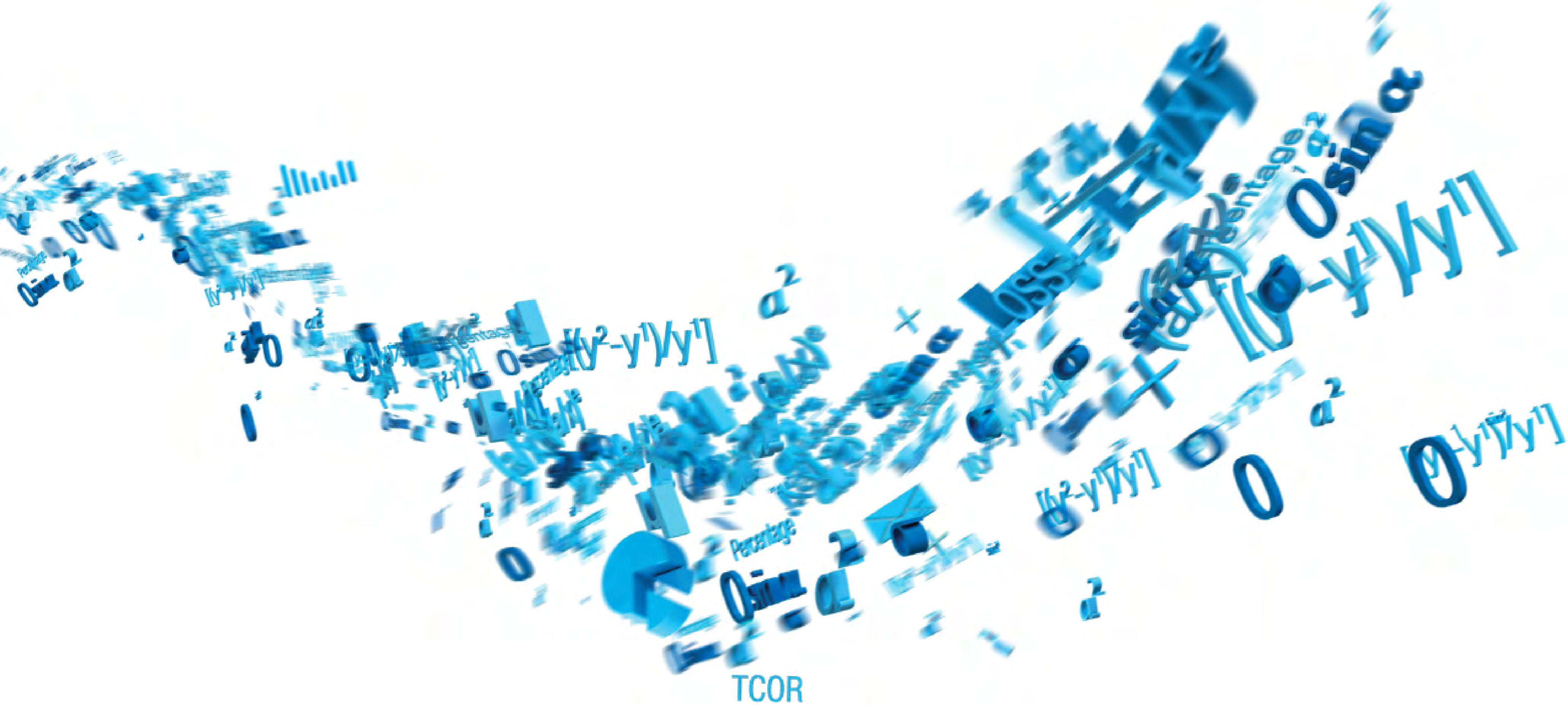
1. BASIS OF ACCOUNTING

The schedule of the regulatory balances presents the balances as at December 31, 2014 in all variance and deferral accounts authorized for OPG. These balances represent the regulatory assets and liabilities for these accounts recorded by OPG in accordance with US GAAP for the purposes of its consolidated financial statements, as modified to include a return on equity amount as part of cost of capital additions recorded in the accounts for recovery from, or refund to, ratepayers. For the purposes of its consolidated financial statements prepared in accordance with US GAAP, as required by FASB Accounting Standards Codification Topic 980, *Regulated Operations*, OPG limits the portion of cost of capital additions recognized as a regulatory asset to the amount calculated using the average rate of capitalized interest applied by OPG to construction and development in progress. All dollar amounts are presented in Canadian dollars.

US GAAP recognizes that rate regulation can create economic benefits and obligations that are required to be obtained from, or settled with, the ratepayers. When OPG assesses that there is sufficient assurance that incurred costs in respect of regulated facilities will be recovered in the future, those costs are deferred and reported as a regulatory asset in its consolidated financial statements. When OPG is required to refund amounts in respect of regulated facilities to ratepayers in the future, including amounts related to costs that have not been incurred and for which the OEB has provided recovery through regulated prices, OPG records a regulatory liability in its consolidated financial statements. The measurement of regulatory assets and liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of *Ontario Regulation 53/05* and the OEB's decisions. The estimates and assumptions made in the interpretation of the regulation and the OEB's decisions are reviewed as part of the OEB's regulatory process.

OPG's most recent annual consolidated financial statements filed with the Ontario Securities Commission ("OSC") are as at and for the year ended December 31, 2013. OPG's most recent interim consolidated financial statements are as at and for the nine months ended September 30, 2014 and have been filed with the OSC.

Aon Hewitt



Report on the Accounting Cost for Post Employment Benefit Plans in Support of Pension and OPEB Cost Variance Account Calculations

Fiscal Year 2013 and the Period from January 1 to October 31, 2014
Ontario Power Generation Inc.

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Table of Contents

Introduction

This report summarizes the accounting costs for fiscal year 2013 and the period from January 1, 2014 to October 31, 2014 for the post employment benefit plans sponsored by Ontario Power Generation Inc. ("OPG"). In addition, Aon Hewitt has prepared this report to provide an independent actuary's confirmation of information for the post employment benefit plans sponsored by OPG in relation to the balance in OPG's Pension and OPEB Cost Variance Account ("the Variance Account") as at December 31, 2014. We understand this report is expected to be filed with the Ontario Energy Board ("OEB").

This report covers the following plans sponsored by OPG:

- Ontario Power Generation Inc. Pension Plan ("RPP");
- Ontario Power Generation Inc. Supplementary Pension Plan ("SPP") ;
- Non-pension Post Retirement Plan which provides other post retirement benefits ("OPRB") including retiree medical, dental, life insurance, and retirement bonus benefits, and
- Post Employment Plan which provides long-term disability benefits ("LTD") including sick leave benefits before LTD begins and the continuation of medical, dental and life insurance while on LTD.

Collectively SPP, OPRB and LTD are known as Other Post Employment Benefits ("OPEB").

The results cover the fiscal year 2013 and the period from January 1, 2014 to October 31, 2014. The results have been developed under Canadian generally accepted accounting principles ("Canadian GAAP") under the former CICA Handbook–Accounting (Part V), Section 3461 ("CICA 3461") and, with the exception of LTD (as outlined on page 7), are the same as the results under US GAAP.

The results in this report do not include amounts related to the benefit plans of the Nuclear Waste Management Organization, which are included in OPG's consolidated financial statements.

Unless otherwise stated, all assumptions, data elements, methodologies, plan provisions, and information about assets reflected in this report are the same as those underlying and/or contained in the December 31, 2012 or the December 31, 2013 disclosure reports ("the Reports") prepared by Aon Hewitt in accordance with US generally accepted accounting principles ("US GAAP") under ASC 715, 712 and 710 for the post employment benefit plans sponsored by OPG. These disclosure reports were dated March 2013 and March 2014, respectively, and are titled as follows:

- US GAAP Accounting Information Non-pension Post-retirement and Post-employment Benefits Plans; and
- US GAAP Accounting Information – Pension Plans.

Sincerely,

Aon Hewitt Inc.

[Original Signed By]

Linda M. Byron
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

Aon Hewitt Inc.

[Original Signed By]

Gregory W. Durant
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

February 2015

Actuarial Report

Pension and OPEB Cost Variance Account

In March 2011, OPG filed with the OEB a motion to review and vary the OEB's decision, issued in March 2011 under case number EB-2010-0008, with respect to pension and OPEB costs. In June 2011, under case number EB-2011-0090, the OEB established the Pension and OPEB Cost Variance Account for the period from March 1, 2011 to December 31, 2012 in its decision and order granting OPG's motion. In March 2013, under case number EB-2012-0002, the OEB authorized the continuation of the Pension and OPEB Cost Variance Account for the period after December 31, 2012 without a prescribed end date. In December 2014, with the establishment of two new regulatory variance accounts for OPG related to pension and OPEB, under case number EB-2013-0321, the OEB ordered that no new variances between actual and forecast pension and OPEB costs be recorded in the Pension and OPEB Cost Variance Account effective November 1, 2014.

Up to October 31, 2014, the Pension and OPEB Cost Variance Account recorded the difference between actual pension and OPEB costs under Canadian GAAP for OPG's regulated operations and related tax impacts, and those reflected in the regulated prices established by the OEB under case number EB-2010-0008. The forecast pension and OPEB costs for the years ending December 31, 2011 and 2012 reflected in the regulated prices established under case number EB-2010-0008 represent the portion of OPG's total forecast pension and OPEB costs determined in accordance with Canadian GAAP for those years attributable to its nuclear and regulated hydroelectric businesses. These forecast costs were based on calculations prepared by an independent actuary, Mercer (Canada) Limited.

Results for 2013 and 2014

This report confirms OPG's total actual pension and OPEB costs for the period from January 1, 2013 to December 31, 2013 and the period from January 1, 2014 to October 31, 2014, as determined in accordance with Canadian GAAP, are as follows:

(in Canadian $ 000's)	January 1 to December 31, 2013	January 1 to October 31, 2014
RPP	$ 473,282	$ 439,303
SPP	28,553	21,532
OPRB	257,010	150,546
LTD	17,205	20,117
Total	$ 776,050	$ 631,498

Further details of the OPG-wide costs provided above, by plan, as well as OPG's actual contributions to the RPP fund and benefit payments for OPEB for the periods from January 1, 2013 to October 31, 2014 are provided in Schedules 1 and 2 to this report.

The balance of the Pension and OPEB Cost Variance Account calculated and recorded by OPG as at December 31, 2014 is $939 million, as reported in the audited schedule of regulatory balances as at December 31, 2014, dated February 18, 2015, prepared by OPG for filing with the OEB. The December 31, 2014 account balance reflects the unamortized portion of the December 31, 2012 balance, as well as additions recorded by OPG during the period from January 1, 2013 to October 31, 2014. Aon Hewitt previously reported on the 2011 and 2012 actual OPG-wide pension and OPEB costs in support of the Pension and OPEB Cost Variance Account balance in the following reports, which were filed by OPG with the OEB under case number EB-2012-0002 (the "2011/2012 Variance Account Reports"):

- "Report on the CICA 3461 (CGAAP) Accounting Cost for Post Employment Benefit Plans in Support of Pension and OPEB Cost Variance Calculations" dated June 2012.
- "Report on the Accounting Cost for Post Employment Benefit Plans for Fiscal Year 2012 and in Support of Pension and OPEB Cost Variance Calculations" dated February 2013.

The pension and OPEB cost variance component of the addition of the Pension and OPEB Cost Variance Account for the fiscal year ending December 31, 2013 and for the period from January 1, 2014 to October 31, 2014 was calculated by OPG by comparing the portion of the above 2013 and 2014 OPG-wide costs under Canadian GAAP attributed to OPG's nuclear and regulated hydroelectric businesses for the corresponding periods to the forecast of such costs included in the regulated prices established by the OEB under case number EB-2010-0008.

Actuarial Methods and Assumptions

Aon Hewitt confirms that the Canadian GAAP OPG-wide costs for the year ended December 31, 2013 and for the period from January 1, 2014 to October 31, 2014 were determined using the actuarial methodology and accounting standards described below. We furthermore confirm that the methodology under Canadian GAAP is consistent with the methodology as outlined in OPG's application to, and approved by, the OEB under case number EB-2010-0008 and used to determine the forecast pension and OPEB costs reflected in the regulated prices established by the OEB in that proceeding. This methodology is also consistent with that used to determine the actual OPG-wide Canadian GAAP costs for the years ended December 31, 2011 and December 31, 2012 outlined in the 2011/2012 Variance Account Reports.

- Benefit obligations for RPP, SPP and OPRB are determined using the projected benefit method prorated on service;
- Benefit obligations for LTD are determined using the projected benefit method on a terminal basis such that the total estimated future benefit is attributed to the year of service in which a disability occurs;
- The discount rates have been determined in accordance with Canadian GAAP (i.e., CICA 3461). The discount rates have been set with reference to those representative of AA corporate bond yields in Canada having a duration similar to the liabilities of the plans. The December 31, 2012 discount rates were 4.30% per annum for determining the 2013 RPP and SPP cost, 4.40% per annum for determining the 2013 OPRB cost, and 3.50% per annum for determining the 2013 LTD cost. The December 31, 2013 discount rates were 4.90% per annum for determining the January 1, 2014 to October 31, 2014 RPP and SPP cost, 5.00% per annum for determining the January 1, 2014 to October 31, 2014 OPRB cost, and 4.10% per annum for determining the January 1, 2014 to October 31, 2014 LTD cost.

- A building block approach was used in determining the expected long-term rate of return on plan assets. Historical markets are studied and long-term historical relationships between equities and fixed-income are preserved consistent with the widely accepted capital market principle that assets with higher volatility generate a greater return over the long run. Current market factors such as inflation and interest rates are evaluated before long-term capital market assumptions are determined. The long-term portfolio return is established using the fund's asset allocations, via a building block approach with proper consideration of diversification and rebalancing. An expected rate of return on assets of 6.25% per annum determined using the above approach was used for determining the 2013 and 2014 RPP costs;
- The best estimate assumptions for base mortality rates reflect OPG's actual experience derived from OPG's historical pensioner data. In addition, in developing costs for 2014, as recommended by us as part of the new comprehensive accounting valuation conducted in 2013, the assumed mortality improvement rates were updated to reflect the improvement scale developed by the Canadian Institute of Actuaries ("CIA") based on a comprehensive study of observed Canadian pensioner experience, as published in the CIA Final Report: Canadian Pensioners' Mortality, which was released on February 13, 2014.
- Other actuarial assumptions are management's best estimate of future events, as determined in consultation with us and as set out in the Reports. These assumptions include the inflation rate and the salary scale increase rate, which were established at 2.00% per annum and 2.50% per annum (plus Promotion, Progression, Merit), respectively, in determining the 2013 and 2014 costs;
- Actuarial gains or losses for RPP, SPP and OPRB have been amortized using the 10% corridor method, except where immediate recognition is required under Canadian GAAP for non-routine events during the year (none during 2013 and 2014);
- Past service costs for RPP, SPP and OPRB have been amortized on a straight-line basis over the expected average remaining service lifetime at the amendment date, except where immediate recognition is required under Canadian GAAP for non-routine events during the year (none during 2013 and 2014);
- For LTD, under Canadian GAAP, the change in the obligation from the beginning of the fiscal year to the end of the fiscal year due to changes in economic assumptions, such as discount rates, is deferred and amortized, and the sum of the following is recognized immediately: (i) the change in the obligation at the end of the year compared to the obligation at the beginning of the year on the same economic basis and (ii) actual benefit payments for the year. In addition, past service costs are also deferred and amortized;
- Expected return on assets and amortization of actuarial gains/losses are based on a market-related value of assets where investment gains and losses on equity assets in excess of an expected return of 6.0% per annum plus the increase in Consumer Price Index are smoothed over five years.

Schedule 1—Summary of 2013 Canadian GAAP Results

The following table provides a summary of Canadian GAAP results for the period from January 1, 2013 to December 31, 2013 for the post employment benefit plans sponsored by OPG. The net periodic pension/benefit cost for this period was determined based on the balance sheet items at January 1, 2013.

(in Canadian $ 000s)	RPP	SPP	OPRB	LTD
Accrued Benefit Asset (Liability) as at January 1, 2013				
Accrued Benefit Obligation	$ (13,614,479)	$ (293,242)	$ (2,871,995)	$ (290,026)
Fair Value of Plan Assets	10,286,143	0	0	0
Excess (Deficit)	$ (3,328,336)	$ (293,242)	$ (2,871,995)	$ (290,026)
Unrecognized Past Service Costs (Credits)	0	0	3,973	1,199
Unrecognized Net Actuarial Loss (Gain)	4,518,837	101,341	944,582	57,628
Accrued Benefit Asset (Liability)	$ 1,190,501	$ (191,901)	$ (1,923,440)	$ (231,199)
Components of Net Periodic Pension/Benefit Cost, January 1, 2013 to December 31, 2013				
Employer Current Service Cost	$ 287,535	$ 9,646	$ 79,804	$ 24,808
Interest Cost	586,807	12,855	128,334	10,530
Expected Return on Plan Assets	(644,460)	0	0	0
Recognition of LTD Actuarial (Gain) Loss	0	0	0	(21,128)
Amortization of Past Service Cost	0	0	535	393
Amortization of Net (Gain) Loss	243,400	6,052	48,337	2,602
Total Cost	$ 473,282	$ 28,553	$ 257,010	$ 17,205
2013 Estimated Employer Pension Contributions / Benefit Payments				
Amounts used for developing net periodic pension/benefit cost	$ 380,000	$ 7,863	$ 70,237	$ 27,933
2013 Actual Employer Pension Contributions / Benefit Payments	$ 300,000	$ 14,006	$ 61,613	$ 25,526

Schedule 2—Summary of 2014 Canadian GAAP Results

The following table provides a summary of Canadian GAAP results for the period from January 1, 2014 to October 31, 2014 for the post employment benefit plans sponsored by OPG. The net periodic pension/benefit cost for this period was determined based on the balance sheet items at January 1, 2014.

(in Canadian $ 000s)	RPP	SPP	OPRB	LTD
Accrued Benefit Asset (Liability) as at January 1, 2014				
Accrued Benefit Obligation	$ (13,368,826)	$ (285,169)	$ (2,439,305)	$ (267,830)
Fair Value of Plan Assets	10,893,428	0	0	0
Excess (Deficit)	$ (2,475,398)	$ (285,169)	$ (2,439,305)	$ (267,830)
Unrecognized Past Service Costs (Credits)	0	0	950	806
Unrecognized Net Actuarial Loss (Gain)	3,492,617	78,721	319,518	44,146
Accrued Benefit Asset (Liability)	$ 1,017,219	$ (206,448)	$ (2,118,837)	$ (222,878)
Components of Net Periodic Pension/Benefit Cost, January 1, 2014 to October 31, 2014				
Employer Current Service Cost	$ 196,247	$ 6,198	$ 43,017	$ 9,597
Interest Cost	546,413	11,758	102,469	9,073
Expected Return on Plan Assets	(520,022)	0	0	0
Recognition of LTD Actuarial (Gain) Loss	0	0	0	0
Amortization of Past Service Cost	0	0	100	132
Amortization of Net (Gain) Loss	216,665	3,576	4,960	1,315
Total Cost	$ 439,303	$ 21,532	$ 150,546	$ 20,117
2014 Estimated Employer Pension Contributions / Benefit Payments	$ 400,000	$ 9,278	$ 63,336	$ 27,644
Amounts used for developing net periodic pension/benefit cost				
January 1 to October 31, 2014 Actual Employer Pension Contributions / Benefit Payments	$ 300,000	$ 12,804	$ 53,788	$ 18,355

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Numbers may not add due to rounding.

Table 1
(Updated version of Ex. H1-1-1 Table 1)
Summary of Deferral and Variance Accounts
Closing Account Balances - 2012 to 2014 ($M)

Line No.	Account	EB-2012-0002 Year End Balance 2012[1]	Actual Year End Balance 2013[2]	Projected Year End Balance 2014[3]	Actual Year End Balance 2014[4]
		(a)	(b)	(c)	(d)
	Regulated Hydroelectric:				
1	**Hydroelectric Water Conditions Variance**	17.1	22.4	12.7	(8.5)
2	**Ancillary Services Net Revenue Variance - Hydroelectric**	34.0	15.8	(10.6)	(16.5)
3	**Hydroelectric Incentive Mechanism Variance**	(2.4)	(5.0)	(7.5)	(7.5)
4	**Hydroelectric Surplus Baseload Generation Variance**	4.1	19.2	52.0	67.1
5	**Income and Other Taxes Variance - Hydroelectric**	(2.5)	(1.1)	(0.1)	(0.2)
6	**Tax Loss Variance - Hydroelectric**	48.2	19.7	0.0	0.0
7	**Capacity Refurbishment Variance - Hydroelectric**	1.1	112.7	232.6	232.6
8	**Gross Revenue Charge Variance**	N/A	N/A	0.0	0.0
9	**Pension and OPEB Cost Variance - Hydroelectric - Historic**	2.5	1.0	0.0	0.0
10	**Pension and OPEB Cost Variance - Hydroelectric - Future**	12.6	11.3	10.5	10.5
11	**Pension and OPEB Cost Variance - Hydroelectric - Post 2012 Additions**	N/A	18.6	35.5	35.5
12	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric**	N/A	N/A	9.2	4.6
13	**Pension & OPEB Cash Payment Variance - Hydroelectric**	N/A	N/A	(0.9)	0.2
14	**Impact for USGAAP Deferral - Hydroelectric**	2.8	1.2	0.0	0.0
15	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**	(3.9)	1.3	3.7	4.5
16	**Total**	113.8	217.3	337.1	322.4
	Nuclear:				
17	**Nuclear Liability Deferral**	206.2	254.0	286.3	285.7
18	**Nuclear Development Variance**	30.2	56.5	59.0	58.8
19	**Ancillary Services Net Revenue Variance - Nuclear**	1.7	1.9	1.7	1.7
20	**Capacity Refurbishment Variance - Nuclear - Capital Portion**	1.3	5.7	13.1	13.2
21	**Capacity Refurbishment Variance - Nuclear - Non-Capital Portion**	11.8	8.9	6.7	1.3
22	**Bruce Lease Net Revenues Variance - Derivative Sub-Account**	230.3	214.4	129.9	153.8
23	**Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - EB-2012-0002**	74.8	52.3	37.3	37.3
24	**Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - Post 2012 Additions**	N/A	85.9	126.8	123.8
25	**Income and Other Taxes Variance - Nuclear**	(32.5)	(17.9)	(8.5)	(13.2)
26	**Tax Loss Variance - Nuclear**	253.3	103.8	0.0	0.0
27	**Pension and OPEB Cost Variance - Nuclear - Historic**	51.5	20.7	0.0	0.0
28	**Pension and OPEB Cost Variance - Nuclear - Future**	257.6	231.8	214.7	214.7
29	**Pension and OPEB Cost Variance - Nuclear - Post 2012 Additions**	N/A	383.7	678.6	678.6
30	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear**	N/A	N/A	62.0	31.3
31	**Pension & OPEB Cash Payment Variance - Nuclear**	N/A	N/A	(0.8)	6.2
32	**Impact for USGAAP Deferral - Nuclear**	60.3	24.7	0.0	0.0
33	**Pickering Life Extension Depreciation Variance**	N/A	9.5	7.8	7.8
34	**Nuclear Deferral and Variance Over/Under Recovery Variance**	6.9	42.6	57.4	56.4
35	**Total**	1,153.3	1,478.5	1,671.9	1,657.5
36	**Grand Total** (line 16 + line 35)	1,267.1	1,695.8	2,009.0	1,979.9

Notes:
1 From Ex. H1-1-2, Table 1a, col. (c).
2 From Ex. H1-1-2, Table 1a, col. (h).
3 From Ex. H1-1-1, Table 1, col. (c).
4 From Ex. H1-1-2, Table 1c, col. (f).

Table 1a
(Updated version of Ex. H1-1-1 Table 1a)
Deferral and Variance Accounts
Continuity of Account Balances - 2012 to 2013 ($M)

Line No.	Account	Audited Year End Balance 2012[1]	EB-2012-0002 Negotiated Reductions[2]	(a)+(b) EB-2012-0002 Year End Balance 2012[3]	Actual 2013 Transactions[4]	Actual 2013 Amortization[4,5]	Actual 2013 Interest[4,6]	Actual 2013 Transfers[4]	(c)+(d)+(e)+(f)+(g) Actual Year End Balance 2013 [4]
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Previously Regulated Hydroelectric:								
1	**Hydroelectric Water Conditions Variance**	17.1	0.0	17.1	15.2	(10.3)	0.4	0.0	22.4
2	**Ancillary Services Net Revenue Variance - Hydroelectric**	34.0	0.0	34.0	1.8	(20.4)	0.4	0.0	15.8
3	**Hydroelectric Incentive Mechanism Variance**	(2.4)	0.0	(2.4)	(2.5)	0.0	(0.0)	0.0	(5.0)
4	**Hydroelectric Surplus Baseload Generation Variance**	4.1	0.0	4.1	14.9	0.0	0.1	0.0	19.2
5	**Income and Other Taxes Variance - Hydroelectric**	(2.5)	0.0	(2.5)	(0.1)	1.5	(0.0)	0.0	(1.1)
6	**Tax Loss Variance - Hydroelectric**	48.2	0.0	48.2	0.0	(28.9)	0.5	0.0	19.7
7	**Capacity Refurbishment Variance - Hydroelectric**	1.1	0.0	1.1	111.1	0.0	0.5	0.0	112.7
8	**Pension and OPEB Cost Variance - Hydroelectric - Historic**	2.5	0.0	2.5	0.0	(1.5)	0.0	0.0	1.0
9	**Pension and OPEB Cost Variance - Hydroelectric - Future**	12.6	0.0	12.6	0.0	(1.3)	0.0	0.0	11.3
10	**Pension and OPEB Cost Variance - Hydroelectric - Post 2012 Additions**	N/A	N/A	N/A	18.6	N/A	0.0	0.0	18.6
11	**Impact for USGAAP Deferral - Hydroelectric**	2.8	0.0	2.8	0.0	(1.7)	0.0	0.0	1.2
12	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**	(3.9)	0.0	(3.9)	2.9	2.3	(0.0)	0.0	1.3
13	**Total**	113.8	0.0	113.8	162.0	(60.3)	1.8	0.0	217.3
	Nuclear:								
14	**Nuclear Liability Deferral**	208.0	(1.8)	206.2	122.7	(74.9)	0.0	0.0	254.0
15	**Nuclear Development Variance**	30.2	0.0	30.2	25.6	0.0	0.7	0.0	56.5
16	**Ancillary Services Net Revenue Variance - Nuclear**	1.7	0.0	1.7	1.2	(1.0)	0.0	0.0	1.9
17	**Capacity Refurbishment Variance - Nuclear - Capital Portion**	1.3	0.0	1.3	4.3	0.0	0.0	0.0	5.7
18	**Capacity Refurbishment Variance - Nuclear - Non-Capital Portion**	11.8	0.0	11.8	4.0	(7.1)	0.1	0.0	8.9
19	**Bruce Lease Net Revenues Variance - Derivative Sub-Account**	230.3	0.0	230.3	24.6	(40.5)	(0.0)	0.0	214.4
20	**Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - EB-2012-0002**	80.2	(5.5)	74.8	0.0	(22.4)	0.0	0.0	52.3
21	**Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - Post 2012 Additions**	N/A	N/A	N/A	85.9	0.0	0.0	0.0	85.9
22	**Income and Other Taxes Variance - Nuclear**	(32.5)	0.0	(32.5)	(4.5)	19.5	(0.3)	0.0	(17.9)
23	**Tax Loss Variance - Nuclear**	253.3	0.0	253.3	0.0	(152.0)	2.5	0.0	103.8
24	**Pension and OPEB Cost Variance - Nuclear - Historic**	51.5	0.0	51.5	0.0	(31.4)	0.5	0.0	20.7
25	**Pension and OPEB Cost Variance - Nuclear - Future**	257.6	0.0	257.6	0.0	(25.8)	0.0	0.0	231.8
26	**Pension and OPEB Cost Variance - Nuclear - Post 2012 Additions**	N/A	N/A	N/A	383.7	N/A	0.0	0.0	383.7
27	**Impact for USGAAP Deferral - Nuclear**	60.3	0.0	60.3	0.0	(36.2)	0.6	0.0	24.7
28	**Pickering Life Extension Depreciation Variance[7]**	N/A	N/A	N/A	(46.8)	56.3	0.0	0.0	9.5
29	**Nuclear Deferral and Variance Over/Under Recovery Variance**	6.9	0.0	6.9	39.5	(4.2)	0.3	0.0	42.6
30	**Total**	1,160.6	(7.3)	1,153.3	640.2	(319.5)	4.4	0.0	1,478.5
31	**Grand Total** (line 13 + line 30)	1,274.4	(7.3)	1,267.1	802.2	(379.8)	6.2	0.0	1,695.8

Notes:

1 From EB-2012-0002 Payment Amounts Order, App. A, Table 1 col. (a) for previously regulated hydroelectric and Table 2 col. (a) for nuclear.

2 From EB-2012-0002 Payment Amounts Order, App. A, Table 1 col. (b) for regulated hydroelectric and Table 2 col. (b) for nuclear.

3 From EB-2012-0002 Payment Amounts Order, App. A, Table 1 col. (c) for previously regulated hydroelectric and Table 2 col. (c) for nuclear. With the exception of balances at lines 3, 4, 7, 10, 15, 17, 21, 26 and 28, all balances were approved by the OEB in EB-2012-0002 (Payment Amounts Order, App. B, Table B-1, col. (a)).

4 From EB-2013-0321 Ex. L-9.1-17 SEC-132 (corrected version filed on June 4, 2014), Attachment 1, Table 1.

5 From the EB-2012-0002 Payment Amounts Order, App. B, Table B-1, col. (c).

6 Effective January 1, 2013, per the EB-2012-0002 Payments Amount Order, no interest is recorded on the balance of Nuclear Liability Deferral Account. Effective January 1, 2013, per the EB-2012-0002 and EB-2013-0321 Payment Amounts Orders, no interest is recorded on the balances of the Bruce Lease Net Revenues Variance Account and the Pension and OPEB Cost Variance Account excluding the Historic Recovery component. Line 19 includes an interest credit related to the inadvertent overstatement in the EB-2012-0002 Payment Amounts Order and related Settlement Agreement of the amount recoverable in 2013 and 2014 for the Bruce Lease Net Revenues Derivative Sub-Account, as noted in EB-2013-0321, Ex. H1-1-1, section 4.13 and OPG's letter to the OEB dated September 26, 2013 referenced therein.

7 Per the EB-2012-0002 and EB-2013-0321 Payment Amounts Orders, for the period from January 1, 2013 to October 31, 2014, the account reflects a credit of $3.9M per month to ratepayers for the benefit of lower non-asset retirement costs depreciation expense and associated income tax impacts resulting from the revision of the Pickering generation stations' service lives, as discussed in Ex. H1-1-1 section 5.14. Per these OEB orders, no interest is recorded in this account.

Numbers may not add due to rounding.

Table 1b
(Updated version of Ex. H1-1-1 Table 1b)
Deferral and Variance Accounts
Continuity of Account Balances - January to October 2014 ($M)

Line No.	Account	Actual Year End Balance 2013[1]	Actual January 1 to October 31, 2014				(a)+(b)+(c)+(d)+(e) Actual Balance October 31, 2014
			Transactions	Amortization[2]	Interest[3]	Transfers	
		(a)	(b)	(c)	(d)	(e)	(f)
	Previously Regulated Hydroelectric:						
1	**Hydroelectric Water Conditions Variance**	22.4	(1.7)	(5.7)	0.3	0.0	15.2
2	**Ancillary Services Net Revenue Variance - Hydroelectric**	15.8	(12.1)	(11.3)	0.0	0.0	(7.6)
3	**Hydroelectric Incentive Mechanism Variance**	(5.0)	(2.4)	0.0	(0.1)	0.0	(7.5)
4	**Hydroelectric Surplus Baseload Generation Variance**	19.2	22.7	0.0	0.3	0.0	42.2
5	**Income and Other Taxes Variance - Hydroelectric**	(1.1)	(0.0)	0.8	(0.0)	0.0	(0.3)
6	**Tax Loss Variance - Hydroelectric**	19.7	0.0	(16.1)	0.1	0.0	3.8
7	**Capacity Refurbishment Variance - Hydroelectric**	112.7	117.3	0.0	2.0	0.0	232.1
8	**Pension and OPEB Cost Variance - Hydroelectric - Historic**	1.0	0.0	(0.9)	0.0	0.0	0.2
9	**Pension and OPEB Cost Variance - Hydroelectric - Future**	11.3	0.0	(0.7)	0.0	0.0	10.6
10	**Pension and OPEB Cost Variance - Hydroelectric - Post 2012 Additions**	18.6	16.8	N/A	0.0	0.0	35.5
11	**Impact for USGAAP Deferral - Hydroelectric**	1.2	0.0	(0.9)	0.0	0.0	0.3
12	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**	1.3	0.6	1.3	0.0	0.0	3.2
13	**Total**	217.3	141.1	(33.5)	2.7	0.0	327.7
	Nuclear:						
14	**Nuclear Liability Deferral**	254.0	81.6	(41.6)	0.0	0.0	294.0
15	**Nuclear Development Variance**	56.5	1.2	0.0	0.7	0.0	58.5
16	**Ancillary Services Net Revenue Variance - Nuclear**	1.9	0.3	(0.6)	0.0	0.0	1.7
17	**Capacity Refurbishment Variance - Nuclear - Capital Portion**	5.7	6.3	0.0	0.1	0.0	12.1
18	**Capacity Refurbishment Variance - Nuclear - Non-Capital Portion**	8.9	(2.4)	(3.9)	0.1	0.0	2.6
19	**Bruce Lease Net Revenues Variance - Derivative Sub-Account**	214.4	(57.5)	(22.5)	0.0	0.0	134.4
20	**Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - EB-2012-0002**	52.3	0.0	(12.5)	0.0	0.0	39.8
21	**Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - Post 2012 Additions**	85.9	41.1	0.0	0.0	0.0	127.0
22	**Income and Other Taxes Variance - Nuclear**	(17.9)	(2.7)	10.8	(0.2)	0.0	(9.9)
23	**Tax Loss Variance - Nuclear**	103.8	0.0	(84.4)	0.5	0.0	19.9
24	**Pension and OPEB Cost Variance - Nuclear - Historic**	20.7	0.0	(17.4)	0.1	0.0	3.4
25	**Pension and OPEB Cost Variance - Nuclear - Future**	231.8	0.0	(14.3)	0.0	0.0	217.5
26	**Pension and OPEB Cost Variance - Nuclear - Post 2012 Additions**	383.7	294.9	N/A	0.0	0.0	678.6
27	**Impact for USGAAP Deferral - Nuclear**	24.7	0.0	(20.1)	0.2	0.0	4.8
28	**Pickering Life Extension Depreciation Variance**[4]	9.5	(39.0)	31.3	0.0	0.0	1.7
29	**Nuclear Deferral and Variance Over/Under Recovery Variance**	42.6	12.1	(2.3)	0.6	0.0	52.9
30	**Total**	1,478.5	336.0	(177.5)	2.2	0.0	1,639.0
31	**Grand Total** (line 13 + line 30)	1,695.8	477.1	(211.0)	5.0	0.0	1,966.7

Notes:
1 From Ex. H1-1-2, Table 1a, col. (h).
2 Calculated as 10/12 multiplied by EB-2012-0002 Payment Amounts Order, App. B, Table B-1, col. (d)
3 See Ex. H1-1-2, Table 1a, Note 6.
4 See Ex. H1-1-2, Table 1a, Note 7.

Table 1c
(Updated version of Ex. H1-1-1 Table 1c)
Deferral and Variance Accounts
Continuity of Account Balances - November and December 2014 ($M)

Line No.	Account	Actual Balance October 31 2014[1]	Actual November 1 to December 31, 2014 Transactions	Amortization[2]	Interest[3,4]	Transfers[5]	(a)+(b)+(c)+(d)+(e) Actual Year End Balance 2014
		(a)	(b)	(c)	(d)	(e)	(f)
	Regulated Hydroelectric (Previously and Newly Regulated):						
1	**Hydroelectric Water Conditions Variance**	15.2	(22.6)	(1.1)	0.0	0.0	(8.5)
2	**Ancillary Services Net Revenue Variance - Hydroelectric**	(7.6)	(6.6)	(2.3)	(0.0)	0.0	(16.5)
3	**Hydroelectric Incentive Mechanism Variance**	(7.5)	0.0	0.0	(0.0)	0.0	(7.5)
4	**Hydroelectric Surplus Baseload Generation Variance**	42.2	24.8	0.0	0.1	0.0	67.1
5	**Income and Other Taxes Variance - Hydroelectric**	(0.3)	(0.1)	0.2	0.0	0.0	(0.2)
6	**Tax Loss Variance - Hydroelectric**	3.8	0.0	(3.2)	0.0	(0.5)	0.0
7	**Capacity Refurbishment Variance - Hydroelectric**	232.1	0.0	0.0	0.6	0.0	232.6
8	**Gross Revenue Charge Variance**	0.0	0.0	0.0	0.0	0.0	0.0
9	**Pension and OPEB Cost Variance - Hydroelectric - Historic**	0.2	0.0	(0.2)	0.0	0.0	0.0
10	**Pension and OPEB Cost Variance - Hydroelectric - Future**	10.6	0.0	(0.1)	0.0	0.0	10.5
11	**Pension and OPEB Cost Variance - Hydroelectric - Post 2012 Additions**	35.5	0.0	0.0	0.0	0.0	35.5
12	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric**	0.0	4.6	0.0	0.0	0.0	4.6
13	**Pension & OPEB Cash Payment Variance - Hydroelectric**	0.0	0.2	0.0	(0.0)	0.0	0.2
14	**Impact for USGAAP Deferral - Hydroelectric**	0.3	0.0	(0.2)	0.0	(0.1)	0.0
15	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**	3.2	0.4	0.3	0.0	0.6	4.5
16	**Total**	327.7	0.8	(6.7)	0.7	0.0	322.4
	Nuclear:						
17	**Nuclear Liability Deferral**	294.0	0.0	(8.3)	0.0	0.0	285.7
18	**Nuclear Development Variance**	58.5	0.2	0.0	0.1	0.0	58.8
19	**Ancillary Services Net Revenue Variance - Nuclear**	1.7	0.2	(0.1)	0.0	0.0	1.7
20	**Capacity Refurbishment Variance - Nuclear - Capital Portion**	12.1	1.1	0.0	0.0	0.0	13.2
21	**Capacity Refurbishment Variance - Nuclear - Non-Capital Portion**	2.6	(0.6)	(0.8)	0.0	0.0	1.3
22	**Bruce Lease Net Revenues Variance - Derivative Sub-Account**	134.4	24.0	(4.5)	(0.1)	0.0	153.8
23	**Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - EB-2012-0002**	39.8	0.0	(2.5)	0.0	0.0	37.3
24	**Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - Post 2012 Additions**	127.0	(3.2)	0.0	0.0	0.0	123.8
25	**Income and Other Taxes Variance - Nuclear**	(9.9)	(5.4)	2.2	(0.0)	0.0	(13.2)
26	**Tax Loss Variance - Nuclear**	19.9	0.0	(16.9)	0.0	(3.0)	0.0
27	**Pension and OPEB Cost Variance - Nuclear - Historic**	3.4	0.0	(3.5)	0.0	0.1	0.0
28	**Pension and OPEB Cost Variance - Nuclear - Future**	217.5	0.0	(2.9)	0.0	0.0	214.7
29	**Pension and OPEB Cost Variance - Nuclear - Post 2012 Additions**	678.6	0.0	0.0	0.0	0.0	678.6
30	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear**	0.0	31.3	0.0	0.0	0.0	31.3
31	**Pension & OPEB Cash Payment Variance - Nuclear**	0.0	6.2	0.0	0.0	0.0	6.2
32	**Impact for USGAAP Deferral - Nuclear**	4.8	0.0	(4.0)	0.0	(0.8)	0.0
33	**Pickering Life Extension Depreciation Variance**[6]	1.7	0.0	6.3	0.0	0.0	7.8
34	**Nuclear Deferral and Variance Over/Under Recovery Variance**	52.9	0.1	(0.5)	0.1	3.7	56.4
35	**Total**	1,639.0	53.9	(35.5)	0.2	0.0	1,657.5
36	**Grand Total** (line 16 + line 35)	1,966.7	54.6	(42.2)	0.9	0.0	1,979.9

Notes:

1 From Ex. H1-1-2, Table 1b, col. (f).

2 Calculated as the value from EB-2012-0002 Payment Amounts Order, App. B, Table B-1, col. (d), multiplied by 2/12.

3 See Ex. H1-1-2, Table 1a, Note 6.

4 Per the EB-2013-0321 Payment Amounts Order, no interest is recorded on the Pension & OPEB Cash Versus Accrual Differential Deferral Account.

5 In accordance with the EB-2013-0321 Payment Amounts Order, the Tax Loss Variance Account and the Impact for USGAAP Deferral Account were terminated on December 31, 2014, with the remaining corresponding balances as of that date transferred to the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account and the Nuclear Deferral and Variance Account. Similarly, in accordance with the EB-2013-0321 Payment Amounts Order, the remaining corresponding Historic Recovery balances of the Pension and OPEB Cost Variance Account at December 31, 2014 were transferred to the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account and the Nuclear Deferral and Variance Over/Under Recovery Variance Account.

6 See Ex. H1-1-2, Table 1a, Note 7.

Numbers may not add due to rounding.

Table 2
(Updated version of Ex. H1-1-1 Table 2)
Hydroelectric Water Conditions Variance Account
Summary of Account Transactions - 2013 and 2014

Line No.	Particulars	Actual 2013[1]	Actual Jan - Oct 2014	Actual Nov - Dec 2014	(b)+(c) Actual Total 2014
		(a)	(b)	(c)	(d)
	Previously Regulated Hydroelectric:				
1	**Forecast Production - EB-2012-0002 / EB-2013-0321[2] (GWh)**	19,832	15,484	3,282	18,766
2	**Actual Calculated Production (GWh)**	19,167	15,579	3,424	19,003
3	**Difference (GWh)** (line 1 - line 2)	664	(96)	(142)	(238)
4	**Payment Amount per EB-2010-0008 / EB-2013-0321 ($/MWh)[3]**	35.78	35.78	40.20	
5	**Revenue Impact ($M)** (line 3 x line 4 / 1000)	23.8	(3.4)	(5.7)	(9.1)
6	**GRC/Water Rental Costs ($M)**	(8.5)	1.7	2.1	3.7
7	**Addition to Variance Account ($M)** (line 5 + line 6)	15.2	(1.7)	(3.7)	(5.4)
	Newly Regulated Hydroelectric:				
8	**Forecast Production - EB-2013-0321[2,5] (GWh)**	N/A	N/A	2,057	2,057
9	**Actual Calculated Production[5] (GWh)**	N/A	N/A	2,623	2,623
10	**Difference (GWh)** (line 8 - line 9)			(566)	(566)
11	**Payment Amount per EB-2013-0321 ($/MWh)[4]**	N/A	N/A	41.93	
12	**Revenue Impact ($M)** (line 10 x line 11 / 1000)	N/A	N/A	(23.7)	(23.7)
13	**GRC/Water Rental Costs ($M)**	N/A	N/A	4.8	4.8
14	**Addition to Variance Account ($M)** (line 12 + line 13)	N/A	N/A	(18.9)	(18.9)
15	**Total Addition to Variance Account ($M)** (line 7 + line 14)	15.2	(1.7)	(22.6)	(24.3)

Notes:
1 As shown in EB-2013-0321 Ex. L-9.1-17 SEC-132, Attachment 1, Table 2, col. (a).
2 2013 and January to October 2014 forecast production has been determined using the average monthly forecasts for 2011 and 2012 underpinning the reference amounts from EB-2010-0008 per EB-2012-0002 Payment Amounts Order, App. B, page 3. November to December 2014 forecast production is as reflected in the 2014 Board-approved production value, in accordance with the EB-2013-0321 Payment Amounts Order, App. G, page 3.
3 From EB-2010-0008 Payment Amounts Order, App. B, Table 1, line 3 for 2013 and January to October 2014. From EB-2013-0321 Payment Amounts Order, App. B, Table 1, line 3 for November to December 2014.
4 From EB-2013-0321 Payment Amounts Order, App. C, Table 1, line 3.
5 In accordance with the EB-2013-0321 Payment Amounts Order, App. G, pp. 2-3, the value represents production for the 21 newly regulated hydroelectric facilities subject to the variance account.

Table 3
(Updated version of Ex. H1-1-1 Table 3)
Ancillary Services Net Revenue Variance Account
Summary of Account Transactions - 2013 and 2014 ($M)

Line No.	Particulars	Actual 2013[1]	Actual Jan - Oct 2014	Actual Nov - Dec 2014	(b)+(c) Actual Total 2014
		(a)	(b)	(c)	(d)
	Previously Regulated Hydroelectric:				
1	**Forecast Revenue - EB-2012-0002 / EB-2013-0321** [2]	38.9	32.4	5.4	37.8
2	**Actual Revenue**	37.1	44.5	8.9	53.4
3	**Addition to Variance Account** (line 1 - line 2)	1.8	(12.1)	(3.5)	(15.6)
	Newly Regulated Hydroelectric:				
4	**Forecast Revenue - EB-2013-0321**[3]	N/A	N/A	3.8	3.8
5	**Actual Revenue**	N/A	N/A	7.7	7.7
6	**Addition to Variance Account Before Adjustment** (line 4 - line 5)	N/A	N/A	(3.9)	(3.9)
7	**Less: EB-2013-0321 Impact Statement (Ex. N1) Adjustment** [4]	N/A	N/A	(0.8)	(0.8)
8	**Addition to Variance Account** (line 6 - line 7)	N/A	N/A	(3.1)	(3.1)
9	**Hydroelectric Addition to Variance Account** (line 3 + line 8)	N/A	N/A	(6.6)	(18.7)
	Nuclear:				
10	**Forecast Revenue - EB-2012-0002 / EB-2013-0321**[5]	3.0	2.5	0.3	2.8
11	**Actual Revenue**	1.7	2.1	0.3	2.4
12	**Addition to Variance Account Before Adjustment** (line 10 - line 11)	1.2	0.3	0.1	0.4
13	**Less: EB-2013-0321 Impact Statement (Ex. N1) Adjustment** [4]	N/A	N/A	(0.1)	(0.1)
14	**Nuclear Addition to Variance Account** (line 12 - line 13)	1.2	0.3	0.2	0.5

Notes:

1 As shown in EB-2013-0321 Ex. L-9.1-17 SEC-132, Attachment 1, Table 3.

2 2013 value is $3.24M/month x 12 months per EB-2012-0002 Payment Amounts Order, App. B, page 4. January to October 2014 value is $3.24M/month x 10 months per EB-2012-0002 Payment Amounts Order, App. B, page 4. November to December 2014: $2.71M/month x 2 months per EB-2013-0321 Payment Amounts Order, App. G, page 4.

3 Calculated as $1.91M/month x 2 months per EB-2013-0321 Payment Amounts Order, App. G, page 4.

4 The adjustments are per the EB-2013-0321 Payment Amounts Order (App. G, p. 4) requirement that amounts recorded in the account do not include those that OPG indicated it is not seeking to recover from, or refund to, ratepayers as part of the differences between the revenue requirement in its EB-2013-0321 pre-filed evidence and the information based on OPG's 2014-2016 Business Plan, which was provided in the EB-2013-0321 Impact Statement at Ex. N1. The total of the adjustments represent a 2-month portion of the $8M test period increase (EB-2013-0321 Ex. N1-1-1, Chart 1) in forecast newly regulated hydroelectric and nuclear ancillary services net revenues between OPG's EB-2013-0321 pre-filed evidence and its 2014-2016 Business Plan. This difference was not included in the updated revenue requirement in the Ex. N1 impact statement. The monthly adjustment amount for newly regulated hydroelectric and nuclear is calculated below. No adjustment is necessary for the previously regulated hydroelectric ancillary services net revenue since, as discussed in section 2.4 of EB-2013-0321 Ex. N1-1-1, the revenue requirement was updated for the 2014-2016 Business Plan values.

Table to Note 4 - Monthly EB-2013-0321 Impact Statement (Ex. N1) Adjustments ($M)

Line No.	Particulars	2014#	2015	Total
		(a)	(b)	(c)
	Newly Regulated Hydroelectric:			
1a	Forecast Revenue - EB-2013-0321 Pre-filed Evidence##	11.3	23.1	34.4
2a	Forecast Revenue - OPG's 2014-2016 Business Plan	13.6	27.8	41.4
3a	Difference (line 1a - line 2a)	(2.3)	(4.7)	(7.0)
4a	Monthly EB-2013-0321 Impact Statement (Ex. N1) Adjustment (line 3a / 18 months)			(0.4)
	Nuclear:			
5a	Forecast Revenue - EB-2013-0321 Pre-filed Evidence+	1.9	1.9	3.8
6a	Forecast Revenue - 2014-2016 Business Plan	2.4	2.5	4.9
7a	Difference (line 5a - line 6a)	(0.5)	(0.6)	(1.1)
8a	Monthly EB-2013-0321 Impact Statement (Ex. N1) Adjustment (line 7a / 24 months)			(0.05)

\# Newly regulated hydroelectric values are for the 6-month period from July 1, 2014 to December 31, 2014.

\## From EB-2013-0321 Ex. G1-1-1 Table 1, line 6: 2014 value is col. (e) multiplied by 6/12, and 2015 value is from col. (f).

\+ From EB-2013-0321 Ex. G2-1-1 Table 1, line 8, cols. (e) and (f).

5 2013 value is $0.25M/month x 12 months per EB-2012-0002 Payment Amounts Order, App. B, page 10.
January to October 2014 value is $0.25M/month x 10 months per EB-2012-0002 Payment Amounts Order, App. B, page 10.
November to December 2014 value is $0.14M/month x 2 months per EB-2013-0321 Payment Amounts Order, App. G, page 10.

Table 4
(Updated version of Ex. H1-1-1 Table 4)
Hydroelectric Incentive Mechanism Variance Account
Summary of Account Transactions - 2014 ($M)

Line No.	Particulars	Actual Jan - Oct 2014	Actual Nov - Dec 2014	(a)+(b) Actual Total 2014
		(a)	(b)	(c)
1	**Actual Previously Regulated Hydroelectric Incentive Mechanism Net Revenue**	15.7	(1.1)	14.6
2	**Actual Newly Regulated Hydroelectric Incentive Mechanism Net Revenue**	N/A	1.0	1.0
3	**Total Actual Regulated Hydroelectric Incentive Mechanism Revenue**	15.7	(0.1)	15.6
4	**Threshold per EB-2012-0002 / EB-2013-0321** [1]	10.8	8.5	
5	**Actual Hydroelectric Incentive Mechanism Net Revenue In Excess of Threshold** (line 3 - line 4; nil if line 3 < line 4)	4.9	0.0	4.9
6	**Percentage** [2]	50%	50%	50%
7	**Addition to Variance Account** (line 5 x line 6)	(2.4)	0.0	(2.4)

Notes:

1 January to October 2014 threshold from EB-2012-0002 Payment Amounts Order, App. B, page 8, multiplied by 10/12.
November to December 2014 threshold from EB-2013-0321 Payment Amounts Order, App. G, page 7.

2 January to October 2014 percentage from EB-2012-0002 Payment Amounts Order, App. B, page 8.
November to December 2014 percentage from EB-2013-0321 Payment Amounts Order, App. G, page 7.

Table 5
(Updated version of Ex. H1-1-1 Table 5)
Hydroelectric Surplus Baseload Generation Variance Account
Summary of Account Transactions - 2014

Line No.	Particulars	Actual Jan - Oct 2014	Actual Nov - Dec 2014	(a)+(b) Actual Total 2014
		(a)	(b)	(c)
	Previously Regulated Hydroelectric:			
1	**Actual Foregone Production Due to SBG Conditions (GWh)**[1]	1,061	581	1,641
2	**Payment Amount per EB-2010-0008 / EB-2013-0321 ($/MWh)**[2]	35.78	40.20	
3	**Revenue ($M)** (line 1 x line 2 / 1000)	38.0	23.3	61.3
4	**GRC/Water Rental Costs ($M)**	(15.3)	(8.4)	(23.6)
5	**Addition to Variance Account ($M)** (line 3 + line 4)	22.7	15.0	37.7
	Newly Regulated Hydroelectric:			
6	**Actual Foregone Production Due to SBG Conditions (GWh)**	N/A	308	308
7	**Payment Amount per EB-2013-0321 ($/MWh)**[3]	N/A	41.93	
8	**Revenue ($M)** (line 6 x line 7 / 1000)	N/A	12.9	12.9
9	**GRC/Water Rental Costs ($M)**	N/A	(3.1)	(3.1)
10	**Addition to Variance Account ($M)** (line 8 + line 9)		9.8	9.8
11	**Total Addition to Variance Account ($M)** (line 5 + line 10)	N/A	24.8	47.5

Notes:

1 Includes an upward adjustment of 29.7 GWh to the 2013 estimated foregone production reflected in the EB-2013-0321 Board-approved account balance, reflecting a refinement to OPG's spill reporting methodology in 2014 based on an accumulation of data since the new Niagara Tunnel was placed in service in March 2013.

2 From EB-2010-0008 Payment Amounts Order, App. B, Table 1, line 3 for 2013 and January to October 2014.
From EB-2013-0321 Payment Amounts Order, App. B, Table 1, line 3 for November to December 2014.

3 From EB-2013-0321 Payment Amounts Order, App. C, Table 1, line 3.

Numbers may not add due to rounding.

Table 6
(Updated version of Ex. H1-1-1 Table 6)
Income and Other Taxes Variance Account
Summary of Account Transactions - 2013 and 2014 ($M)

No.	Particulars	Note	Actual 2013[1]			Actual Jan - Oct 2014			Actual Nov - Dec 2014			Actual Total 2014		
			Previously Hydroelectric	Nuclear	(a)+(b) Total	Previously Hydroelectric	Nuclear	(d)+(e) Total	Previously Hydroelectric	Nuclear	(g)+(h) Total	Previously Hydroelectric	Nuclear	(j)+(k) Total
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Entry (i): Increase of Scientific Research and Experimental Development ("SR&ED") Investment Tax Credits (ITCs) Recognition Percentage from 50% to 75%													
1	**Forecast SR&ED ITCs, net of Tax on ITCs, at 50%**	2	(0.1)	(6.5)	(6.6)	(0.1)	(6.5)	(6.6)				(0.1)	(6.5)	(6.6)
2	**Forecast SR&ED ITCs, net of Tax on ITCs, at 75%** (line 1 x 3/2)		(0.1)	(9.8)	(9.9)	(0.1)	(9.8)	(9.9)				(0.1)	(9.8)	(9.9)
3	**Addition to Variance Account - SR&ED ITCs Recognition Percentage Increase** (cols. (a) to (c): line 2 - line 1; cols. (d) to (f): (line 2 - line 1) x 10/12)		(0.0)	(3.3)	(3.3)	(0.0)	(2.7)	(2.7)	0.0	0.0	0.0	(0.0)	(2.7)	(2.7)
	Entry (ii): Reduction in Contractor Payments Qualifying for SR&ED ITCs from 100% to 80%													
4	**Annual Qualifying Contractor Payments Reflected in Forecast SR&ED ITCs**		0.6	57.4	58.0	0.6	57.4	58.0				0.6	57.4	58.0
5	**20% Portion Not Eligible for SR&ED ITCs** (line 4 x 20%)		0.1	11.5	11.6	0.1	11.5	11.6				0.1	11.5	11.6
6	**Investment Tax Credit Rate**		20%	20%	20%	15%	15%	15%				15%	15%	15%
7	**Reduction in SR&ED ITCs** (cols (a) to (c): line 5 x line 6; cols (d) to (f): line 5 x line 6 x 10/12)		0.0	2.3	2.3	0.0	1.4	1.5				0.0	1.4	1.5
8	**Tax on 2013 Reduction in SR&ED ITCs**		0.0	0.0	0.0	0.0	0.4	0.4				0.0	0.4	0.4
9	**Addition to Variance Account - Reduction in Contractor Payments Qualifying for SR&ED ITCs** ((line 7 - line 8) x 75% SR&ED ITC recognition percentage)		0.0	1.7	1.7	0.0	0.8	0.8	0.0	0.0	0.0	0.0	0.8	0.8
	Entry (iii): Income Tax Variance Due to Nuclear Waste Management Capital Expenditures Adjustment													
10	**Non-Deductible Portion of Cash Expenditures for Nuclear Waste & Decommissioning**		0.0	2.9	2.9	0.0	2.9	2.9				0.0	2.9	2.9
11	**Additional Capital Cost Allowance**		0.0	3.7	3.7	0.0	3.0	3.0				0.0	3.0	3.0
12	**Impact on Taxable Income** (line 10 - line 11)		0.0	(0.8)	(0.8)	0.0	(0.1)	(0.1)	0.0	0.0	0.0	0.0	(0.1)	(0.1)
13	**Income Tax Rate**	3	25%	25%	25%	25%	25%	25%				25%	25%	25%
14	**Addition to Variance Account - Nuclear Waste Management Capital Expenditures Adjustment** (line 12 x line 13)		0.0	(0.2)	(0.2)	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	(0.0)	(0.0)
	Entry (iv): Increase of SR&ED ITCs Recognition Percentage from 75% to 100% in 2013 for April 1, 2008 to Dec 31, 2008, during Jan to Oct 2014 for 2009, and during Nov to Dec 2014 for 2010	4												
15	**Actual SR&ED ITCs, net of Tax on ITCs, at 75%**	5	(0.1)	(8.5)	(8.6)	(0.1)	(10.4)	(10.5)	(0.2)	(16.3)	(16.5)	(0.3)	(26.7)	(27.0)
16	**Actual SR&ED ITCs, net of Tax on ITCs, at 100%** (line 15 x 4/3)		(0.1)	(11.3)	(11.4)	(0.1)	(13.9)	(14.0)	(0.2)	(21.7)	(21.9)	(0.4)	(35.6)	(35.9)
17	**Addition to Variance Account - SR&ED ITCs Recognition Percentage Increase to 100%** (line 16 - line 15)		(0.0)	(2.8)	(2.9)	(0.0)	(3.5)	(3.5)	(0.1)	(5.4)	(5.5)	(0.1)	(8.9)	(9.0)
	Entry (v): ITC Rate Reduction from 20% to 15% Effective in 2014													
18	**Forecast SR&ED ITCs Based on 20% ITC Rate, at 75%**	6	0.0	0.0	0.0	0.1	13.1	13.2				0.1	13.1	13.2
19	**Forecast SR&ED ITCs Based on 15% ITC Rate, at 75%** (line 18 x 3/4)		0.0	0.0	0.0	0.1	9.8	9.9				0.1	9.8	9.9
20	**Addition to Variance Account - ITC Rate Reduction Effective in 2014** ((line 18 - line 19) x 10/12)		0.0	0.0	0.0	0.0	2.7	2.8	0.0	0.0	0.0	0.0	2.7	2.8
21	**Total Addition to Variance Account** (line 3 + line 9 + line 14 + line 17 + line 20)		(0.1)	(4.5)	(4.6)	(0.0)	(2.7)	(2.7)	(0.1)	(5.4)	(5.5)	(0.1)	(8.1)	(8.2)

Notes:
1 As shown in EB-2013-0321 Ex. L-9.1-17 SEC-132 (corrected version filed on June 4, 2014), Attachment 1, Table 6.
2 Annualized forecasts for 2013 and 2014 have been determined based on amounts reflected in the payment amounts approved in EB-2010-0008 using the methodology from the EB-2012-0002 Payment Amounts Order, and are calculated as shown in EB-2012-0002 Ex. H1-1-2 Table 4, Note 2.
3 2013 tax rate from EB-2013-0321 Ex. L-1.0-1 Staff-002, Attachment 1, Table 29, line 29. 2014 tax rate from EB-2013-0321 Payment Amounts Order, App. A, Table 7, line 31, col. (c).
4 Entry (iv) was recorded in 2013 following the resolution during 2013 of the 2008 taxation year audit, and in 2014 following the resolution during 2014 of the 2009 taxation year audit. An additional entry of less than $0.1M/year is recorded in 2013 and 2014 relating to SR&ED qualifying capital expenditures.
5 Represents SR&ED ITCs, net of tax on ITCs, for the period from April 1, 2008 to December 31, 2008 and for full year 2009 previously credited to ratepayers at 75% through the December 31, 2010 and December 31, 2012 OEB-approved balances of the Income and Other Taxes Variance Account.
6 The annualized forecast for 2014 is calculated from EB-2010-0008 Ex. F4-4-1 as follows: Table 2, line 5 col. (e) multiplied by 3/2 for previously regulated hydroelectric, and Table 3, line 6, col. (e) multiplied by 3/2 for nuclear.

Table 7
(Updated version of Ex. H1-1-1 Table 7)
Capacity Refurbishment Variance Account - Hydroelectric
Summary of Account Transactions - 2014 ($M)

Line No.	Particulars	Note	Actual Jan - Oct 2014	Actual Nov - Dec 2014	(a)+(b) Actual Total 2014
			(a)	(b)	(c)
	Previously Regulated Hydroelectric:				
1	**Niagara Tunnel Net Plant Amount Not Reflected in EB-2010-0008 Rate Base**	1	1,345.1		
2	**Weighted Average Cost of Capital - EB-2010-0008**	2	7.40%		
3	**Niagara Tunnel Project - Cost of Capital** (line 1 x line 2 x 10/12)		82.9		82.9
4	**Niagara Tunnel Project - Depreciation**	3	12.2		12.2
5	**Difference Between Forecast and Actual Capital Cost Allowance Deduction**	4	(0.7)		(0.7)
6	**Increase in Regulatory Taxable Income**	5	61.8		61.8
7	**Niagara Tunnel Project - Income Tax Impact** (line 6 x 25 % / (1 - 25%))		20.6		20.6
8	**Niagara Tunnel Project - Total Capital Addition** (line 3 + line 4 + line 7)		115.7		115.7
	Capital Additions for Other Projects:				
9	**Sir Adam Beck I GS Unit G7 Frequency Conversion**		0.4	0.0	0.4
10	**Sir Adam Beck I GS Unit G3 Upgrade**		1.2	0.0	1.2
11	**Sir Adam Beck I GS Unit G10 Upgrade**		0.0	(0.1)	(0.1)
12	**Addition to Variance Account for Other Projects Before Adjustment** (lines 9 through 11)	6	1.6	(0.1)	1.5
13	**Less: EB-2013-0321 Impact Statement (Ex. N1) Adjustment**	7	N/A	(0.1)	(0.1)
14	**Addition to Variance Account for Other Projects** (line 12 - line 13)		1.6	0.0	1.6
15	**Total Addition to Variance Account - Previously Regulated Hydroelectric** (line 8 + line 14)		117.3	0.0	117.3

Notes:

1 Represents the 2014 actual Niagara Tunnel project net plant rate base value calculated as follows: Board-approved in-service amount for the new Niagara Tunnel of $1,364.6M (EB-2013-0321 Payment Amounts Order, App. A, Table 1a, Note 2) less the resulting actual 2014 accumulated depreciation rate base amount of $19.5M.

2 From EB-2010-0008 Payment Amounts Order, App. A, Table 5b, col. (c), line 6.

3 Represents 10/12 of the actual 2014 full-year depreciation expense of $14.4M for the Niagara Tunnel Project.

4 Amount is calculated as the difference between forecast CCA deduction of $36.5M and actual CCA deduction of $36.9M recognized in 2014 related to the Niagara Tunnel Project, multiplied by 10/12. The forecast amount is based on 2011 and 2012 CCA amounts underpinning the OEB-approved forecast income tax expense in EB-2010-0008.

5 The increase in regulatory taxable income is calculated as the sum of lines 4 and 5, plus the return on equity (“ROE”) component of the cost of capital addition at line 3. The 2014 ROE component is calculated as: net plant amount at line 1, multiplied by the EB-2010-0008 OEB-approved equity portion (47%) of the capital structure, multiplied by the OEB-approved ROE rate of 9.55% (from EB-2010-0008 Payment Amounts Order, App. A, Table 5b, col. (c), line 5), multiplied by 10/12.

6 Additions to the account for January to October 2014 also include an entry of less than $0.1M related to the Sir Adam Beck G9 Upgrade project.

7 The adjustments are per the EB-2013-0321 Payment Amounts Order, App. G, p. 10 requirements which are the same as those described in Ex. H1-1-2 Table 3, Note 4 and Ex. H1-1-2 Table 13, Note 6.

Table 8
(Updated version of Ex. H1-1-1 Table 8)
Pension and OPEB Cost Variance Account
Summary of Account Transactions - 2013 and 2014[1] ($M)

Line No.	Particulars	Note	Actual 2013[2]			Actual Jan to Oct 2014		
			Previously Regulated Hydroelectric	Nuclear	(a)+(b) Total	Previously Regulated Hydroelectric	Nuclear	(d)+(e) Total
			(a)	(b)	(c)	(d)	(e)	(f)
1	**Forecast Accrual Pension Costs - EB-2012-0002**	3	7.0	138.4	145.4	5.8	115.3	121.1
2	**Forecast Accrual OPEB Costs - EB-2012-0002**	3	8.2	163.0	171.2	6.8	135.8	142.6
3	**Total Forecast Accrual Pension and OPEB Costs** (line 1 + line 2)		15.1	301.4	316.5	12.6	251.2	263.8
4	**Actual Accrual Pension Costs**	4	18.0	365.3	383.3	18.4	341.4	359.8
5	**Actual Accrual OPEB Costs**	4	11.5	233.7	245.2	8.0	149.4	157.4
6	**Total Actual Accrual Pension and OPEB Costs** (line 4 + line 5)		29.5	599.0	628.5	26.4	490.8	517.2
7	**Addition to Variance Account - Pension Costs** (line 4 - line 1)		11.0	226.9	237.9	12.6	226.1	238.6
8	**Addition to Variance Account - OPEB Costs** (line 5 - line 2)		3.4	70.7	74.0	1.2	13.5	14.8
9	**Addition to Variance Account - Income Tax Impact**	5	4.3	86.1	90.4	3.0	55.3	58.3
10	**Total Addition to Variance Account** (line 7 + line 8 + line 9)		18.6	383.7	402.3	16.8	294.9	311.7

Notes:
1. All cost amounts are presented on a CGAAP basis, as per the EB-2012-0002 Payment Amounts Order, App. B.
2. As shown in EB-2013-0321 Ex. L-9.1-17 SEC-132, Attachment 1, Table 8.
3. Forecasts have been determined based on amounts reflected in the payment amounts approved in EB-2010-0008, and are the same as those used to derive the OEB-approved 2012 additions to the variance account (shown in EB-2012-0002 Ex. H1-1-2, Table 5, line 1 (pension) and line 2 (OPEB), cols (d)-(f)). Total forecast costs for the regulated operations are as per EB-2012-0002 Payment Amounts Order, App. B, p. 6, determined as $26.38M/month x 12 for 2013 and $26.38/month x 10 for January to October 2014.
4. Amounts represent the regulated portion (excluding newly regulated hydroelectric) of OPG's 2013 and January to October 2014 total actual pension and OPEB costs on a CGAAP basis, which are provided at pages 5, 8 and 9 of Ex. H1-1-2, Attachment 2.
5. From Ex. H1-1-2 Table 8a, line 8.

Numbers may not add due to rounding.

Table 8a
(Updated version of Ex. H1-1-1 Table 8a)
Pension and OPEB Cost Variance Account
Calculation of Income Tax Impact - 2013 and 2014 ($M)

Line No.	Particulars	Note	Actual 2013[1]			Actual Jan to Oct 2014		
			Previously Regulated Hydroelectric	**Nuclear**	(a)+(b) **Total**	**Previously Regulated Hydroelectric**	**Nuclear**	(d)+(e) **Total**
			(a)	(b)	(c)	(d)	(e)	(f)
1	**Forecast Regulatory Income Tax Impact**	2	0.5	10.3	10.8	0.4	8.6	9.0
	Actual Additions to / Deductions from Regulatory Earnings Before Tax							
2	**Accrual Pension Costs**	3	18.0	365.3	383.3	18.4	341.4	359.8
3	**Accrual OPEB Costs**	4	11.5	233.7	245.2	8.0	149.4	157.4
4	**Less: Pension Plan Contributions**	5	11.4	231.6	242.9	12.5	233.1	245.7
5	**Less: OPEB Payments**	5	3.8	78.1	81.9	3.6	66.0	69.6
6	**Net Additions to Regulatory Earnings Before Tax**		14.2	289.4	303.6	10.3	191.6	201.9
7	**Actual Regulatory Income Tax Impact** (line 6 x 25% / (1 - 25%))		4.7	96.5	101.2	3.4	63.9	67.3
8	**Addition to Variance Account - Regulatory Income Tax Impact** (line 7 - line 1)		4.3	86.1	90.4	3.0	55.3	58.3

Notes:

1 As shown in EB-2013-0321 Ex. L-9.1-17 SEC-132, Attachment 1, Table 8a.

2 Forecasts have been determined based on amounts reflected in the payment amounts approved in EB-2010-0008, and for 2013, are the same amounts used to derive the OEB-approved 2012 additions (shown in EB-2012-0002 Ex. H1-1-2, Table 5a, line 1, cols. (d)-(f)). For January to October 2014, the EB-2012-0002 annual forecasts are prorated by 10/12.

3 From Ex. H1-1-2 Table 8, line 4, cols. (d)-(e).

4 From Ex. H1-1-2 Table 8, line 5, cols. (d)-(e).

5 Represents the regulated portion (excluding newly regulated hydroelectric) of OPG's 2013 and January to October 2014 total actual pension and OPEB cash amounts, which are provided at pages 8 and 9 of Ex. H1-1-2, Attachment 2. 2013 amounts in col. (c) are as shown in EB-2013-0321 Ex. L-1.0-1 Staff-002, Attachment 1, Table 29, lines 15 and 16. 2013 amounts at line 4 are also found in EB-2013-0321 Ex. L-6.8-1 Staff-114.

Numbers may not add due to rounding.

Table 9
(Updated version of Ex. H1-1-1 Table 9)
Hydroelectric Deferral and Variance Over/Under Recovery Variance Account
Summary of Account Transactions - 2013 and 2014

Line No.	Particulars	Note	Actual 2013[1]	Actual Jan - Oct 2014	Actual Nov - Dec 2014	(b)+(c) Actual Total 2014
			(a)	(b)	(c)	(d)
1	**Hydroelectric Rider 2013-A / 2014-A ($/MWh)**	2	3.04	2.02	2.02	
2	**Hydroelectric Rider 2013-B ($/MWh)**	3	0.58			
3	**Mar 2013 - Dec 2014 Hydroelectric Production Forecast Used to Set Rider 2013-A and Rider 2014-A (TWh)**	4	16.7	16.5	3.3	19.9
4	**Mar 2013 - Dec 2014 Actual Hydroelectric Production (TWh)**		15.9	16.2	3.1	19.3
5	**Actual Production Variance for Mar 2013 - Dec 2014 (TWh)** (line 3 - line 4)		0.8	0.3	0.2	0.5
6	**Addition to Variance Account ($M)** (line 5 x (line 1 + line 2))		2.9	0.6	0.4	1.0

Notes:
1 As shown in EB-2013-0321 Ex. L-9.1-17 SEC-132, Attachment 1, Table 9.
2 From EB-2012-0002 Payment Amounts Order, App. A, Table 1, line 13, col. (g) for 2013 and col. (h) for 2014.
3 Interim period shortfall rider in effect for 2013 from EB-2012-0002 Payment Amounts Order, App. A, Table 3, line 7, col. (a).
4 Value for 2013 is calculated from the EB-2012-0002 Payment Amounts Order, App. A, Table 3, col. (a): line 6 minus line 5.
Annual value for 2014 is from EB-2012-0002 Payment Amounts Order, App. A, Table 1, line 12, col. (g). Values for January to October 2014 and November to December 2014 are averages of the corresponding monthly forecasts found at EB-2012-0002 Ex. L-2-1 Staff-16, Attachment 1, Table 2, lines 1 and 3.

Table 10
(Updated version of Ex. H1-1-1 Table 10)
Nuclear Liability Deferral Account
Summary of Account Transactions - 2013 and 2014 ($M)

Line No.	Particulars	Note	Actual 2013[1]	Actual Jan - Oct 2014
			(a)	(b)
	Revenue Requirement Impact of Current Approved ONFA Reference Plan Effective January 1, 2012:			
1	**Depreciation Expense** (col. (a) from Table to Note 2, line 13a, col. (d); col. (b) = col. (a) x 10/12)	2	51.7	43.1
	Return on Rate Base			
2	**Average Asset Retirement Costs**	3	38.3	(13.4)
3	**Weighted Average Accretion Rate**	4	5.37%	5.37%
4	**Return on Rate Base** (col. (a) = line 2 x line 3; col. (b) = line 2 x line 3 x 10/12)		2.1	(0.6)
	Variable Expenses	5		
5	**Used Fuel Storage and Disposal Variable Expenses**		26.1	23.3
6	**Low & Intermediate Level Waste Management Variable Expenses**		1.0	1.1
7	**Total Variable Expenses** (line 5 + line 6)		27.1	24.4
	Income Tax Impact			
8	**Forecast Contributions to Nuclear Segregated Funds**	6	142.7	118.9
9	**Contributions to Nuclear Segregated Funds based on the Current Approved ONFA Reference Plan**	7	98.1	141.6
10	**Decrease (Increase) in Contributions to Nuclear Segregated Funds** (line 8 - line 9)		44.6	(22.7)
11	**Net Increase in Regulatory Taxable Income** (line 1 + line 4 + line 7 + line 10)		125.5	44.2
12	**Income Tax Rate**		25.00%	25.00%
13	**Income Tax Impact** (line 11 x line 12 / (1 - line 12))		41.8	14.7
14	**Addition to Deferral Account** (line 1 + line 4 + line 7 + line 13)		122.7	81.6

Notes:

1 As shown in EB-2013-0321 Ex. L-9.1-17 SEC-132, Attachment 1, Table 10.

2 As shown in EB-2013-0321 Ex. L-9.1-17 SEC-132, Attachment 1, Table 10, Table to Note 1. The depreciation expense component of the addition to the deferral account is calculated as follows:

Table to Note 2 - Depreciation Expense ($M)

Line No.		Pickering Units 1 & 4 (formerly Pickering A)	Pickering Units 5-8 (formerly Pickering B)	Darlington	Total
		(a)	(b)	(c)	(d)
	Incremental ARC - Depreciation Impact of Adjustments at December 31, 2011 and 2012:				
1a	Asset Retirement Cost ("ARC") Adjustment at December 31, 2011 #	368.4	175.9	(105.1)	439.2
2a	Remaining Useful Life as at December 31, 2011(months) +	120.0	33.0	480.0	
3a	2012 Annual Depreciation (line 1a / line 2a x 12 for cols. (a) through (c))	36.8	64.0	(2.6)	98.2
4a	ARC Adjustment at December 31, 2012 ##	(178.5)	133.3	(231.7)	(276.9)
5a	Net ARC Adjustment Balance at December 31, 2012 (line 1a - line 3a + line 4a)	153.1	245.2	(334.2)	64.1
6a	Remaining Useful Life as at December 31, 2012 (months) ++	96.0	88.0	468.0	
7a	Annual Depreciation Beginning in 2013 (line 5a / line 6a x 12 for cols. (a) through (c))	19.1	33.4	(8.6)	44.0
	Base ARC (Excluding Incremental ARC Above) - Depreciation Impact of Pickering Service Life Changes:				
8a	ARC at December 31, 2011 Excluding December 31, 2011 Adjustment *	17.3	(27.0)	1,485.0	1,475.4
9a	2012 Annual Depreciation (line 8a / line 2a x 12 for cols. (a) through (c))	1.7	(9.8)	37.1	29.0
10a	ARC at December 31, 2012 Excluding Dec. 31, 2011 and 2012 Adjustments (line 8a - line 9a)	15.6	(17.2)	1,447.9	1,446.3
11a	2013 Annual Depreciation (line 10a / line 6a x 12 for cols. (a) through (c))	1.9	(2.3)	37.1	36.7
12a	Annual Depreciation Impact Beginning in 2013 (line 11a - line 9a)	0.2	7.5	0.0	7.7
13a	Total Annual Depreciation Expense Impact Beginning in 2013 (line 7a + line 12a)	19.4	40.9	(8.6)	51.7

From EB-2013-0321, Ex. C2-1-1 Table 4, line 7 and EB-2012-0002 Ex. H1-1-2, Table 9, note 2, line 1a.

+ Represents remaining estimated average service life, for accounting purposes, of the nuclear stations as at December 31, 2011, as per EB-2012-0002, Ex. H1-1-2, Table 9, Note 2, line 2a.

From EB-2013-0321 Ex. C2-1-1, Table 4, line 14.

++ Represents remaining estimated average service life, for accounting purposes, of the nuclear stations as at December 31, 2012, as per EB-2013-0321 Ex. F4-1-1, page 3.

* Amount in col. (d) from EB-2013-0321 Ex. C2-1-1, Table 2, col. (b), line 28.

3 2013 value is calculated as follows from Note 2, col. (d): (line 5a + (line 5a - line 13a))/2. 2014 value is calculated as 2013 value less Note 2, line 13a, col. (d).

4 Per EB-2012-0002 Payment Amounts Order, App. B, p. 9.

5 Annual values calculated as the difference between: (A) the product of (i) 2013/2014 unit cost rates for each of the Used Fuel Storage and Disposal programs and the Low and Intermediate Level Waste ("L&ILW") Storage and Disposal programs arising from the current approved ONFA Reference Plan, and (ii) average number of forecast fuel bundles and L&ILW volumes reflected in the EB-2010-0008 payment amounts, and (B) the average of 2011 and 2012 forecast variable expenses reflected in the EB-2010-0008 payment amounts. For January to October 2014, the annual forecast value is prorated by 10/12.

6 Annual values calculated as the average of 2011 and 2012 contributions from EB-2010-0008 Payment Amounts Order, App. A: Table 6, line 16, col. (c) for 2011 and Table 7, line 16, col. (c) for 2012. For January to October 2014, the annual forecast value is prorated by 10/12.

7 2013 value is as shown in EB-2013-0321 Ex. L-1.0-1 Staff-002, Attachment 1, Table 7, col. (a), line 16.

Table 11
(Updated version of Ex. H1-1-1 Table 11)
Nuclear Development Variance Account
Summary of Account Transactions - 2014[1] ($M)

Line No.	Particulars	Actual Jan - Oct 2014	Actual Nov - Dec 2014	(a)+(b) Actual Total 2014
		(a)	(b)	(c)
1	**Forecast Costs - EB-2012-0002 / EB-2013-0321**	0.0	0.0	0.0
2	**Actual Costs**	1.2	0.2	1.5
3	**Addition to Variance Account** (line 2 - line 1)	1.2	0.2	1.5

Notes:
1 The 2013 forecast is nil as per EB-2012-0002 Payment Amounts Order, App. B, p. 9, as no Darlington New Nuclear costs were reflected in the EB-2010-0008 approved revenue requirement. Similarly, the 2014 forecast is nil as per the EB-2013-0321 Payment Amounts Order, App. G, p. 9, as no such costs were reflected in the EB-2013-0321 approved revenue requirement.

Numbers may not add due to rounding.

Table 12
(Updated version of Ex. H1-1-1 Table 12)
Capacity Refurbishment Variance Account - Nuclear
Summary of Account Transactions - 2013 and 2014 ($M)

Line No.	Particulars	Note	Actual 2013[1]	Actual Jan - Oct 2014	Actual Nov - Dec 2014	(b)+(c) Actual Total 2014
			(a)	(b)	(c)	(d)
	Non-Capital Addition to Variance Account:					
	Forecast Non-Capital Costs - EB-2012-0002 / EB-2013-0321:					
1	**Darlington Refurbishment**	2,3	5.2	4.3	2.1	6.4
2	**Fuel Channel Life Cycle Management Project**	2,3	5.9	4.9	0.6	5.5
3	**Pickering Continued Operations**	2,3	42.0	35.0	3.1	38.1
4	**Fuel Channel Life Extension Project**	2,3	0.0	0.0	0.0	0.0
5	**Total** (lines 1 through 4)		53.1	44.2	5.8	50.0
	Actual Non-Capital Costs:					
6	**Darlington Refurbishment**		6.3	5.6	0.6	6.3
7	**Fuel Channel Life Cycle Management Project**		9.2	7.8	0.5	8.3
8	**Pickering Continued Operations**		41.5	25.4	4.3	29.7
9	**Fuel Channel Life Extension Project**		0.0	3.0	1.9	4.9
10	**Total** (lines 6 through 9)		57.0	41.8	7.3	49.1
	Non-Capital Addition to Variance Account:					
11	**Darlington Refurbishment** (line 6 - line 1)		1.1	1.3	(1.4)	(0.1)
12	**Fuel Channel Life Cycle Management Project** (line 7 - line 2)		3.3	2.9	(0.1)	2.8
13	**Pickering Continued Operations** (line 8 - line 3)		(0.5)	(9.6)	1.2	(8.4)
14	**Fuel Channel Life Extension Project** (line 9 - line 4)		0.0	3.0	1.9	4.9
15	**Non-Capital Addition to Variance Account Before Adjustment** (lines 11 through 14)		4.0	(2.4)	1.6	(0.8)
16	**Less: EB-2013-0321 Impact Statement (Ex. N1) Adjustment**	4	N/A	N/A	2.1	2.1
17	**Total Non-Capital Addition to Variance Account - Nuclear** (line 15 - line 16)		4.0	(2.4)	(0.6)	(3.0)
	Capital Addition to Variance Account - Darlington Refurbishment:					
18	**Forecast Cost of Capital Amount** (col. (c): from Note 5, line 3b, col. (c) x 2/12)	5		0.0	1.8	1.8
19	**Actual 2014 Net Plant Rate Base Amount**	6		121.2	121.2	
20	**Weighted Average Cost of Capital**	7		7.40%	6.86%	
21	**Actual Cost of Capital Amount** (col. (b): line 19 x line 20 x 10/12; col. (c): line 19 x line 20 x 2/12)			7.5	1.4	8.9
22	**Cost of Capital Variance** (line 21 - line 18)			7.5	(0.4)	7.0
23	**Forecast Depreciation** (col. (c): from Note 5, line 5b, col. (c) x 2/12)	5		0.0	0.8	0.8
24	**Actual Depreciation**			3.7	1.0	4.7
25	**Depreciation Variance** (line 24 - line 23)			3.7	0.3	4.0
	Income Tax Impact:					
26	**Forecast Capital Cost Allowance Deduction**	8		3.3	11.1	14.4
27	**Actual Capital Cost Allowance Deduction**			27.3	5.0	32.3
28	**Difference** (line 26 - line 27)			(24.0)	6.2	(17.8)
29	**Net Increase (Decrease) in Regulatory Taxable Income**	9,10		(15.8)	6.2	(9.6)
30	**Income Tax Rate**	11		25.00%	25.00%	25.00%
31	**Income Tax Impact** (line 29 x line 30 / (1 - line 30))			(4.8)	2.1	(2.7)
32	**Capital Addition to Variance Account Before Adjustment** (line 22 + line 25 + line 31)			6.3	1.9	8.3
33	**Less: EB-2013-0321 Impact Statement (Ex. N1) Adjustment**			N/A	0.8	0.8
34	**Total Capital Addition to Variance Account - Nuclear** (line 32 - line 33)		4.3	6.3	1.1	7.4

For notes see Table 12a.

Table 12a
Notes to Table 12
Capacity Refurbishment Variance Account - Nuclear - 2013 and 2014

Notes:

1 Non-capital variance account addition calculation and Darlington capital addition total are as shown in EB-2013-0321 Ex. L-9.1-17 SEC-132, Table 12.

2 Forecasts for 2013 and January to October 2014 have been determined based on amounts reflected in the EB-2010-0008 payment amounts, with individual annual values found at EB-2012-0002 Ex. H1-1-2, Table 12, col. (d), lines 2-4. The total annual non-capital cost forecast of $53.1M is as per the EB-2012-0002 Payment Amounts Order, App. B, p. 10, at $4.42M/month. The total January to October 2014 non-capital cost forecast is therefore $4.42M/month multiplied by 10 months.

3 In accordance with the EB-2013-0321 Payment Amounts Order (App. G, p.10), the forecasts for November and December 2014 have been determined as shown below at line 4a, on the basis of amounts underpinning the EB-2013-0321 payment amounts:

Table to Note 3 - EB-2013-0321 and OPG's 2014-2016 Business Plan Forecast Costs ($M)

Line No.		Darlington Refurbishment Non-Capital[#]	Fuel Channel Life Cycle Mgmt Project[##]	Pickering Continued Operations[+]	Fuel Channel Life Extension Project[++]
		(a)	(b)	(c)	(d)
1a	2014 Full Year Forecast Costs - EB-2013-0321	6.6	6.8	37.1	0.0
2a	2015 Full Year Forecast Costs - EB-2013-0321	18.2	0.6	0.0	0.0
3a	Total Forecast Costs - EB-2013-0321	24.9	7.4	37.1	0.0
4a	Nov - Dec 2014 Average Annual Forecast from EB-2013-0321 ((line 3a / 24 months) x 2)	2.1	0.6	3.1	0.0
5a	2014 Full Year Forecast Costs - OPG's 2014-2016 Business Plan	6.6	8.8	39.1	
6a	2015 Full Year Forecast Costs - OPG's 2014-2016 Business Plan	20.4	0.5	0.0	
7a	Total Forecast from OPG's 2014-2016 Business Plan	27.0	9.2	39.1	
8a	Nov to Dec 2014 Average Annual Forecast - OPG's 2014-2016 Business Plan ((line 7a / 24 months) x 2)	2.3	0.8	3.3	
9a	Nov to Dec 2014 EB-2013-0321 Impact Statement (Ex. N1) Adjustment (cols. (a)-(c): line 8a - line 4a)	0.2	0.2	0.2	1.6

\# Lines 1a and 2a from EB-2013-0321 Decision with Reasons, p. 55.
\## Lines 1a and 2a from EB-2013-0321 Ex. F2-3-1, Table 1, line 11, cols. (e) and (f).
\+ Line 1a from EB-2013-0321 Ex. F2-2-3, p. 4, Chart 1, "Subtotal" line.
\++ The Fuel Channel Life Extension Project was not reflected in OPG's 2013-2015 Business Plan underpinning the EB-2013-0321 payment amounts.

4 The adjustments are per the EB-2013-0321 Payment Amounts Order (App. G, p.10) requirement that amounts recorded in the account do not include those that OPG indicated it is not seeking to recover from, or refund to, ratepayers as part of the differences between the revenue requirement in its EB-2013-0321 pre-filed evidence and the information based on OPG's 2014-2016 Business Plan, which was provided in the EB-2013-0321 Impact Statement at Ex. N1. The adjustments are 2/24 of the higher corresponding costs reflected in the total test period OM&A increase of $26M (EB-2013-0321 Ex. N1-1-1, Chart 1) between OPG's EB-2013-0321 pre-filed evidence and its 2014-2016 Business Plan. This difference was not included in the updated revenue requirement in the Ex. N1 Impact Statement. The individual November to December 2014 adjustments total $2.1M and are shown in Note 3, line 9a, cols. (a)-(d).
The Fuel Channel Life Cycle Extension Project was considered in OPG's 2014-2016 Business Plan (see EB-2013-0321 Ex. F2-3-3, Attachment 1, Tab 11) as part of the nuclear portfolio project OM&A. In addition to addressing requirements with respect to the EB-2013-0321 Ex. N1 Impact Statement, the adjustment also limits the amount recoverable from ratepayers for project cost variances to the variance in total nuclear portfolio project OM&A from OPG's 2014-2016 Busines Plan.

5 The annual forecast (reference) amounts are determined as follows:

Table to Note 5 - Darlington Refurbishment Forecast Capital Amounts - EB-2013-0321 ($M)

Line No.		2014	2015	((a)+(b)) / 2 Reference Amount
		(a)	(b)	(c)
1b	Forecast Net Plant Rate Base Amount[a]	116.0	204.6	
2b	Weighted Average Cost of Capital[b]	6.86%	6.85%	
3b	Cost of Capital Forecast Amount (line 1b x line 2b)	8.0	14.0	11.0
4b	ROE Component of Cost of Capital Amount[c]	4.9	8.6	6.7
5b	Depreciation[d]	3.0	6.1	4.5
6b	Capital Cost Allowance Deduction[e]	39.3	94.3	66.8

a Cols. (a) and (b) from EB-2013-0321 Ex. L-4.9-1 Staff-048, p. 2, Chart 1.
b Cols. (a) and (b) from EB-2013-0321 Payment Amounts Order, App. A, col. (c), line 6 of Tables 5b and 6b, respectively.
c Calculated as line 1b x equity portion (45%) of the EB-2013-0321 capital structure x EB-2013-0321 ROE rate of 9.36% (2014) and 9.30% (2015) (from EB-2013-0321 Payment Amounts Order, App. A, Tables 5b and 6b, col. (c), line 5).
d From EB-2013-0321 Ex. F4-1-1, Table 2, Note 1 and EB-2013-0321 Ex. L-4.9 Staff-048, p. 2, Chart 1.
e From EB-2013-0321 Ex. D2-2-1, p. 29, Note 2.

6 The 2014 actual net plant rate base amount is calculated as follows:

Table to Note 6 - 2014 Actual Darlington Refurbishment Net Plant Rate Base Amount ($M)

Line No.		Opening Balance^	In-Service Additions/ Depreciation	(a)-(b) Closing Balance	((a)+(c)) / 2 Rate Base Amount
		(a)	(b)	(c)	(d)
1b	Gross Plant	104.2	43.5	147.6	125.9
2b	Less: Accumulated Depreciation	2.3	4.7	7.0	4.7
3b	Net Plant	101.9	38.8	140.6	121.2

^ Amounts are 2013 closing values from EB-2013-0321 Ex. L-9.1-17 SEC-132, Attachment 1, Table 12a, Note 1, col. (c), lines 4a and 5a.

7 Col. (b) is from EB-2010-0008 Payment Amounts Order, App. A, Table 5b, col. (c), line 6. Col. (c) is from EB-2013-0321 Payment Amounts Order, App. A, Table 6b, col. (c), line 6.

8 Col. (b) is 10/12 x the average of cols. (a) and (b) from EB-2013-0321 Ex. L-9.1-17 SEC-132, Attachment 1, Table 12a, line 5. Col. (c) is from Note 5, col. (c), line 6b x 2/12.

9 The decrease in regulatory taxable income in col. (b) is calculated as the sum of lines 25 and 28, plus the ROE component of the cost of capital variance at line 22. The ROE component is calculated as: net plant amount at line 19, multiplied by the EB-2010-0008 OEB-approved equity portion (47%) of the capital structure, multiplied by the OEB-approved ROE rate of 9.55% (from EB-2010-0008 Payment Amounts Order, App. A, Table 5b, col. (b), line 5), multiplied by 10/12.

10 The increase in regulatory taxable income in col. (c) is calculated as the sum of lines 25 and 28, plus the ROE component of the cost of capital variance at line 22. The ROE component of the variance is calculated as 2/12 of the difference between: (i) line 19 multiplied by the EB-2013-0321 OEB-approved equity portion (45%) of the capital structure, multiplied by the OEB-approved ROE rate of 9.36% (from Note c), and (ii) Note 5, col. (c), line 4b.

11 From EB-2013-0321 Payment Amounts Order, App. A, Table 7, line 31.

Table 13
(Updated version of Ex. H1-1-1 Table 13)
Bruce Lease Net Revenues Variance Account
Summary of Account Transactions - 2013 and 2014

Line No.	Particulars	Note	Actual 2013[1]	Actual Jan - Oct 2014	Actual Nov - Dec 2014	(b)+(c) Actual Total 2014
			(a)	(b)	(c)	(d)
1	**Actual Total Bruce Lease Net Revenues ($M)**	2	7.9	122.2	(15.5)	106.7
2	**Forecast Bruce Lease Net Revenues - EB-2010-0008 / EB-2013-0321 ($M)**	3	135.5	135.5	40.2	
3	**Forecast Nuclear Production (TWh)**	4	51.0	51.0	47.8	
4	**Rate Credited to Customers ($/MWh)** (line 2 / line 3)		2.7	2.7	0.8	
5	**Actual Nuclear Production (TWh)**	5	44.7	39.8	8.2	
6	**Amount Credited to Customers ($M)** (line 4 x line 5)		118.5	105.8	6.9	112.7
7	**Total Addition to Variance Account Before Adjustment ($M)** (line 6 - line 1)		110.5	(16.4)	22.5	6.0
8	**Less: EB-2013-0321 Impact Statement (Ex. N1) Adjustment ($M)**	6	N/A	N/A	1.7	1.7
9	**Total Addition to Variance Account ($M)** (line 7 - line 8)		110.5	(16.4)	20.8	4.4
10	**Less: Addition to Derivative Sub-Account ($M)**	7	24.6	(57.5)	24.0	(33.5)
11	**Addition to Non-Derivative Sub-Account ($M)** (line 9 - line 10)		85.9	41.1	(3.2)	37.9

Notes:

1 As shown in EB-2013-0321 Ex. L-9.1-17 SEC-132 (corrected version filed on June 4, 2014), Attachment 1, Table 13.

2 From Ex. H1-1-2 Table 13a, line 30, cols. (a), (d), and (g).

3 Per EB-2012-0002 Payment Amounts Order, App. B, pp. 11-12, amount in cols. (a) and (b) is determined as the annual average (at $11.30M/month) of Bruce Lease net revenues reflected in the EB-2010-0008 approved revenue requirement (EB-2010-0008 Payment Amounts Order, App. A, Table 2, line 20). Per EB-2013-0321 Payment Amounts Order, App. G, pp. 11-12, amount in col. (c) is determined as the average (at $3.35M/month) of the 2014 and 2015 of Board-approved Bruce Lease net revenues (EB-2013-0321 Payment Amounts Order, App. A, Table 3, line 20).

4 Value in col. (a) and (b) is the average of 2011 and 2012 annual nuclear production from EB-2010-0008 Payment Amounts Order, App. A, Table 3, line 1, cols. (d) and (e). Value in col. (c) is the average of 2014 and 2015 annual nuclear production from EB-2013-0321 Payment Amounts Order, App. A, Table 4, line 1, cols. (g) and (h).

5 Col. (a) is from EB-2013-0321 Ex. L-1.0-1 Staff-002, Attachment 1, Table 14, col. (d), line 3. Cols. (b) and (c) are from Ex. H1-1-2, Table 14, line 10, cols. (b) and (c).

6 The adjustment in col. (c) is per the EB-2013-0321 Payment Amounts Order (App. G, p. 11) requirement that OPG shall ensure that amounts recorded in the account do not include those that OPG indicated it is not seeking to recover from, or refund to, ratepayers as part of the differences between the revenue requirement in its EB-2013-0321 pre-filed evidence and the information based on OPG's 2014-2016 Business Plan provided in the EB-2013-0321 Impact Statement at Ex. N1. The adjustment represents 2/24 of the $20M total test period decrease (EB-2013-0321 Ex. N1-1-1, Chart 1) in forecast Bruce Lease net revenues between OPG's EB-2013-0321 pre-filed evidence and the 2014-2016 Business Plan that was not included in the updated revenue requirement in that Impact Statement.

7 Cols. (b) and (c) are from Ex. H1-1-2 Table 13a, line 29, cols. (f) and (i), respectively.

Numbers may not add due to rounding.

Table 13a
(Updated version of Ex. H1-1-1 Table 13a)
Bruce Lease Net Revenue Variance Account
Comparison of Bruce Lease Net Revenues - 2013 and 2014 ($M)[1]

Line No.	Particulars	Actual 2013[2]	Average of 2011/2012 Board Approved (EB-2010-0008)[3]	(b) - (a) Change	Actual Jan - Oct 2014	10/12 of Average of 2011/2012 Board Approved (EB-2010-0008)	(e) - (d) Change	Actual Nov - Dec 2014	2/12 of Average 2014/2015 Board Approved (EB-2013-0321)[3]	(h) - (g) Change	(d) + (g) Actual Total 2014	Board Approved 2014 (EB-2013-0321)[4]	(k) - (j) Change
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Revenues:												
1	**Site Services (OPG to Bruce Power)**	0.6	0.6	(0.1)	0.5	0.5	(0.1)	0.0	0.1	0.1	0.5	0.7	0.1
2	**Low & Intermediate Level Waste Services**	5.3	13.0	7.6	3.2	10.8	7.6	0.5	2.7	2.1	3.7	14.8	11.1
3	**Cobalt-60**	0.6	0.5	(0.1)	0.4	0.4	(0.0)	0.1	0.1	(0.1)	0.6	0.5	(0.0)
4	**Total Services Revenue**	6.6	14.0	7.4	4.2	11.7	7.5	0.7	2.9	2.2	4.9	16.0	11.1
5	**Fixed (Base) Rent**	40.9	40.9	0.0	34.1	34.1	0.0	6.4	6.4	0.0	40.6	38.7	(1.9)
6	**Supplemental Rent - Non-Derivative Portion**	203.8	194.5	(9.3)	172.7	162.1	(10.6)	34.5	35.0	0.5	207.2	207.9	0.7
7	**Amortization of Initial Deferred Rent**	12.1	12.1	(0.1)	10.1	10.1	(0.0)	2.0	2.0	(0.0)	12.1	12.1	(0.0)
8	**Total Non-Derivative Rent Revenue**	256.9	247.5	(9.4)	216.8	206.3	(10.6)	43.0	43.5	0.5	259.8	258.6	(1.2)
9	**Total Non-Derivative Revenue** (line 4 + line 8)	263.5	261.6	(1.9)	221.0	218.0	(3.0)	43.7	46.3	2.6	264.7	274.6	10.0
10	**Supplemental Rent - Derivative Portion**	(32.8)	0.0	32.8	76.7	0.0	(76.7)	(32.0)	0.0	32.0	44.7	0.0	(44.7)
11	**Total Revenue** (line 9 + line 10)	230.7	261.6	30.9	297.7	218.0	(79.7)	11.7	46.3	34.6	309.4	274.6	(34.7)
	Costs:												
12	**Depreciation**	104.5	34.5	(70.0)	86.6	28.8	(57.9)	17.3	17.8	0.5	104.0	106.8	2.8
13	**Property Tax**	11.6	13.8	2.3	9.8	11.5	1.7	1.9	2.3	0.5	11.6	13.7	2.1
14	**Accretion**	369.0	300.9	(68.1)	322.4	250.7	(71.7)	64.3	65.0	0.7	386.7	382.9	(3.8)
15	**(Earnings) Losses on Segregated Funds**	(337.1)	(295.4)	41.7	(346.8)	(246.2)	100.6	(65.0)	(58.9)	6.1	(411.8)	(347.0)	64.7
16	**Used Fuel Storage and Disposal**	54.0	20.5	(33.5)	47.8	17.1	(30.7)	11.1	9.2	(1.9)	58.9	54.3	(4.5)
17	**Waste Management Variable Expenses and Facilities Removal Costs**	2.8	0.8	(2.0)	3.6	0.6	(3.0)	0.2	0.5	0.3	3.9	2.4	(1.5)
18	**Interest**	20.2	9.4	(10.8)	15.3	7.8	(7.5)	3.3	2.2	(1.1)	18.6	13.4	(5.2)
19	**Total Costs Before Income Tax** (lines 12 through 18)	225.0	84.5	(140.5)	138.7	70.4	(68.3)	33.2	38.2	5.0	171.9	226.5	54.6
20	**Income Tax - Current - Non-Derivative Portion**[5]	26.9	4.3	(22.6)	49.9	3.6	(46.3)	7.0	9.7	2.6	56.9	57.1	0.2
21	**Income Tax - Future/Deferred - Non-Derivative Portion**[6]	(20.8)	37.3	58.1	(32.2)	31.1	63.3	(5.0)	(8.2)	(3.2)	(37.2)	(48.6)	(11.3)
22	**Total Income Tax - Non-Derivative Portion**	6.1	41.6	35.5	17.6	34.7	17.0	2.0	1.4	(0.6)	19.7	8.5	(11.2)
23	**Total Non-Derivative Costs** (line 19 + line 22)	231.1	126.0	(105.0)	156.3	105.0	(51.3)	35.2	39.6	4.4	191.5	235.0	43.4
24	**Income Tax - Current - Derivative Portion**[7]	(26.9)	0.0	26.9	(0.6)	0.0	0.6	0.0	(3.3)	(3.3)	(0.6)	(19.8)	(19.2)
25	**Income Tax - Future/Deferred - Derivative Portion**[8]	18.7	0.0	(18.7)	19.7	0.0	(19.7)	(8.0)	3.3	11.3	11.7	19.8	8.1
26	**Total Income Tax - Derivative Portion**	(8.2)	0.0	8.2	19.2	0.0	(19.2)	(8.0)	0.0	8.0	11.2	0.0	(11.2)
27	**Total Costs** (line 23 + line 26)	222.8	126.0	(96.8)	175.5	105.0	(70.5)	27.2	39.6	12.4	202.7	235.0	32.2
28	**Bruce Lease Net Revenues - Non-Derivative Portion** (line 9 - line 23)	32.5	135.5	103.1	64.7	113.0	48.3	8.5	6.7	(1.8)	73.2	39.7	(33.5)
29	**Bruce Lease Net Revenues - Derivative Portion** (line 10 - line 26)	(24.6)	0.0	24.6	57.5	0.0	(57.5)	(24.0)	0.0	24.0	33.5	0.0	(33.5)
30	**Total Bruce Lease Net Revenues** (line 28 + line 29)	7.9	135.5	127.6	122.2	113.0	(9.3)	(15.5)	6.7	22.2	106.7	39.7	(67.0)

Notes:
1 All amounts for 2013 and January to October 2014 are presented on a CGAAP basis, as this is the basis used to determine EB-2010-0008 Board-approved forecasts for 2011 and 2012. All amounts for November to December 2014 are presented on a US GAAP basis, which was used to determine the EB-2013-0321 Board approved forecast (shown in col. (k) for 2014).
2 Amounts are as shown in EB-2013-0321, Ex. L-1.0-1 Staff-002, Attachment 1, Table 36, with the exception of lines 5 and 21 (which have been adjusted to CGAAP basis for a total net increase to Bruce Lease Net Revenues at line 30 of $1.6M, per EB-2013-0321 Ex. L-9.1-17 SEC-132 (corrected version filed on June 4, 2014), Attachment 1, Table 13, Note 2), and internally calculated values at lines 8, 9, 11, 22, 23, 27, 28 and 30,
3 Bruce Lease Net Revenues forecast for 2011 and 2012 is detailed in EB-2010-0008 Ex. G2-2-1, Table 2 (revenues) and Table 5 (costs).
4 Bruce Lease Net Revenues forecast for 2014 is detailed EB-2013-0321 Ex. G2-2-1, Table 2 (revenues) and Table 5 (costs).
5 Cols. (a), (d) and (g) from corresponding columns of Ex. H1-1-2 Table 13b, line 38.
6 Cols. (a), (d) and (g) from corresponding columns of Ex. H1-1-2 Table 13b, line 46.
7 Cols. (a), (d) and (g) from corresponding columns of Ex. H1-1-2 Table 13b, line 37.
8 Cols. (a), (d) and (g) from corresponding columns of Ex. H1-1-2 Table 13b, line 45.

Numbers may not add due to rounding.

Table 13b
(Updated version of Ex. H1-1-1 Table 13b)
Bruce Lease Net Revenues Variance Account
Calculation of Bruce Income Taxes - 2013 and 2014 ($M)[1]

Line No.	Particulars	Note	Actual 2013[2]	Actual Jan - Oct 2014	Actual Nov - Dec 2014	(b)+(c) Actual Total 2014
			(a)	(b)	(c)	(d)
	Determination of Taxable Income					
1	**Earnings (Loss) Before Tax**	3	5.7	159.0	(21.5)	137.5
	Additions for Tax Purposes - Temporary Differences:					
2	**Base Rent Accrual**		40.1	35.0	7.4	42.4
3	**Depreciation**		104.5	86.6	17.3	104.0
4	**Accretion**		369.0	322.4	64.3	386.7
5	**Used Fuel and Waste Management Expenses and Faciities Removal Costs**		56.8	51.4	11.4	62.7
6	**Receipts from Nuclear Segregated Funds**		30.4	29.3	4.7	34.0
7	**Change in Fair Value of Bruce Derivative**		32.8	(76.7)	32.0	(44.7)
8	**Other**		2.5	4.4	0.5	4.9
9	**Total Additions - Temporary Differences**		636.2	452.4	137.7	590.1
	Deductions for Tax Purposes - Permanent Differences:					
10	**Deferred Rent Revenue**		14.2	11.8	2.4	14.2
	Deductions for Tax Purposes - Temporary Differences:					
11	**CCA**		5.7	4.4	0.9	5.3
12	**Cash Expenditures for Used Fuel, Waste Management & Decommissioning and Facilities Removal**		91.3	75.2	24.9	100.1
13	**Contributions to Nuclear Segregated Funds**		85.9	(26.2)	(5.1)	(31.3)
14	**Earnings (Losses) on Nuclear Segregated Funds**		337.1	346.8	65.0	411.8
15	**Supplemental Rent Payment Reduction**		78.7	0.0	0.0	0.0
16	**Total Deductions - Temporary Differences**		598.6	400.2	85.7	485.9
17	**Taxable Income/(Loss) Before Loss Carry-Over** (line 1 + line 9 - line 10- line 16)		29.1	199.4	28.1	227.5
18	**Tax Loss Carry-Over to Future Years / (from Prior Years)**	4	(29.1)	(2.3)	0.0	(2.3)
19	**Taxable Income After Loss Carry-Over** (line 17 + line 18)		0.0	197.1	28.1	225.3
	Determination of Total Current Income Taxes					
20	**Taxable Income After Loss Carry-Over** (from line 19)		0.0	197.1	28.1	225.3
21	**Income Tax Rate - Current**		25.00%	25.00%	25.00%	25.00%
22	**Income Taxes - Current**		0.0	49.3	7.0	56.3
	Determination of Total Deferred Income Taxes					
23	**Total Net Short-Term Temporary Differences** (line 3 + line 6 - line 11 - line 12)		37.9	36.4	(3.7)	32.6
24	**Income Tax Rate - Current**		25.00%	25.00%	25.00%	25.00%
25	**Deferred Income Taxes - Short-Term**		(9.5)	(9.1)	0.9	(8.2)
26	**Total Net Long-Term Temporary Differences** (line 9 - line 16 - line 23)		(0.4)	15.9	55.8	71.6
27	**Income Tax Rate - Long-Term**		25.00%	25.00%	25.00%	25.00%
28	**Deferred Income Taxes - Long-Term**		0.1	(4.0)	(13.9)	(17.9)
29	**Tax Loss / Tax Loss Carry-Over** (line 17 or line 18)		(29.1)	(2.3)	0.0	(2.3)
30	**Income Tax Rate - Current**		25.00%	25.00%	25.00%	25.00%
31	**Deferred Income Taxes - Tax Loss / Tax Loss Carry-Over**		7.3	0.6	0.0	0.6
32	**Deferred Income Tax - Total** (line 25 + line 28 + line 31)		(2.1)	(12.5)	(13.0)	(25.5)
	Determination of Derivative and Non-Derivative Portions of Total Current Income Taxes					
33	**Taxable Income Before Loss Carry-Over - Impact of Derivative** (from line 15)		(78.7)	0.0	0.0	0.0
34	**Tax Loss Carry-Over From Prior Years - Impact of Derivative** (from line 18)	5	(29.1)	(2.3)	0.0	(2.3)
35	**Taxable Income After Tax Loss Carry-Over From Prior Years - Impact of Derivative** (line 33 + line 34)		(107.7)	(2.3)	0.0	(2.3)
36	**Income Tax Rate - Current**		25.00%	25.00%	25.00%	25.00%
37	**Income Taxes - Current - Derivative Portion**		(26.9)	(0.6)	0.0	(0.6)
38	**Income Taxes - Current - Non-Derivative Portion** (line 22 - line 37)		26.9	49.9	7.0	56.9
	Determination of Derivative and Non-Derivative Portions of Total Deferred Income Taxes					
39	**Net Long-Term Temporary Differences - Impact of Derivative** (line 7 - line 15)		(45.8)	(76.7)	32.0	(44.7)
40	**Income Tax Rate - Long-Term**		25.00%	25.00%	25.00%	25.00%
41	**Deferred Income Taxes - Long-Term - Derivative Portion**		11.5	19.2	(8.0)	11.2
42	**Tax Loss Carry-Over - Impact of Derivative** (from line 34)		(29.1)	(2.3)	0.0	(2.3)
43	**Income Tax Rate**		25.00%	25.00%	25.00%	25.00%
44	**Deferred Income Taxes - Tax Loss Carry-Over - Derivative Portion**		7.3	0.6	0.0	0.6
45	**Deferred Income Taxes - Total - Derivative Portion** (line 41 + line 44)		18.7	19.7	(8.0)	11.7
46	**Deferred Income Taxes - Total - Non-Derivative Portion** (line 32 - line 45)		(20.8)	(32.2)	(5.0)	(37.2)
	Income Tax Rate - Current					
47	**Federal Tax**		15.00%	15.00%	15.00%	15.00%
48	**Provincial Tax**		11.25%	11.25%	11.25%	11.25%
49	**Provincial Manufacturing & Processing Profits Deduction**		-1.25%	-1.25%	-1.25%	-1.25%
50	**Total Income Tax Rate - Current**		25.00%	25.00%	25.00%	25.00%
	Income Tax Rate - Long-Term					
51	**Federal Tax**		15.00%	15.00%	15.00%	15.00%
52	**Provincial Tax**		10.00%	10.00%	10.00%	10.00%
53	**Provincial Manufacturing & Processing Profits Deduction**		0.00%	0.00%	0.00%	0.00%
54	**Total Income Tax Rate - Long-Term**		25.00%	25.00%	25.00%	25.00%

Notes:
1. All amounts for 2013 and January to October 2014 are presented on a CGAAP basis, as this is the basis used to determine EB-2010-0008 Board-approved forecasts for 2011 and 2012. All amounts for November to December 2014 are presented on a US GAAP basis, which was used to determined the EB-2013-0321 Board approved forecasts.
2. With the exception of lines 1 and 2 (which have been adjusted to CGAAP basis) and internally calculated values at lines 9, 26, 28 and 46, amounts are as shown in EB-2013-0321 Ex. L-1.0-1 Staff-002, Attachment 1, Table 38.
3. Earnings (Loss) Before Tax is derived as the difference between Total Revenue in Ex. H1-1-2, Table 13a, line 11 and Total Costs Before Income Tax in Ex. H1-1-2, Table 13a, line 19.
4. Amount in col. (b) is calculated as amount in EB-2013-0321 Ex. G2-2-1, Table 9, line 3, col. (c) less amount in col. (a).
5. As noted in EB-2013-0321, Ex. L-1.0-1 Staff-002, Table 38, Note 2 the full amount of brought forward Bruce tax losses would be utilized in 2012 in the absence of the income tax deduction for the supplemental rent payment reduction in 2012. As such, in the absence of this deduction, no losses would be available for utilization against the non-derivative portion of the 2013 and 2014 taxable income.

Table 13c
(Updated version of Ex. H1-1-1 Table 13c)
Amortization of Bruce Lease Net Revenues Variance Account - Derivative Sub-Account ($M)
As at December 31, 2014

Line No.	Particulars	Amount at Dec. 31, 2014
		(a)
	Amount for Recovery in 2015 and 2016 Before Prior Recovery Adjustment	
	2015:	
1	**Forecast Partial Supplemental Rent Rebate**	82.7
2	**Less: Income Tax Impact** (line 1 x tax rate of 25%)	20.7
3	**Net Amount**	62.1
	2016:	
4	**Forecast Partial Supplemental Rent Rebate**	85.5
5	**Less: Income Tax Impact** (line 4 x tax rate of 25%)	21.4
6	**Net Amount**	64.1
7	**Total Amount for Recovery in 2015 and 2016 Before Prior Recovery Adjustment**	126.2
	(line 3 + line 6)	
	Prior Recovery Adjustment	
	2013:	
8	**Amount Recovered per EB-2012-0002 (Prior to EB-2012-0002 Prior Recovery Adjustment)**[1]	60.2
9	**Actual Partial Supplemental Rent Rebate**[2]	78.7
10	**Less: Income Tax Impact** (line 9 x tax rate of 25%)	19.7
11	**Net Amount**	59.0
12	**Prior Recovery Adjustment for 2013** (line 8 - line 11)	1.2
	2014:	
13	**Amount Recovered per EB-2012-0002 (Prior to EB-2012-0002 Prior Recovery Adjustment)**[1]	62.2
14	**Actual Partial Supplemental Rent Rebate**[2]	0.0
15	**Less: Income Tax Impact** (line 14 x tax rate of 25%)	0.0
16	**Net Amount**	0.0
17	**Prior Recovery Adjustment for 2014** (line 13 - line 16)	62.2
18	**Correction of EB-2012-0002 Calculation Error (including interest at OEB-prescribed rate)**[3]	9.0
19	**Total Prior Recovery Adjustment** (line 12 + line 17 + line 18)	72.4
	Amount for Recovery in 2015 and 2016 After Prior Recovery Adjustment	
20	**2015 Amortization** (line 3 - line 19)	(10.4)
21	**2016 Amortization** (line 6)	64.1
22	**Total Amount for Recovery in 2015 and 2016** (line 20 + line 21)	53.7

Notes:

1 From EB-2012-0002 Settlement Agreement Ex. M1-1, Att. 2, Table 14c, col. (a), line 6 (2013) and line 9 (2014).

2 From Ex. H1-1-2 Table 13b, line 15, col. (a) for 2013 and sum of cols. (b) and (c) for 2014.

3 As discussed in EB-2013-0321 Ex. H1-1-1, p. 14, lines 16-20 and OPG's letter to the OEB dated September 26, 2013. The amount of the error was $8.9M. Interest credit added is the sum of Ex. H1-1-2 Table 1a, line 19, col. (f), Ex. H1-1-2 Table 1b, line 19, col. (d), and Ex. H1-1-2 Table 1c, line 22, col. (d).

Numbers may not add due to rounding.

Table 14
(Updated version of Ex. H1-1-1 Table 14)
Nuclear Deferral and Variance Over/Under Recovery Variance Account
Summary of Account Transactions - 2013 and 2014

Line No.	Particulars	Note	Actual 2013[1]	Actual Jan - Oct 2014	Actual Nov - Dec 2014	(b)+(c) Actual Total 2014
			(a)	(b)	(c)	(d)
1	**Nuclear Rider 2013-A / 2014-A ($/MWh)**	2	6.27	4.18	4.18	
2	**Nuclear Rider 2013-B ($/MWh)**	3	0.41			
3	**Interim Nuclear Rider ($/MWh)**	4	4.33			
4	**Interim Period Production Forecast (TWh)**	5	9.0			
5	**Actual Nuclear Production for Jan-Feb 2013 (TWh)**		8.0			
6	**Production Variance (TWh)** (line 4 - line 5)		1.0			
7	**Under Recovery Due to Difference in Interim Period Production ($M)** (line 3 x line 6)		4.4			
8	**Full Year Nuclear Forecast Production Used to Set Rider 2013-A (TWh)**	6	51.0			
9	**Mar 2013 - Dec 2014 Nuclear Production Forecast Used to Set Rider 2013-A and Rider 2014-A (TWh)**	7	42.0	42.7	8.3	51.0
10	**Mar 2013 - Dec 2014 Actual Nuclear Production (TWh)**		36.7	39.8	8.2	48.1
11	**Actual Nuclear Production Variance for Mar 2013 - Dec 2014 (TWh)** (line 9 - line 10)		5.3	2.9	0.0	2.9
12	**Under Recovery Due to Difference in Mar 2013 - Dec 2014 Production ($M)** (line 11 x (line 1 + line 2))		35.1	12.1	0.1	12.1
13	**Addition to Variance Account ($M)** (line 7 + line 12)		39.5	12.1	0.1	12.1

Notes:
1 As shown in EB-2013-0321 Ex. L-9.1-17 SEC-132 (corrected version filed on June 4, 2014), Attachment 1, Table 14.
2 From EB-2012-0002 Payment Amounts Order, App. A, Table 2, line 13, col. (g) for 2013 and col. (h) for 2014.
3 From EB-2012-0002 Payment Amounts Order, App. A, Table 3, col. (b), line 7.
4 From EB-2012-0002 Payment Amounts Order, App. A, Table 3, col. (b), line 2.
5 From EB-2012-0002 Payment Amounts Order, App. A, Table 3, col. (b), line 5.
6 From EB-2012-0002 Payment Amounts Order, App. A, Table 2, col. (g), line 12.
7 Value for 2013 is calculated as line 8 less line 4. Annual value for 2014 is from EB-2012-0002 Payment Amounts Order, App. A, Table 2, col. (h), line 12. Values for January to October 2014 and November to December 2014 are average of the corresponding monthly forecasts found at EB-2012-0002 Ex. L-2-1 Staff-16, Attachment 1, Table 3, lines 1 and 3.

Numbers may not add due to rounding.

Table 15
(Updated version of Ex. H1-2-1 Table 1)
Calculation of Deferral and Variance Account Recovery Payment Rider - Regulated Hydroelectric ($M)

Line No.	Account	Actual Balance at December 31, 2014[1]	EB-2013-0321 Board Approved Amortization 2015[2]	(a)-(b) 2014 Balance Less 2015 Approved Amortization	Recovery Period (Months)	Amortization Jul - Dec 2015	Amortization Jan - Dec 2016	(e)+(f) Amortization Jul 2015 - Dec 2016	(c)-(g) Unamortized Balance At Dec 31, 2016
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	**Hydroelectric Water Conditions Variance**	(8.5)	0.0	(8.5)	18	(2.8)	(5.6)	(8.5)	0.0
2	**Ancillary Services Net Revenue Variance - Hydroelectric**	(16.5)	0.0	(16.5)	18	(5.5)	(11.0)	(16.5)	0.0
3	**Hydroelectric Incentive Mechanism Variance**	(7.5)	(5.0)	(2.5)	18	(0.8)	(1.7)	(2.5)	0.0
4	**Hydroelectric Surplus Baseload Generation Variance**	67.1	19.2	47.9	18	16.0	31.9	47.9	0.0
5	**Income and Other Taxes Variance - Hydroelectric**	(0.2)	0.0	(0.2)	18	(0.1)	(0.1)	(0.2)	0.0
6	**Capacity Refurbishment Variance - Hydroelectric**	232.6	112.7	119.9	18	40.0	79.9	119.9	0.0
7	**Pension and OPEB Cost Variance - Hydroelectric - Historic**	0.0	0.0	0.0	18	0.0	0.0	0.0	0.0
8	**Pension and OPEB Cost Variance - Hydroelectric - Future**	10.5	0.0	10.5	120	1.1	1.1	2.1	8.4
9	**Pension and OPEB Cost Variance - Hydroelectric - Post 2012 Additions**	35.5	0.0	35.5	24	8.9	17.7	26.6	8.9
10	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**	4.5	0.0	4.5	18	1.5	3.0	4.5	0.0
11	**Total** (lines 1 through 10)	317.6	127.0	190.6				173.4	17.3
12	**Forecast Production[3] (TWh)**							48.8	
13	**Regulated Hydroelectric Payment Rider ($/MWh)** (line 11 / line 12)							3.55	

Notes:
1 From Ex. H1-1-2 Table 1.
2 From EB-2013-0321 Payment Amounts Order App. E, Table 1, col. (e).
3 Board-approved 2014-2015 previously regulated hydroelectric production from EB-2013-0321 Payment Amounts Order, App. B, Table 1, line 2 multiplied by 18 months divided by 24 months, plus July 1, 2014 to December 31, 2015 newly regulated hydroelectric production from EB-2013-0321 Payment Amounts Order, App. C, Table 1, line 2, col. (c).

Numbers may not add due to rounding.

Table 16
(Updated version of Ex. H1-2-1 Table 2)
Calculation of Deferral and Variance Account Recovery Payment Rider - Nuclear ($M)

Line No.	Account	Actual Balance at December 31, 2014[1]	EB-2013-0321 Board Approved Amortization 2015[2]	(a)-(b) 2014 Balance Less 2015 Approved Amortization	Recovery Period (Months)	Amortization Jul - Dec 2015	Amortization Jan - Dec 2016	(e)+(f) Amortization Jul 2015 - Dec 2016	(c)-(g) Unamortized Balance At Dec 31, 2016
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	**Nuclear Liability Deferral**	285.7	0.0	285.7	18	95.2	190.5	285.7	0.0
2	**Nuclear Development Variance**	58.8	56.5	2.3	18	0.8	1.6	2.3	0.0
3	**Ancillary Services Net Revenue Variance - Nuclear**	1.7	0.0	1.7	18	0.6	1.2	1.7	0.0
4	**Capacity Refurbishment Variance - Nuclear - Capital Portion**	13.2	5.7	7.6	18	2.5	5.0	7.6	0.0
5	**Capacity Refurbishment Variance - Nuclear - Non-Capital Portion**	1.3	0.0	1.3	18	0.4	0.8	1.3	0.0
6	**Bruce Lease Net Revenues Variance - Derivative Sub-Account[3]**	153.8	0.0	153.8	n/a	(10.4)	64.1	53.7	100.0
7	**Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - EB-2012-0002**	37.3	0.0	37.3	18	18.7	18.7	37.3	0.0
8	**Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - Post 2012 Additions**	123.8	0.0	123.8	18	41.3	82.5	123.8	0.0
9	**Income and Other Taxes Variance - Nuclear**	(13.2)	0.0	(13.2)	18	(4.4)	(8.8)	(13.2)	0.0
10	**Pension and OPEB Cost Variance - Nuclear - Historic**	0.0	0.0	0.0	18	0.0	0.0	0.0	0.0
11	**Pension and OPEB Cost Variance - Nuclear - Future**	214.7	0.0	214.7	120	21.5	21.5	42.9	171.7
12	**Pension and OPEB Cost Variance - Nuclear - Post 2012 Additions**	678.6	0.0	678.6	24	169.6	339.3	508.9	169.6
13	**Pickering Life Extension Depreciation Variance**	7.8	0.0	7.8	18	2.6	5.2	7.8	0.0
14	**Nuclear Deferral and Variance Over/Under Recovery Variance**	56.4	0.0	56.4	18	18.8	37.6	56.4	0.0
15	**Total** (lines 1 through 14)	1,619.9	62.2	1,557.8				1,116.3	441.4
16	**Forecast Production[4] (TWh)**							71.7	
17	**Nuclear Payment Rider ($/MWh)** (line 15 / line 16)							15.57	

Notes:
1 From Ex. H1-1-2 Table 1.
2 From EB-2013-0321 Payment Amounts Order Appendix F, Table 1, col. (e).
3 Amortization in cols. (e) and (f) is from Ex. H1-1-2 Table 13c, lines 20 and 21.
4 Board-approved 2014-2015 nuclear production from EB-2013-0321 Payment Amounts Order, App. D, Table 1, line 2 multiplied by 18 months divided by 24 months.

Numbers may not add due to rounding.

Table 17
(Updated version of Ex. I1-1-2 Table 1)
Annualized Residential Consumer Impact
Test Period January 1, 2015 to December 31, 2016

Line No.	Description	Amount
		(a)
1	**Typical Consumption[1] (kWh/Month)**	842
2	**Typical Usage of OPG Generation (kWh/Month)** (line 1 x line 11)	489
3	**Typical Bill[1] ($/Month)**	132.57
4	**Typical Bill Impact ($/Month)** (line 2 x line 8 / 1000)	**3.00**
5	**Typical Bill Impact (%)** (line 4 / line 3)	**2.3%**
6	EB-2013-0321 Payment Amounts Order OPG weighted average rate for 2015[2] ($/MWh)	54.75
7	Blended OPG 2015-16 weighted average rate with proposed riders[3] ($/MWh)	60.89
8	Change in OPG weighted average rate ($/MWh) (line 7 - line 6)	6.14
9	Approved 2014-15 OPG Regulated Production[4] (TWh)	161.6
10	Forecast of Provincial Demand[5] (TWh)	278.3
11	OPG Proportion of Consumer Usage (line 9 / line 10)	58.1%

Notes:

1. Typical monthly consumption (800 kWh) and typical monthly bill are based on the OEB "Bill Calculator" for estimating monthly electricity bills (using Time of Use pricing), available at: http://www.ontarioenergyboard.ca/OEB/Consumers/Electricity/Your+Electricity+Utility
   Typical Consumption includes line losses.
2. From Ex. I1-1-2 Table 2, line 11, col. (a).
3. From Ex. I1-1-2 Table 2, line 11, col. (b).
4. From Ex. I1-1-2 Table 2, line 7.
5. Based on forecast demand for 2014 (139.5 TWh) and 2015 (138.8 TWh) from Table 3.1 of IESO 18-Month Outlook Update for September 2014 to February 2016, published September 4, 2014.

Numbers may not add due to rounding.

Table 18
(Updated version of Ex. I1-1-2 Table 2)
Computation of Percent Change in Payment Amounts
EB-2013-0321 to EB-2014-0370

Line No.	Description	Note	Nov-Dec 2014 per EB-2013-0321 Payment Amounts Order	Weighted Average 2015-16 per EB-2013-0321 Payment Amounts Order plus EB-2014-0370	((b)/(a))-1 **Percent Change In Payment Amounts**
			(a)	(b)	(c)
1	**Previously Regulated Hydroelectric Rate Including Rider ($/MWh)**	1	42.22	45.83	9%
2	**Newly Regulated Hydroelectric Rate including Rider ($/MWh)**	2	41.93	44.49	6%
3	**Nuclear Rate Including Rider ($/MWh)**	3	63.47	71.63	13%
4	**Approved 2014-15 Previously Regulated Hydroelectric Production (TWh)**	4	41.1	41.1	
5	**Approved 2014-15 Newly Regulated Hydroelectric Production (TWh)**	4	24.8	24.8	
6	**Approved 2014-15 Nuclear Production (TWh)**	4	95.6	95.6	
7	**Total Approved 2014-15 Production (TWh)** (line 4 + line 5 + line 6)		161.6	161.6	
8	**Previously Regulated Hydroelectric Portion of Production-Weighted Average Rate ($/MWh)** (line 1 x line 4 / line 7)		10.74	11.66	
9	**Newly Regulated Hydroelectric Portion of Production-Weighted Average Rate ($/MWh)** (line 2 x line 5 / line 7)		6.45	6.84	
10	**Nuclear Portion of Production-Weighted Average Rate ($/MWh)** (line 3 x line 6 / line 7)		37.56	42.39	
11	**Total Production-Weighted Average Rate ($/MWh)** (line 8 + line 9 + line 10)		54.75	60.89	
12	**OVERALL CHANGE IN PAYMENT AMOUNTS FROM EB-2013-0321 TO EB-2014-0370**				**11.2%**
	((line 11 col. (b) / line 11 col. (a)) -1)				

Notes:

1 Col. (a) is payment amount from EB-2013-0321 Payment Amounts Order, App. B, Table 1, line 3 ($40.20/MWh) plus EB-2012-0002 Approved Hydroelectric Rider 2014-A from EB-2012-0002 Payment Amounts Order, App. A, Table 1, line 13, col. (h) ($2.02/MWh)
Col. (b) is production-weighted average of approved and proposed rates and riders for 2015 - 2016.

2 Col. (a) is payment amount from EB-2013-0321 Payment Amounts Order, App. B, Table 1, line 3 ($41.93/MWh).
Col. (b) is production-weighted average of approved and proposed rates and riders for 2015 - 2016.

3 Col. (a) is payment amount from EB-2013-0321 Payment Amounts Order, App. D, Table 1, line 3 ($59.29/MWh) plus EB-2012-0002 Approved Nuclear Rider 2014-A from EB-2012-0002 Payment Amounts Order, App. A, Table 2, line 13, col. (h) ($4.18/MWh)
Col. (b) is production-weighted average of approved and proposed rates and riders for 2015 - 2016.

4 Previously regulated hydroelectric from EB-2013-0321 Payment Amounts Order, App. B, Table 1, line 2.
Newly regulated hydroelectric from EB-2013-0321 Ex. E1-1-1, Table 1, line 8, col. (e) plus col. (f).
Nuclear from EB-2013-0321 Payment Amounts Order, App. D, Table 1, line 2.
Forecast production is held constant in cols. (a), (b), (c), (d) and (e) at values approved in order to isolate the effect of the overall change in payment amounts.