CCC Interrogatory #001

Interrogatory

Reference(s):
Ex. A1/T1/S2/p. 2

OPG is seeking approval of payment riders effective July 1, 2015 of $3.55/MWh for the output of its Hydroelectric facilities and $15.57/MWh for the output of its Nuclear facilities. Please provide a schedule setting out the approved base payment amounts and approved rider amounts for each year since 2008. Does OPG expect its rate riders to be generally of the same magnitude as those set out in this Application for 2015 and beyond? If not, does OPG see the rate riders increasing or decreasing over time?

Response

Please refer to attachment 1 for the requested table.

OPG has no forecast of riders beyond those proposed in this application. As riders are intended to clear variance account balances, and variance account transactions, both positive and negative are, by their very nature unpredictable beyond a relatively short time period.

Table 1
History of Payment Amounts and Riders for Prescribed Facilities

	O.Reg 53/05	EB-2007-0905	EB-2010-0008	EB-2012-0002		EB-2013-0321	
Effective date	1-Apr-05	1-Apr-08	1-Mar-11	1-Jan-13	1-Jan-14	1-Nov-14	1-Jan-15
Previously Regulated Hydroelectric							
Base Payment Amount ($/MWh)	33.00	36.66	35.78	35.78	35.78	40.20	40.20
D&V Rider [1, 2] ($/MWh)	-	-	(1.65)	3.04	2.02	2.02	6.04
Total	33.00	36.66	34.13	38.82	37.80	42.22	46.24
Nuclear							
Base Payment Amount ($/MWh)	49.50	52.98	51.52	51.52	51.52	59.29	59.29
D&V Rider [2] ($/MWh)	-	2.00	4.33	6.27	4.18	4.18	1.33
Total	49.50	54.98	55.85	57.79	55.70	63.47	60.62
Newly Regulated Hydroelectric						1-Jul-14	1-Jan-15
Base Payment Amount ($/MWh)						41.93	41.93
Rider ($/MWh)						-	-
Total						41.93	41.93

Notes:
1 Implicit D&V rider of $0.425/MWh was embedded in Hydro base payment amount during EB2007-0905 test period.
2 D&V Riders shown as effective Nov 1, 2014 are those approved in EB-2012-0002 which continued to Dec 31, 2014.

LPMA Interrogatory #001

Interrogatory

Reference(s):
A1, Tab 1, Schedule 2, Updated

Please explain why OPG is proposing an 18 month clearance period rather than a 12 month period for all accounts excluding the two accounts noted in paragraph 3.

Response

OPG is proposing an 18 month clearance for most of its accounts because the Application proposes that the new payment riders become effective July 1, 2015 and an 18 month clearance period (July 1, 2015 to December 31, 2016) will allow subsequent clearance periods to begin at the start of the calendar year.

Board Staff Interrogatory #001

Interrogatory

Reference(s):
Exh H1-1-2 Table 1
Summary of Deferral and Variance Accounts

The last column of Table 1 summarizes the 2014 year end balances. Please provide a revision to this table, or prepare another table that illustrates the balances (a) previously approved for disposition by EB-2012-0002 and (b) previously approved for disposition by EB-2013-0321 and (c) requested for disposition by EB-2014-0370.

Response

Please see attached table.

Numbers may not add due to rounding.

Filed: 2015-03-27
EB-2014-0370
Exhibit L: Interrogatory Responses
H-Staff-001
Attachment 1
Table 1

	Summary of Deferral and Variance Accounts Closing Account Balances - 2012 to 2014 ($M)					Approved / Requested for Disposition ($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]**	**Previously Approved for Disposition in EB-2012-0002[5]**	**Previously Approved for Disposition in EB-2013-0321[6]**	**Requested for Disposition in EB-2014-0370[7]**
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Regulated Hydroelectric:							
1	**Hydroelectric Water Conditions Variance**	17.1	22.4	12.7	(8.5)	17.1	0.0	(8.5)
2	**Ancillary Services Net Revenue Variance - Hydroelectric**	34.0	15.8	(10.6)	(16.5)	34.0	0.0	(16.5)
3	**Hydroelectric Incentive Mechanism Variance**	(2.4)	(5.0)	(7.5)	(7.5)	0.0	(5.0)	(2.5)
4	**Hydroelectric Surplus Baseload Generation Variance**	4.1	19.2	52.0	67.1	0.0	19.2	47.9
5	**Income and Other Taxes Variance - Hydroelectric**	(2.5)	(1.1)	(0.1)	(0.2)	(2.5)	0.0	(0.2)
6	**Tax Loss Variance - Hydroelectric**	48.2	19.7	0.0	0.0	48.2	0.0	0.0
7	**Capacity Refurbishment Variance - Hydroelectric**	1.1	112.7	232.6	232.6	0.0	112.7	119.9
8	**Gross Revenue Charge Variance**	N/A	N/A	0.0	0.0	N/A	0.0	0.0
9	**Pension and OPEB Cost Variance - Hydroelectric - Historic**	2.5	1.0	0.0	0.0	2.6	0.0	0.0
10	**Pension and OPEB Cost Variance - Hydroelectric - Future**	12.6	11.3	10.5	10.5	12.6	0.0	10.5
11	**Pension and OPEB Cost Variance - Hydroelectric - Post 2012 Additions**	N/A	18.6	35.5	35.5	N/A	0.0	35.5
12	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric**	N/A	N/A	9.2	4.6	N/A	0.0	0.0
13	**Pension & OPEB Cash Payment Variance - Hydroelectric**	N/A	N/A	(0.9)	0.2	N/A	0.0	0.0
14	**Impact for USGAAP Deferral - Hydroelectric**	2.8	1.2	0.0	0.0	2.8	0.0	0.0
15	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**	(3.9)	1.3	3.7	4.5	(3.9)	0.0	4.5
16	**Total**	113.8	217.3	337.1	322.4	111.0	127.0	190.6
	Nuclear:							
17	**Nuclear Liability Deferral**	206.2	254.0	286.3	285.7	124.8	0.0	285.7
18	**Nuclear Development Variance**	30.2	56.5	59.0	58.8	0.0	56.5	2.3
19	**Ancillary Services Net Revenue Variance - Nuclear**	1.7	1.9	1.7	1.7	1.7	0.0	1.7
20	**Capacity Refurbishment Variance - Nuclear - Capital Portion**	1.3	5.7	13.1	13.6	0.0	5.7	7.9
21	**Capacity Refurbishment Variance - Nuclear - Non-Capital Portion**	11.8	8.9	6.7	1.3	11.8	0.0	1.3
22	**Bruce Lease Net Revenues Variance - Derivative Sub-Account**	230.3	214.4	129.9	153.8	230.3	0.0	153.8
23	**Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - EB-2012-0002**	74.8	52.3	37.3	37.3	74.8	0.0	37.3
24	**Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - Post 2012 Additions**	N/A	85.9	126.8	123.9	N/A	0.0	123.9
25	**Income and Other Taxes Variance - Nuclear**	(32.5)	(17.9)	(8.5)	(13.6)	(32.5)	0.0	(13.6)
26	**Tax Loss Variance - Nuclear**	253.3	103.8	0.0	0.0	253.3	0.0	0.0
27	**Pension and OPEB Cost Variance - Nuclear - Historic**	51.5	20.7	0.0	0.0	52.3	0.0	0.0
28	**Pension and OPEB Cost Variance - Nuclear - Future**	257.6	231.8	214.7	214.7	257.6	0.0	214.7
29	**Pension and OPEB Cost Variance - Nuclear - Post 2012 Additions**	N/A	383.7	678.6	678.6	N/A	0.0	678.6
30	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear**	N/A	N/A	62.0	31.3	N/A	0.0	0.0
31	**Pension & OPEB Cash Payment Variance - Nuclear**	N/A	N/A	(0.8)	6.2	N/A	0.0	0.0
32	**Impact for USGAAP Deferral - Nuclear**	60.3	24.7	0.0	0.0	60.3	0.0	0.0
33	**Pickering Life Extension Depreciation Variance**	N/A	9.5	7.8	7.8	(93.8)	0.0	7.8
34	**Nuclear Deferral and Variance Over/Under Recovery Variance**	6.9	42.6	57.4	56.4	6.9	0.0	56.4
35	**Total**	1,153.3	1,478.5	1,671.9	1,657.5	947.3	62.2	1,557.8
36	**Grand Total** (line 16 + line 35)	1,267.1	1,695.8	2,009.0	1,979.9	1,058.3	189.2	1,748.4

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).
5 From EB-2012-0002 Payment Amounts Order Appendix A Table 1 and Table 2, col. (e).
6 From EB-2013-0321 Payment Amounts Order Appendix E Table 1, col. (e) for Hydroelectric and Appendix F Table 1, col. (e) for Nuclear.
7 From Ex. H1-1-2, Table 15 and Table 16, col. (c).

Board Staff Interrogatory #002

Interrogatory

Reference(s):
Exh H1-1-2 Table 1c
Continuity of Account Balances – November and December 2014

Please create a separate table breaking out lines 1 to 16 for Previously Regulated and Newly Regulated Hydroelectric where sub-accounts exist.

Response

The attached table breaks out the account activities from Table 1c, lines 1 to 16 of Ex. H1-1-2 between previously and newly regulated hydroelectric facilities.

Numbers may not add due to rounding.

Table 1
(Recast of Ex. H1-1-2 Table 1c)
Deferral and Variance Accounts
Continuity of Previously and Newly Regulated Hydroelectric Account Balances - November and December 2014 ($M)

Line No.	Account	Actual Balance October 31 2014	Actual November 1 to December 31, 2014 Transactions	Amortization	Interest	Transfers	(a)+(b)+(c)+(d)+(e) Actual Year End Balance 2014
		(a)	(b)	(c)	(d)	(e)	(f)
	Previously Regulated Hydroelectric:						
1	**Hydroelectric Water Conditions Variance**	15.2	(3.7)	(1.1)	0.0	0.0	10.5
2	**Ancillary Services Net Revenue Variance**	(7.6)	(3.5)	(2.3)	(0.0)	0.0	(13.4)
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	15.0	0.0	0.1	0.0	57.3
5	**Income and Other Taxes Variance**	(0.3)	(0.1)	0.2	0.0	0.0	(0.2)
6	**Tax Loss Variance**	3.8	0.0	(3.2)	0.0	(0.5)	0.0
7	**Capacity Refurbishment Variance**	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 - Historic**	0.2	0.0	(0.2)	0.0	0.0	0.0
10	**Pension and OPEB Cost Variance - Future**	10.6	0.0	(0.1)	0.0	0.0	10.5
11	**Pension and OPEB Cost Variance - Post 2012 Additions**	35.5	0.0	0.0	0.0	0.0	35.5
12	**Pension and OPEB Cash Versus Accrual Differential Deferral**	0.0	1.7	0.0	0.0	0.0	1.7
13	**Pension and OPEB Cash Payment Variance**	0.0	0.3	0.0	0.0	0.0	0.3
14	**Impact for USGAAP Deferral**	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	10.2	(6.7)	0.7	0.0	331.9
	Newly Regulated Hydroelectric:						
17	**Hydroelectric Water Conditions Variance**	N/A	(18.9)	0.0	(0.0)	0.0	(19.0)
18	**Ancillary Services Net Revenue Variance**	N/A	(3.1)	0.0	(0.0)	0.0	(3.1)
19	**Hydroelectric Incentive Mechanism Variance**	N/A	0.0	0.0	0.0	0.0	0.0
20	**Hydroelectric Surplus Baseload Generation Variance**	N/A	9.8	0.0	0.0	0.0	9.8
21	**Income and Other Taxes Variance**	N/A	0.0	0.0	0.0	0.0	0.0
22	**Capacity Refurbishment Variance**	N/A	0.0	0.0	0.0	0.0	0.0
23	**Pension and OPEB Cash Versus Accrual Differential Deferral**	N/A	2.9	0.0	0.0	0.0	2.9
24	**Pension and OPEB Cash Payment Variance**	N/A	(0.1)	0.0	0.0	0.0	(0.1)
25	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**	N/A	0.0	0.0	0.0	0.0	0.0
26	**Total**	0.0	(9.5)	0.0	(0.0)	0.0	(9.5)
	Total Regulated Hydroelectric[1]:						
27	**Hydroelectric Water Conditions Variance**	15.2	(22.6)	(1.1)	0.0	0.0	(8.5)
28	**Ancillary Services Net Revenue Variance**	(7.6)	(6.6)	(2.3)	(0.0)	0.0	(16.5)
29	**Hydroelectric Incentive Mechanism Variance**	(7.5)	0.0	0.0	(0.0)	0.0	(7.5)
30	**Hydroelectric Surplus Baseload Generation Variance**	42.2	24.8	0.0	0.1	0.0	67.1
31	**Income and Other Taxes Variance**	(0.3)	(0.1)	0.2	0.0	0.0	(0.2)
32	**Tax Loss Variance**	3.8	0.0	(3.2)	0.0	(0.5)	0.0
33	**Capacity Refurbishment Variance**	232.1	0.0	0.0	0.6	0.0	232.6
34	**Gross Revenue Charge Variance**	0.0	0.0	0.0	0.0	0.0	0.0
35	**Pension and OPEB Cost Variance - Historic**	0.2	0.0	(0.2)	0.0	0.0	0.0
36	**Pension and OPEB Cost Variance - Future**	10.6	0.0	(0.1)	0.0	0.0	10.5
37	**Pension and OPEB Cost Variance - Post 2012 Additions**	35.5	0.0	0.0	0.0	0.0	35.5
38	**Pension and OPEB Cash Versus Accrual Differential Deferral**	0.0	4.6	0.0	0.0	0.0	4.6
39	**Pension and OPEB Cash Payment Variance**	0.0	0.2	0.0	0.0	0.0	0.2
40	**Impact for USGAAP Deferral**	0.3	0.0	(0.2)	0.0	(0.1)	0.0
41	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**	3.2	0.4	0.3	0.0	0.6	4.5
42	**Grand Total**	327.7	0.8	(6.7)	0.7	0.0	322.4

Notes:
1 As shown in Ex. H1-1-2, Table 1c, rows 1 to 16, respectively.

Board Staff Interrogatory #003

Interrogatory

Reference(s):
Exh H1-1-1 page 6, Exh H1-1-2 Table 4
Hydroelectric Incentive Mechanism Variance Account

For the period November to December 2014, please provide a table that breaks out actual incentive payment and incentive payment adjustment due to SBG separately for the previously and newly regulated hydroelectric facilities. Provide data in $k.

Response

OPG interprets the question's references to:

- "Actual Incentive Payment" as Actual Hydroelectric Incentive Mechanism ("HIM") revenue, before adjusting for any Unintended Benefit associated with SBG;
- "Incentive Payment Adjustment" as the Unintended Benefit repayment as defined in EB-2013-0321 Payments Amount Order.

The requested data for November to December 2014 is shown in the table below:

	Actual HIM Revenue ($k) (a)	Incentive Payment Adjustment ($k) (b)	Actual HIM Net Revenue ($k) (c = a – b)
Previously regulated	4,860	5,960	-1,100
Newly regulated	5,040	4,036	1,004

Board Staff Interrogatory #004

Interrogatory

Reference(s):
Exh H1-1-2 Table 5
Hydroelectric Surplus Baseload Generation Variance Account

Note 1 to Table 5 states that the Actual Foregone Production Due to SBG Conditions (GWh) for the Previously Regulated Hydroelectric Facilities for 2014:

> 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.

The 2013 year end SBG Variance Account balance was approved for clearance in EB-2013-0321.

a) Does the upward adjustment of 29.7 GWh reflect 2013 foregone production or 2014 foregone production?

b) Line 1 of Table 5 is “Actual Foregone Production”. Please explain the need for an adjustment to actuals.

c) Please explain further the spill reporting refinement with respect to the explanation at Exh E1-2-1 page 3 of EB-2013-0321.

Response

a) The adjustment reflects additional foregone production in respect of 2013 that was not reflected in the EB-2013-0321 OEB approved, audited December 31, 2013 account balance, as the adjustment was finalized and recorded as a true-up entry in the account in 2014.

b) There is no adjustment to the 2014 actuals. The adjustment in respect of 2013 production is reflected in the “Actual Foregone Production” value for 2014 in Ex. H1-1-2 Table 5 for presentation purposes only, as a means of indicating that it was captured in the account in 2014.

c) There is no change to the spill reporting methodology described in EB-2013-0321 Ex. E1-2-1, section 3.0, pp. 2-4. The refinement is related to the use of a more accurate average conversion efficiency used to calculate the amount of MWh obtained from a given level of flow. The average conversion efficiency was increased based on an analysis of accumulated data observations taken over a period of approximately one year (to account for the seasonal variations of inflow conditions), following the placement in-service of the third Niagara Tunnel in March 2013.

Board Staff Interrogatory #005

Interrogatory

Reference(s):
Exh H1-1-2 Table 5
Hydroelectric Surplus Baseload Generation Variance Account

The Jan-Oct 2014 actual foregone production due to SBG conditions was 1,061 GWh, and the Nov-Dec 2014 actual foregone production due to SBG conditions was 581 GWh. Please provide the drivers behind the Nov-Dec 2014 foregone production.

Response

The drivers of the forgone production due to SBG spill at the Previously Regulated Hydroelectric plants for November to December 2014 are:

1. Average monthly production from the Newly Regulated Hydroelectric plants was higher in November and December 2014 relative to January through October 2014.

2. Average monthly nuclear production—both OPG and Bruce Power—was higher in November and December 2014 relative to January through October 2014.

3. Average monthly wind production in November and December 2014 was higher relative to January through October 2014.

Board Staff Interrogatory #006

Interrogatory

Reference(s):
Exh H1-1-2 page 5
Income and Other Taxes Variance Account

The application update filed on February 20, 2015 refers to a difference in Scientific Research & Experimental Development (SR&ED) investment tax credits. Were the changes to the expected recoveries for SR&EDs based on negotiations with the tax authorities or based on tax rules? Please explain.

Response

Neither. The changes were based on the completion of the 2010 audit in late 2014.

As discussed in EB-2013-0321 and EB-2010-0008, the amount of SR&ED investment tax credits ("ITCs") recognized by OPG for accounting purposes and credited to ratepayers is determined based on an assessment of the likelihood of their acceptance by tax authorities, in accordance with generally accepted accounting principles. For taxation years for which the audit has not yet been resolved, OPG has been recognizing and crediting ratepayers with 75 per cent of the claimed SR&ED ITCs (as attributed to regulated operations), including for the 2010 taxation year. The completion of the 2010 audit in late 2014 did not result in changes to OPG's SR&ED ITC claim, and therefore the remaining 25 per cent of the 2010 SR&ED ITCs was recognized and credited to ratepayers.

Board Staff Interrogatory #007

Interrogatory

Reference(s):
Exh H1-1-2 Table 7
Capacity Refurbishment Variance Account - Hydroelectric

The OEB approved the addition to rate base for the Niagara Tunnel Project in EB-2013-0321. OPG has used cost of capital numbers from EB-2010-0008 for the weighted average cost of capital of 7.40% and ROE of 9.55% in Table 7. The OEB made the following findings concerning the Niagara Tunnel Project in EB-2010-0008.

> *Board Findings*
> The Board will not require additional reporting on the status of the Niagara Tunnel Project prior to OPG's next payments case. The Board does not intend to manage the project, nor will it to conduct any sort of intermediate review, or "mini-hearing". The appropriate course of action is for the Board to conduct a thorough prudence review at the time that OPG proposes to add the project to rate base. The Board will expect OPG to file Project Execution Plans, as well as any other progress reports completed over the duration of the project, at the time of the prudence review.[1]

a) Please explain when and in which proceeding the OEB approved the *Capacity Refurbishment Variance Account – Hydroelectric.*

b) Please explain why OPG has used the cost of capital parameters from the EB- 2010-0008 case when the OEB approved the project costs in EB-2013-0321.

[1] EB-2010-0008, Decision with Reasons, March 10, 2011, page 28

Response

a) The Capacity Refurbishment Variance Account was first approved by the OEB in EB-2007-0905. The account applies to all of OPG's prescribed facilities. As we have done in previous applications (e.g., EB-2012-0002), OPG has broken out the balance in this account into its nuclear and hydroelectric components as an aid to the parties reviewing its application.

b) OPG has used the cost of capital parameters that were in effect at the time entries were made into the account. Accordingly, the cost of capital parameters approved in EB-2010-0008 would have applied up until up November 1, 2014. Beginning November 1, 2014, the new cost of capital parameters approved in EB-2013-0321 would begin to apply to the account.

Board Staff Interrogatory #008

Interrogatory

Reference(s):
Exh H1-1-2 Table 12a Note 6
Capacity Refurbishment Variance Account - Nuclear

The Table to Note 6 summarizes the 2014 Actual Darlington Refurbishment Net Plant Rate Base Amount. The OEB approved 2014 in-service additions of $18.7M and $209.4M in 2015. OPG has shown $43.5M as 2014 in-service additions in Table 12a. Please explain how the data in this table are consistent with the EB-2013-0321 Decision with Reasons at page 58.

Response

The $43.5M presented in Table to Note 6, line 1b, col. (b) in Ex. H1-1-2 Table 12a represents the actual 2014 in-service addition for the Darlington Refurbishment Project. As the Capacity Refurbishment Variance Account captures differences between the actual in-service amounts and the amounts approved by the OEB, the variance to the 2014 OEB approved amount of $18.7M is a proper addition to this account.

The key drivers of the in-service addition variance were an earlier than forecast in-service for part of the Heavy Water Storage and Drum Handling Facility; a deferral of in-service amounts from 2013 to 2014 for the Water and Sewer Project; an in-service addition for the Vehicle Screening Facility Project, partly offset by the deferral from 2014 to 2015 of the Electrical Power Distribution System Project.

Board Staff Interrogatory #009

Interrogatory

Reference(s):
Exh H1-3-1, Attachment 1, Page 14 of 15
Pensions & OPEB Cash Versus Accrual Differential Deferral Account

In the description of the account OPG has stated: The deferral account shall also record any associated income tax impacts. In the OEB's Payment Amounts Order,[2] the OEB stated the following.

> The Decision's description of the Pensions & OPEB Cash Versus Accrual Differential Deferral Account did not include taxes and the Board finds that this account will not record taxes. When a determination is made regarding the account balance, any tax matters can be addressed at that time.

In the Payment Amounts Order in Appendix G on page 14, the paragraph includes the sentence, "The deferral account shall also record any associated income tax impacts."

It appears to OEB staff that the wording in Appendix G was original wording proposed by OPG in the related application that was inadvertently not amended for the final Payment Amounts Order to reflect the OEB's finding on page 6 of the Order. Please explain if OPG agrees with this view. If OPG disagrees, please explain what OPG wants the OEB to decide and why.

[2] EB-2013-0321, Payment Amounts Order, December 18, 2014, page 6.

Response

OPG agrees that there is an inconsistency between page 6 of the EB-2013-0321 Payments Amount Order and the description of the account found at page 14 of that Order.

OPG is seeking no approvals with respect to the Pension and OPEB Cash Versus Accrual Differential Deferral Account in this application. OPG expects that the above noted inconsistency will be corrected in the payment amounts order issued in this proceeding.

Board Staff Interrogatory #010

Interrogatory

Reference(s):
Exh H1-1-1, Pages 13-16
Pension and OPEB Cost Variance Account - Post 2012 Additions

Amortization Period for Recovery of Balances
OPG has proposed to recover variances that have arisen since 2012 over 24 months.[3] In the previous application to clear the account balances as at December 31, 2012, EB-2012-0002, the balances were approved for recovery over the expected average remaining service life (EARSL) of the employees which was 12 years in 2012. In the 2013 audited financial statements the EARSL was 13 years for pensions and 14 years for OPEBs.[4] In the funding valuation report, the going concern special payments are made over a 15-year period.[5]

[3] Exh A1-1-2 page 1
[4] EB-2013-0321, Exh L-2.1-ED-3, Attachment 1, page 45.
[5] EB-2013-0321, Undertaking J9.6, Attachment 1, page 26.

a) Please recalculate the amount to be recovered in the period July 1, 2015 to June 30, 2017 using 15 years as the recovery or amortization period rather than 24 months for the amounts that have accrued since December 31, 2012.

b) Please recalculate the rate impact using the 15-year recovery period rather than the 24-month proposal.

c) Please identify the EARSL for pensions and for OPEBs as at December 31, 2014.

d) If the answer to (c) is not 15 years, please provide calculations (a) and (b) for the answer to (c).

Response

a) By assuming a change in the amortization period from 24 months to 180 months, the total amount recovered from the Pension and OPEB Cost Variance Account - Post 2012 Additions between July 1, 2015 and June 30, 2017 is calculated to be $95.2M.

b) By amortizing the Pension and OPEB Cost Variance Account - Post 2012 Additions over 180 months, the total rate impact associated with this application is $1.60/month; a 1.2% increase in the typical residential bill.

c) The EARSL as at December 31, 2013, which is reflected in the 2014 costs, is 11.7 years for OPG's pension plans and 12.7 years for OPEB. The resulting weighted average EARSL for both pension and OPEB is approximately 12 years. The

EARSL as at December 31, 2014, which is reflected in OPG's 2015 costs, is 11.8 years for the pension plans and 12.8 years for OPEB. The resulting weighted average EARSL for both pension and OPEB is also approximately 12 years.

d) By assuming a change in the amortization period from 24 months to 144 months, the total amount recovered from the Pension and OPEB Cost Variance Account - Post 2012 Additions between July 1, 2015 and June 30, 2017 is calculated to be $119.0M.

By amortizing the Pension and OPEB Cost Variance Account - Post 2012 Additions over 144 months, the total rate impact associated with this application is $1.66/month; a 1.3% increase in the typical residential bill.

OPG notes that the EB-2012-0002 recovery period of 12 years for the Future Recovery component of the account was the result of a comprehensive negotiated settlement between OPG and the intervenors. In OPG's view, there is no basis for linking the recovery of the amounts recorded in the account to EARSL, as OPG explained in EB-2012-0002 Ex. L-3-7 SEC-25, or the 15-year period over which going concern special payments are made.

The variances recorded in the account relate to pension and OPEB costs incurred and recognized in previous years, not costs for a future period. Therefore, there is no causal relationship between the amounts in the account and the period during which employees are expected to render future service (i.e., EARSL).

In addition, it is important to note that pension and OPEB costs determined in accordance with USGAAP already reflect a smoothing, using EARSL, of changes in the pension and OPEB liabilities due to certain impacts, such as actuarial gains and losses. Therefore, using a recovery period based on either EARSL, or the 15-year funding period, on top of the smoothing over EARSL that already happens, would result in a significant extension to the period over which these changes in the pension and OPEB liabilities would be recovered.

Board Staff Interrogatory #011

Interrogatory

Reference(s):
H1-1-2 Attachment 2, Aon Hewitt, pages 1-10
Pickering Extension to 2020 – Impact on Pensions & OPEBs

OPG intends to maintain Pickering in operation until the end of 2020.

a) Please explain what assumptions the actuary has included in the valuation for December 31, 2014 related to Pickering end of life in 2020.

b) If the actuary has not included staff reductions related to Pickering in the 2014 year end valuation, please describe in detail the reasons why staff reductions would not be assumed to occur in the pension and OPEB cost projections for regulatory purposes.

c) If forecast staff reductions have not been included in the year end actuarial valuations, please describe when in the future OPG would include these staff reductions in the valuations for regulatory purposes. Please provide the reasons for the answer.

Response

a) The actuary has not included any assumptions related to workforce reductions associated with the end of Pickering operations in valuing OPG's December 31, 2014 pension and OPEB liabilities in accordance with US GAAP, as reported in OPG's audited financial statements.

For clarity, the December 31, 2014 pension and OPEB liabilities serve as the basis for OPG's 2015 pension and OPEB costs. The 2014 pension and OPEB costs reflected in the 2014 additions to the Pension and OPEB Cost Variance Account were based on the actuarial valuations of the liabilities at December 31, 2013.

b) No effects of any eventual workforce reductions associated with the end of Pickering operations are reflected in OPG's December 31, 2014 pension and OPEB liabilities because it would be contrary to US GAAP and to generally accepted actuarial practice. USGAAP requires that increases in pension and OPEB liabilities related to a significant reduction in the number of employees be recognized when its financial effects can be reasonably estimated. Decreases in pension and OPEB liabilities arising from a significant workforce reduction are generally recognized when the employees terminate, in accordance with US GAAP. At this point, there is significant uncertainly with respect to the workforce effects of the Pickering closure and the associated impact on OPG's pension and OPEB liabilities.

c) OPG expects to recognize the effects of the eventual workforce reduction associated with the Pickering end of life on its pension and OPEB liabilities when it meets the requirements of US GAAP, as discussed in part b). OPG's auditors would need to be satisfied that OPG's financial statements reflecting these effects comply with US GAAP.

Board Staff Interrogatory #012

Interrogatory

Reference(s):
H1-1-2 Attachment 2, Aon Hewitt, pages 8-9
Contributions to Pension Plan and Payments to Retirees

In Attachment 2 filed in this proceeding, the actual payments that OPG made in 2013 and in 2014 appear to be substantially less than the estimated amounts shown on pages 8 and 9 of Aon Hewitt's report.

In the recent cost of service case, Aon Hewitt's funding valuation, Undertaking J9.6 Attachment 1, on page 19, shows the minimum required company contributions for 2014 through 2016.

Does OPG intend to make the minimum contributions recommended by its actuary? Please explain.

Response

Yes. The *Pension Benefits Act* (Ontario) requires employers to make minimum contributions to registered pension plans as set out in the actuarial funding valuations. As such, OPG intends to make at least the minimum required contributions to its registered pension plan in 2015 and 2016 as recommended by Aon Hewitt in the January 1, 2014 actuarial valuation of the plan.

For greater clarity, OPG notes that its full-year 2014 total contribution to the registered pension plan was $360,000k, which is consistent with the minimum required contribution of $358,237k set out on page 19 of the January 1, 2014 actuarial valuation. The contribution amount of $300,000k shown at the bottom of page 9 of Ex. H1-1-2, Attachment 2 represents 10/12 of $360,000k, as it relates to the ten-month period from January 1, 2014 to October 31, 2014 covered by the Pension and OPEB Cost Variance Account.

Board Staff Interrogatory #013

Interrogatory

Reference(s):
H1-1-2 Table 8a
Pension & OPEB Cost Variance Account - Income Tax Impact

a) Please explain how OPG allocated the actual contributions to the pension plan and payments to retirees to the regulated business in 2013 and in 2014 up to October 31, 2014, and for the two-month period of November and December 2104. Please show the numbers, calculations and explain the basis of how the calculations were made.

b) In Undertaking J13.7 in the last payments case, OPG stated that it would make pension contributions in 2014 and 2015 of $729.5M for the regulated business. OPG now plans to contribute $651.5M. Please explain why OPG plans to reduce pension contributions.

Response

a) OPG's total actual pension contributions and OPEB payments made in 2013, the ten month period of January to October 2014, and the two month period of November and December 2014 were attributed to the regulated business using the same approach as in EB-2013-0321, EB-2012-0002 and EB-2010-0008. Under this approach, the pension contributions and OPEB payments are attributed to the regulated business in the same proportion as the corresponding costs. The description of the methodology used by OPG to attribute pension and OPEB costs to the regulated business, which was reviewed as part of the independent cost allocation studies filed in EB-2013-0321 and EB-2010-0008, can be found in EB-2013-0321 Ex. F4-3-1, section 6.3.4.

The calculations underlying the attribution of OPG's total actual pension contributions and OPEB payments to the regulated business for 2013 and the ten month period of January to October 2014 are provided in Attachment 1. Pension contributions and OPEB payments for November and December 2014 do not enter the calculation of any December 31, 2014 deferral and variance account balances that OPG seeks to clear in this proceeding.

b) One cannot draw the conclusion that "OPG plans to reduce pension contributions," from the fact that these two figures differ.

In its EB-2013-0321 Decision with Reasons, the OEB chose (p. 87) to set the 2014-15 payment amounts using pension cash contribution amounts for the 2014 to 2015 test period which were provided in EB-2013-0321 Undertaking J9.6. These amounts totaled $651.5M and represented the estimated minimum contributions for 2014 and 2015 pursuant to the January 1, 2014 actuarial valuation for funding purposes (as attributed to the regulated business).[1] This figure differs from $729.5M provided by OPG in EB-2013-0321 Undertaking J13.7 because J13.7 contained OPG's most recent forecast of total 2015 pension contributions attributed to the regulated business, which was per the Second Impact Statement (Ex. N2-1-1).

As explained in EB-2013-0321 Undertaking J11.9 and OPG's Reply Argument (p. 182), notwithstanding the completion of the January 1, 2014 actuarial valuation that showed the updated estimate of minimum required contributions for 2015, OPG's total 2015 pension contributions could be higher and would not be finalized until sometime in 2015.

[1] EB-2013-0321 Decision With Reasons, Table 21 (p. 84), $321.9M for 2014 plus $329.6M for 2015

Table 1
Allocation of Actual Pension Plan Contributions and OPEB Payments - 2013 and January to October 2014 ($M)

Line No.	Description	Actual January to December 2013				Actual January to October 2014			
		Total OPG	Previously Regulated Hydroelectric	Nuclear	Total Previously Regulated Hydroelectric and Nuclear	Total OPG	Previously Regulated Hydroelectric	Nuclear	Total Previously Regulated Hydroelectric and Nuclear
		(a)	(b)	(c)	(d) = (b) + (c)	(e)	(f)	(g)	(h) = (f) + (g)
	Pension and OPEB Costs[1]								
1	Pension Costs	473.3	18.0	365.3	383.3	439.3	18.4	341.4	359.8
2	OPEB Costs	302.8	11.5	233.7	245.2	192.2	8.0	149.4	157.4
	Total	776.1	29.5	599.0	628.5	631.5	26.4	490.8	517.2
	Allocation percentages[2]								
3	Pension	100%	3.8%	77.2%	81.0%	100%	4.2%	77.7%	81.9%
4	OPEB	100%	3.8%	77.2%	81.0%	100%	4.2%	77.7%	81.9%
	Pension Plan Contributions and OPEB Payments[3]								
5	Pension Plan Contributions	300.0	11.4	231.6	242.9	300.0	12.5	233.1	245.7
6	OPEB Payments	101.1	3.8	78.1	81.9	84.9	3.6	66.0	69.6
7	Total	401.1	15.2	309.7	324.8	384.9	16.1	299.1	315.3

Notes:
1 Total OPG costs presented in cols. (a) and (e) of lines 1 and 2 are from Ex. H1-1-2 Attachment 2, pages 5 and 8, and pages 5 and 9, respectively.
Pension costs for 2013 and January to October 2014 presented in line 1 cols. (b)-(d) and (f)-(h), respectively are as found at Ex. H1-1-2, Table 8, line 4, cols. (a)-(f).
OPEB costs for 2013 and January to October 2014 presented in line 2 cols. (b)-(d) and (f)-(h), respectively are as found at Ex. H1-1-2, Table 8, line 5, cols. (a)-(f).
2 Cols. (b) and (c) for 2013 and cols. (f) and (g) for January to October 2014 of lines 3 and 4 are calculated by dividing the corresponding costs in lines 1 and 2 by the total costs in col. (a) for 2013 and col. (e) for January to October 2014.
3 Cols. (b) and (c) are calculated as col. (a) multiplied by the corresponding allocation percentage in cols. (b) and (c) of lines 3 and 4 for 2013.
For January to October 2014, cols. (f) and (g) are calculated as col. (e) multiplied by the corresponding allocation percentage in cols. (f) and (g) of lines 3 and 4.

Board Staff Interrogatory #014

Interrogatory

Reference(s):
Exh H1-1-2 Table 1b
Pension & OPEB Cost Variance Account

Please explain why there is an interest entry for the Pension and OPEB Cost Variance – Nuclear – Historic for the period January 1 to October 31, 2014.

Response

There is an interest entry during this period because the Settlement Agreement approved by the OEB in EB-2012-0002 provides for interest to apply to this account during this period, as explained in greater detail below.

During the January 1 to October 31, 2014 period, the Pension and OPEB Cost Variance – Nuclear – Historic Account is governed by the terms of the OEB's Decision and Order in EB-2012-0002.

The EB-2012-0002 Payment Amounts Order dated April 18, 2013 provides on pages 6 and 7 of Appendix B that:

> The balance in this account as at December 31, 2012, including interest accrued to that date shall be split into Historic Recovery and Future Recovery components. The Historic Recovery component of the account balance shall be 2/12ths of the total balance in the account as at December 31, 2012. The Future Recovery component of the account balance shall be 10/12ths of the total balance in the account as at December 31, 2012.
>
> The Historic Recovery component of the account balance, together with interest projected to accrue on this component during the period from January 1, 2013 to December 31, 2014, shall be recovered over 24 months commencing January 1, 2013. The Future Recovery component shall be recovered over a period of 144 months commencing January 1, 2013.
>
> OPG shall not record any interest on the Future Recovery component during the period from January 1, 2013 to December 31, 2014.
>
> To the extent the actual interest amounts during the period from January 1, 2013 to December 31, 2014 related to the Historic Recovery component are different from those used in establishing amortization amounts in this order, OPG shall record such differences in an interest sub-account of the Pension and OPEB Cost Variance Account.

Board Staff Interrogatory #015

Interrogatory

Reference(s):
Exh H1-1-2 Table 10
Nuclear Liability Deferral Account

Please provide the details for the calculation of the average asset retirement costs for Jan.- Oct 2014 of $(13.4)M at line 2 of the table.

Response

The average asset retirement cost of $(13.4)M for 2014 is the 2013 average retirement cost value less depreciation as described in Ex. H1-1-2, Table 10, Note 3, which states that the "2014 value is calculated as 2013 value less Note 2, line 13a, col. (d)" (i.e., $38.3M – $51.7M = $(13.4)M).

AMPCO Interrogatory #001

Interrogatory

Reference(s):

1. EB-2014-0370 H1-T1-S2 Table 1 (Column b)
2. EB-2013-0321 H1-T1-S1 Table 1 (Column h)

Preamble: At reference 2, OPG provides the projected year-end balance 2013 for each deferral and variance account. At reference 1, OPG provides the actual year-end balances 2013 by account.

Please explain the reason for any 2013 actual account variance balances of 10 per cent or greater compared to projected.

Response

OPG declines to answer this question on the basis that it is not relevant.

This application is about clearance of 2014 balances. The 2014 balances have been audited, and such audit by necessity included examination of the actual transactions during 2013. Examination of the reasons for differences between actual 2013 balances, and the balances that OPG projected (but did not propose to clear) at the time it prepared its EB-2013-0321 application is not useful to the OEB in reaching a decision in the current application.

OPG also notes that the actual 2013 balances in four accounts whose difference between projected and actual balances meet the question's 10 per cent threshold have already been approved for clearance by the OEB in EB-2013-0321. These are the Hydroelectric Incentive Mechanism Variance Account, Hydroelectric Surplus Baseload Generation Variance Account, the Nuclear Development Variance Account and the Capacity Refurbishment Variance Account – Nuclear – Capital Portion.

AMPCO Interrogatory #002

Interrogatory

Reference(s):

EB-2014-0370 H1-T1-S2 Table 1

a) Please list and discuss any changes in methodology to calculate account balances in the current application compared to EB-2012-0002.

b) Please list and discuss any changes in disposition methodology of the accounts in the current application compared to EB-2012-0002.

Response

a) There are no changes in methodology to calculate account balances as compared to EB-2012-0002.

b) There are no changes in disposition methodology in the current application compared to EB-2012-0002.

AMPCO Interrogatory #003

Interrogatory

Reference(s):

H1-T1-S1 Page 17 Nuclear Liability Deferral Account

a) Please discuss if other than through an ONFA Reference Plan update process, there have been any changes since January 1, 2013 that impact the amounts recorded in the Nuclear Liability Deferral Account of the calculation of the Nuclear Liabilities.

b) Please provide the amounts of any changes indentified in part (a).

c) Please explain more fully how the 2013 and 2014 account additions for lines 2, 5 and 6 in Table 10 (H1-T1-S2) are derived and explain any variances compared to the amounts provided in EB-2013-0321.

Response

a) and b) No, there have been no changes.

c) Line 2 – Average Asset Retirement Costs:

The average asset retirement costs ("ARC") at line 2 are calculated by taking the average of the year's opening and closing ARC balances. The average ARC is then multiplied by the weighted average accretion rate of 5.37 per cent, as per the EB-2012-0002 Payment Amounts Order p. 9, to derive the return on rate base addition to the Nuclear Liability Deferral Account at Ex. H1-1-2, Table 10, line 4. The addition in 2014 is prorated by 10/12 for the 10 month period January to October 2014.

The average ARC of $38.3M for 2013 is the average of the opening ARC balance of $64.1M[1] and the closing balance of $12.4M (opening ARC balance less annual depreciation of $51.7M[2]). The average ARC of ($13.4M) for 2014 is derived similarly, as explained in Ex. H-Staff-015.

There was no change to the 2013 average ARC or the return on rate base account addition from EB-2013-0321, where these values were shown in Ex. L-9.1-17-SEC-132 Table 10, col. (a), line 2 and line 4, respectively.

Lines 5 and 6 – Used Fuel Storage and Disposal and Low & Intermediate Level Waste Management Variable Expenses:

[1] As shown in Ex. H1-1-2, Table 10, line 5a
[2] As shown in Ex. H1-1-2, Table 10, line 13a

The additions to the Nuclear Liability Deferral Account related to used fuel storage and disposal and low and intermediate level waste management variable expenses are calculated as the difference between the forecast expenses included in the EB-2010-0008 Board-approved revenue requirement and corresponding amounts calculated by substituting the forecast per \$/bundle or per \$/m^3 cost rates with the actual cost rates arising from the current approved ONFA Reference Plan. The specific calculations are outlined in Ex. H1-1-2 Table 10, Note 5.

There was no change to the 2013 account additions for these items, from EB-2013-0321, where the same values as in this application are shown in Ex. L-9.1-17-SEC-132 Table 10, line 5 and line 6, respectively.

AMPCO Interrogatory #004

Interrogatory

Reference(s):
H1-T1-S1 Page 21 Bruce Lease Net Revenues

Preamble: The evidence states that the derivation of the 2013 and 2014 debit entries of $85.9M and $40.8M, respectively, to the non-derivative subaccount relate primarily to the impacts of the current approved ONFA Reference Plan effective January 1, 2012, partially offset by higher earnings on the nuclear segregated funds than was reflected in the EB-2010-0008 forecasts.

a) Please confirm the funds that make up the nuclear segregated funds.

b) Please provide and compare the earnings on the nuclear segregated funds reflected in the EB-2010-0008 forecasts to the actual earnings by fund by year.

c) Please explain the reason for the increase in higher earnings by fund.

d) Please provide the table and line numbers that are affected by the impacts of the current approved ONFA Reference Plan and explain how they are affected.

e) Please provide the table and line numbers that are affected by higher earnings on the nuclear segregated funds and explain how they are affected.

Response

a) OPG's nuclear segregated funds are comprised of the Decommissioning Fund and the Used Fuel Fund.

b) Refer to Chart 1, below, for a comparison of OPG's earnings (attributable to the Bruce facilities) for each of the Decommissioning Fund and the Used Fuel Fund for 2013 and January 1 to October 31, 2014 to the average of the corresponding EB-2010-0008 forecast earnings for 2011 and 2012.

c) The actual Decommissioning Fund earnings attributable to the Bruce facilities in each of 2013 and January 1 to October 31, 2014 were higher than the corresponding EB-2010-0008 forecast earnings for 2011 and 2012. This was primarily due to the impact of favourable market conditions on fund performance in 2010 and 2011.

The actual Used Fuel Fund earnings attributable to the Bruce facilities in each of 2013 and January 1 to October 31, 2014 were also higher than the EB-2010-0008 forecast earnings for 2011 and 2012. This reflected the impact of favourable market conditions on the earnings for the portion of the fund related to the used fuel bundles in excess of the first 2.23

million bundle threshold, which earns the market rate of return pursuant to the ONFA. Additionally, in 2014, the earnings on the portion of the fund related to the first 2.23 million used fuel bundles, for which the Province of Ontario guarantees OPG's annual return at 3.25 percent plus the change in the Ontario CPI pursuant to the ONFA, benefited from a higher increase in the Ontario CPI than assumed in the forecast.

d) The accounting and revenue requirement impacts of the current approved ONFA Reference Plan are explained in detail in EB-2012-0002 Ex. H2-1-1, Sections 3.0 and 4.0 and EB-2013-0321 Ex. C2-1-1, Section 3.0. In summary, accounting for the current approved ONFA Reference Plan increased the carrying balance of the nuclear asset retirement obligation ("ARO") and asset retirement costs ("ARC") attributed to the Bruce facilities by $1,201.2M[1]. This resulted in an increase in depreciation and accretion expenses for the Bruce facilities. Higher variable costs for used fuel and low and intermediate level waste ("L&ILW") for the Bruce facilities also resulted, due to higher storage and disposal cost estimates as well as a lower discount rate.

Chart 2 outlines the specific line numbers of Ex. H1-1-2, Table 13a that are affected by the impacts of the current approved ONFA Reference Plan.

e) Chart 3 outlines the specific line numbers of Ex. H1-1-2, Table 13a that are affected by the higher nuclear segregated fund earnings.

[1] EB-2013-0321 Ex. C2-1-1 Table 4, col. (g), line 6 plus line 7 for ARO and line 13 plus line 14 for ARC.

Chart 1

Bruce Facilities - Comparison of Nuclear Segregated Fund Earnings by Fund ($M)

Line No.	Description	Average of 2011/2012 EB-2010-0008 Forecast Earnings[1]	Actual Earnings[2]	(b)-(a) Difference
		(a)	(b)	(c)
	2013:			
1	Decommissioning Fund	124.0	138.1	14.1
2	Used Fuel Fund	171.4	199.0	27.6
3	Total	295.4	337.1	41.7
	January 1 to October 31, 2014:			
4	Decommissioning Fund	103.4	119.5	16.1
5	Used Fuel Fund	142.8	227.3	84.5
6	Total	246.2	346.8	100.6

Notes to Chart 1:

1 Represents the average of 2011 and 2012 forecast fund earnings underpinning the approved EB-2010-0008 revenue requirement. The 2014 amounts represent 10/12 of the average 2011/2012 forecast fund earnings.

2 2013 earnings at line 3 are as shown in Ex. H1-1-2 Table 13a line 15 col. (a). January 1 to October 31, 2014 earnings at line 6 are as shown in Ex. H1-1-2 Table 13a line 15 col. (d).

Chart 2

Ex H1-1-2 Table 13a Line Items Affected by Current Approved ONFA Reference Plan

<table>
<tr><th>Line No.</th><th>Line Particulars</th><th>Impact of Current Approved ONFA Reference Plan</th></tr>
<tr><td>12</td><td>Depreciation</td><td>Higher depreciation expense due to the increase in the ARC balance</td></tr>
<tr><td>14</td><td>Accretion</td><td>Higher accretion expense due to the increase in the ARO balance</td></tr>
<tr><td>15</td><td>Earnings (Losses) on Segregated Funds</td><td>Higher earnings on the segregated funds reflecting fund contributions and balances per current approved ONFA Reference Plan</td></tr>
<tr><td>16</td><td>Used Fuel Storage and Disposal</td><td>Higher used fuel storage and disposal variable expenses due to higher underlying cost estimates and a lower discount rate</td></tr>
<tr><td>17</td><td>Waste Management Variable Expenses and Facilities Removal Costs</td><td>Higher L&ILW variable expenses due to higher underlying cost estimates and a lower discount rate</td></tr>
<tr><td>20</td><td>Income Tax - Current – Non-Derivative Portion</td><td>Current income tax impact of changes in contributions to the segregated funds</td></tr>
<tr><td>21</td><td>Income Tax - Future/Deferred - Non-Derivative Portion</td><td>Income tax impact of higher depreciation, accretion, used fuel and L&ILW variable expenses, net of higher segregated fund earnings, and changes in contributions to the segregated funds.</td></tr>
<tr><td>19</td><td>Total Costs Before Income Tax</td><td rowspan="5">Internally calculated as indicated in the corresponding line item captions at Ex. H1-1-2 Table 13a</td></tr>
<tr><td>23</td><td>Total Non-Derivative Costs</td></tr>
<tr><td>27</td><td>Total Costs</td></tr>
<tr><td>28</td><td>Bruce Lease Net Revenues - Non-Derivative Portion</td></tr>
<tr><td>30</td><td>Total Bruce Lease Net Revenues</td></tr>
</table>

Chart 3

Ex H1-1-2 Table 13a Line Items Affected by Higher Nuclear Segregated Fund Earnings

Line No.	Line Particulars	Impact of Higher Nuclear Segregated Fund Earnings
15	(Earnings) Losses on Segregated Funds	Higher earnings on the nuclear segregated funds attributable to the Bruce facilities
21	Income Tax - Future/Deferred - Non-Derivative Portion	Income tax impact of higher segregated fund earnings. The calculation of this line is from Ex. H1-1-2 Table 13b, line 46.
19	Total Costs Before Income Tax	Internally calculated as indicated in the corresponding line item captions at Ex. H1-1-2 Table 13a
23	Total Non-Derivative Costs	
27	Total Costs	
28	Bruce Lease Net Revenues - Non-Derivative Portion	
30	Total Bruce Lease Net Revenues	

AMPCO Interrogatory #005

Interrogatory

Reference(s):

a) Please provide a copy of OPG's 2014 Consolidated Financial Statement.

Response

Refer to Attachment 1.

ONTARIO POWER GENERATION INC.

CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2014

STATEMENT OF MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL INFORMATION

Ontario Power Generation Inc.'s (OPG) management is responsible for the presentation and preparation of the annual consolidated financial statements and Management's Discussion and Analysis (MD&A).

The consolidated financial statements have been prepared in accordance with United States generally accepted accounting principles (US GAAP) and the rules and regulations of the United States Securities and Exchange Commission for annual financial statements. The MD&A has been prepared in accordance with the requirements of securities regulators, including National Instrument 51-102 of the Canadian Securities Administrators and its related published requirements.

The consolidated financial statements and information in the MD&A necessarily include amounts based on informed judgments and estimates of the expected effects of current events and transactions with appropriate consideration to materiality. Something is considered material if it is reasonably expected to have a significant impact on the Company's earnings, cash flow, value of an asset or liability, or reputation. In addition, in preparing the financial information we must interpret the requirements described above, make determinations as to the relevancy of information to be included, and make estimates and assumptions that affect the reported information. The MD&A also includes information regarding the impact of current transactions and events, sources of liquidity and capital resources, operating trends, and risks and uncertainties. Actual results in the future may differ materially from our present assessment of this information because future events and circumstances may not occur as expected.

In meeting our responsibility for the reliability of the financial information, we maintain and rely on a comprehensive system of internal controls and internal audits, including organizational and procedural controls and internal controls over financial reporting. Our system of internal controls includes: written communication of our policies and procedures governing corporate conduct and risk management; comprehensive business planning; effective segregation of duties; delegation of authority and personal accountability; careful selection and training of personnel; and accounting policies, which we regularly update. This structure ensures appropriate internal controls over transactions, assets and records. We also regularly audit internal controls. These controls and audits are designed to provide us with reasonable assurance that the financial records are reliable for preparing financial statements and other financial information, assets are safeguarded against unauthorized use or disposition, liabilities are recognized, and we are in compliance with all regulatory requirements.

Management, including the President and Chief Executive Officer (CEO) and Chief Financial Officer (CFO), is responsible for maintaining disclosure controls and procedures (DC&P) and internal controls over financial reporting (ICOFR). DC&P is designed to provide reasonable assurance that all relevant information is gathered and reported to senior management, including the President and CEO and the CFO, on a timely basis so that appropriate decisions can be made regarding public disclosure. ICOFR is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements in accordance with US GAAP.

An evaluation of the effectiveness of the design and operation of OPG's DC&P and ICOFR was conducted as of December 31, 2014. Accordingly, we, as OPG's President and CEO and CFO, will certify OPG's annual disclosure documents filed with the Ontario Securities Commission, which includes attesting to the design and effectiveness of OPG's DC&P and ICOFR.

The Board of Directors, based on recommendations from its Audit and Finance Committee, reviews and approves the consolidated financial statements and the MD&A, and oversees management's responsibilities for the presentation and preparation of financial information, maintenance of appropriate internal controls, management and control of major areas of financial risk, and assessment of significant and related party transactions.

The consolidated financial statements have been audited by Ernst & Young LLP, independent external auditors appointed by the Board of Directors. The Independent Auditors' Report outlines the auditors' responsibilities and the scope of their examination and their opinion on OPG's consolidated financial statements. The independent external auditors, as confirmed by the Audit and Finance Committee, had direct and full access to the Audit and Finance Committee, with and without the presence of management, to discuss their audit and their findings therefrom, as to the integrity of OPG's financial reporting and the effectiveness of the system of internal controls.

Tom Mitchell (signed)
President and Chief Executive Officer

Beth Summers (signed)
Chief Financial Officer

March 13, 2015

INDEPENDENT AUDITORS' REPORT

To the Shareholder of Ontario Power Generation Inc.

We have audited the accompanying consolidated financial statements of Ontario Power Generation Inc., which comprise the consolidated balance sheets as at December 31, 2014 and 2013, and the consolidated statements of income, comprehensive income, cash flows, and changes in shareholder's equity for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with United States generally accepted accounting principles, and for such internal controls as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

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

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal controls relevant to the entity's preparation and fair presentation of the consolidated financial statements 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 controls. 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 consolidated financial statements.

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

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Ontario Power Generation Inc. as at December 31, 2014 and 2013 and the results of its operations and its cash flows for the years then ended in accordance with United States generally accepted accounting principles.

Toronto, Canada

March 13, 2015

Ernst & Young LLP (signed)

Chartered Professional Accountants,
Licensed Public Accountants

CONSOLIDATED STATEMENTS OF INCOME

Years Ended December 31 *(millions of dollars except where noted)*	**2014**	**2013**
Revenue *(Note 16)*	**4,963**	4,863
Fuel expense *(Note 16)*	**641**	708
Gross margin *(Note 16)*	**4,322**	4,155
Expenses *(Note 16)*		
Operations, maintenance and administration	**2,615**	2,747
Depreciation and amortization *(Note 4)*	**754**	963
Accretion on fixed asset removal and nuclear waste management liabilities *(Note 8)*	**797**	756
Earnings on nuclear fixed asset removal and nuclear waste management funds *(Note 8)*	**(714)**	(628)
Regulatory disallowance related to the Niagara Tunnel project *(Note 3)*	**77**	-
Income from investments subject to significant influence	**(41)**	(35)
Property taxes	**32**	53
Restructuring *(Note 21)*	**18**	50
	3,538	3,906
Income before other income, interest, income taxes, and extraordinary item	**784**	249
Other income	**(3)**	(3)
Income before interest, income taxes, and extraordinary item	**787**	252
Net interest expense *(Note 7)*	**80**	86
Income before income taxes and extraordinary item	**707**	166
Income tax expense *(Note 9)*	**139**	31
Income before extraordinary item	**568**	135
Extraordinary item [1] *(Note 3)*	**243**	-
Net income	**811**	135
Net income attributable to the Shareholder	**804**	135
Net income attributable to non-controlling interests	**7**	-
Basic and diluted net income per common share before extraordinary item *(dollars)*	**2.19**	0.53
Extraordinary item per common share *(dollars)*	**0.95**	-
Basic and diluted net income per common share *(dollars)*	**3.14**	0.53
Common shares outstanding *(millions)*	**256.3**	256.3

[1] Wholly attributable to the Shareholder.

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Years Ended December 31 *(millions of dollars)*	**2014**	**2013**
Net income	**811**	135
Other comprehensive income, net of income taxes *(Note 10)*		
Recognition of initial pension and other post-employment benefits regulatory asset related to facilities prescribed for rate regulation beginning in 2014 *(Note 3)* [1]	**184**	-
Actuarial (loss) gain and past service credits on re-measurement of liabilities for pension and other post-employment benefits [2]	**(35)**	226
Reclassification to income of amounts related to pension and other post-employment benefits [3]	**27**	42
Net (loss) gain on derivatives designated as cash flow hedges [4]	**(2)**	14
Reclassification to income of losses on derivatives designated as cash flow hedges [5]	**14**	13
Other comprehensive income	**188**	295
Comprehensive income	**999**	430
Comprehensive income attributable to the Shareholder	**992**	430
Comprehensive income attributable to non-controlling interests	**7**	-

[1] Net of income tax expenses of $61 million and nil for 2014 and 2013, respectively.
[2] Net of income tax recoveries of $12 million and expenses of $75 million for 2014 and 2013, respectively.
[3] Net of income tax expenses of $10 million and $15 million for 2014 and 2013, respectively.
[4] Net of income tax recoveries of $1 million and expenses of $3 million for 2014 and 2013, respectively.
[5] Net of income tax expenses of $2 million and $2 million for 2014 and 2013, respectively.

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31 *(millions of dollars)*	**2014**	**2013**
Operating activities		
Net income	**811**	135
Adjust for non-cash items:		
Depreciation and amortization *(Note 4)*	**754**	963
Accretion on fixed asset removal and nuclear waste management liabilities *(Note 8)*	**797**	756
Earnings on nuclear fixed asset removal and nuclear waste management funds *(Note 8)*	**(714)**	(628)
Pension and other post-employment benefit costs *(Note 11)*	**460**	455
Extraordinary item *(Note 3)*	**(243)**	-
Deferred income taxes and other accrued charges	**56**	(3)
Provision for restructuring *(Note 21)*	**12**	50
Mark-to-market on derivative instruments	**(52)**	39
Provision for used nuclear fuel and low and intermediate level waste *(Note 8)*	**116**	109
Regulatory assets and liabilities	**(104)**	(232)
Provision for materials and supplies	**38**	43
Regulatory disallowance related to the Niagara Tunnel project *(Note 3)*	**77**	-
Other	**(14)**	(15)
	1,994	1,672
Contributions to nuclear fixed asset removal and nuclear waste management funds *(Note 8)*	**(139)**	(184)
Expenditures on fixed asset removal and nuclear waste management *(Note 8)*	**(212)**	(199)
Reimbursement of expenditures on nuclear fixed asset removal and nuclear waste management *(Note 8)*	**77**	75
Contributions to pension funds and expenditures on other post-employment benefits and supplementary pension plans *(Note 11)*	**(473)**	(407)
Expenditures on restructuring *(Note 21)*	**(35)**	(13)
Net changes to other long-term assets and liabilities	**9**	(9)
Net changes to non-cash working capital balances *(Note 17)*	**212**	239
Cash flow provided by operating activities	**1,433**	1,174
Investing activities		
Investment in property, plant and equipment and intangible assets *(Notes 4 and 16)*	**(1,545)**	(1,568)
Cash flow used in investing activities	**(1,545)**	(1,568)
Financing activities		
Issuance of long-term debt *(Note 6)*	**200**	515
Repayment of long-term debt *(Note 6)*	**(3)**	(4)
Distribution paid to non-controlling interests	**(5)**	-
Issuance of short-term notes *(Note 7)*	**3,332**	914
Repayment of short-term notes *(Note 7)*	**(3,364)**	(882)
Cash flow provided by financing activities	**160**	543
Net increase in cash and cash equivalents	**48**	149
Cash and cash equivalents, beginning of year	**562**	413
Cash and cash equivalents, end of year	**610**	562

See accompanying notes to the consolidated financial statements

CONSOLIDATED BALANCE SHEETS

As at December 31 *(millions of dollars)*	**2014**	**2013**
Assets		
Current assets		
Cash and cash equivalents	**610**	562
Receivables from related parties *(Note 18)*	**482**	402
Other accounts receivable and prepaid expenses	**136**	148
Nuclear fixed asset removal and nuclear waste management funds *(Notes 8 and 16)*	**25**	25
Fuel inventory *(Note 16)*	**334**	390
Materials and supplies *(Note 16)*	**94**	95
Regulatory assets *(Note 5)*	**167**	306
Income taxes recoverable	**-**	51
Deferred income taxes *(Note 9)*	**8**	-
	1,856	1,979
Property, plant and equipment *(Notes 4, 15, and 16)*	**25,859**	24,441
Less: accumulated depreciation	**8,266**	7,703
	17,593	16,738
Intangible assets *(Notes 4 and 16)*	**432**	402
Less: accumulated amortization	**356**	343
	76	59
Other assets		
Nuclear fixed asset removal and nuclear waste management funds *(Notes 8 and 16)*	**14,354**	13,471
Long-term materials and supplies *(Note 16)*	**338**	330
Regulatory assets *(Note 5)*	**7,024**	5,094
Investments subject to significant influence *(Note 19)*	**348**	359
Other long-term assets	**64**	61
	22,128	19,315
	41,653	38,091

See accompanying notes to the consolidated financial statements

CONSOLIDATED BALANCE SHEETS

As at December 31 *(millions of dollars)*	**2014**	**2013**
Liabilities		
Current liabilities		
Accounts payable and accrued charges *(Note 18)*	**1,151**	1,026
Short-term debt *(Note 7)*	**-**	32
Deferred revenue due within one year	**12**	12
Deferred income taxes *(Note 9)*	**-**	14
Long-term debt due within one year *(Note 6)*	**503**	5
Income taxes payable	**24**	-
Regulatory liabilities *(Note 5)*	**5**	16
	1,695	1,105
Long-term debt *(Note 6)*	**5,227**	5,620
Other liabilities		
Fixed asset removal and nuclear waste management liabilities *(Notes 8 and 16)*	**17,028**	16,257
Pension liabilities *(Note 11)*	**3,570**	2,741
Other post-employment benefit liabilities *(Note 11)*	**3,050**	2,628
Long-term accounts payable and accrued charges	**529**	653
Deferred revenue	**212**	180
Deferred income taxes *(Note 9)*	**836**	565
Regulatory liabilities *(Note 5)*	**39**	8
	25,264	23,032
Equity		
Common shares *(Note 14)* [1]	**5,126**	5,126
Retained earnings	**4,696**	3,892
Accumulated other comprehensive loss *(Note 10)*	**(496)**	(684)
Equity attributable to the Shareholder	**9,326**	8,334
Equity attributable to non-controlling interests *(Note 22)*	**141**	-
Total equity	**9,467**	8,334
	41,653	38,091

[1] 256,300,010 common shares outstanding at a stated value of $5,126 million as at December 31, 2014 and 2013.

Commitments and Contingencies *(Notes 6, 9, 11, 12, and 15)*

See accompanying notes to the consolidated financial statements

On behalf of the Board of Directors:

Bernard Lord (signed)
Chairman

M. George Lewis (signed)
Director

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY

Years Ended December 31 *(millions of dollars)*	**2014**	**2013**
Common shares *(Note 14)*	**5,126**	5,126
Retained earnings		
Balance at beginning of year	**3,892**	3,757
Net income attributable to the Shareholder	**804**	135
Balance, end of year	**4,696**	3,892
Accumulated other comprehensive loss, net of income taxes		
Balance at beginning of year	**(684)**	(979)
Other comprehensive income	**188**	295
Balance, end of year	**(496)**	(684)
Equity attributable to the Shareholder	**9,326**	8,334
Equity attributable to non-controlling interests *(Note 22)*		
Balance at beginning of year	**-**	-
Equity contribution from non-controlling interests	**141**	-
Distribution to non-controlling interests	**(7)**	-
Net income attributable to non-controlling interests	**7**	-
Balance, end of year	**141**	-
Total equity	**9,467**	8,334

See accompanying notes to the consolidated financial statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the years ended December 31, 2014 and 2013

1. DESCRIPTION OF BUSINESS

Ontario Power Generation Inc. (OPG or the Company) was incorporated on December 1, 1998 pursuant to the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the Province and Shareholder). OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG's mission is to be Ontario's low cost electricity generator through a focus on three corporate strategies: operational excellence, project excellence, and financial sustainability.

2. BASIS OF PRESENTATION

These consolidated financial statements have been prepared and presented in accordance with United States generally accepted accounting principles (US GAAP) and the rules and regulations of the United States Securities and Exchange Commission for annual financial statements, as required by *Ontario Regulation 395/11*, as amended, a regulation under the *Financial Administration Act* (Ontario) effective January 1, 2012.

During the first quarter of 2014, OPG received exemptive relief from the Ontario Securities Commission (OSC) requirements of section 3.2 of National Instrument 52-107 *Acceptable Accounting Policies and Auditing Standards*. The exemption allows OPG to file consolidated financial statements based on US GAAP without becoming a Securities and Exchange Commission registrant, or issuing public debt. The exemption will terminate on the earliest of the following:

- January 1, 2019
- The financial year that commences after OPG ceases to have activities subject to rate regulation
- The effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within International Financial Reporting Standards specific to entities with rate-regulated activities.

All dollar amounts are presented in Canadian dollars, except in tabular format where noted. Certain of the 2013 comparative amounts have been reclassified from financial statements previously presented to conform to the 2014 consolidated financial statement presentation.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Consolidation

The consolidated financial statements of the Company include the accounts of OPG and its majority-owned subsidiaries, and a variable interest entity (VIE) where OPG is the primary beneficiary. All significant intercompany balances and intercompany transactions have been eliminated on consolidation.

Where OPG does not control an investment, but has significant influence over operating and financing policies of the investee, the investment is accounted for under the equity method. OPG co-owns the Portlands Energy Centre (PEC) gas-fired combined cycle generating station with TransCanada Energy Ltd. and co-owns the Brighton Beach gas-fired combined cycle generating station with ATCO Power Canada Ltd. OPG accounts for its 50 percent ownership interest in each of these jointly controlled entities under the equity method.

Variable Interest Entities

OPG performs ongoing analysis to assess whether it holds any variable interest entities (VIEs). VIEs of which OPG is deemed to be the primary beneficiary are consolidated. The primary beneficiary of a VIE has both the power to direct the activities of the entity that most significantly impact its economic performance and the obligation to absorb losses of the entity that could potentially be significant to the Company. In circumstances where OPG is not deemed to be the primary beneficiary, the VIE is not recorded in OPG's consolidated financial statements.

In 2002, OPG and other Canadian nuclear waste producers established the Nuclear Waste Management Organization (NWMO) in accordance with the *Nuclear Fuel Waste Act* (NFWA). The primary long-term mandate of the NWMO is to implement an approach to address the long-term management of used nuclear fuel. In addition to the above mandate, the NWMO provides project management services for OPG's Deep Geologic Repository project for Low and Intermediate Level Waste (L&ILW) and other nuclear lifecycle liability management services. OPG has the majority of voting rights at the Board of Directors' and members' level. In addition, the NFWA requires the nuclear fuel waste owners to establish and make payments into trust funds for the purpose of funding the implementation of the long-term management plan. OPG currently provides approximately 90 percent of NWMO's funding, primarily towards the Adaptive Phased Management plan for the long-term management of nuclear used fuel. As a result, OPG is expected to absorb a majority of the NWMO's expected losses through future funding in the event of any shortfall. Therefore, OPG holds a variable interest in the NWMO, of which it is the primary beneficiary. Accordingly, the applicable amounts in the accounts of the NWMO, after elimination of all significant intercompany transactions, are consolidated.

Use of Management Estimates

The preparation of financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the consolidated financial statements, and the reported amounts of revenues and expenses during the reporting periods. Management evaluates the Company's estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in the period incurred. Significant estimates are included in the determination of pension and other post-employment benefits (OPEB), asset retirement obligations (AROs), income taxes (including deferred income taxes), contingencies, regulatory assets and liabilities, valuation of derivative instruments, depreciation and amortization expenses, and inventories. Actual results may differ significantly from these estimates.

Cash and Cash Equivalents and Short-Term Investments

Cash and cash equivalents include cash on deposit and money market securities with a maturity of less than 90 days on the date of purchase. All other money market securities with a maturity on the date of purchase that is greater than 90 days, but less than one year, are recorded as short-term investments. These securities are valued at the lower of cost and market.

Inventories

Inventories, consisting of fuel and materials and supplies, are measured at the lower of cost and market. Cost is determined as weighted average cost for fuel inventory and average cost for materials and supplies.

Property, Plant and Equipment, Intangible Assets and Depreciation and Amortization

Property, plant and equipment and intangible assets are recorded at cost. Interest costs incurred during construction and development are capitalized as part of the cost of the asset based on the interest rates on OPG's long-term debt.

Depreciation and amortization rates for the various classes of assets are based on their estimated service lives. Any asset removal costs that have not been specifically provided for in current or previous periods are charged to operations, maintenance and administration (OM&A) expenses. Repairs and maintenance costs are also expensed when incurred.

Property, plant and equipment are depreciated on a straight-line basis except for computers and transport and work equipment. These are mostly depreciated on a declining balance basis. Intangible assets, which include major application software, are amortized on a straight-line basis. As at December 31, 2014, the amortization periods of property, plant and equipment and intangible assets are as follows:

Nuclear generating stations and major components	15 to 59 years [1]
Thermal generating stations and major components	25 to 50 years
Hydroelectric generating stations and major components	10 to 100 years
Administration and service facilities	10 to 50 years
Computers, and transport and work equipment assets – declining balance	9% to 40% per year
Major application software	5 years
Service equipment	5 to 10 years

[1] As at December 31, 2014, the end of station life for depreciation purposes for the Darlington, Pickering, and Bruce A and B nuclear generating stations ranges between 2019 and 2051. Major components are depreciated over the lesser of the station life and the life of the components.

Asset Impairment

Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. The review is based on the presence of impairment indicators such as the future economic benefit of the assets and external market conditions. The net carrying amount of assets is considered impaired if it exceeds the sum of the estimated undiscounted cash flows expected to result from the asset's use and eventual disposition. In cases where the sum of the undiscounted expected future cash flows is less than the carrying amount, an impairment loss is recognized. This loss equals the amount by which the carrying amount exceeds the fair value. Fair value is determined using expected discounted cash flows when quoted market prices are not available. The impairment is recognized in income in the period in which it is identified.

The carrying value of investments accounted for under the equity method are reviewed annually for the presence of any indicators of impairment. If an impairment exists and is determined to be other-than-temporary, an impairment charge is recognized. This charge equals the amount by which the carrying value exceeds the investment's fair value.

Rate Regulated Accounting

The *Ontario Energy Board Act, 1998* and *Ontario Regulation 53/05* provide that OPG receives regulated prices for electricity generated from the following facilities that are prescribed for rate regulation: the Sir Adam Beck 1, 2 and Pump generating station, DeCew Falls 1 and 2, and R.H. Saunders hydroelectric facilities, the Pickering and Darlington nuclear facilities, and 48 previously unregulated hydroelectric generating facilities that were prescribed for rate regulation beginning in 2014 pursuant to a November 2013 amendment to *Ontario Regulation 53/05*. OPG's regulated prices for these facilities are determined by the Ontario Energy Board (OEB).

The OEB is a self-funding Crown corporation. Its mandate and authority come from the *Ontario Energy Board Act, 1998*, the *Electricity Act, 1998*, and a number of other provincial statutes. The OEB is an independent, quasi-judicial tribunal that reports to the Legislature of the Province through the Minister of Energy. It regulates market participants in Ontario's natural gas and electricity industries. The OEB carries out its regulatory functions through public hearings and other more informal processes, such as consultations.

US GAAP recognizes that rate regulation can create economic benefits and obligations that are required by the regulator to be obtained from, or settled with, the ratepayers. When the Company assesses that there is sufficient assurance that incurred costs in respect of the regulated facilities will be recovered in the future, those costs are deferred and reported as a regulatory asset. When the Company is required to refund amounts to ratepayers in the future in respect of the regulated facilities, including amounts related to costs that have not been incurred and for which the OEB has provided recovery through regulated prices, the Company records a regulatory liability.

Certain of the regulatory assets and liabilities recognized by the Company relate to variance and deferral accounts authorized by the OEB, including those authorized pursuant to *Ontario Regulation 53/05.* These accounts typically capture differences between actual costs and revenues and the corresponding forecast amounts approved in the setting of the regulated prices, or record the impact of items not reflected in approved regulated prices. The measurement of these 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.

Regulatory assets and liabilities for variance and deferral account balances approved by the OEB for inclusion in regulated prices are amortized based on approved recovery or repayment periods. Disallowed balances, including associated interest, are charged to operations in the period that the OEB's decision is issued. Interest is applied to regulatory balances as prescribed by the OEB, in order to recognize the cost of financing amounts to be recovered from, or repaid to, ratepayers.

Regulatory assets and liabilities for variance and deferral account balances approved by the OEB are classified as current if they are expected to be recovered from, or refunded to, ratepayers within 12 months of the end of the reporting period, based on recovery or repayment periods established by the OEB. All other regulatory asset and liability balances are classified as long-term on the consolidated balance sheets.

In addition to regulatory assets and liabilities for variance and deferral accounts, OPG recognizes regulatory assets and liabilities for unamortized amounts recorded in accumulated other comprehensive income (AOCI) in respect of pension and OPEB obligations, and deferred income taxes, in order to reflect the expected recovery or repayment of these amounts in respect of the regulated operations through future regulated prices charged to customers. There are measurement uncertainties related to these balances due to the assumptions made in the determination of pension and OPEB obligations and deferred income taxes attributed to the regulated facilities.

The regulatory asset for unamortized pension and OPEB amounts recorded in AOCI has reflected the OEB's use, since April 1, 2008, of the accrual basis of accounting for including pension and OPEB amounts in approved regulated prices. This is also the manner in which these costs are recognized in OPG's consolidated financial statements. Therefore, unamortized amounts in respect of OPG's pension and OPEB plans that are recognized in AOCI generally have not been reflected in the regulated prices until they have been reclassified from AOCI and recognized as amortization components of the benefit costs for these plans. The regulatory asset is reversed as underlying unamortized balances are amortized as components of the benefit cost.

In setting new regulated prices effective November 1, 2014, the OEB limited amounts for pension and OPEB allowed in the approved revenue requirements to OPG's cash expenditures on its pension and OPEB plans for the regulated business. It is the Company's position that this decision by the OEB does not constitute a change in the basis of OPG's recovery of pension and OPEB costs. This position is based on the OEB's establishment of the Pension & OPEB Cash Versus Accrual Differential Deferral Account which, effective November 1, 2014, records the difference between OPG's actual pension and OPEB costs for the regulated business determined on an accrual basis and the corresponding actual cash expenditures for these plans, the OEB's expectation in the November 2014 decision that a transition to a cash basis of recovery for OPG, if required, would be addressed in a future OPG rate proceeding, and the OEB's intention to hold a generic hearing on the regulatory treatment and recovery of pension and OPEB costs. Accordingly, the Company continues to believe that there is sufficient likelihood that unamortized pension and OPEB amounts that have not yet been reclassified from AOCI will be included in future regulated prices as they are recognized in benefit costs. Therefore, the Company has continued to recognize a regulatory asset for these unamortized amounts. If, in a future proceeding, the OEB decides that the recovery basis for pension and OPEB amounts should be changed, OPG may be required to adjust the regulatory assets for unamortized pension and OPEB amounts recorded in AOCI and the Pension & OPEB Cash Versus Accrual Differential Deferral Account.

See Notes 5, 8, 9, and 11 to these consolidated financial statements for additional disclosures related to the OEB's decisions, regulatory assets and liabilities, and rate regulated accounting.

Fixed Asset Removal and Nuclear Waste Management Liabilities

OPG recognizes AROs for fixed asset removal and nuclear waste management, discounted for the time value of money. OPG estimates both the amount and timing of future cash expenditures based on current plans for fixed asset removal and nuclear waste management. The liabilities are initially recorded at their estimated fair value, which is based on a discounted value of the expected costs to be paid.

On an ongoing basis, the liabilities for nuclear fixed asset removal and nuclear waste management (Nuclear Liabilities) are increased by the present value of the incremental cost portion for the nuclear waste generated each year, with the corresponding amounts charged to operating expenses. Variable expenses relating to low and intermediate level nuclear waste are charged to OM&A expenses. Variable expenses relating to the management and storage of nuclear used fuel are charged to fuel expense. The liabilities may also be adjusted due to any changes in the estimated amount or timing of the underlying future cash flows. Upon settlement of the liabilities, a gain or loss would be recorded.

Accretion arises because the nuclear liabilities are reported on a net present value basis. Accretion expense is the increase in the carrying amount of the liabilities due to the passage of time.

The asset retirement cost is capitalized by increasing the carrying value of the related fixed assets. The capitalized cost is depreciated over the remaining service life of the related fixed assets and is included in depreciation and amortization expenses.

Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

Pursuant to the Ontario Nuclear Funds Agreement (ONFA) between OPG and the Province, OPG established a Used Fuel Segregated Fund (Used Fuel Fund) and a Decommissioning Segregated Fund (Decommissioning Fund) (together the Nuclear Funds). The Used Fuel Fund is intended to fund expenditures associated with the management of radioactive used nuclear fuel bundles, while the Decommissioning Fund was established to fund expenditures associated with nuclear fixed asset removal, long-term L&ILW management, and certain costs for used fuel storage incurred after the nuclear stations are shut down. OPG maintains the Nuclear Funds in third-party custodial accounts that are segregated from the rest of OPG's assets.

OPG's investments in the Nuclear Funds and the corresponding payable/receivable to/from the Province are classified as held-for-trading. The Nuclear Funds are measured at fair value based on the bid prices of the underlying equity and fixed income securities, and, in the case of the alternative investment portfolio, using appropriate valuation techniques as outlined in Note 13 to these consolidated financial statements, with realized and unrealized gains and losses recognized in OPG's consolidated statements of income.

Revenue Recognition

All of OPG's electricity generation is offered into the real-time energy spot market administered by the Independent Electricity System Operator (IESO). Revenue is recognized as electricity is generated and metered to the IESO.

Effective January 1, 2015, the Ontario Power Authority (OPA) merged with the IESO. The new entity continued under the name Independent Electricity System Operator (IESO). As such, the IESO is substituted as the counterparty of Energy Supply Agreements (ESA) or other agreements that were previously executed with the OPA.

Revenue Recognition – Regulated Generation

Energy revenue generated from OPG's regulated facilities is based on regulated prices determined by the OEB that currently include a base regulated price and a rate rider for the recovery or repayment of approved variance and deferral account balances.

The base regulated prices in effect during 2014 and 2013 were determined by the OEB using a two-year forecast cost of service methodology based on revenue requirements, taking into account a forecast of production and operating costs for the regulated facilities and a return on rate base. Rate base is a regulatory construct that represents the average net level of investment in regulated fixed and intangible assets and an allowance for working capital. The revenues from the regulated hydroelectric facilities are also subject to the OEB-approved hydroelectric incentive mechanism. The mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to ratepayers.

The rate riders in effect during 2014 and 2013 were established by the OEB following its March 2013 decision approving a settlement agreement between OPG and intervenors on OPG's application to recover or repay balances in most of the OEB-authorized regulatory variance and deferral accounts as at December 31, 2012. The OEB-authorized variance and deferral accounts are discussed in Note 5 to these consolidated financial statements.

Revenue Recognition – Unregulated Generation and Other Revenue

The electricity generation from OPG's unregulated assets received the Ontario electricity spot market price, except where an ESA with the IESO or a cost recovery agreement is in place. As at December 31, 2014, virtually all of OPG's operating unregulated assets are subject to an ESA. Revenue generated by generating stations subject to a cost recovery agreement or an ESA is recognized in accordance with the terms of the agreement or contract.

OPG also sells into, and purchases from, interconnected markets of other provinces and the United States (US) northeast and midwest. All contracts that are not designated as hedges are recorded in the consolidated balance sheets at market value, with gains or losses recorded in the consolidated statements of income. Gains and losses on energy trading contracts (including those to be physically settled) are recorded on a net basis in the consolidated statements of income. Accordingly, power purchases of $131 million were netted against revenue in 2014 (2013 – $94 million).

OPG derives non-energy revenue under the terms of a lease arrangement and associated agreements with Bruce Power L.P. related to the Bruce nuclear generating stations. This includes lease revenue and revenue from heavy water sales and detritiation services. The benefit of OPG's net revenues from the lease of the Bruce stations and related agreements, including a portion of heavy water sales, are credited to ratepayers, as it reduces the regulated price of the generation of the nuclear facilities owned and operated by OPG. The minimum lease payments are recognized in revenue on a straight-line basis over the term of the lease.

In addition, non-energy revenue includes isotope sales, real estate rentals and other service revenues. Revenues from these activities are recognized as services are provided, or as products are delivered.

Derivatives

All derivatives, including embedded derivatives that must be separately accounted for, generally are classified as held-for-trading and recorded at fair value in the consolidated balance sheets. Transaction costs are expensed as incurred for financial instruments classified or designated as held-for-trading.

Derivatives qualify for hedge accounting if they meet stringent documentation requirements and the derivative instrument that is designated as a hedge is expected to effectively hedge the identified risk throughout the life of the hedged item. At the inception of a hedging relationship, OPG documents the relationship between the hedging instrument and the hedged item, its risk management objective, and its strategy for undertaking the hedge. A documented assessment is made, both at the inception of a hedge and on an ongoing basis, of whether or not the derivatives that are used in hedging transactions are highly effective in offsetting the changes attributable to the hedged risks in the fair values or cash flows of the hedged items.

All derivative contracts not designated as hedges are recorded on the consolidated balance sheets as derivative assets or liabilities at fair value with changes in fair value recorded in the revenue of the Services, Trading, and Other Non-Generation segment. Refer to Note 12 for a discussion of OPG's risks and the derivative instruments used to manage the risks.

Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly arm's-length transaction between market participants at the measurement date. Fair value measurements are required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model. OPG uses a fair value hierarchy, grouping assets and liabilities into three levels based on the relative objectivity of the inputs used to measure fair value, with Level 1 representing the most objective. Refer to Note 13 for a discussion of fair value measurements and the fair value hierarchy.

Research and Development

Research and development costs are expensed in the year incurred. Research and development costs incurred to discharge long-term obligations, such as the nuclear waste management liabilities, for which specific provisions have already been made, are charged to the related liability.

Leases

Leases are evaluated and classified as either operating or capital leases for financial reporting purposes. Capital leases, which transfer substantially all of the risks and benefits incidental to ownership of the leased item, are capitalized at the inception of the lease at the fair value of the leased property or, if lower, at the present value of the minimum lease payments. Capital leases are depreciated over the shorter of the estimated useful life of the asset or the lease term.

Leases where the lessor retains substantially all the risks and benefits incidental to ownership of the asset are classified as operating leases. Operating lease payments, other than contingent rentals, are recognized as an expense in the consolidated statements of income on a straight-line basis over the lease term. Where the amount of rent expense recognized is different from the actual operating lease payment, other than contingent rentals, the difference is deferred and included as assets or liabilities on the consolidated balance sheets.

Pension and Other Post-Employment Benefits

OPG's post-employment benefit programs consist of a contributory defined benefit registered pension plan, a defined benefit supplementary pension plan, and other post-retirement benefits (OPRB) including group life insurance and health care benefits, and long-term disability (LTD) benefits. Post-employment benefit programs are also provided by the NWMO, which is consolidated into OPG's financial results. Information on the Company's post-employment benefit programs is presented on a consolidated basis.

OPG accrues its obligations under pension and OPEB plans in accordance with US GAAP. The obligations for pension and OPRB are determined using the projected benefit method pro-rated on service. The obligation for LTD benefits is determined using the projected benefit method on a terminal basis. Pension and OPEB obligations are impacted by factors including interest rates, adjustments arising from plan amendments, changes in demographic assumptions, experience gains or losses, salary levels, inflation, and cost escalation. Pension and OPEB costs and obligations are determined annually by independent actuaries using management's best estimate assumptions.

Assumptions are significant inputs to actuarial models that measure pension and OPEB obligations and related effects on operations. Two critical assumptions – discount rate and inflation – are important elements in the determination of benefit costs and obligations. In addition, the expected return on plan assets is a critical assumption in the determination of registered pension plan costs. These assumptions, as well as other assumptions involving demographic factors such as retirement age, mortality, and employee turnover, are evaluated periodically by management in consultation with independent actuaries. During the evaluation process, the assumptions are updated to reflect past experience and expectations for the future. Actual results in any given year will often differ from actuarial assumptions because of economic and other factors. In accordance with US GAAP, for pension and OPRB, the impact of these updates and differences on the respective benefit obligations is accumulated and amortized over future periods; for LTD benefits, the impact of these updates and differences is immediately recognized as OPEB costs in the period incurred.

The discount rates, which are representative of AA corporate bond yields, are used to calculate the present value of the expected future cash flows on the measurement date to determine the projected benefit obligations for the Company's employee benefit plans. A lower discount rate increases the benefit obligations and increases benefit costs. The expected rate of return on plan assets is based on the pension fund's asset allocation, as well as the expected return considering long-term historical risks and returns associated with each asset class within the plan portfolio. A lower expected rate of return on plan assets increases pension cost.

Pension fund assets include equity securities, corporate and government debt securities, pooled funds, real estate, infrastructure, and other investments. These assets are managed by professional investment managers. The pension fund does not invest in equity or debt securities issued by OPG. Pension fund assets are valued using market-related values for purposes of determining the amortization of actuarial gains or losses and the expected return on plan assets. The market-related value recognizes gains and losses on equity assets relative to a six percent assumed real return over a five-year period.

Pension and OPEB costs include current service costs, interest costs on the obligations, the expected return on pension plan assets, adjustments for plan amendments and adjustments for actuarial gains or losses, which result from changes in assumptions and experience gains and losses. Past service costs or credits arising from pension and OPRB plan amendments are amortized on a straight-line basis over the expected average remaining service life to full eligibility of the employees covered by the plan. Past service costs or credits arising from amendments to LTD benefits are immediately recognized as OPEB costs in the period incurred. Due to the long-term nature of pension and OPRB liabilities, the excess of the net cumulative unamortized gain or loss, over 10 percent of the greater of the benefit obligation and the market-related value of the plan assets (corridor), is amortized over the expected average remaining service life of the employees since OPG expects to realize the associated economic benefit over that period. Actuarial gains or losses for LTD benefits are immediately recognized as OPEB costs in the period incurred.

OPG recognizes on its consolidated balance sheets the funded status of its defined benefit plans. The funded status is measured as the difference between the fair value of plan assets and the benefit obligation on a plan-by-plan basis.

Actuarial gains or losses and past service costs or credits that arise during the year and are not recognized immediately as components of benefit costs are recognized as increases or decreases in other comprehensive income (OCI), net of income taxes. These unamortized amounts in AOCI are subsequently reclassified and recognized as components of pension and OPRB costs as discussed above.

OPG records an offsetting regulatory asset or liability for the portion of the adjustments to AOCI that is attributable to regulated operations in order to reflect the expected recovery or refund of these amounts through future regulated prices charged to customers. For the recoverable or refundable portion attributable to regulated operations, OPG records a corresponding change in this regulatory asset or liability for the amount of the increases or decreases in OCI and for the reclassification of AOCI amounts into benefit costs during the period.

When the recognition of the transfer of employees and employee-related benefits gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement. A curtailment is the loss by employees of the right to earn future benefits under the plan. A settlement is the discharge of a plan's liability.

Income Taxes and Investment Tax Credits

OPG is exempt from income tax under the *Income Tax Act* (Canada). However, under the *Electricity Act, 1998*, OPG is required to make payments in lieu of corporate income taxes to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by the *Electricity Act, 1998* and related regulations. This results in OPG effectively paying taxes similar to what would be imposed under the federal and Ontario tax acts.

OPG follows the liability method of accounting for income taxes. Under the liability method, deferred income tax assets and liabilities are determined based on differences between the accounting and tax bases of assets and liabilities. Deferred amounts are measured using the enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect of a change in tax rates on deferred income tax assets and liabilities is included in income in the period the change is enacted.

If management determines that it is more likely than not that some, or all, of a deferred income tax asset will not be realized, a valuation allowance is recorded to report the balance at the amount expected to be realized.

OPG recognizes deferred income taxes associated with its regulated operations and records an offsetting regulatory asset or liability for the deferred income taxes that are expected to be recovered or refunded through future regulated prices charged to customers.

Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return and investment tax credits are recorded only when the more likely than not recognition threshold is satisfied. Tax benefits and investment tax credits recognized are measured at the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement.

Investment tax credits are recorded as a reduction to income tax expense. OPG classifies interest and penalties associated with unrecognized tax benefits as income tax expense.

Changes in Accounting Policies and Estimates

<u>Impacts of Regulation of the Newly Regulated Hydroelectric Facilities, and the OEB's 2014 Decision and Order</u>

The OEB's decision on OPG's September 2013 application for new regulated prices for OPG's nuclear and existing regulated hydroelectric generation was issued in November 2014, following a public hearing process. This decision was followed by the OEB's order in December 2014 establishing new regulated prices for these facilities effective November 1, 2014.

The OEB's decision and order also established a regulated price for the generation from the 48 newly regulated hydroelectric facilities. The regulated prices for these facilities are also effective November 1, 2014.

As a result of the rate regulation of these 48 previously unregulated hydroelectric facilities in 2014, OPG recognized regulatory assets related to deferred income taxes, and unamortized amounts recorded in AOCI in respect of pension and OPEB obligations. The increase in the regulatory asset related to deferred income taxes resulted in a net extraordinary gain of $243 million in the consolidated statement of income for 2014. The increase in regulatory assets related to pension and OPEB obligations resulted in an increase of $184 million in OCI, net of $61 million in income taxes.

The OEB's decision and order approved a $1,365 million addition to regulated rate base due to the completion and in-service addition of the Niagara Tunnel project in March 2013. The approved rate base amount is lower than the cost of the asset. Under Accounting Standards Codification (ASC) Topic 980 *Regulated Operations,* disallowances by a regulator on recently completed assets are generally required to be written off during the period when the regulator's decision is issued. As such, the OEB's cost disallowance on the Niagara Tunnel project resulted in a write-off of costs of $77 million in 2014, including $1 million of expected project close out costs. In December 2014, OPG filed a motion asking the OEB to review and vary certain parts of its decision, including the disallowance of the Niagara Tunnel expenditures.

Investment Companies

For reporting periods beginning January 1, 2014, OPG adopted the updates to ASC Topic 946, *Investment Companies*. Based on the amended scope of the standard, OPG concluded that OPG Ventures Inc., the Decommissioning Fund, the Used Fuel Fund and the Ontario NFWA Trust should be treated as investment entities for accounting purposes. As the investments of these entities are already recorded at fair value, there were no measurement differences upon adoption of this update. Additional disclosures required under ASC Topic 946 are provided in Note 8.

Pension and Other Post-Employment Benefits

The weighted average discount rate used to determine the projected pension benefit obligations and the projected benefit obligations for OPEB as at December 31, 2014 was 4.0 percent. This represents a decrease, compared to the 4.9 percent discount rate that was used to determine the obligations as at December 31, 2013.

The deficit for the registered pension plans increased from $2,461 million as at December 31, 2013 to $3,262 million as at December 31, 2014 largely as a result of the decrease in the discount rates at 2014 year end, partially offset by the favourable return on pension fund assets in 2014.

The projected benefit obligations for OPEB increased from $2,719 million at December 31, 2013 to $3,143 million as at December 31, 2014. This increase in the obligation was largely due to the decrease in the discount rates.

As at December 31, 2014, the unamortized net actuarial loss and unamortized past service costs for the pension and OPEB plans totalled $4,869 million (2013 – $3,899 million). Details of the unamortized net actuarial loss and unamortized past service costs at December 31, 2014 and 2013 are as follows:

	Registered Pension Plans		**Supplementary Pension Plans**		**Other Post-Employment Benefits**	
(millions of dollars)	**2014**	**2013**	**2014**	**2013**	**2014**	**2013**
Net actuarial gain not yet subject to amortization due to use of market-related values	**(878)**	(886)	**-**	-	**-**	-
Net actuarial loss not subject to amortization due to use of the corridor	**1,568**	1,339	**32**	29	**288**	245
Net actuarial loss subject to amortization	**3,443**	3,043	**65**	50	**350**	78
Unamortized net actuarial loss	**4,133**	3,496	**97**	79	**638**	323
Unamortized past service costs	**-**	-	**-**	-	**1**	1

A change in assumptions, holding all other assumptions constant, would increase (decrease) 2014 costs as follows:

(millions of dollars)	**Registered Pension Plans** [1]	**Supplementary Pension Plans** [1]	**Other Post-Employment Benefits** [1]
Expected long-term rate of return			
0.25% increase	(25)	n/a	n/a
0.25% decrease	25	n/a	n/a
Discount rate			
0.25% increase	(51)	(1)	(10)
0.25% decrease	54	1	12
Inflation			
0.25% increase	90	1	1
0.25% decrease	(85)	(1)	(1)
Salary increases			
0.25% increase	20	3	1
0.25% decrease	(20)	(3)	(1)
Health care cost trend rate			
1% increase	n/a	n/a	75
1% decrease	n/a	n/a	(37)

n/a – change in assumption not applicable.
[1] Excludes the impact of regulatory variance and deferral accounts.

Recent Accounting Pronouncements

Revenue from Contracts with Customers

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2014-09, *Revenue from Contracts with Customers* (ASU 2014-09), which supersedes nearly all existing revenue recognition guidance, including industry-specific guidance under US GAAP. The core principle of ASU 2014-09 is to recognize revenues when promised goods or services are transferred to customers in an amount that reflects the consideration to which an entity expects to be entitled for those goods or services. ASU 2014-09 defines a five step process to achieve this core principle and, in doing so, more judgement and estimates may be required, compared to the requirements under existing US GAAP. The standard will be effective for OPG's 2017 fiscal year, including interim periods in 2017. In applying the standard, entities would have the option between two retrospective transition methods: (i) a full retrospective approach reflecting the application of the standard in each prior reporting period with the option to elect certain practical expedients, or (ii) a modified retrospective approach with the cumulative effect of initially adopting ASU 2014-09 recognized at the date of adoption and additional disclosures. OPG is currently assessing the impact of this new standard on its consolidated financial statements and has not yet determined the method by which it will adopt the standard in 2017.

Consolidation

In February 2015, the FASB issued Accounting Standards Update 2015-02, Consolidation (Topic 810): Amendments to the Consolidation Analysis (ASU 2015-02), which incorporates targeted changes to the consolidation guidance for limited partnerships, limited liability corporations and securitization structures. Specifically for OPG, limited partnerships will now be VIEs unless the limited partners hold substantive "kick-out" or participating rights. It is expected that more limited partnerships will therefore be considered VIEs and where OPG is the primary beneficiary; the limited partnerships that are not currently consolidated would be consolidated. The amendments will be effective for OPG's 2016 fiscal year, including interim periods in 2016. OPG is currently assessing the impact of the standard on its consolidated financial statements and has not yet determined the impact of the standard in 2016.

4. PROPERTY, PLANT AND EQUIPMENT, INTANGIBLE ASSETS AND DEPRECIATION AND AMORTIZATION

Depreciation and amortization expenses for the years ended December 31 consist of the following:

(millions of dollars)	**2014**	**2013**
Depreciation	**451**	513
Amortization of intangible assets	**13**	14
Amortization of regulatory assets and liabilities *(Note 5)*	**290**	436
	754	963

Property, plant and equipment as at December 31 consist of the following:

(millions of dollars)	**2014**	**2013** *(adjusted - Note 16)*
Nuclear generating stations	**9,313**	9,116
Regulated hydroelectric generating stations	**9,287**	9,296
Contracted generation portfolio generating stations	**3,600**	2,475
Other property, plant and equipment	**1,833**	414
Construction in progress	**1,826**	3,140
	25,859	24,441
Less: accumulated depreciation		
Generating stations	**6,771**	7,478
Other property, plant and equipment	**1,495**	225
	8,266	7,703
	17,593	16,738

Construction in progress as at December 31 consists of the following:

(millions of dollars)	**2014**	**2013**
Darlington Refurbishment	**1,309**	658
Atikokan Biomass Conversion	**6**	144
Lower Mattagami River Project	**-**	1,982
Other	**511**	356
	1,826	3,140

Interest capitalized to construction and development in progress at an average rate of five percent during 2014 (2013 – five percent) was $135 million (2013 – $127 million).

Intangible assets as at December 31 consist of the following:

(millions of dollars)	**2014**	**2013** *(adjusted - Note 16)*
Nuclear generating stations	**116**	114
Regulated hydroelectric generating stations	**4**	4
Contracted generation portfolio generating stations	**5**	5
Computer software and other intangible assets	**261**	257
Development in progress	**46**	22
	432	402
Less: accumulated amortization		
Generating stations	**109**	103
Computer software and other intangible assets	**247**	240
	356	343
	76	59

The estimated aggregate amortization expense for intangible assets currently recognized for each of the five succeeding years is as follows:

(millions of dollars)	**2015**	**2016**	**2017**	**2018**	**2019**
Amortization expense	11	8	4	2	-

5. REGULATORY ASSETS AND LIABILITIES

In March 2013, the OEB approved a settlement agreement between OPG and intervenors on all aspects of OPG's application requesting approval to recover or repay balances in most of the authorized variance and deferral accounts as at December 31, 2012 (the Settlement Agreement). In approving the Settlement Agreement, the OEB authorized the disposition of approved balances over periods ranging from two to 12 years beginning on January 1, 2013. In April 2013, the OEB issued an order authorizing OPG to collect $633 million over the period from January 1, 2013 to December 31, 2014 through rate riders effective during that period. During 2014 and 2013, the Company amortized the regulatory assets and liabilities for the variance and deferral balances approved for disposition based on recovery or repayment periods authorized by the OEB's approval of the Settlement Agreement. Any shortfall or over-recovery of approved balances due to differences between actual and forecast production was recorded in the authorized Nuclear Deferral and Variance Over/Under Recovery Variance Account and Hydroelectric Deferral and Variance Over/Under Recovery Variance Account to be collected from, or refunded to, ratepayers in the future.

The OEB's March 2013 decision and April 2013 order also authorized the continuation of previously existing variance and deferral accounts, including those authorized pursuant to *Ontario Regulation 53/05*. During the period from January 1, 2013 to October 31, 2014, the Company recognized regulatory assets and liabilities for additions recorded in these variance and deferral accounts as authorized by the OEB, relative to the forecast amounts reflected in the cost of service regulated prices then in effect, where applicable.

In November 2014 and December 2014, respectively, the OEB issued its decision and order establishing new regulated prices for OPG's regulated generation effective November 1, 2014. The OEB's decision and order approved the recovery or repayment of the balances in four variance accounts as at December 31, 2013 totalling $189 million, without adjustments. The recovery or repayment was approved for the following accounts: the Hydroelectric Incentive Mechanism Variance Account, the Hydroelectric Surplus Baseload Generation Variance Account, the nuclear capital and hydroelectric portions of the Capacity Refurbishment Variance Account, and the

Nuclear Development Variance Account. The OEB authorized the recovery or repayment of these balances over a 12-month period, through rate riders effective from January 1, 2015 to December 31, 2015.

In its decision and order, the OEB also approved the continuation of previously authorized variance and deferral accounts and, effective November 1, 2014, extended all applicable accounts to the 48 newly regulated hydroelectric facilities. During the period from November 1, 2014 to December 31, 2014, the Company recognized regulatory assets and liabilities for additions recorded in these variance and deferral accounts as authorized by the OEB. During this period, the Company also recognized regulatory assets for additions to the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB Cash Payment Variance Account, which were established by the OEB effective November 1, 2014.

During 2014 and 2013, OPG recorded interest on the balances of the variance and deferral accounts as authorized by the OEB. For accounts subject to interest during this period, interest was recorded using the OEB-prescribed interest rate of 1.47 percent per annum.

In December 2014, OPG filed an application with the OEB requesting approval of the December 31, 2014 balances in most of the authorized regulatory variance and deferral accounts. The application requests recovery of these balances through new rate riders beginning on July 1, 2015. The decision on OPG's application will be made by the OEB following a public hearing process, which commenced in the first quarter of 2015.

The regulatory assets and liabilities recorded as at December 31 are as follows:

(millions of dollars)	**2014**	**2013**
Regulatory assets		
Variance and deferral accounts authorized by the OEB		
Pension and OPEB Cost Variance Account	**939**	667
Bruce Lease Net Revenues Variance Account	**315**	353
Nuclear Liability Deferral Account	**286**	254
Capacity Refurbishment Variance Account	**190**	100
Hydroelectric Surplus Baseload Generation Variance Account	**67**	19
Nuclear Development Variance Account	**59**	57
Other variance and deferral accounts	**111**	233
	1,967	1,683
Pension and OPEB Regulatory Asset *(Note 11)*	**4,363**	3,158
Deferred Income Taxes *(Note 9)*	**861**	559
Total regulatory assets	**7,191**	5,400
Less: current portion	**167**	306
Non-current regulatory assets	**7,024**	5,094
Regulatory liabilities		
Variance and deferral accounts authorized by the OEB		
Other variance and deferral accounts	**44**	24
Total regulatory liabilities	**44**	24
Less: current portion	**5**	16
Non-current regulatory liabilities	**39**	8

The changes in the regulatory assets and liabilities during 2014 and 2013 are as follows:

(millions of dollars)	**Pension and OPEB Cost Variance**	**Bruce Lease Net Revenues Variance**	**Nuclear Liability Deferral**	**Capacity Refurbish -ment Variance**	**Hydro-electric Surplus Baseload Generation Variance**	**Nuclear Develop-ment Variance**	**Other Variance and Deferral (net)**	**Pension and OPEB Regula-tory Asset**	**Deferred Income Taxes**
Net regulatory assets January 1, 2013	324	311	208	14	4	30	384	4,494	668
Increase (decrease)	402	110	123	93	15	26	53	(1,336)	(109)
Interest	1	(5)	(2)	-	-	1	3	-	-
Amortization	(60)	(63)	(75)	(7)	-	-	(231)	-	-
Net regulatory assets December 31, 2013	667	353	254	100	19	57	209	3,158	559
Increase	**312**	**4**	**82**	**92**	**48**	**1**	**9**	**1,205**	**302**
Interest	**-**	**-**	**-**	**3**	**-**	**1**	**2**	**-**	**-**
Amortization	**(40)**	**(42)**	**(50)**	**(5)**	**-**	**-**	**(153)**	**-**	**-**
Net regulatory assets December 31, 2014	**939**	**315**	**286**	**190**	**67**	**59**	**67**	**4,363**	**861**

Pension and OPEB Cost Variance Account

As authorized by the OEB, for the period from March 1, 2011 to October 31, 2014, the Pension and OPEB Cost Variance Account recorded the difference between actual pension and OPEB costs for the regulated business determined on an accrual basis and related tax impacts, and the corresponding amounts reflected in the regulated prices then in effect. In its November 2014 decision, the OEB determined that the pension and OPEB amounts for the regulated business reflected in the new regulated prices effective November 1, 2014 would be limited to OPG's estimated minimum contributions to its registered pension plan and a forecast of OPG's expenditures on the OPEB and supplementary pension plans. As such, the OEB ordered the Pension and OPEB Cost Variance Account to record only amortization beginning on November 1, 2014.

In its March 2013 decision and April 2013 order, the OEB authorized the recovery of 2/12 of the balance in the Pension and OPEB Cost Variance Account as at December 31, 2012 over a 24-month period ending December 31, 2014. The OEB also authorized the recovery of 10/12 of the account balance as at December 31, 2012 over a 144-month period ending December 31, 2024. Accordingly, effective January 1, 2013, OPG recorded amortization of the regulatory asset for the account on a straight-line basis over these periods.

Bruce Lease Net Revenues Variance Account

As per *Ontario Regulation 53/05*, the OEB is required to include the difference between OPG's revenues and costs associated with its ownership of the two nuclear stations on lease to Bruce Power L.P. in the determination of the regulated prices for production from OPG's regulated nuclear facilities. The OEB established a variance account that captures differences between OPG's revenues and costs related to the nuclear generating station on lease to Bruce Power L.P. and the corresponding forecasts included in approved nuclear regulated prices.

In its March 2013 decision and April 2013 order, the OEB ordered the portion of the balance in the Bruce Lease Net Revenues Variance Account as at December 31, 2012 related to the impact of the derivative liability embedded in the Bruce Power lease agreement (Bruce Lease) to be recovered on the basis of OPG's expected rent rebate payments to Bruce Power L.P. and associated income tax impacts. Effective January 1, 2013, OPG recorded amortization of the regulatory asset for this portion of the account on that basis.

The non-derivative portion of the balance as at December 31, 2012 was authorized by the OEB to be recovered over a 48-month period ending December 31, 2016. Effective January 1, 2013, OPG recorded amortization of the regulatory asset for the non-derivative portion of the account on a straight-line basis over this period.

Nuclear Liability Deferral Account

As per *Ontario Regulation 53/05*, the OEB has authorized the Nuclear Liability Deferral Account (NLDA) in connection with changes to OPG's liabilities for nuclear used fuel management and nuclear decommissioning and L&ILW management associated with the nuclear facilities owned and operated by OPG, which are comprised of the Pickering and Darlington nuclear generating stations. The deferral account records the revenue requirement impact associated with the changes in these liabilities arising from an approved reference plan, in accordance with the terms of the ONFA. During 2012, the Province approved the 2012 ONFA Reference Plan covering the period from 2012 to 2016, with an effective date of January 1, 2012. As the regulated prices in effect prior to November 1, 2014 did not reflect the impact of the 2012 ONFA Reference Plan, OPG recorded an increase to the regulatory asset for the NLDA during the period from January 1, 2012 to October 31, 2014.

Components of the increase in the regulatory asset for the NLDA relating to the above increase in liabilities, with reductions to corresponding expenses for the years ended December 31, 2014 and 2013 are summarized as follows:

(millions of dollars)	**2014**	**2013**
Fuel expense	**23**	26
Low and intermediate level waste management variable expenses [1]	**1**	1
Depreciation expense	**43**	52
Return on rate base [2]	**-**	2
Interest [3]	**-**	(2)
Income taxes	**15**	42
	82	121

[1] Amount was recorded as a reduction to OM&A expenses.
[2] Amount was recorded as a reduction to accretion on fixed asset removal and nuclear waste management liabilities.
[3] Amount in 2013 represents the write-off of interest recorded on the balance of the account as of December 31, 2012, pursuant to the OEB-approved Settlement Agreement.

In its March 2013 decision and April 2013 order, the OEB approved the recovery of a portion of the balance in the NLDA as at December 31, 2012 over a 24-month period ending December 31, 2014. Accordingly, effective January 1, 2013, OPG recorded amortization of the regulatory asset for this account on a straight-line basis over this period. As ordered by the OEB per the terms of the Settlement Agreement, effective January 1, 2013, no interest is recorded on the balance of this account.

Capacity Refurbishment Variance Account

Pursuant to *Ontario Regulation 53/05*, the OEB has authorized the Capacity Refurbishment Variance Account (CRVA). The account captures variances from forecasts reflected in the regulated prices for capital and non-capital costs incurred to increase the output of, refurbish, or add operating capacity to the regulated facilities. The balance in the account as at December 31, 2014 includes variances related to the Niagara Tunnel project, the refurbishment of the Darlington nuclear generating station, life extension initiatives at the Pickering nuclear generation station, and other projects.

OPG determines amounts to be recovered from, or refunded to, customers with respect to variances in capital costs as the difference from forecast depreciation expense and cost of capital associated with the in-service capital reflected in the regulated prices and associated income tax effects. The cost of capital amount in the account is calculated using the weighted average cost of capital, including a return on equity, as approved by the OEB in determining the regulated prices. In accordance with US GAAP, in recognizing a regulatory asset for the CRVA, 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 to construction and development in progress.

As the regulated prices in effect prior to November 1, 2014 did not reflect the impact of the Niagara Tunnel declared in-service in March 2013, the CRVA additions for the period from January 1, 2014 to October 31, 2014 included $116 million (year ended December 31, 2013 – $114 million) to be recovered from ratepayers related to the Niagara Tunnel. This amount included $83 million (2013 – $83 million) for the capital cost component determined using the weighted average cost of capital. OPG recognized an increase of $89 million in the regulatory asset for the CRVA related to the Niagara Tunnel in 2014 (2013 – $88 million), of which $56 million (2013 – $56 million) represented the capital cost component determined using the average rate of five percent for capitalized interest applied to construction and development in progress for the year ended December 31, 2014 (2013 – five percent).

In its March 2013 decision and April 2013 order, the OEB approved the recovery of the nuclear non-capital cost portion of the account balance as at December 31, 2012 over a 24-month period ending December 31, 2014. Accordingly, effective January 1, 2013, OPG recorded amortization of the regulatory asset for this portion of the account on a straight-line basis over this period. In setting new regulated prices effective November 1, 2014, the OEB approved the recovery of the December 31, 2013 nuclear capital and hydroelectric portions of the account balance, totaling $119 million, over a 12-month period beginning on January 1, 2015.

Hydroelectric Surplus Baseload Generation Variance Account

The Hydroelectric Surplus Baseload Generation Variance Account records the impact of foregone production at OPG's regulated hydroelectric facilities due to surplus baseload generation conditions. The variance account was authorized by the OEB, effective March 1, 2011 for the previously regulated hydroelectric facilities. The OEB extended this account to the applicable newly regulated hydroelectric facilities effective November 1, 2014.

In its November 2014 decision and December 2014 order, the OEB approved the recovery of the account balance as at December 31, 2013 over a 12-month period beginning on January 1, 2015.

Nuclear Development Variance Account

The Nuclear Development Variance Account was established pursuant to *Ontario Regulation 53/05* and records differences between actual non-capital costs incurred by OPG in the course of planning and preparing for the development of proposed new nuclear facilities, and the forecast amount of these costs included in the nuclear regulated prices.

In its November 2014 decision, the OEB approved the recovery of the account balance as at December 31, 2013 over a 12-month period beginning on January 1, 2015.

Other Variance and Deferral Accounts

As at December 31, 2014 and 2013, regulatory assets for other variance and deferral accounts included amounts for the Nuclear Deferral and Variance Over/Under Recovery Variance Account and the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account.

As at December 31, 2014, regulatory assets for other variance and deferral accounts also included amounts for the Pension & OPEB Cash Versus Accrual Differential Deferral Account, the Pickering Life Extension Depreciation Variance Account, and the Pension & OPEB Cash Payment Variance Account. The Pickering Life Extension Depreciation Variance Account balance was recorded wholly during the period from November 1, 2014 to December 31, 2014. This balance represents an offset to the ratepayer credit for the reduction in depreciation expense for the Pickering nuclear generating station that was reflected both as a reduction to the new base regulated prices effective November 1, 2014 and the nuclear rate rider in effect to the end of 2014. The Pension & OPEB Cash Payment Variance Account records, effective November 1, 2014, the difference between OPG's actual contributions to its registered pension plans and expenditures on its OPEB and supplementary pension plans for the regulated business, and the corresponding amounts reflected in the regulated prices. As at December 31, 2013, regulatory assets for other variance and deferral accounts also included the Tax Loss Variance Account and the Impact for USGAAP Deferral Account, the OEB-approved balances of which were fully amortized by December 31, 2014.

Regulatory liabilities for other variance and deferral accounts included amounts for the Income and Other Taxes Variance Account and the Hydroelectric Incentive Mechanism Variance Account. The Income and Other Taxes Variance Account includes deviations in income taxes for the regulated business, from those approved by the OEB in setting regulated prices and caused by changes in tax rates and rules, as well as reassessments. The Hydroelectric Incentive Mechanism Variance Account records a credit to ratepayers equal to 50 percent of OPG's Hydroelectric Incentive Mechanism net revenues above a specified threshold for the previously regulated hydroelectric facilities, and, effective November 1, 2014, for the newly regulated hydroelectric facilities.

The regulatory liabilities for other variance and deferral accounts as at December 31, 2014 and the regulatory assets for other variance and deferral accounts as at December 31, 2013 also included amounts for the Ancillary Services Net Revenue Variance Account and the Hydroelectric Water Conditions Variance Account. The Ancillary Services Net Revenue Variance Account was authorized by the OEB to capture differences between actual nuclear and regulated hydroelectric ancillary services net revenue and the forecast amounts of such revenue approved by the OEB in setting regulated prices. The Hydroelectric Water Conditions Variance Account captures the impact of differences in regulated hydroelectric electricity production due to differences between forecast water conditions underlying the production forecast approved by the OEB in setting regulated hydroelectric prices, and the actual water conditions. Both of these accounts apply to the newly regulated hydroelectric stations effective November 1, 2014.

In its March 2013 decision and April 2013 order, the OEB approved the recovery or repayment of the majority of the balances of the other variance and deferral accounts as at December 31, 2012 over a 24-month period ending December 31, 2014. Accordingly, effective January 1, 2013, OPG recorded amortization of the applicable balances on a straight-line basis over this period.

Pension & OPEB Cash Versus Accrual Differential Deferral Account

The OEB established the Pension & OPEB Cash Versus Accrual Differential Deferral Account in its November 2014 decision. The deferral account records, effective November 1, 2014, the difference between OPG's actual pension and OPEB costs for the regulated business determined on an accrual basis and the corresponding actual cash expenditures for these plans. The OEB established the deferral account as a result of determining that the pension and OPEB amounts reflected in the regulated prices effective November 1, 2014 would be limited to a forecast of OPG's cash expenditures on its pension and OPEB plans, rather than costs determined on an accrual basis in accordance with US GAAP. In making this determination, the OEB indicated that a generic proceeding on the regulatory treatment and recovery of pension and OPEB costs would be beneficial, and that the disposition of the deferral account balance will be based on the outcome of that proceeding. The scope or timing of the generic proceeding has not been announced.

During the year ended December 31, 2014, OPG recognized a regulatory asset of $36 million for the addition to the Pension & OPEB Cash Versus Accrual Differential Deferral Account. As directed by the OEB, no interest is recorded on the balance of this account.

Pension and OPEB Regulatory Asset

The Pension and OPEB Regulatory Asset represents unamortized amounts in respect of OPG's pension and OPEB plans that have been recognized in OCI and not yet reclassified into the amortization component of the benefit costs in respect of these plans. These amounts are expected to be recovered from ratepayers through future regulated prices. The regulatory asset is reversed as underlying unamortized balances are amortized in components of benefit costs. Refer to Note 3 for a detailed discussion of pension and OPEB cost recovery methodology under the heading *Rate Regulated Accounting*. The AOCI amounts related to pension and OPEB plans are presented in Note 11.

Deferred Income Taxes

OPG is required to recognize deferred income taxes associated with its rate regulated operations, including deferred income taxes on temporary differences related to the regulatory assets and liabilities recognized for accounting purposes. In addition, OPG is required to recognize a separate regulatory asset or liability for the amount of deferred income taxes expected to be included in future regulated prices and recovered from, or paid to, customers. Income taxes are discussed in Note 9.

6. LONG-TERM DEBT

Long-term debt consists of the following as at December 31:

(millions of dollars)	2014	2013
Long-term debt [1]		
Notes payable to the OEFC		
Senior Notes [2]		
3.43% due 2015	**500**	500
4.91% due 2016	**270**	270
5.35% due 2017	**900**	900
5.27% due 2018	**395**	395
5.44% due 2019	**365**	365
4.56% due 2020	**660**	660
4.28% due 2021	**185**	185
3.30% due 2022	**150**	150
3.12% due 2023	**40**	40
5.07% due 2041	**300**	300
4.36% due 2042	**200**	200
UMH Energy Partnership debt [3]		
Senior Notes		
7.86% due to 2041	**190**	193
Lower Mattagami Energy Limited Partnership [4]		
Senior Notes		
2.59% due 2015	**-**	92
2.35% due 2017	**200**	200
4.46% due 2021	**225**	225
3.53% due 2024	**200**	-
5.26% due 2041	**250**	250
5.05% due 2043	**200**	200
4.26% due 2046	**275**	275
4.26% due 2052	**225**	225
	5,730	5,625
Less: due within one year	**503**	5
Long-term debt	**5,227**	5,620

1 The interest rates disclosed reflect the effective interest rate of the debt.

2 OEFC senior debt is entitled to receive, in full, amounts owing in respect of the senior debt and is pari passu to the Lower Mattagami Energy Limited Partnership (LME) senior notes.

3 These notes are secured by the assets of the Upper Mattagami and Hound Chute project. Principal repayments of approximately $3 million per year are paid on a semi-annual basis until maturity in 2041 at which time the remaining principal balance of $116 million becomes due.

4 These notes are secured by the assets of the Lower Mattagami River project, including existing operating facilities and facilities being constructed, and are recourse to OPG until the recourse release date. These notes rank pari passu to the OEFC senior notes.

OPG maintained a credit facility with the OEFC related to the Niagara Tunnel project for an amount up to $1.6 billion which expired on December 31, 2014. As at December 31, 2014, advances under this facility were $1,065 million (2013 – $1,065 million).

OPG maintained a $500 million general corporate credit facility with the OEFC which expired on December 31, 2014 with no amounts outstanding. In December 2014, OPG entered into an agreement with the OEFC for an $800 million general corporate credit facility which expires on December 31, 2016, in support of its financing requirements for the period 2015-2016. As at December 31, 2014, there were no amounts outstanding under this facility.

Interest paid in 2014 was $273 million (2013 – $255 million), of which $264 million (2013 – $246 million) relates to interest paid on long-term corporate debt.

The book value of the pledged assets as at December 31, 2014 was $3,271 million (2013 – $2,756 million).

A summary of the contractual maturities of all long-term borrowings by year is as follows:

(millions of dollars)	
2015	**503**
2016	**273**
2017	**1,103**
2018	**398**
2019	**368**
Thereafter	**3,085**
	5,730

7. SHORT-TERM DEBT AND NET INTEREST EXPENSE

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. In May 2014, OPG renewed and extended both tranches by one year to May 2019. As at December 31, 2014 and 2013, there were no outstanding borrowings under the bank credit facility.

The LME maintains a $600 million bank credit facility to support the funding requirements for the Lower Mattagami River project. The facility consists of two tranches. In August 2014, OPG extended the maturity of the first tranche to August 2019, from August 2018. The second tranche matures in August 2015. As at December 31, 2014, no external commercial paper was outstanding under this program (2013 – $32 million).

As at December 31, 2014, OPG maintained $25 million of short-term, uncommitted overdraft facilities and $390 million of short-term, uncommitted credit facilities, which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other general corporate purposes. As at December 31, 2014, a total of $336 million of Letters of Credit had been issued. This included $310 million for the supplementary pension plans, $25 million for general corporate purposes, and $1 million related to the operation of the PEC.

The Company has an agreement to sell an undivided co-ownership interest in its current and future accounts receivable to an independent trust. The Company also retains an undivided co-ownership interest in the receivables sold to the trust. Under the agreement, OPG continues to service the receivables. The transfer provides the trust with ownership of a share of the payments generated by the receivables, computed on a monthly basis. The trust's recourse to the Company is generally limited to its income earned on the receivables. In September 2014, the maximum amount of co-ownership interest that can be sold under this agreement was reduced to $150 million and the expiry date was extended from November 30, 2014 to November 30, 2016. As at December 31, 2014, there were

Letters of Credit outstanding under this agreement of $150 million (2013 – $80 million), which were issued in support of OPG's supplementary pension plans.

In October 2014, UMH Energy Partnership (UMH) entered into an $8 million of short-term, uncommitted overdraft facility and $16 million of irrevocable, standby letters of credit facilities in support of its operations. As at December 31, 2014, a total of $14 million of Letters of Credit had been issued under this facility.

The following table summarizes the net interest expense for the years ended December 31:

(millions of dollars)	**2014**	**2013**
Interest on long-term debt	**291**	280
Interest on short-term debt	**9**	9
Interest income	**(10)**	(10)
Interest capitalized to property, plant and equipment and intangible assets	**(135)**	(127)
Interest related to regulatory assets and liabilities [1]	**(75)**	(66)
Net interest expense	**80**	86

[1] Includes interest to recognize the cost of financing related to regulatory assets and liabilities, as authorized by the OEB, and interest deferred in the Capacity Refurbishment Variance Account and the Bruce Lease Net Revenues Variance Account.

8. FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT LIABILITIES

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

(millions of dollars)	**2014**	**2013**
Liability for nuclear used fuel management	**10,459**	9,957
Liability for nuclear decommissioning and low and intermediate level waste management	**6,204**	5,946
Liability for non-nuclear fixed asset removal	**365**	354
Fixed asset removal and nuclear waste management liabilities	**17,028**	16,257

The changes in the fixed asset removal and nuclear waste management liabilities for the years ended December 31 are as follows:

(millions of dollars)	**2014**	**2013**
Liabilities, beginning of year	**16,257**	15,522
Increase in liabilities due to accretion [1]	**867**	826
Increase in liabilities due to nuclear used fuel, nuclear waste management variable expenses and other expenses	**116**	109
Liabilities settled by expenditures on fixed asset removal and nuclear waste management	**(212)**	(199)
Change in the liabilities for non-nuclear fixed asset removal	**-**	(1)
Liabilities, end of year	**17,028**	16,257

[1] The increase in liabilities due to accretion for 2014 excludes the impact of regulatory variance and deferral accounts.

OPG's fixed asset removal and nuclear waste management liabilities are comprised of expected costs to be incurred up to and beyond termination of operations and the closure of nuclear, thermal generating plant facilities, and other facilities. Costs will be incurred for activities such as preparation for safe storage, safe storage, dismantling, demolition and disposal of facilities and equipment, remediation and restoration of sites, and the ongoing and long-term management of nuclear used fuel and L&ILW waste material. Under the terms of the Bruce agreement, OPG continues to be primarily responsible for the nuclear fixed asset removal and nuclear waste management liabilities associated with the Bruce nuclear generating stations.

The determination of the accrual for fixed asset removal and nuclear waste management costs requires significant assumptions since these programs are long-term in nature. The most recent update of the cost estimates for the nuclear waste management and decommissioning liabilities is contained in the approved 2012 ONFA Reference Plan.

For the purposes of calculating OPG's nuclear fixed asset removal and nuclear waste management liabilities, as at December 31, 2014, consistent with the current accounting end of life assumptions, nuclear station decommissioning is projected to occur over the next 40 years. The estimates for the Nuclear Liabilities include cash flow estimates for decommissioning nuclear stations for approximately 40 years after station shut down and to 2071 for placement of used fuel into the long-term disposal repository followed by extended monitoring.

The significant assumptions underlying operational and technical factors used in the calculation of the accrued Nuclear Liabilities are subject to periodic review. Changes to these assumptions, including changes to assumptions on the timing of the programs, end of life dates, financial indicators, or the technology employed may result in significant changes to the value of the accrued liabilities. With programs of this duration and the evolving technology to handle the nuclear waste, there is a significant degree of uncertainty surrounding the measurement of the costs for these programs, which may increase or decrease over time.

Liability for Nuclear Used Fuel Management Costs

The liability for nuclear used fuel management represents the cost of managing the highly radioactive used nuclear fuel bundles. The federal NFWA, proclaimed into force in 2002, requires that Canada's nuclear fuel waste owners form a nuclear waste management organization, and that each waste owner establish a trust fund for used fuel management costs. To estimate its liability for nuclear used fuel management costs, OPG has adopted a conservative approach consistent with the Adaptive Phased Management concept approved by the Government of Canada, which assumes a deep geologic repository in-service date of 2035 at the earliest.

Liability for Nuclear Decommissioning and L&ILW Management Costs

The liability for nuclear decommissioning and L&ILW management represents the estimated costs of decommissioning nuclear generating stations after the end of their service lives, as well as the cost of managing L&ILW generated by the nuclear stations. The significant assumptions used in estimating future nuclear fixed asset removal costs include decommissioning of nuclear generating stations on a deferred dismantlement basis, where the reactors will remain in a safe storage state for a 30-year period prior to an approximate 10-year dismantlement period.

The life cycle costs of L&ILW management include the costs of processing and storage of such radioactive wastes during and following the operation of the nuclear stations, as well as the costs of the ultimate long-term management of these wastes. The current assumptions used to establish the accrued L&ILW management costs include a L&ILW deep geologic repository. Agreement has been reached with local municipalities for OPG to develop a deep geologic repository for the long-term management of L&ILW adjacent to the Western Waste Management Facility. OPG has suspended design activities for the L&ILW deep geologic repository pending receipt of the site preparation and construction licence.

Liability for Non-Nuclear Fixed Asset Removal Costs

The liability for non-nuclear fixed asset removal primarily represents the estimated costs of decommissioning OPG's thermal generating stations at the end of their services lives. The liability is based on third-party cost estimates after an in-depth review of plant sites and an assessment of required clean-up and restoration activities. In 2011, OPG completed a review of the liability for most of its thermal generating stations. For the purpose of measuring the liability, asset removal activities are estimated to take place over the next 15 years.

As at December 31, 2014, in addition to the $143 million liability for active sites, OPG has an ARO of $222 million for decommissioning and restoration costs associated with plant sites that are not currently in use for electricity generation, including the Nanticoke and Lambton generating stations.

Ontario Nuclear Funds Agreement

The Decommissioning Fund was established to fund the future costs of nuclear fixed asset removal, long-term L&ILW management, and certain costs for used fuel storage incurred after the stations are shutdown. As at December 31, 2014, the Decommissioning Fund was in an overfunded position.

The Used Fuel Fund was established to fund future costs of long-term nuclear used fuel waste management. OPG is responsible for the risk and liability of cost increases for used fuel waste management, subject to graduated liability thresholds specified in the ONFA, which limit OPG's total financial exposure at approximately $13.7 billion in present value dollars as at December 31, 2014, based on used fuel bundle projections of 2.23 million bundles, consistent with the station life assumptions included within the initial financial reference plan. The graduated liability thresholds do not apply to additional used fuel bundles beyond 2.23 million.

OPG makes quarterly payments to the Used Fuel Fund over the life of its nuclear generating stations, as specified in the ONFA. Required funding for 2014 under the ONFA was $139 million (2013 – $184 million), including a contribution to the Ontario NFWA Trust (the Trust) of $161 million (2013 – $154 million). The Trust forms part of the Used Fuel Fund, and contributions to the Trust, as required by the NFWA, may be applied towards OPG's ONFA payment obligations. Based on the approved 2012 ONFA Reference Plan, OPG is required to contribute annual amounts to the Used Fuel Fund, ranging from $143 million to $288 million over the years 2015 to 2019. The required contributions are disclosed in Note 15.

As required by the terms of the ONFA, the Province has provided a Provincial Guarantee to the Canadian Nuclear Safety Commission (CNSC) since 2003, on behalf of OPG. The *Nuclear Safety and Control Act* (Canada) requires OPG to have sufficient funds available to discharge the current nuclear decommissioning and waste management liabilities. The Provincial Guarantee provides for any shortfall between the CNSC consolidated financial guarantee requirement and the value of the Nuclear Funds. OPG pays the Province an annual guarantee fee of 0.5 percent of the amount of the Provincial Guarantee provided by the Province. The current value of the Provincial Guarantee amount of $1,551 million is in effect through to the end of 2017. In each of January 2014 and 2015, OPG paid a guarantee fee of $8 million based on a Provincial Guarantee amount of $1,551 million.

Decommissioning Fund

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

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

Under the ONFA, if there is a surplus in the Decommissioning Fund such that the liabilities, as defined by the most recently approved ONFA Reference Plan, are at least 120 percent funded, OPG may direct up to 50 percent of the surplus over 120 percent to be treated as a contribution to the Used Fuel Fund and the OEFC would be entitled to a distribution of an equal amount. In such instances, OPG recognizes 50 percent of the excess greater than 120 percent in income. Since OPG is responsible for the risks associated with liability cost increases and investment returns in the Decommissioning Fund, future contributions to the Decommissioning Fund may be required should the fund be in an underfunded position at the time of the next liability reference plan review.

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

Used Fuel Fund

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

Under the ONFA, the Province is entitled to any surplus in the Used Fuel Fund, subject to a threshold funded ratio of 110 percent compared to the value of the associated liabilities based on the most recently approved ONFA Reference Plan.

Nuclear Funds

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

	Fair Value	
(millions of dollars)	**2014**	**2013**
Decommissioning Fund	**7,346**	6,591
Due to Province – Decommissioning Fund	**(1,100)**	(624)
	6,246	5,967
Used Fuel Fund [1]	**9,562**	8,519
Due to Province – Used Fuel Fund	**(1,429)**	(990)
	8,133	7,529
Total Nuclear Funds	**14,379**	13,496
Less: current portion	**25**	25
Non-current Nuclear Funds	**14,354**	13,471

[1] The Ontario NFWA Trust represented $3,114 million as at December 31, 2014 (2013 – $2,668 million) of the Used Fuel Fund on a fair value basis.

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

(millions of dollars)	Fair Value 2014	2013
Cash and cash equivalents and short-term investments	**464**	262
Alternative investments	**1,003**	598
Pooled funds	**1,293**	2,173
Marketable equity securities	**8,176**	7,332
Fixed income securities	**5,969**	4,713
Net receivables/payables	**3**	32
	16,908	15,110
Due to Province	**(2,529)**	(1,614)
	14,379	13,496

The nature and type of investments made by OPG have the attributes of an investment company in accordance with ASC Topic 946. As such, beginning January 1, 2014, the Company applied guidance outlined in ASC Topic 946 for all investments owned by the Nuclear Funds. OPG's consolidated financial statements retained investment company accounting for the Nuclear Funds. The adoption of investment company accounting for the Nuclear Funds did not result in an effect on net income or change in net assets from operations, as investments held by OPG's Nuclear Funds continue to be recorded at fair value.

The investments in the Nuclear Funds are segregated from other assets in the consolidated group that are not investment companies.

The historical cost, gross unrealized aggregate appreciation and depreciation of investment, gross unrealized foreign exchange gains, and fair value of the Nuclear Funds as of December 31, 2014 and 2013 are summarized as follows:

	2014		
(millions of dollars)	**Decommissioning Fund**	**Used Fuel Fund [1]**	**Total**
Historical cost	**6,188**	**8,163**	**14,351**
Gross unrealized gains (losses)			
Aggregate appreciation	**1,218**	**1,441**	**2,659**
Aggregate depreciation	**(150)**	**(174)**	**(324)**
Foreign exchange	**90**	**132**	**222**
	7,346	**9,562**	**16,908**
Due to Province	**(1,100)**	**(1,429)**	**(2,529)**
Total fair value	**6,246**	**8,133**	**14,379**
Less: current portion	**7**	**18**	**25**
Non-current fair value	**6,239**	**8,115**	**14,354**

[1] The Ontario NFWA Trust represented $3,114 million as at December 31, 2014 of the Used Fuel Fund on a fair value basis.

	2013		
(millions of dollars)	**Decommissioning Fund**	**Used Fuel Fund [1]**	**Total**
Historical cost	5,571	7,240	12,811
Gross unrealized gains (losses)			
Aggregate appreciation	1,111	1,365	2,476
Aggregate depreciation	(118)	(136)	(254)
Foreign exchange	27	50	77
	6,591	8,519	15,110
Due to Province	(624)	(990)	(1,614)
Fair value	5,967	7,529	13,496
Less: current portion	12	13	25
Non-current fair value	5,955	7,516	13,471

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

Net realized and unrealized gains or losses from investments for the years ended December 31, 2014 and 2013 are summarized as follows:

	2014		
(millions of dollars)	**Decommissioning Fund**	**Used Fuel Fund**	**Total**
Net realized gains			
Realized gains	**401**	**545**	**946**
Realized foreign exchange gains	**36**	**36**	**72**
Net realized gains	**437**	**581**	**1,018**
Net unrealized gains			
Unrealized gains	**75**	**38**	**113**
Unrealized foreign exchange gains	**63**	**82**	**145**
Net unrealized gains	**138**	**120**	**258**

	2013		
(millions of dollars)	**Decommissioning Fund**	**Used Fuel Fund**	**Total**
Net realized gains			
Realized gains	182	174	356
Realized foreign exchange losses	(9)	(8)	(17)
Net realized gains	173	166	339
Net unrealized gains			
Unrealized gains	410	639	1,049
Unrealized foreign exchange gains	97	114	211
Net unrealized gains	507	753	1,260

The change in the Nuclear Funds for the years ended December 31 is as follows:

	Fair Value	
(millions of dollars)	**2014**	**2013**
Decommissioning Fund, beginning of year	**5,967**	5,707
Increase in fund due to return on investments	**782**	854
Decrease in fund due to reimbursement of expenditures	**(27)**	(34)
Increase in due to Province	**(476)**	(560)
Decommissioning Fund, end of year	**6,246**	5,967
Used Fuel Fund, beginning of year	**7,529**	7,010
Increase in fund due to contributions made	**139**	184
Increase in fund due to return on investments	**954**	1,131
Decrease in fund due to reimbursement of expenditures	**(50)**	(41)
Increase in due to Province	**(439)**	(755)
Used Fuel Fund, end of year	**8,133**	7,529

The earnings from the Nuclear Funds during 2014 and 2013 were impacted by the Bruce Lease Net Revenues Variance Account authorized by the OEB. The earnings on the Nuclear Funds for the years ended December 31 are as follows:

(millions of dollars)	**2014**	**2013**
Decommissioning Fund	**306**	294
Used Fuel Fund	**515**	376
Bruce Lease Net Revenues Variance Account	**(107)**	(42)
Total earnings	**714**	628

9. INCOME TAXES

OPG follows the liability method of tax accounting for all its business segments. The Company records an offsetting regulatory asset or liability for the deferred income taxes that are expected to be recovered or refunded through future regulated prices charged to customers for generation from OPG's regulated facilities.

During 2014, OPG recorded a decrease in the deferred income tax liability for the income taxes that are expected to be recovered or refunded through regulated prices charged to customers of $22 million (2013 – $109 million). Since these deferred income taxes are expected to be refunded through future regulated prices, OPG recorded a corresponding decrease to the regulatory asset for deferred income taxes. As a result, the deferred income tax expense for 2014 and 2013 was not impacted.

The amount of tax refunds received net of taxes paid during 2014 was $29 million (the amount of taxes paid during 2013 was $14 million).

The following table summarizes the deferred income tax liabilities recorded for the rate regulated operations that are expected to be recovered through future regulated prices:

(millions of dollars)	**2014**	**2013**
January 1:		
Deferred income tax liabilities on temporary differences related to regulated operations	**418**	500
Deferred income tax liabilities resulting from the regulatory asset for deferred income taxes	**141**	168
	559	668
Impact of regulation of the newly regulated facilities:		
Deferred income tax liabilities on temporary differences as of June 30, related to the hydroelectric facilities prescribed for regulation effective in 2014 *(Note 3)*	**243**	-
Deferred income tax liabilities resulting from the regulatory asset for deferred income taxes related to the regulation of hydroelectric facilities effective in 2014 *(Note 3)*	**81**	-
	883	668
Changes during the year:		
Decrease in deferred income tax liabilities on temporary differences related to regulated operations, including newly regulated hydroelectric facilities effective July 1, 2014	**(17)**	(82)
Decrease in deferred income tax liabilities resulting from the regulatory asset for deferred income taxes, including newly regulated hydroelectric facilities effective July 1, 2014	**(5)**	(27)
Balance at December 31	**861**	559

A reconciliation between the statutory and the effective rate of income taxes is as follows:

(millions of dollars)	**2014**	**2013**
Income before income taxes and extraordinary item	**707**	166
Combined Canadian federal and provincial statutory enacted income tax rates	**26.5%**	26.5%
Statutory income tax rates applied to accounting income	**187**	44
(Decrease) increase in income taxes resulting from:		
Income tax components of regulatory variance and deferral accounts	**(79)**	(102)
Non-taxable income items	**(6)**	(3)
Regulatory asset for deferred income taxes	**25**	113
Scientific Research and Experimental Development investment tax credits	**(16)**	(22)
Other	**28**	1
	(48)	(13)
Income tax expense	**139**	31
Effective rate of income taxes	**19.7%**	18.7%

Significant components of the income tax expense are presented in the table below:

(millions of dollars)	**2014**	**2013**
Current income tax expense (recovery):		
Current payable	**123**	48
Change in income tax positions	**(15)**	9
Income tax components of regulatory variance and deferral accounts	**(10)**	9
Scientific Research and Experimental Development investment tax credits	**(29)**	(30)
Other	**14**	7
	83	43
Deferred income tax expense (recovery):		
Change in temporary differences	**100**	(14)
Income tax components of regulatory variance and deferral accounts	**(69)**	(111)
Regulatory asset for deferred income taxes	**25**	113
	56	(12)
Income tax expense	**139**	31

The income tax effects of temporary differences that give rise to deferred income tax assets and liabilities as at December 31 are as follows:

(millions of dollars)	**2014**	**2013**
Deferred income tax assets:		
Fixed asset removal and nuclear waste management liabilities	**4,247**	4,055
Other liabilities and assets	**1,973**	1,672
Future recoverable Ontario minimum tax	**11**	30
	6,231	5,757
Deferred income tax liabilities:		
Property, plant and equipment and intangible assets	**(1,478)**	(1,463)
Nuclear fixed asset removal and nuclear waste management funds	**(3,595)**	(3,374)
Other liabilities and assets	**(1,986)**	(1,499)
	(7,059)	(6,336)
Net deferred income tax liabilities	**(828)**	(579)
Represented by:		
Current portion – asset (liability)	**8**	(14)
Long-term portion – liability	**(836)**	(565)
	(828)	(579)

The tax benefit associated with an income tax position is recognized only when it is more likely than not that such a position will be sustained upon examination by the taxing authorities based on the technical merits of the position. The current and deferred income tax benefit is equal to the largest amount, considering possible settlement outcomes, that is greater than 50 percent likely of being realized upon settlement with the taxing authorities.

A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

(millions of dollars)	**2014**	**2013**
Unrecognized tax benefits, beginning of year	**91**	82
Additions based on tax positions related to the current year	**11**	13
Additions for tax positions of prior years	**12**	-
Reductions for tax positions of prior years	**(35)**	(4)
Unrecognized tax benefits, end of year	**79**	91

As at December 31, 2014, OPG's unrecognized tax benefits were $79 million (2013 – $91 million), excluding interest and penalties, all of which, if recognized, would affect OPG's effective tax rate. Changes in unrecognized tax benefits over the next 12 months cannot be predicted with certainty.

OPG recognizes interest and penalties related to unrecognized tax benefits as income tax expense. As at December 31, 2014, OPG has recorded interest on unrecognized tax benefits of $6 million (2013 – $10 million). OPG considers its significant tax jurisdiction to be Canada. OPG remains subject to income tax examination for years after 2010.

10. ACCUMULATED OTHER COMPREHENSIVE LOSS

The changes in the balance of each component of accumulated other comprehensive loss (AOCL), net of taxes, during the years ended December 31, 2014 and 2013 are as follows:

	2014		
(millions of dollars)	**Unrealized Gains and Losses on Cash Flow Hedges** [1]	**Pension and Other Post-Employment Benefits** [1]	**Total** [1]
AOCL, beginning of year	**(129)**	**(555)**	**(684)**
Net loss on cash flow hedges	**(2)**	**-**	**(2)**
Recognition of initial pension and OPEB regulatory asset for amounts recorded prior to regulation of facilities, effective July 1, 2014 *(Note 3)*	**-**	**184**	**184**
Actuarial loss on re-measurement of liabilities for pension and other post-employment benefits	**-**	**(35)**	**(35)**
Amounts reclassified from AOCL	**14**	**27**	**41**
Other comprehensive income for the year	**12**	**176**	**188**
AOCL, end of year	**(117)**	**(379)**	**(496)**

[1] All amounts are net of income taxes.

	2013		
(millions of dollars)	**Unrealized Gains and Losses on Cash Flow Hedges** [1]	**Pension and Other Post-Employment Benefits** [1]	**Total** [1]
AOCL, beginning of year	(156)	(823)	(979)
Net gain on cash flow hedges	14	-	14
Actuarial gain and past service credits on re-measurement of liabilities for pension and other post-employment benefits	-	226	226
Amounts reclassified from AOCL	13	42	55
Other comprehensive income (loss) for the year	27	268	295
AOCL, end of year	(129)	(555)	(684)

[1] All amounts are net of income taxes.

The significant amounts reclassified out of each component of AOCL, net of income taxes, during the years ended December 31, 2014 and 2013 are as follows:

	Amount Reclassified from AOCL		
(millions of dollars)	**2014**	**2013**	**Statement of Income Line Item**
Amortization of losses from cash flow hedges			
Losses	**16**	15	Net interest expense
Income tax expense	**(2)**	(2)	
	14	13	
Amortization of amounts related to pension and other post-employment benefits			
Actuarial losses and past service costs	**37**	57	See (1) below
Income tax expense	**(10)**	(15)	
	27	42	
Total reclassifications for the year	**41**	55	

[1] These AOCL components are included in the computation of pension and OPEB costs (see Note 11 for additional details).

11. PENSION AND OTHER POST-EMPLOYMENT BENEFITS

Fund Assets

The OPG registered pension fund investment guidelines are stated in an approved Statement of Investment Policies and Procedures (SIPP). The SIPP is reviewed and approved by OPG's Audit and Finance Committee at least annually and includes a discussion regarding investment objectives and expectations, asset mix and rebalancing, and the basis for measuring the performance of the pension fund assets.

In accordance with the SIPP, investment allocation decisions are made with a view to achieve OPG's objective to meet obligations of the plan as they come due. The pension fund assets are invested in three categories of asset classes. The first category is liability hedging assets which are intended to hedge the inflation and interest rate sensitivity of the plan liabilities. The second category is return enhancing assets which are intended to obtain higher investment returns compared to the returns expected for liability hedging assets. The third category is return diversifying strategies which are intended to improve the overall return of the pension fund while controlling the amount of downside market risk.

To achieve the above objective, OPG has adopted the following target strategic asset allocation:

	Target
Asset Class	
Liability Hedging Assets	54%
Return Enhancing Assets	33%
Return Diversifying Assets	13%

The plan may enter into derivative securities, such as interest rate swaps and forward foreign exchange contracts, for risk management purposes, where such activity is consistent with its investment objective.

Significant Concentrations of Risk in Fund Assets

The assets of the pension fund are diversified to limit the impact of any individual investment. The pension fund is diversified across multiple asset classes. Fixed income securities are diversified among Canadian government provincial bonds, government agency bonds, real return bonds, corporate bonds, and an interest rate overlay hedging program, which is disclosed under pooled funds. Equity securities are diversified across Canadian, US, and non-North American stocks. There are also real estate and infrastructure portfolios that are approximately five percent of the total pension fund assets. Investments in the above asset classes are further diversified across funds, investment managers, strategies, vintages, sectors and geographies, depending on the specific characteristics of each asset class.

Credit risk with respect to the pension fund's fixed income securities is managed by risk tolerance guidelines, which requires that fixed income securities comply with various investment constraints that ensure prudent diversification and prescribed minimum required credit rating quality. Credit risk, as it relates to the pension fund's derivatives, is managed through the use of International Swap and Derivatives Association documentation and counterparty management performed by the fund's investment managers.

Risk Management

Risk management oversight with respect to the pension fund includes but is not limited to the following activities:

- Periodic asset/liability management and strategic asset allocation studies
- Monitoring of funding levels and funding ratios
- Monitoring compliance with asset allocation guidelines and investment management agreements
- Monitoring asset class performance against asset class benchmarks
- Monitoring investment manager performance against benchmarks
- Monitoring of risk tolerance guidelines.

Expected Rate of Return on Plan Assets

The expected rate of return on plan assets is based on the fund's asset allocation, as well as the expected return considering long-term historical risks and returns associated with each asset class within the plan portfolio. The asset management decisions consider the economic liabilities of the plan.

Fair Value Measurements

OPG is required to classify fair value measurements using a fair value hierarchy. This hierarchy groups financial instruments into three levels, based on the significance of inputs used in measuring the fair value of the assets and liabilities. Refer to Note 13 for a detailed discussion of fair value measurements and the fair value hierarchy.

The following tables present pension plan assets measured at fair value in accordance with the fair value hierarchy:

	December 31, 2014			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Cash and cash equivalents	251	-	-	251
Short-term investments	-	3	-	3
Fixed income				
Corporate debt securities	-	349	-	349
Non-US government bonds	-	1,704	-	1,704
Equities				
Canadian	1,955	-	-	1,955
US	2,016	-	-	2,016
Non-North American	2,147	-	-	2,147
Pooled funds	12	2,450	866	3,328
Infrastructure	-	-	338	338
Real estate	-	-	300	300
Other	-	-	5	5
	6,381	4,506	1,509	12,396 [1]

[1] The table above excludes pension fund receivables and payables.

	December 31, 2013			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Cash and cash equivalents	320	-	-	320
Short-term investments	-	5	-	5
Fixed income				
Corporate debt securities	-	315	-	315
Non-US government bonds	-	1,514	-	1,514
Equities				
Canadian	2,087	-	-	2,087
US	2,031	-	-	2,031
Non-North American	2,357	-	-	2,357
Pooled funds	38	1,959	11	2,008
Infrastructure	-	-	208	208
Real estate	-	-	210	210
Other	-	2	-	2
	6,833	3,795	429	11,057 [1]

[1] The table above exclude pension fund receivables and payables.

The following tables present the changes in the fair value of financial instruments classified in Level 3:

	For the years ended December 31				
(millions of dollars)	**Pooled Funds**	**Infrastructure**	**Real Estate**	**Other**	**Total**
Opening balance, January 1, 2013	8	160	72	-	240
Total realized and unrealized gains	3	19	6	-	28
Purchases, sales, and settlements	-	29	132	-	161
					-
Closing balance, December 31, 2013	11	208	210	-	429
Transfer from Level 2 to Level 3	-	-	-	2	2
Total realized and unrealized gains	69	37	76	-	182
Purchases, sales, and settlements	786	93	14	3	896
Closing balance, December 31, 2014	866	338	300	5	1,509

During the years ended December 31, 2014 and 2013, there were no transfers between Level 1 and Level 2.

Plan Costs and Liabilities

Details of OPG's pension and OPEB obligations, pension fund assets and costs are presented in the following tables:

	Registered and Supplementary Pension Plans 2014	Registered and Supplementary Pension Plans 2013	Other Post-Employment Benefits 2014	Other Post-Employment Benefits 2013
Weighted Average Assumptions – Benefit Obligations at Year-End				
Rate used to discount future benefits	**4.00%**	4.90%	**4.03%**	4.91%
Salary schedule escalation rate - next six years	**2.00%**	2.50%	**2.50%**	2.50%
- thereafter	**2.50%**	2.50%	**2.50%**	2.50%
Rate of cost of living increase to pensions	**2.00%**	2.00%	**n/a**	n/a
Initial health care trend rate	**n/a**	n/a	**6.09%**	6.19%
Ultimate health care trend rate	**n/a**	n/a	**4.33%**	4.34%
Year ultimate health care trend rate reached	**n/a**	n/a	**2030**	2030
Rate of increase in disability benefits	**n/a**	n/a	**2.00%**	2.00%

	Registered and Supplementary Pension Plans 2014	Registered and Supplementary Pension Plans 2013	Other Post-Employment Benefits 2014	Other Post-Employment Benefits 2013
Weighted Average Assumptions – Costs for the Year				
Expected return on plan assets, net of expenses	**6.25%**	6.25%	**n/a**	n/a
Rate used to discount future benefits	**4.90%**	4.30%	**4.90%**	4.32%
Salary schedule escalation rate	**2.50%**	2.50%	**2.50%**	2.50
Rate of cost of living increase to pensions	**2.00%**	2.00%	**n/a**	n/a
Initial health care trend rate	**n/a**	n/a	**6.19%**	6.38%
Ultimate health care trend rate	**n/a**	n/a	**4.34%**	4.38%
Year ultimate health care trend rate reached	**n/a**	n/a	**2030**	2030
Rate of increase in disability benefits	**n/a**	n/a	**2.00%**	2.00%
Expected average remaining service life for employees (years)	**12**	13	**13**	14

(millions of dollars)	Registered Pension Plans 2014	Registered Pension Plans 2013	Supplementary Pension Plans 2014	Supplementary Pension Plans 2013	Other Post-Employment Benefits 2014	Other Post-Employment Benefits 2013
Components of Cost Recognized						
Current service costs	**238**	291	**8**	10	**64**	106
Interest on projected benefit obligation	**658**	589	**14**	13	**135**	139
Expected return on plan assets, net of expenses	**(628)**	(648)	**-**	-	**-**	-
Amortization of past service costs [1]	**-**	-	**-**	-	**-**	1
Amortization of net actuarial loss [1]	**260**	244	**4**	6	**6**	48
Recognition of LTD net actuarial gain	**-**	-	**-**	-	**(3)**	(32)
Costs recognized [2]	**528**	476	**26**	29	**202**	262

[1] The amortization of past service costs and net actuarial loss was recognized as an increase to OCI. This increase was partially offset by the impact of the Pension and OPEB Regulatory Asset as discussed in Note 5.

[2] Excludes the impact of regulatory variance and deferral accounts. These regulatory accounts are discussed in Note 5.

Total benefit costs, including the impact of the Pension and OPEB Cost Variance Account, the Pension & OPEB Cash Payment Variance Account, the Pension & OPEB Cash Versus Accrual Differential Deferral Account, for the years ended December 31 are as follows:

(millions of dollars)	**2014**	**2013**
Registered pension plans	**528**	476
Supplementary pension plans	**26**	29
Other post-employment benefits	**202**	262
Pension and OPEB Cost Variance Account *(Note 5)*	**(254)**	(312)
Pension & OPEB Cash Payment Variance Account *(Note 5)*	**(6)**	-
Pension & OPEB Cash Versus Accrual Differential Deferral Account *(Note 5)*	**(36)**	-
Pension and other post-employment benefit costs	**460**	455

The pension and OPEB obligations and the pension fund assets measured as at December 31 are as follows:

	Registered Pension Plans		**Supplementary Pension Plans**		**Other Post-Employment Benefits**	
(millions of dollars)	**2014**	**2013**	**2014**	**2013**	**2014**	**2013**
Change in Plan Assets						
Fair value of plan assets at beginning of year	**10,961**	10,337	**-**	-	**-**	-
Contributions by employer	**364**	306	**16**	14	**93**	87
Contributions by employees	**70**	74	**-**	-	**-**	-
Actual return on plan assets, net of expenses	**1,677**	923	**-**	-	**-**	-
Benefit payments	**(665)**	(679)	**(16)**	(14)	**(93)**	(87)
Fair value of plan assets at end of year	**12,407**	10,961	**-**	-	**-**	-
Change in Projected Benefit Obligations						
Projected benefit obligations at beginning of year	**13,422**	13,669	**289**	297	**2,719**	3,174
Employer current service costs	**238**	291	**8**	10	**64**	106
Contributions by employees	**70**	74	**-**	-	**-**	-
Interest on projected benefit obligation	**658**	589	**14**	13	**135**	139
Benefit payments	**(665)**	(679)	**(16)**	(14)	**(93)**	(87)
Past service credits	**-**	-	**-**	-	**-**	(2)
Net actuarial loss (gain)	**1,946**	(522)	**22**	(17)	**318**	(611)
Projected benefit obligations at end of year	**15,669**	13,422	**317**	289	**3,143**	2,719
Funded status – deficit at end of year	**(3,262)**	(2,461)	**(317)**	(289)	**(3,143)**	(2,719)

The following table provides the pension and OPEB liabilities and their classification on the consolidated balance sheets as at December 31:

(millions of dollars)	**Registered Pension Plans 2014**	**Registered Pension Plans 2013**	**Supplementary Pension Plans 2014**	**Supplementary Pension Plans 2013**	**Other Post-Employment Benefits 2014**	**Other Post-Employment Benefits 2013**
Current liabilities	**-**	-	**(9)**	(9)	**(93)**	(91)
Non-current liabilities	**(3,262)**	(2,461)	**(308)**	(280)	**(3,050)**	(2,628)
Total liabilities	**(3,262)**	(2,461)	**(317)**	(289)	**(3,143)**	(2,719)

The accumulated benefit obligations for the registered pension plans and supplementary pension plans as at December 31, 2014 are $14,333 million and $274 million, respectively (2013 – $12,242 million and $237 million, respectively). The accumulated benefit obligation differs from the projected benefit obligation in that the accumulated benefit obligation includes no assumption about future compensation levels.

The following table provides the components of OPG's OCI related to pension and OPEB plans and the offsetting Pension and OPEB Regulatory Asset as discussed in Note 5 for the years ended December 31, on a pre-tax basis:

(millions of dollars)	**Registered Pension Plans 2014**	**Registered Pension Plans 2013**	**Supplementary Pension Plans 2014**	**Supplementary Pension Plans 2013**	**Other Post-Employment Benefits 2014**	**Other Post-Employment Benefits 2013**
Changes in plan assets and benefit obligations recognized in OCI						
Current year net actuarial loss (gain)	**897**	(797)	**22**	(17)	**321**	(579)
Current year past service credits	**-**	-	**-**	-	**-**	(2)
Amortization of net actuarial loss	**(260)**	(244)	**(4)**	(6)	**(6)**	(48)
Amortization of past service costs	**-**	-	**-**	-	**-**	(1)
Total decrease (increase) in OCI	**637**	(1,041)	**18**	(23)	**315**	(630)
Less: Increase (decrease) in Pension and OPEB Regulatory Asset, excluding extraordinary gain *(Note 5)*	**652**	(814)	**19**	(18)	**289**	(504)
Less: Recognition of initial Pension & OPEB regulatory asset related to facilities prescribed for rate regulation beginning in 2014 *(Note 3)*	**219**	-	**5**	-	**21**	-
Net (increase) decrease in OCI (pre-tax)	**(234)**	(227)	**(6)**	(5)	**5**	(126)

The following table provides the components of OPG's AOCL and the offsetting Pension and OPEB Regulatory Asset that have not yet been recognized as components of benefit costs as at December 31, on a pre-tax basis:

(millions of dollars)	**Registered Pension Plans 2014**	**Registered Pension Plans 2013**	**Supplementary Pension Plans 2014**	**Supplementary Pension Plans 2013**	**Other Post-Employment Benefits 2014**	**Other Post-Employment Benefits 2013**
Unamortized amounts recognized in AOCL						
Past service costs	**-**	-	**-**	-	**1**	1
Net actuarial loss	**4,133**	3,496	**97**	79	**638**	323
Total recognized in AOCL	**4,133**	3,496	**97**	79	**639**	324
Less: Pension and OPEB Regulatory Asset *(Note 5)*	**3,702**	2,831	**88**	64	**573**	263
Net recognized in AOCL (pre-tax)	**431**	665	**9**	15	**66**	61

The following table provides the components of OPG's AOCI and the offsetting Pension and OPEB Regulatory Asset as at December 31 (included in the table above) that are expected to be amortized as components of benefit costs and recognized as increases to OCI and reductions in the Pension and OPEB Regulatory Asset, related to the currently regulated facilities, in 2015, on a pre-tax basis:

(millions of dollars)	Registered Pension Plans	Supplementary Pension Plans	Other Post-Employment Benefits
Net actuarial loss	**292**	**6**	**27**
Total increase in AOCI	**292**	**6**	**27**
Less: Estimated decrease in Pension and OPEB Regulatory Asset	**261**	**5**	**25**
Net increase in AOCI (pre-tax)	**31**	**1**	**2**

Based on the most recently filed actuarial valuation, for funding purposes, of the OPG registered pension plan, as at January 1, 2014, there was an unfunded liability on a going-concern basis of $1,143 million and a deficiency on a wind-up basis of $7,034 million. In the previously filed actuarial valuation, as at January 1, 2011, there was an unfunded liability on a going-concern basis of $555 million and a deficiency on a wind-up basis of $5,663 million. The funded status to be determined in the next filed funding valuation, which must have an effective date no later than January 1, 2017, could be significantly different. For 2015, OPG's required contribution to its registered pension plan is expected to be $364 million. The amount of OPG's additional voluntary contribution, if any, is revisited from time to time. OPG will continue to assess the requirements for contributions to the pension plan.

Based on the most recently filed actuarial valuation, for funding purposes, of the NWMO registered pension plan, as at January 1, 2014, there was a surplus on a going-concern basis of $23 million and a deficiency on a wind-up basis of $1 million. In the previously filed actuarial valuation, as at January 1, 2013, there was a surplus on a going-concern basis of $14 million and a deficiency on a wind-up basis of $15 million. The next filed funding valuation must have an effective date no later than January 1, 2015.

The supplementary pension plans are not funded, but are secured by Letters of Credit totalling $310 million as at December 31, 2014 (2013 – $302 million).

Estimated future benefit payments to participants in the pension and OPEB plans based on the assumptions used to measure the benefit obligations as at December 31, 2014 are as follows:

(millions of dollars)	Registered Pension Plans	Supplementary Pension Plans	Other Post-Employment Benefits
2015	563	10	93
2016	590	11	97
2017	596	11	101
2018	634	12	107
2019	666	13	112
2020 through 2024	3,788	77	636

A one percent increase or decrease in the health care trend rate would result in an increase in the current service and interest components of the 2014 OPEB cost recognized of $42 million (2013 – $54 million) or a decrease in the service and interest components of the 2014 OPEB cost recognized of $31 million (2013 – $39 million). A one percent increase or decrease in the health care trend rate would result in an increase in the projected OPEB obligation at December 31, 2014 of $567 million (2013 – $472 million) or a decrease in the projected OPEB obligation at December 31, 2014 of $432 million (2013 – $360 million).

12. RISK MANAGEMENT AND DERIVATIVES

OPG is exposed to risks related to changes in electricity prices associated with a wholesale spot market for electricity in Ontario, changes in market interest rates on debt expected to be issued in the future, and movements in foreign currency that affect its assets, liabilities, and forecasted transactions. Select derivative instruments are used to manage such risks. Derivatives are used as hedging instruments, as well as for trading purposes.

Interest rate risk is the risk that the value of assets and liabilities can change due to movements in related interest rates. Interest rate risk for OPG arises with the need to refinance existing debt and/or undertake new financing. The management of these risks is undertaken by using derivatives to hedge the exposure in accordance with corporate risk management policies. OPG periodically uses interest rate swap agreements to mitigate elements of interest rate risk exposure associated with anticipated financing.

The LME has entered into forward start interest rate swaps to hedge against the effect of future changes in interest rates for long-term debt for the Lower Mattagami River project. All forward interest rate swap contracts have been offset or settled since the second quarter of 2014.

Electricity price risk for the Company is the potential for adverse movements in the market price of electricity. Exposure to electricity price risk is reduced as a result of regulated prices and contractual arrangements for a significant portion of OPG's business. Effective November 1, 2014, virtually all of this exposure was mitigated with the implementation of a regulated price for OPG's 48 previously unregulated hydroelectric facilities, which were prescribed for regulation beginning in 2014.

The conditional reduction to revenue in the future, embedded in the terms of the Bruce Lease, is treated as a derivative. Assumptions related to future electricity prices impact the valuation of the derivative liability embedded in the Bruce Lease.

OPG's foreign exchange exposure is attributable to two primary factors: US dollar denominated transactions such as the purchase of fuels. OPG enters into foreign exchange derivatives and agreements with major financial institutions, when necessary, in order to manage the Company's exposure to foreign currency movements.

The majority of OPG's revenues are derived from sales through the IESO-administered spot market. Although the credit exposure to the IESO represents a significant portion of OPG's accounts receivable, the Company's management accepts this risk due to the IESO's primary role in the Ontario electricity market. The remaining receivables exposure is to a diverse group of generally high quality counterparties. OPG's allowance for doubtful accounts as at December 31, 2014 was less than $1 million.

The following is a summary of OPG's derivative instruments:

	2014			
(millions of dollars except where noted)	**Notional Quantity**	**Terms**	**Fair Value**	**Balance Sheet Line Item**
As at December 31, 2014				
Derivative embedded in the Bruce Lease	**n/a**	**5 years**	**(302)**	Long-term accounts payable and accrued charges
Other derivative instruments	**various**	**various**	**11**	Various
Total derivatives			**(291)**	

			2013	
(millions of dollars except where noted)	**Notional Quantity**	**Terms**	**Fair Value**	**Balance Sheet Line Item**
Derivative embedded in the Bruce Lease	n/a	6 years	(346)	Long-term accounts payable and accrued charges
Other derivative instruments	various	various	(8)	Various
Total derivatives			(354)	

The following table shows the amount related to derivatives recorded in AOCL and income for the years ended December 31:

(millions of dollars)	**2014**	**2013**
Cash flow hedges (recorded in AOCL)		
(Loss) gain in OCI	**(3)**	17
Reclassification of losses to net interest expense	**19**	18
Reclassification of gains to fuel expense	**(3)**	(3)
Commodity derivatives (recorded in income)		
Realized losses in revenue	**(11)**	(7)
Unrealized gains (losses) in revenue	**9**	(4)
Embedded derivative (recorded in income)		
Unrealized gains (losses) in revenue [1]	**44**	(33)

[1] Excludes the impact of the Bruce Lease Net Revenues Variance Account.

Existing net losses of $20 million deferred in AOCL as at December 31, 2014 are expected to be reclassified to net income within the next 12 months.

13. FAIR VALUE MEASUREMENTS

OPG is required to classify fair value measurements using a fair value hierarchy. This hierarchy groups financial assets and liabilities into three levels, based on the significance of inputs used in measuring the fair value of the financial assets and liabilities. The level within which the financial asset or liability is classified is determined based on the attribute of significance to the inputs to the fair value measurement. The fair value hierarchy has the following levels:

- Level 1: Valuation of inputs is based on unadjusted quoted market prices observed in active markets for identical assets or liabilities.
- Level 2: Valuation is based on inputs other than quoted prices under Level 1 that are observable for the asset or liability, either directly or indirectly.
- Level 3: Valuation is based on inputs for the asset or liability that are not based on observable market data.

The fair value of financial instruments traded in active markets is based on quoted market prices at the consolidated balance sheet dates. A market is regarded as active if quoted prices are readily and regularly available from an exchange, dealer, broker, industry group, pricing service, or regulatory agency, and those prices represent actual and regularly occurring market transactions on an arm's length basis. The quoted market price used for financial assets held by OPG is the current bid price. These instruments are included in Level 1 and are comprised primarily of equity investments and fund investments.

For financial instruments for which quoted market prices are not directly available, fair values are estimated using forward price curves developed from observable market prices or rates. The estimation of fair value may include the use of valuation techniques or models, based wherever possible on assumptions supported by observable market prices or rates prevailing at the consolidated balance sheet dates. This is the case for over-the-counter derivatives and securities, which include energy commodity derivatives, foreign exchange derivatives, interest rate swap derivatives, and fund investments. Pooled fund investments are valued at the unit values supplied by the pooled fund administrators. The unit values represent the underlying net assets at fair values, determined using closing market prices. Valuation models use general assumptions and market data and therefore do not reflect the specific risks and other factors that would affect a particular instrument's fair value. The methodologies used for calculating the fair value adjustments are reviewed on an ongoing basis to ensure that they remain appropriate. If all significant inputs required to fair value an instrument are observable, the instrument is included in Level 2.

If one or more of the significant inputs is not based on observable market data, the instrument is included in Level 3. Specific valuation techniques are used to value these instruments. Significant Level 3 inputs include: recent comparable transactions, comparable benchmark information, bid/ask spread of similar transactions, and other relevant factors.

Transfers into, out of, or between levels are deemed to have occurred on the date of the event or change in circumstances that caused the transfer to occur.

The Company is required to determine the fair value of all its financial instruments. The following is a summary of OPG's financial instruments as at December 31:

	Fair Value		**Carrying Value** [1]		
(millions of dollars)	**2014**	**2013**	**2014**	**2013**	**Balance Sheet Line Item**
Nuclear fixed asset removal and nuclear waste management funds (includes current portion)	**14,379**	13,496	**14,379**	13,496	Nuclear fixed asset removal and nuclear waste management funds
Payable related to cash flow hedges	**(63)**	(56)	**(63)**	(56)	Long-term accounts payable and accrued charges
Derivative embedded in the Bruce Lease	**(302)**	(346)	**(302)**	(346)	Long-term accounts payable and accrued charges
Long-term debt (includes current portion)	**(6,326)**	(5,955)	**(5,730)**	(5,625)	Long-term debt
Other financial instruments	**19**	1	**19**	1	Various

[1] The carrying values of other financial instruments included in cash and cash equivalents, receivables from related parties, other accounts receivable and prepaid expenses, and accounts payable and accrued charges approximate their fair values due to the immediate or short-term maturity of these financial instruments.

The fair value of long-term debt instruments is determined based on a conventional pricing model, which is a function of future cash flows, the current market yield curve and term to maturity. These inputs are considered Level 2 inputs.

The following tables present assets and liabilities measured at fair value in accordance with the fair value hierarchy:

	December 31, 2014			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Decommissioning Fund	**3,069**	**2,787**	**390**	**6,246**
Used Fuel Fund	**617**	**7,444**	**72**	**8,133**
Other financial instruments	**4**	**5**	**16**	**25**
Total	**3,690**	**10,236**	**478**	**14,404**
Liabilities				
Derivative embedded in the Bruce Lease	**-**	**-**	**(302)**	**(302)**
Other financial instruments	**(3)**	**(3)**	**-**	**(6)**
Total	**(3)**	**(3)**	**(302)**	**(308)**
Net assets	**3,687**	**10,233**	**176**	**14,096**

	December 31, 2013			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Decommissioning Fund	3,005	2,715	247	5,967
Used Fuel Fund	526	6,961	42	7,529
Other financial instruments	5	3	12	20
Total	3,536	9,679	301	13,516
Liabilities				
Derivative embedded in the Bruce Lease	-	-	(346)	(346)
Other financial instruments	(8)	(11)	-	(19)
Total	(8)	(11)	(346)	(365)
Net assets (liabilities)	3,528	9,668	(45)	13,151

During the year ended December 31, 2014, there were no transfers between Level 1 and Level 2. In addition, there were no transfers into and out of Level 3.

The following tables present the changes in OPG's assets and liabilities measured at fair value based on Level 3:

(millions of dollars)	**Decom-missioning Fund**	**Used Fuel Fund**	**Derivative Embedded in the Bruce Lease [1]**	**Other financial instruments**
Opening balance, January 1, 2013	163	13	(392)	13
Unrealized gains included in earnings on nuclear fixed asset removal and nuclear waste management funds [1]	18	3	-	-
Unrealized losses included in revenue	-	-	(33)	(1)
Realized losses included in revenue	(1)	-	-	(2)
Purchases	83	14	-	2
Sales	(3)	-	-	-
Settlements	(13)	12	79	-
Closing balance, December 31, 2013	247	42	(346)	12
Unrealized gains included in earnings on nuclear fixed asset removal and nuclear waste management funds [1]	**20**	**4**	**-**	**-**
Unrealized gains included in revenue	**-**	**-**	**44**	**2**
Realized gains (losses) included in revenue	**1**	**-**	**-**	**(11)**
Purchases	**148**	**28**	**-**	**13**
Sales	**(12)**	**(2)**	**-**	**-**
Settlements	**(14)**	**-**	**-**	**-**
Closing balance, December 31, 2014	**390**	**72**	**(302)**	**16**

[1] Total gains (losses) exclude the impact of the Bruce Lease Net Revenues Variance Account.

Derivative Embedded in the Bruce Lease

The revenue from the Bruce Lease is reduced in each calendar year where the expected future annual arithmetic average hourly Ontario electricity price falls below $30/MWh and certain other conditions are met. The conditional reduction to revenue in the future, embedded in the terms of the Bruce Lease, is treated as a derivative.

Due to an unobservable input used in the pricing model of the Bruce Lease embedded derivative, the measurement of the liability is classified within Level 3.

The following table presents the quantitative information about the Level 3 fair value measurement of the Bruce Lease embedded derivative as at December 31, 2014:

(millions of dollars except where noted)	**Fair Value**	**Valuation Technique**	**Unobservable Input**	**Range**
Derivative embedded in the Bruce Lease	(302)	Option model	Risk Premium [1]	0% - 30%

[1] Represents the range of premiums used in the valuation analysis that OPG has determined market participants would use when pricing the derivative.

The term related to the derivative embedded in the Bruce Lease is based on the remaining service lives, for accounting purposes, for certain units of the Bruce generating stations. As at December 31, 2014, the estimated service life, for accounting purposes, of these Bruce units is to 2019. OPG's exposure to changes in the fair value of the Bruce Lease embedded derivative is mitigated as part of the OEB regulatory process, since the revenue from the lease of the Bruce generating stations is included in the determination of regulated prices and is subject to the Bruce Lease Net Revenues Variance Account. As such, the income statement impact of changes in the derivative liability is offset by the income statement impact of the Bruce Lease Net Revenues Variance Account.

Decommissioning Fund and Used Fuel Fund

Nuclear Funds investments classified as Level 3 consist of real estate and infrastructure investments within the alternative investment portfolio. The fair value of the investments within the Nuclear Funds' alternative investment portfolio is determined using appropriate valuation techniques, such as recent arm's length market transactions, reference to current fair values of other instruments that are substantially the same, discounted cash flow analyses, third-party independent appraisals, valuation multiples, or other valuation methods. Any control, size, liquidity or other discounts or premiums on the investments are considered in the determination of fair value.

The process of valuing investments for which no published market price exists is based on inherent uncertainties and the resulting values may differ from values that would have been used had a ready market existed for the investments. The values may also differ from the prices at which the investments may be sold.

The following are the classes of investments within the Nuclear Funds that are reported on the basis of net asset value as at December 31, 2014:

(millions of dollars except where noted)	**Fair Value**	**Unfunded Commitments**	**Redemption Frequency**	**Redemption Notice**
Infrastructure	496	262	n/a	n/a
Real Estate	507	256	n/a	n/a
Pooled Funds				
Short-term Investments	18	n/a	Daily	1 - 5 Days
Fixed Income	585	n/a	Daily	1 - 5 Days
Equity	690	n/a	Daily	1 - 5 Days
Total	2,296	518		

The fair value of the above investments is classified as either Level 2 or Level 3.

<u>Infrastructure</u>

This class includes investments in funds whose investment objective is to generate a combination of long-term capital appreciation and current income generally through investments such as energy, transportation and utilities.

The fair values of investments in this class have been estimated using the Nuclear Funds' ownership interest in partners' capital and/or underlying investments held by subsidiaries of an infrastructure fund.

The investments in the respective infrastructure funds are not redeemable. However, the Nuclear Funds may transfer any of its partnership interests/shares to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Distributions from each infrastructure fund will be received based on the operations of the underlying investments and/or as the underlying investments of the infrastructure funds are liquidated. It is not possible to estimate when the underlying assets of the infrastructure funds will be liquidated. However, the infrastructure funds have a maturity end period ranging from 2019 to 2025.

<u>Real Estate</u>

This class includes investment in institutional-grade real estate property located in Canada. The investment objective is to provide a stable level of income with the opportunity for long-term capital appreciation.

The fair values of the investments in this class have been estimated using the net asset value of the Nuclear Funds' ownership interest in these investments.

The partnership investments are not redeemable. However, the Nuclear Funds may transfer any of their partnership interests to another party, as stipulated in the partnership agreement, with prior written consent of the other limited partners. For investments in private real estate corporations, shares may be redeemed through a pre-established redemption process. It is not possible to estimate when the underlying assets in this class will be liquidated.

Pooled Funds

This class represents investments in pooled funds, which primarily include a diversified portfolio of fixed income securities, issued mainly by Canadian corporations and diversified portfolios of Emerging Market listed equity. The investment objective of the pooled funds is to achieve capital appreciation and income through professionally managed portfolios.

The fair value of the investments in this class has been estimated using the net asset value per share of the investments.

There are no significant restrictions on the ability to sell investments in this class.

14. COMMON SHARES

As at December 31, 2014 and 2013, OPG had 256,300,010 common shares issued and outstanding at a stated value of $5,126 million. OPG is authorized to issue an unlimited number of common shares without nominal or par value. Any issue of new shares is subject to the consent of OPG's shareholder.

15. COMMITMENTS AND CONTINGENCIES

Litigation

Various legal proceedings are pending against OPG or its subsidiaries covering a wide range of matters that arise in the ordinary course of its business activities.

On August 9, 2006, a Notice of Action and Statement of Claim filed with the Ontario Superior Court of Justice in the amount of $500 million was served against OPG and Bruce Power L.P. by British Energy Limited and British Energy International Holdings Limited (together British Energy). The action is for contribution and indemnity of any amounts British Energy was liable for in an arbitration against it by some of the owners of Bruce Power L.P. regarding an alleged breach of British Energy's representations and warranties to the claimants when they purchased British Energy's interest in Bruce Power L.P. (the Arbitration). Both the action and the Arbitration relate to corrosion to a steam generator unit discovered after OPG leased the Bruce nuclear generating stations to Bruce Power L.P.

In 2012, the arbitrator found that British Energy was liable to the claimants for some of the damages they claimed. The final settlement amount was valued by British Energy at $71 million. In September 2014, British Energy amended its Statement of Claim (Amended Claim) to reduce the claim amount to $100 million to reflect that the purchasers of British Energy's interest in Bruce Power L.P. did not receive the full damages they originally claimed in the Arbitration. British Energy also added an allegation to its Amended Claim that OPG breached a covenant to maintain the steam generator between the time of the initial agreement to lease and the effective date of the lease in accordance with "Good Utility Practices".

Certain First Nations have commenced actions against OPG for interference with their respective reserve and traditional land rights. As well, OPG has been brought into certain actions by the First Nations against other parties as a third party defendant.

Each of these matters is subject to various uncertainties. Some of these matters may be resolved unfavourably. While it is not possible to determine the ultimate outcome of the various pending actions, it is the Company's belief that their resolution is not likely to have a material adverse impact on its financial position.

Environmental

Current operations are subject to regulation with respect to emissions to air, water, and land as well as other environmental matters by federal, provincial, and local authorities. The cost of obligations associated with current operations is provided for on an ongoing basis. Management believes it has made adequate provision in the consolidated financial statements to meet certain other environmental obligations. As at December 31, 2014, OPG's environmental liabilities were $15 million (2013 – $15 million).

Guarantees

The Company and its joint venture partners have jointly guaranteed the financial performance of jointly owned entities related primarily to the payment of liabilities. As at December 31, 2014, the total amount of guarantees OPG provided to these entities was $78 million. OPG may terminate some of these guarantees within a short time frame by providing written notice to the counterparties at any time. Other guarantees have terms ending between 2019 and 2029. As at December 31, 2014, the potential impact of the fair value of these guarantees to income has been estimated to be negligible and OPG does not expect to make any payments associated with these guarantees.

Contractual and Commercial Commitments

OPG's contractual obligations and other significant commercial commitments as at December 31, 2014, are as follows:

(millions of dollars)	**2015**	**2016**	**2017**	**2018**	**2019**	**Thereafter**	**Total**
Contractual obligations:							
Fuel supply agreements	193	172	154	134	51	109	813
Contributions under the Ontario Nuclear Funds Agreement [1]	143	150	163	193	288	2,418	3,355
Pension contributions to the OPG registered pension plan [2]	364	370	-	-	-	-	734
Long-term debt repayment	503	273	1,103	398	368	3,085	5,730
Interest on long-term debt	261	249	230	174	155	1,986	3,055
Unconditional purchase obligations	97	8	-	-	-	-	105
Operating lease obligations	16	15	15	13	12	65	136
Commitments related to Darlington Refurbishment [3]	150	-	-	-	-	-	150
Operating licence	22	23	23	18	19	-	105
Accounts payable	295	-	-	-	-	-	295
Other	125	19	14	5	60	9	232
	2,169	1,279	1,702	935	953	7,672	14,710
Significant commercial commitments:							
Lower Mattagami River project	95	-	-	-	-	-	95
Total	2,264	1,279	1,702	935	953	7,672	14,805

[1] Contributions under the Ontario Nuclear Funds Agreement (ONFA) are based on the 2012 ONFA Reference Plan contribution schedule approved in 2012.

[2] The pension contributions include ongoing funding requirements and additional funding requirements towards the deficit, in accordance with the actuarial valuation of the OPG registered pension plan as at January 1, 2014. The next actuarial valuation of the OPG registered pension plan must have an effective date no later than January 1, 2017. The pension contributions are affected by various factors including market performance, changes in actuarial assumptions, plan experience, changes in the pension regulatory environment, and the timing of funding valuations. Funding requirements after 2017 for the OPG registered pension plan are excluded due to significant variability in the assumptions required to project the timing of future cash flows. The amount of OPG's additional voluntary contribution, if any, is revisited from time to time.

[3] Estimated currently committed costs to close the project, including demobilization of project staff and cancellation of existing contracts and material orders.

Lower Mattagami

The Lower Mattagami River project increased the capacity of the four generating stations on the Lower Mattagami River by 438 MW. As of December 31, 2014, all six new units were placed in-service. The capital project expenditures for the year ended December 31, 2014 were $387 million and the life-to-date expenditures were $2.4 billion. The project budget of $2.6 billion includes the design-build contract, as well as contingencies, interest, and other OPG costs, including project management, contract management, impact agreements with First Nations, and transmission connection costs. The remaining contractual commitments for the project relate to project completion activities.

Darlington Refurbishment

As of December 31, 2014, OPG has issued contracts valued at over $2 billion related to the refurbishment of the Darlington nuclear station. Some of these contracts relate to work to be completed in the current planning phase, scheduled to end in 2015, while others are for work that will be performed in the execution phase of the project. These contracts contain suspension and termination provisions. The most significant contracts include the Retube and Feeder Replacement (RFR) contract, and the Turbine Generator contract. Significant contracts awarded to-date are as follows:

- In February 2014, OPG awarded the Turbine Generator contract for engineering integration and field installation, valued at approximately $200 million.
- In March 2013, OPG awarded the Turbine Generator contract for equipment supply and technical services, valued at approximately $350 million.
- In March 2012, OPG awarded a RFR contract, with an estimated value at over $600 million.

Capital project expenditures for 2014 were $696 million and the life-to-date capital expenditures as at December 31, 2014 were $1,462 million. A budget and schedule for the refurbishment of the four units are expected to be completed in 2015.

Lease Commitments

The Company is party to various leases for real estate and equipment under operating lease arrangements. Real estate and transport equipment base rent expense for the year ended December 31, 2014 was $11 million (2013 – $15 million).

The Company leases Bruce A and B nuclear generating stations to Bruce Power L.P. until 2018, with Bruce Power L.P. having an option to renew for up to 25 years thereafter.

As per *Ontario Regulation 53/05* pursuant to the *Ontario Energy Board Act, 1998*, the difference between OPG's revenues, including lease revenues, and costs, including depreciation expense, associated with its ownership of the Bruce A and B nuclear generating stations is included in the determination of OPG's nuclear regulated prices established by the OEB. These revenues and costs are determined on the basis of the manner in which they are recognized in OPG's consolidated financial statements. As the assets on lease to Bruce Power L.P. are not prescribed facilities under *Ontario Regulation 53/05*, the net book value of the assets is not included in the regulated rate base.

During 2014, OPG recorded lease revenue related to the Bruce generating stations of $258 million (2013 – $176 million), which included supplemental rent from Bruce Power L.P. of $207 million (2013 – $125 million). The amount of supplemental rent shown in 2013 was net of a contractually required rebate of $79 million. The net book value of property, plant and equipment on lease to Bruce Power L.P. as at December 31, 2014 was $1,755 million (2013 – $1,859 million).

Other Commitments

The Company maintains labour agreements with the Power Workers' Union (PWU) and the Society of Energy Professionals (The Society). As at December 31, 2014, OPG had approximately 9,700 regular employees and about 89 percent of its regular labour force was covered by the collective bargaining agreements. The current collective agreement between OPG and the PWU has a three-year term, which expires on March 31, 2015. The Company's current collective agreement with The Society was established through an arbitration award issued on April 8, 2013. This agreement has a three-year term, which expires on December 31, 2015. The Society filed a Judicial Review Application in the second quarter of 2013 to the Superior Court of Ontario in the matter of the arbitration award. The case was heard at Divisional Court on October 30, 2014 and a ruling was issued November 27, 2014 dismissing the Society's application. On December 11, 2014, the Society filed a motion for leave to appeal the Divisional Court ruling. The motion has been heard and a decision is expected in the next few months.

Contractual and commercial commitments as noted exclude certain purchase orders, as they represent purchase authorizations rather than legally binding contracts, and are subject to change without significant penalties.

16. BUSINESS SEGMENTS

Effective January 1, 2014, OPG revised the composition of its reportable business segments to reflect changes in its generation portfolio and internal reporting. These changes primarily reflect 48 of OPG's hydroelectric generating facilities which were prescribed for rate regulation beginning in 2014, and ending the use of coal at the Nanticoke and Lambton generating stations in 2013. OPG's reportable business segments, effective January 1, 2014, are as follows:

- Regulated – Nuclear Generation
- Regulated – Nuclear Waste Management
- Regulated – Hydroelectric
- Contracted Generation Portfolio
- Services, Trading, and Other Non-Generation.

OPG's Regulated – Nuclear Generation and Regulated – Nuclear Waste Management segments are unchanged.

Regulated – Nuclear Generation Segment

OPG's Regulated – Nuclear Generation business segment operates in Ontario, generating and selling electricity from the nuclear generating stations that it owns and operates. The business segment includes electricity generated by the Pickering and Darlington Nuclear generating stations. This business segment also includes revenue under the terms of a lease arrangement and related agreements with Bruce Power L.P. related to the Bruce Nuclear generating stations. This revenue includes lease revenue and revenue from heavy water sales and services such as detritiation. Revenue is also earned from isotope sales and ancillary services. Ancillary revenues are earned through voltage control and reactive support. Revenues under the agreements with Bruce Power and from isotope sales and ancillary services are included by the OEB in the determining of the regulated prices for OPG's nuclear facilities, which has the effect of reducing OPG's nuclear regulated prices.

Regulated – Nuclear Waste Management Segment

OPG's Regulated – Nuclear Waste Management segment engages in the management of nuclear used fuel and L&ILW, the decommissioning of OPG's nuclear generating stations (including the stations on lease to Bruce Power L.P.), the management of the Nuclear Funds, and related activities including the inspection and maintenance of the waste storage facilities. Accordingly, accretion expense on the Nuclear Liabilities and earnings from the Nuclear Funds are reported under this segment.

As the nuclear generating stations operate over time, OPG incurs variable costs related to used nuclear fuel bundles and L&ILW which increase the Nuclear Liabilities. OPG charges these variable costs to current operations in the Regulated – Nuclear Generation segment to reflect the cost of producing energy and earning revenue under the Bruce Power lease arrangement and related agreements. Since variable costs increase the Nuclear Liabilities in the Regulated – Nuclear Waste Management segment, OPG records an inter-segment charge between the Regulated – Nuclear Generation and the Regulated – Nuclear Waste Management segments. The impact of the inter-segment charge is eliminated on OPG's consolidated statements of income and balance sheets.

The Regulated – Nuclear Waste Management segment is considered regulated because the costs associated with the Nuclear Liabilities are included by the OEB in determining regulated prices for production from OPG's regulated nuclear facilities.

Regulated – Hydroelectric Segment

OPG's Regulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from most of the Company's hydroelectric generating stations. The business segment includes the results of the Sir Adam Beck 1, 2 and Pump generating station (GS), DeCew Falls 1 and 2, and the R.H. Saunders hydroelectric facilities. This segment also includes the results of the 48 newly regulated hydroelectric stations. The OEB's order, issued in December 2014, established regulated prices for these assets effective November 1, 2014. The comparative information for these 48 hydroelectric stations, previously reported under the Unregulated – Hydroelectric segment in OPG's 2013 annual MD&A and consolidated financial statements, has been reclassified to conform to this new presentation.

Contracted Generation Portfolio Segment

The Contracted Generation Portfolio business segment operates in Ontario, generating and selling electricity from the Company's generating stations that are not prescribed for rate regulation. The segment primarily includes generating facilities that are under an ESA with the IESO or other long-term contracts.

Activities of generating stations that are not currently subject to a contract or rate regulation, but are available to generate electricity for sale, if required, are also included in the Contracted Generation Portfolio segment. Since the Lambton GS and Nanticoke GS were generating electricity up to the end of 2013, the activities related to these stations for the comparative period are reported in the Contracted Generation Portfolio segment. These stations ended coal-fired operations as a result of a Shareholder declaration issued in March 2013 mandating that OPG end the use of coal at these stations by the end of 2013. Therefore, effective January 1, 2014, the activities related to the Lambton GS and Nanticoke GS are reported under the Services, Trading, and Other Non-Generation business segment. The comparative information for the unregulated generating stations, previously reported under the Unregulated – Hydroelectric and Unregulated – Thermal segments in OPG's 2013 annual MD&A and consolidated financial statements, has been reclassified to conform to this new presentation.

The Contracted Generation Portfolio segment also includes OPG's share of equity income from its 50 percent ownership interests in the PEC and Brighton Beach stations. OPG's share of the in-service generating capacity and generation volume from its interests in the PEC and Brighton Beach stations are also included in this segment.

Services, Trading, and Other Non-Generation Segment

The Services, Trading, and Other Non-Generation segment is a non-generation segment that is not subject to rate regulation. It includes the revenue and expenses related to OPG's trading and other non-hedging activities. As part of these activities, OPG transacts with counterparties in Ontario and neighbouring energy markets in predominantly short-term trading activities of typically one year or less in duration. These activities relate to electricity that is purchased and sold at the Ontario border, financial energy trades, sales of financial risk management products, and sales of energy-related products. In addition, OPG has a wholly owned trading subsidiary that transacts solely in the United States market. All contracts that are not designated as hedges are recorded as assets or liabilities at fair value, with changes in fair value recorded in the revenue of this segment. In addition, this segment includes revenue from real estate rentals and other unregulated service revenues. The above activities were previously reported in the Other category.

OM&A expenses of the generation business segments include an inter-segment service fee for the use of certain property, plant and equipment, and intangible assets held within the Services, Trading and Other Non-Generation segment. The total service fee is recorded as a reduction to the segment's OM&A expenses.

The service fee included in OM&A expenses by segment in 2014 and 2013 was as follows:

(millions of dollars)	**2014**	**2013** *(adjusted)*
Regulated – Nuclear Generation	**23**	23
Regulated – Hydroelectric	**6**	4
Contracted Generation Portfolio	**3**	6
Services, Trading, and Other Non-Generation	**(32)**	(33)

Information for the comparative period has been adjusted to reflect the changes to OPG's reportable business segments and is labeled "adjusted".

Segment Income (Loss) for the Year Ended December 31, 2014 *(millions of dollars)*	**Regulated** **Nuclear Generation**	**Nuclear Waste Management**	**Hydroelectric**	**Unregulated** **Contracted Generation Portfolio**	**Services, Trading, and Other Non-Generation**	**Elimination**	**Total**
Revenue	**3,015**	**121**	**1,417**	**329**	**197**	**(116)**	**4,963**
Fuel expense	**258**	**-**	**343**	**37**	**3**	**-**	**641**
Gross margin	**2,757**	**121**	**1,074**	**292**	**194**	**(116)**	**4,322**
Operations, maintenance and administration	**1,983**	**129**	**325**	**175**	**119**	**(116)**	**2,615**
Depreciation and amortization	**529**	**-**	**167**	**38**	**20**	**-**	**754**
Accretion on fixed asset removal and nuclear waste management liabilities	**-**	**782**	**-**	**8**	**7**	**-**	**797**
Earnings on nuclear fixed asset removal and nuclear waste management funds	**-**	**(714)**	**-**	**-**	**-**	**-**	**(714)**
Regulatory disallowance related to the Niagara Tunnel project	**-**	**-**	**77**	**-**	**-**	**-**	**77**
Income from investments subject to significant influence	**-**	**-**	**-**	**(41)**	**-**	**-**	**(41)**
Property taxes	**28**	**-**	**1**	**(1)**	**4**	**-**	**32**
Restructuring	**-**	**-**	**-**	**8**	**10**	**-**	**18**
Other loss (income)	**-**	**-**	**2**	**(6)**	**1**	**-**	**(3)**
Income (loss) before interest, income taxes, and extraordinary item	**217**	**(76)**	**502**	**111**	**33**	**-**	**787**

Segment (Loss) Income for the Year Ended December 31, 2013 *(millions of dollars)* *(adjusted)*	**Regulated**			**Unregulated**			
	Nuclear Generation	**Nuclear Waste Manage-ment**	**Hydro-electric**	**Contracted Generation Portfolio**	**Services, Trading, and Other Non-Generation**	**Elimination**	**Total**
Revenue	2,889	113	1,236	657	77	(109)	4,863
Fuel expense	237	-	344	127	-	-	708
Gross margin	2,652	113	892	530	77	(109)	4,155
Operations, maintenance and administration	2,022	121	298	408	7	(109)	2,747
Depreciation and amortization	626	-	186	132	19	-	963
Accretion on fixed asset removal and nuclear waste management liabilities	-	742	-	14	-	-	756
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(628)	-	-	-	-	(628)
Income from investments subject to significant influence	-	-	-	(35)	-	-	(35)
Property taxes	29	-	(1)	14	11	-	53
Restructuring	-	-	-	50	-	-	50
Other loss (income)	(1)	-	4	(4)	(2)	-	(3)
(Loss) income before interest, income taxes, and extraordinary items	(24)	(122)	405	(49)	42	-	252

Selected Consolidated Balance Sheet Information as at December 31, 2014 *(millions of dollars)*	**Nuclear Generation**	**Regulated Nuclear Waste Manage-ment**	**Hydro-electric**	**Unregulated Contracted Generation Portfolio**	**Services, Trading, and Other Non-Generation**	**Total**
Segment property, plant and equipment in-service, net	**4,679**	**-**	**7,483**	**3,267**	**338**	**15,767**
Segment construction in progress	**1,655**	**-**	**86**	**35**	**50**	**1,826**
Segment property, plant and equipment, net	**6,334**	**-**	**7,569**	**3,302**	**388**	**17,593**
Segment intangible assets in-service, net	**11**	**-**	**1**	**4**	**14**	**30**
Segment development in progress	**2**	**-**	**1**	**-**	**43**	**46**
Segment intangible assets, net	**13**	**-**	**2**	**4**	**57**	**76**
Segment fuel inventory	**298**	**-**	**-**	**36**	**-**	**334**
Segment materials and supplies inventory, net:						
Current	**93**	**-**	**-**	**1**	**-**	**94**
Long-term	**332**	**-**	**1**	**5**	**-**	**338**
Nuclear fixed asset removal and nuclear waste management funds (current and non-current portions)	**-**	**14,379**	**-**	**-**	**-**	**14,379**
Fixed asset removal and nuclear waste management liabilities	**-**	**(16,663)**	**-**	**(333)**	**(32)**	**(17,028)**

Selected Consolidated Balance Sheet Information as at December 31, 2013 *(millions of dollars)* *(adjusted)*	**Regulated**			**Unregulated**		
	Nuclear Generation	**Nuclear Waste Manage-ment**	**Hydro-electric**	**Contracted Generation Portfolio**	**Services, Trading, and Other Non-Generation**	**Total**
Segment property, plant and equipment in-service, net	4,864	-	7,624	921	189	13,598
Segment construction in progress	866	-	81	2,150	43	3,140
Segment property, plant and equipment, net	5,730	-	7,705	3,071	232	16,738
Segment intangible assets in-service, net	15	-	1	4	17	37
Segment development in progress	2	-	-	-	20	22
Segment intangible assets, net	17	-	1	4	37	59
Segment fuel inventory	334	-	-	56	-	390
Segment materials and supplies inventory, net:						
Current	94	-	-	1	-	95
Long-term	322	-	1	7	-	330
Nuclear fixed asset removal and nuclear waste management funds (current and non-current portions)	-	13,496	-	-	-	13,496
Fixed asset removal and nuclear waste management liabilities	-	(15,903)	-	(322)	(32)	(16,257)

Selected Consolidated Cash Flow Information *(millions of dollars)*	**Regulated**			**Unregulated**		
	Nuclear Generation	**Nuclear Waste Management**	**Hydro-electric**	**Contracted Generation Portfolio**	**Services, Trading, and Other Non-Generation**	**Total**
Year ended December 31, 2014 Investment in property, plant and equipment, and intangible assets	**991**	**-**	**84**	**423**	**47**	**1,545**
Year ended December 31, 2013 *(adjusted)* Investment in property, plant and equipment, and intangible assets	633	-	172	724	39	1,568

17. NET CHANGES IN NON-CASH WORKING CAPITAL BALANCES

(millions of dollars)	**2014**	**2013**
Receivables from related parties	**(80)**	40
Other accounts receivable and prepaid expenses	**15**	(21)
Fuel inventory	**56**	115
Income taxes payable/recoverable	**75**	12
Materials and supplies	**1**	(5)
Accounts payable and accrued charges	**145**	98
	212	239

18. RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and successor entities of Ontario Hydro, including Hydro One Inc. (Hydro One), the IESO, and the OEFC, and jointly controlled entities. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

These transactions for the years ended December 31 are summarized below:

	2014		**2013**	
(millions of dollars)	**Revenue**	**Expenses**	**Revenue**	**Expenses**
Hydro One				
Electricity sales	**23**	**-**	15	-
Services	**1**	**13**	-	14
Province of Ontario				
Decommissioning Fund excess funding	**-**	**476**	-	560
Used Fuel Fund rate of return guarantee	**-**	**439**	-	755
Gross revenue charges	**-**	**123**	-	124
ONFA guarantee fee	**-**	**8**	-	8
Pension benefits guarantee fee	**-**	**2**	-	1
OEFC				
Gross revenue charges	**-**	**209**	-	208
Interest expense on long-term notes	**-**	**187**	-	187
Income taxes, net of investment tax credits	**-**	**136**	-	28
Contingency support agreement	**83**	**-**	360	-
Capital tax	**-**	**-**	-	1
IESO				
Electricity related revenue	**4,305**	**75**	4,015	62
	4,412	**1,668**	4,390	1,948

The receivable and payable balances, as at December 31, between OPG and its related parties are summarized below:

(millions of dollars)	**2014**	**2013**
Receivables from related parties		
Hydro One	**1**	2
IESO	**468**	331
OEFC	**10**	67
PEC	**3**	2
Accounts payable and accrued charges		
Hydro One	**8**	3
OEFC	**63**	65
Province of Ontario	**3**	2

19. INVESTMENTS SUBJECT TO SIGNIFICANT INFLUENCE

Investments subject to significant influence consist of OPG's 50 percent ownership interest in the jointly controlled entities of PEC and Brighton Beach, which are accounted for using the equity method as described in Note 3. Details of the balance included in the consolidated balance sheets as at December 31 are as follows:

(millions of dollars)	**2014**	**2013**
PEC		
Current assets	**15**	19
Long-term assets	**287**	303
Current liabilities	**(5)**	(15)
Long-term liabilities	**(4)**	(4)
Brighton Beach		
Current assets	**6**	5
Long-term assets	**186**	196
Current liabilities	**(13)**	(11)
Long-term liabilities	**(6)**	(5)
Long-term debt	**(118)**	(129)
Investments subject to significant influence	**348**	359

20. RESEARCH AND DEVELOPMENT

For the year ended December 31, 2014, research and development expenses of $84 million (2013 – $104 million) were charged to operations.

21. RESTRUCTURING

In response to the Ministry of Energy's Long-Term Energy Plan, Supply Mix Directive and various other directives, OPG has been undertaking restructuring activities since 2011 pertaining to the closure of its coal-fired generating units at the Lambton GS, Nanticoke GS, Atikokan GS and Thunder Bay GS. These activities have an impact on staff requirements and require OPG to record the corresponding restructuring costs.

In December 2013, the Minister of Energy issued a Directive to the former OPA to negotiate and enter into a contract for electricity from one unit at the Thunder Bay GS using advanced biomass fuel. The resulting impact on staff requirements has been finalized during 2014. The total severance costs related to the Thunder Bay GS are estimated to be $8 million and were recorded during the second and third quarters of 2014. Additional severance costs of $4 million related to the Lambton and Nanticoke generating stations were also recorded during 2014. Relocation costs of $6 million were recorded as incurred during 2014.

OPG conducted discussions with key stakeholders, including The Society and the PWU, in accordance with their respective collective bargaining agreements, at all plants impacted to date by the regulation requiring the cessation of coal-fired electricity generation. Given collective agreement provisions allowing deferral of severance payout to future periods, the restructuring liability is expected to be fully drawn down by 2017.

The change in the restructuring liability during 2014 and 2013 is as follows:

(millions of dollars)	
Liability, beginning of year	3
Restructuring charges during the year	50
Payments during the year	(13)
Liability, December 31, 2013	40
Restructuring charges during the year	**18**
Payments during the year	**(41)**
Liability, end of year	**17**

22. NON-CONTROLLING INTEREST

Lower Mattagami Limited Partnership (LMLP) is an Ontario limited partnership between OPG, Amisk-oo-Skow Finance Corporation (AFC), a corporation wholly owned by the Moose Cree First Nation, and LM Extension Inc., a wholly owned subsidiary of OPG. The principal business of LMLP is the development, construction, ownership, operation and maintenance of hydroelectric generating facilities located on the Lower Mattagami River. As incremental units are placed in-service, the AFC may acquire up to a 25 percent interest in the assets through its investment in LMLP.

During 2014, all six new units constructed as part of the Lower Mattagami River project were declared in-service. Subsequent to the units' in-service dates, the AFC made contributions of $141 million to acquire their equity interest in LMLP, through the settlement of existing liabilities, including long-term debt. As of December 31, 2014, the AFC had a 25 percent interest in LMLP. OPG consolidates the results of LMLP in its consolidated financial statements and the non-controlling interest represents the AFC's equity interest in LMLP.

AMPCO Interrogatory #006

Interrogatory

Reference(s):

a) Please provide the % total increase to the hydroelectric and nuclear payment amounts as a result of this application and show the calculation.

b) Please provide the % increase on a typical monthly bill as a result of this application.

Response

a) The per cent total increase in hydroelectric and nuclear payment amounts can be found in Ex. H1-1-2, Table 18, Lines 1,2,3, and 12 of column (c). The accompanying notes describe the calculations.

b) The per cent increase on a typical monthly bill as a result of this application can be found in Ex. H1-1-2, Table 17, Line 5 of column (a).

CCC Interrogatory #002

Interrogatory

Reference(s):
Ex. H1/T1/S1/p. 7

Please provide a detailed explanation as to how the amounts in the Hydroelectric Surplus Baseload Generation Variance Account are calculated.

Response

The December 31, 2014 balance in the Hydroelectric Surplus Baseload Generation Variance Account is comprised of the 2013 balance, year-to-date additions, and interest.

The method of calculating additions to this account is described in Ex. H-1-3-1, Attachment 1 at pages 7 and 8. In summary, the additions to the variance account are the revenues related to actual forgone production due to surplus baseload generation ("SBG") conditions less gross revenue charge ("GRC") and water rental costs related to actual forgone production due to SBG conditions. The revenue and GRC/water rental components are calculated monthly. The revenue component is the actual foregone production due to SBG conditions (in MWh) multiplied by the OEB-approved payment amount (in $/MWh). The GRC/water rental component is the same actual foregone production due to SBG conditions multiplied by the GRC / water rental rate to determine the related costs. Please refer to Ex. H1-1-2 Table 5 for the numerical details of the actual 2014 variance account additions.

The method of determining the actual foregone production due to SBG conditions (in MWh), was described in detail in EB-2013-0321 Ex. L-5.4-17 SEC-070.

The interest is calculated monthly by applying the OEB-prescribed interest rate to the opening balance of the variance account from the previous month.

CCC Interrogatory #003

Interrogatory

Reference(s):
EX. H1/T1/S1/p. 9

With respect to the Tax Loss Variance Account what is the rationale for transferring the remaining balances to the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account and the Nuclear Deferral and Variance Over/Under Recovery Variance Account? Why is OPG not proposing to clear those amounts?

Response

Transferring the remaining balances in the Tax Loss Variance Account to the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account and the Nuclear Deferral and Variance Over/Under Recovery Variance Account is required under the EB-2013-0321 Payment Amounts Order (Appendix G, p. 5).

> *OPG shall continue to record only interest and amortization in the Tax Loss Variance Account during the period from November 1, 2014 to December 31, 2014. The previously regulated hydroelectric and nuclear balances remaining in this account at December 31, 2014 shall be transferred to the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account and the Nuclear Deferral and Variance Over/Under Recovery Variance Account, respectively. Following this transfer, the Tax Loss Variance Account shall be terminated on December 31, 2014.*

CCC Interrogatory #004

Interrogatory

Reference(s):
H1/T1/S1/p. 10

The evidence indicates that the Capacity Refurbishment Variance Account was established to record variances between the actual capital and non-capital costs incurred to increase the output of, refurbish or add operating capacity to a prescribed facility and those costs reflected in the approved revenue requirement. With respect to the Niagara Tunnel Project, if OPG is seeking recovery of all of the capital costs associated with the project, do ratepayers get the benefit of all the increased revenues associated with these costs? If not, why not? What are the increased revenues in each year associated with the Niagara Tunnel Project?

Response

As the question notes, the Capacity Refurbishment Variance Account only records variances between actual and forecast costs, it does not include revenue variances. However, the principle benefit that ratepayers receive from the Niagara Tunnel Project is the incremental generation produced by the project.

OPG estimates the incremental net revenues attributable to the Niagara Tunnel Project to be $9.9M from March through December, 2013 and $8.0M from January through October, 2014.

CCC Interrogatory #005

Interrogatory

Reference(s):
Ex. H1/T1/S2/p. 4

Please explain the extent to which OPG can control the amount of ancillary services net revenue it receives. Does OPG have incentives in place to increase ancillary service revenues? If not, why not? Please explain the nature of the "newly negotiated contract with the IESO", and the reason why this contract has resulted in higher regulation service revenues.

Response

OPG cannot control the revenues earned for the provision of the four types of ancillary services: black start capability, operating reserve, reactive support/voltage control and regulation service. The demand for these four ancillary services is determined solely by the IESO based on prevailing power system conditions and reliability standards.

The prices paid for black start capability, reactive support/voltage control and regulation service are based on contracts between individual market participants and the IESO. For OPG, the contract prices for these ancillary services are based on OPG's cost to supply these services. More information can be found on the IESO website here:
http://www.ieso.ca/Pages/Participate/Markets-and-Programs/Procurement-Market.aspx

The price for operating reserve is determined in the IESO's real-time operating reserve market that functions parallel to, and in a similar manner as, the real time energy market. Since the price for operating reserve is established through competitive forces, operating reserve prices are outside of OPG's control. More information can be found on the IESO website here:
http://www.ieso.ca/Pages/Participate/Markets-and-Programs/Operating-Reserve-Markets.aspx

There are no incentives for OPG to increase ancillary services net revenue as OPG cannot control either the IESO's demand for ancillary services or the price paid for these services and all ancillary services net revenues are returned to ratepayers.

The higher regulation service revenues in November and December 2014 are the result of i) higher operating reserve prices; and, ii) a new regulation service contract in effect November 1, 2014 which contains higher fixed payments.

CCC Interrogatory #006

Interrogatory

Reference(s):
Ex. H1/T1/S2/p. 21

Please explain why the proposed amortization of the Pickering Life Extension Depreciation Variance Account is to 2016.

Response

Please see response to Ex. L A-LPMA-001.

CCC Interrogatory #007

Interrogatory

Reference(s):
Ex. H1/T1/S2/Table 1

With respect to the 2012 to 2014 Variance Accounts, which record interest and which do not. For those that do not record interest please explain why.

Response

The following deferral and variance accounts do not record interest as specified in the EB-2013-0321 Payment Amounts Order Appendix G:

1. Pension and OPEB Cost Variance Account effective November 1, 2014
2. Nuclear Liability Deferral Account
3. Bruce Lease Net Revenues Variance Account for the period from November 1, 2014 to December 31, 2014
4. Pickering Life Extension Depreciation Variance Account effective November 1, 2014
5. Pension and OPEB Cash Versus Accrual Differential Deferral Account

The following deferral and variance accounts do not record interest as specified in the EB-2012-0002 Payment Amounts Order Appendix B:

1. Pension and OPEB Cost Variance Account in respect of the Future Recovery component during the period from January 1, 2013 to December 31, 2014
2. Nuclear Liability Deferral Account effective January 1, 2013
3. Bruce Lease Net Revenues Variance Account for the period from January 1, 2013 to December 31, 2014
4. Pickering Life Extension Depreciation Variance Account

Except where directed otherwise by the Board, OPG records interest on the balances in all deferral and variance accounts using the interest rates set by the Board from time to time pursuant to the Board’s interest rate policy (EB-2013-0321 Payment Amounts Order, Appendix G, p.15).

CCC Interrogatory #008

Interrogatory

Reference(s):
H1/T2/S1/p. 1

With respect to the Pension and OPEB Cash Versus Accrual Differential Deferral Account and the Pension and OPEB Cash Payment Variance Account OPG is proposing to deal with these in a future proceeding. What process does OPG expect to follow with respect to these accounts? What is the estimated customer impact associated with the clearance of these accounts?

Response

OPG expects that the process for addressing these accounts would depend on the results of the OEB's proposed generic hearing on the recovery of pension and OPEBs in regulated rates. The timing of this generic hearing is not known at this time.

The estimated customer impact associated with the future clearance of these accounts would depend on the balance to be recovered and the amortization period determined at the time.

Based on the December 31, 2014 balance in these accounts, and assuming an 18 month amortization period, the typical residential customer impact is estimated to be $0.13 per month, in addition to the impact of OPG's proposed account clearance.

CME Interrogatory #001

Interrogatory

Reference(s):
Exhibit HI, Tab 1, Schedule 2, Table 5

Hydroelectric Surplus Baseload Generation Variance Account

Note 1 to Table 5 states that OPG's spill reporting methodology has undergone a "refinement". CME would like to better understand the nature of that refinement.

a) Board Staff IR No.4 requests that OPG explain further the spill reporting refinement. In answering Board Staff IR No.4, please ensure that you identify the drivers for the refinement, and the material changes which have occurred; and

b) Please identify the amount that would be recorded in the Hydroelectric Surplus Baseload Generation Variance Account if that "refinement" to the spill reporting methodology was not implemented.

Response

a) Please refer to Ex. L H-Staff-004 part c).

b) The December 31, 2014 balance of the Hydroelectric Surplus Baseload Generation Variance Account would be approximately $66.5M compared to $67.1M, which is approximately $0.65M lower if the refinement was not applied in calculating the 2013 foregone production.

CME Interrogatory #002

Interrogatory

Reference(s):
Exhibit HI, Tab 2, Schedule 1, page 4 of 5
Pension and OP EB Cost Variance Account - Post 2012 Additions

OPG proposes that the Pension and OPEB Cost Variance Account - Post 2012 Additions be amortized over 24 months commencing July 1, 2015. Please provide a more detailed explanation for the reasons why this variance account should be amortized over 24 months instead of the 18 months.

Response

OPG has proposed a longer amortization period (24 months) for the Pension and OPEB Cost Variance Account in recognition of the larger balance in this account. The longer amortization period balances OPG's desire to recover these past amounts as quickly as possible with a concern over customer impacts.

CME Interrogatory #003

Interrogatory

Reference(s):
Exhibit H1, Tab 2, Schedule 2, page 1 of 5
Pension and OPEB Cash Versus Actual Differential Deferral Account and the Pension and OPEB Cash Payment Variance Account

OPG states that it will bring forward the Pension and OPEB Cash Versus Actual Differential Deferral Account and the Pension and OPEB Cash Payment Variance Account in a future application. Please provide a more detailed explanation as to why clearance of these deferral and variance accounts are to be dealt with in a future application instead of this application.

Response

Please see response to Ex. L H-LPMA-002.

Energy Probe Interrogatory #001

Interrogatory

Reference(s):
Exhibit – H1, T1, Sch. 1/p.1+ and related tables
Exhibit – I1, T1, Sch. 1/p.1 and related tables

Would the Board's decision in EB-2014-0369 have any impact on any figures or amounts shown in this Application? If so, please indicate what changes would be needed.

Response

No, there would be no impact.

If some, or all, of the Niagara Tunnel Project disallowance and 2013 tax loss adjustment is reversed as part of EB-2014-0369, then the impacts of this reversal would be accounted for in 2015, as required by USGAAP (assuming that the EB-2014-0369 decision is rendered in 2015). Accordingly, there would be no impact on the current application which seeks to clear balances as at December 31, 2014.

In its EB-2014-0369 Motion, OPG has proposed that the OEB establish a new deferral account to record the impact of the Board's decision on the motion.

Energy Probe Interrogatory #002

Interrogatory

Reference(s):
Exhibit – H1, T1, Sch. 1/p.1+

Please indicate what payment amounts OPG received for the newly regulated hydroelectric facilities from the date on which Board regulation commenced for those facilities (July 1,2014) to the day before the effective date for the final payment amounts (November 1, 2014) for those facilities.

Response

In its EB-2013-0321 Decision with Reasons at page 137, the OEB stated that, “From July 1, 2014 through October 31, 2014 the Board has determined that the payment amounts for the newly regulated hydroelectric facilities will remain HOEP, which is the amount that OPG actually recovered over that time period pursuant to the Board’s interim rate order.”

The actual amount received by OPG for the production from these facilities for the July 1, 2014 to October 31, 2014 period was $66.6M. Production over this period was 3.3 TWh, yielding an average payment of $19.9/MWh.

LPMA Interrogatory #002

Interrogatory

Reference(s):
Exhibit H1, Tab 1, Schedule 1

a) Please explain fully why OPG is not proposing to dispose of the three newly created accounts in EB-2013-0321 as noted at the bottom of page 2.

b) Please provide the balance in each of these accounts as of December 31, 2014.

Response

a) OPG's reasons for not proposing to dispose of balances in the three newly created accounts are set out below:
   i. Gross Revenue Charge Variance Account – the December 31, 2014 balance in this account is nil;
   ii. Pension and OPEB Cash Payment Variance Account – OPG believes that the disposition of the balance in this account should await the OEB's planned generic hearing on the recovery of pension and OPEB's in regulated rates; and,
   iii. Pension and OPEB Cash Versus Accrual Deferral Account – same as (ii).

b) The December 31, 2014 balances in these accounts are set out in Ex. H1-1-2, Table 1, lines 8, 12, 13 and 30, 31.

LPMA Interrogatory #003

Interrogatory

Reference(s):
Exhibit H1, Tab 1, Schedule 2, Tables 1a, 1b and 1c

a) Please add a column to Table 1a that identifies each account as having their December 31, 2013 balance cleared through rate riders as determined in previous proceedings, and accounts that were not proposed for the clearance of their December 31, 2013 balances.

b) Please add a column to each of Tables 1b and 1c that shows the interest accrued in 2014 for each of the accounts identified in part (a) above that were not proposed for the clearance of the balances at December 31, 2013.

Response

a) Two additional columns have been added to Table 1a in Attachment 1. Column (i) indicates whether or not there was account clearance activity during 2013 and 2014 via the riders set in EB-2012-0002. Column (j) indicates whether or not accounts were proposed for clearance in EB-2013-0321.

b) Interest accrued in 2014 for the December 31, 2013 balances which were not proposed for clearance in EB-2013-0321 (per col. (j) from Attachment 1, Table 1a) is found in Ex. H1-1-2 Tables 1b and 1c, col. (d). Interest was recorded in these accounts pursuant to the EB-2012-0002 Payment Amounts Order for the period January 1, 2014 to October 31, 2014 and in accordance with the EB-2013-0321 Payment Amounts Order thereafter.[1] The interest recorded during 2014 includes interest on the remaining unamortized December 31, 2012 account balances approved in EB-2012-0002, as well as additions recorded in the accounts in 2013 and 2014.

[1] As proposed in its September 16, 2013 letter to the OEB, OPG also recorded a $0.1M interest credit in the Bruce Lease Net Revenues Variance Account – Derivative Sub-Account (Ex. H1-1-2 Table 1c, line 22, col. (d)) in 2014 as a result of an inadvertent error in OPG's EB-2012-0002 calculation of the amortization of the account balance, as discussed in Ex. H1-1-1, p. 20, lines 14-20.

Numbers may not add due to rounding.

Table 1a
(Recast of Ex. H1-1-2 Table 1a per H-LPMA-003, Part a)
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]	Rider in Place From EB-2012-0002?[8]	Proposed for Clearance in EB-2013-0321?
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Previously Regulated Hydroelectric:										
1	**Hydroelectric Water Conditions Variance**	17.1	0.0	17.1	15.2	(10.3)	0.4	0.0	22.4	Yes	No
2	**Ancillary Services Net Revenue Variance - Hydroelectric**	34.0	0.0	34.0	1.8	(20.4)	0.4	0.0	15.8	Yes	No
3	**Hydroelectric Incentive Mechanism Variance**	(2.4)	0.0	(2.4)	(2.5)	0.0	(0.0)	0.0	(5.0)	No	Yes
4	**Hydroelectric Surplus Baseload Generation Variance**	4.1	0.0	4.1	14.9	0.0	0.1	0.0	19.2	No	Yes
5	**Income and Other Taxes Variance - Hydroelectric**	(2.5)	0.0	(2.5)	(0.1)	1.5	(0.0)	0.0	(1.1)	Yes	No
6	**Tax Loss Variance - Hydroelectric**	48.2	0.0	48.2	0.0	(28.9)	0.5	0.0	19.7	Yes	No
7	**Capacity Refurbishment Variance - Hydroelectric**	1.1	0.0	1.1	111.1	0.0	0.5	0.0	112.7	No	Yes
8	**Pension and OPEB Cost Variance - Hydroelectric - Historic**	2.5	0.0	2.5	0.0	(1.5)	0.0	0.0	1.0	Yes	No
9	**Pension and OPEB Cost Variance - Hydroelectric - Future**	12.6	0.0	12.6	0.0	(1.3)	0.0	0.0	11.3	Yes	No
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	N/A	No
11	**Impact for USGAAP Deferral - Hydroelectric**	2.8	0.0	2.8	0.0	(1.7)	0.0	0.0	1.2	Yes	No
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	Yes	No
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	Yes	No
15	**Nuclear Development Variance**	30.2	0.0	30.2	25.6	0.0	0.7	0.0	56.5	No	Yes
16	**Ancillary Services Net Revenue Variance - Nuclear**	1.7	0.0	1.7	1.2	(1.0)	0.0	0.0	1.9	Yes	No
17	**Capacity Refurbishment Variance - Nuclear - Capital Portion**	1.3	0.0	1.3	4.3	0.0	0.0	0.0	5.7	No	Yes
18	**Capacity Refurbishment Variance - Nuclear - Non-Capital Portion**	11.8	0.0	11.8	4.0	(7.1)	0.1	0.0	8.9	Yes	No
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	Yes	No
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	Yes	No
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	N/A	No
22	**Income and Other Taxes Variance - Nuclear**	(32.5)	0.0	(32.5)	(4.5)	19.5	(0.3)	0.0	(17.9)	Yes	No
23	**Tax Loss Variance - Nuclear**	253.3	0.0	253.3	0.0	(152.0)	2.5	0.0	103.8	Yes	No
24	**Pension and OPEB Cost Variance - Nuclear - Historic**	51.5	0.0	51.5	0.0	(31.4)	0.5	0.0	20.7	Yes	No
25	**Pension and OPEB Cost Variance - Nuclear - Future**	257.6	0.0	257.6	0.0	(25.8)	0.0	0.0	231.8	Yes	No
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	N/A	No
27	**Impact for USGAAP Deferral - Nuclear**	60.3	0.0	60.3	0.0	(36.2)	0.6	0.0	24.7	Yes	No
28	**Pickering Life Extension Depreciation Variance**[7]	N/A	N/A	N/A	(46.8)	56.3	0.0	0.0	9.5	Yes	No
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	Yes	No
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 previously 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.

8 "N/A" indicates account balance did not exist at the time of EB-2012-0002.

PWU Interrogatory #001

Interrogatory

Reference(s):
(a): Exh, H1-1-2, Table 1 (Updated version of Ex H-1-1 , Table 1). Summary of Deferral and Variance Accounts:

> The Reference indicates that the deferral and variance account total balance has increased from $1,267.1 million as at year-end 2012 to $1,979.9 million as at year-end 2014.

(b): Board Decision and Order in EB-2013-0321, page 134:

> In this Decision the Board determined that the effective date for the payment amounts for the nuclear and previously regulated hydroelectric facilities would be November 1, 2014 and not January 1, 2014 that was requested by OPG.

a) Please confirm if the increase of the total balance of the deferral and variance accounts indicated in Ref (a) is partly attributable to the Board's Decision with respect to the effective date of payment amounts indicated in Ref (b).

b) If confirmed, what is the increase in the total balance of the deferral and variance accounts in Ref (a) that is attributable to the Board's Decision in Ref (b)

c) Please identify the variance and deferral accounts and their respective amounts where the 2014 year-end balance shown in Table 1 in Ref (a) would have been materially different had OPG's 2014/2015 payment amounts in EB-2013-0321 been approved effective as at January 1, 2014, as requested by OPG.

Response

a) Confirmed.

b) The increase in the account balances attributable to the Board's decision on timing is approximately $380M. The hypothetical balances for all of OPG's deferral and variance accounts as at December 31, 2014 would have totalled approximately $1.6B, assuming an effective date of January 1, 2014 for the payment amounts for the previously regulated hydroelectric and nuclear assets and November 1, 2014 for the newly regulated hydroelectric assets.

c) Accounts whose balances would have been materially different assuming an effective date of January 1, 2014 for the payment amounts of previously regulated hydroelectric and nuclear assets and November 1, 2014 for the newly regulated hydroelectric assets are listed in the attached table along with a comparison of the actual and hypothetical balances.

Numbers may not add due to rounding.

Table 1
Summary of Hypothetical Deferral and Variance Account Balances with Material Variance from Actual Balances ($M)

Line No.	Account	Actual Year End 2014 Balance (Nov 1, 2014 effective date)[1]	Hypothetical Year End 2014 Balance (Jan 1, 2014 effective date)[2]	Difference (b) - (a)
		(a)	(b)	(c)
1	**Pension and OPEB Cost Variance - Post 2012 Additions (Hydroelectric & Nuclear)**	714.0	403	(311)
2	**Capacity Refurbishment Variance - Hydroelectric**	232.6	115	(118)
3	**Nuclear Liability Deferral**	285.7	204	(82)
4	**Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - Post 2012 Additions**	123.8	44	(80)
5	**Pickering Life Extension Depreciation Variance**	7.8	47	39
6	**Pension & OPEB Cash Versus Accrual Differential Deferral (Hydroelectric & Nuclear)**	36.0	227	191

Notes:
1 From Ex. H1-1-2 Table 1 col. (d).
2 Assuming a November 1, 2014 effective date for the newly regulated hydroelectric assets.

PWU Interrogatory #002

Interrogatory

Reference(s):
Exh, H 1-2-1, page 1

The Ref. states:

2.0 SUMMARY

OPG is requesting recovery of the audited December 31, 2014 balances in all deferral and variance accounts, except for the Pension and OPEB Cash Versus Accrual Differential Deferral Account and Pension and OPEB Cash Payment Variance Account, adjusted for amounts previously approved for recovery in 2015.

OPG will bring forward the Pension and OPEB Cash Versus Accrual Differential Deferral Account and Pension and OPEB Cash Payment Variance Account in a future application.

a) Please explain why OPG is not seeking recovery of the audited December 31, 2014 balance for the Pension and OPEB Cash Payment Variance Account.

Response

Please see response to Ex. L H-LPMA-002.

PWU Interrogatory #003

Interrogatory

Reference(s):

a) Board Staff Interrogatory H-Staff-10

b) EB-2013-0321, Undertaking J9.6 Attachment. Actuarial Valuation as at January 1, 2014, Ontario Power Generation Inc. Pension Plan, June 2014. Page 26.

The special payments are payments required to liquidate the unfunded liability and/or solvency deficiency:

The going concern special payments are payments required to liquidate the unfunded liability, with interest at the going concern valuation discount rate, by equal monthly installments over a period of 15 years beginning no later than 12 months from the valuation date of the report in which the going concern unfunded liability was determined;

a) Please confirm that the ability to make special payments to liquidate the going concern unfunded liability over a period of 15 years is a requirement under the Pension Benefits Act.

b) Please explain OPG's understanding of and the appropriateness or relevance of using 15 years over which OPG is able to make special payments to liquidate the going concern unfunded liability as the basis of the amortization period to be used by OPG for the recovery of the balances of the Pension and OPEB Cost Variance Account - Post 2012 Additions.

c) Please discuss the impact on the future solvency of OPG's pension plan of recovering the balances of the Pension and OPEB Cost Variance Account – Post 2012 Additions on the basis of:

i. The expected average remaining service life (EARS)
ii. The 15 years period cited above

Response

a) OPG confirms that it is required to make special payments toward the going concern unfunded liability over a period of up to 15 years pursuant to the *Pension Benefits Act* (Ontario).

b) Please see OPG's response to L-H-Staff-010.

c) OPG is committed to making at least the minimum required contributions to its registered pension plan as required by the *Pension Benefits Act* (Ontario). OPG funds these contributions from operating cash flow. An extended recovery period for the over $700M balance of the Pension and OPEB Cost Recovery Variance Account – Post 2012 Additions would significantly reduce OPG's operating cash flow. A shortfall in the operating cash flow could lead to additional borrowing.

Board Staff Interrogatory #016

Interrogatory

Reference(s):
Decision with Reasons, EB-2013-0321, page 125
Exh I1-1-2 Table 1 and Table 2

The EB-2013-0321 Decision with Reasons states:

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

The EB-2013-0321 application consumer bill impact was $5.31/month and the associated increase in payment amounts was 23.4% (Exh N2 of EB-2013-0321). The impact of the EB-2013-0321 Decision with Reasons was a consumer bill impact of $2.53/month and an 11.1% increase in payment amounts.

Please determine the consumer dollar increase and bill impact percentage of EB-2013-0321 if the 2013 year end balances had been cleared for all accounts instead of just 4 for two scenarios.

a) Equivalent to Exh N2 of EB-2013-0321, but with disposition of 2013 year end balances for all deferral and variance accounts. Clearly identify disposition periods for account balances.

b) Equivalent to EB-2013-0321 Decision with Reasons, but with disposition of 2013 year end balances for all deferral and variance accounts. Clearly identify disposition periods for account balances.

Response

In OPG's view, the customer bill impacts and payment amounts approved by the OEB in EB-2013-0321 are the relevant starting point for considering the impacts from the current application; not an alternative set of customer bill impacts or payment amounts that was neither proposed nor approved in the last proceeding. Notwithstanding this view, OPG provides the following responses:

a) This question is very similar to one that was asked in EB-2013-0321 (i.e., Board Staff 192). Accordingly, OPG has responded to this question using the same assumptions as were used in EB-2013-0321 Ex L-9.6-1 Staff–192. These assumptions are summarized below.

- Accounts with balances over $100M are recovered over 24 months with the following two exceptions;
  - The balance in the Pension and OPEB Cost Variance - Nuclear – Future account is recovered over 120 months, which is the period remaining per the Settlement Agreement in EB-2012-0002.

  - In accordance with the Settlement Agreement in EB-2012-0002, clearance of the derivative sub account of the Bruce Lease Net Revenues Variance account is to be accomplished using OPG's forecast of payouts to Bruce Power rather than by straight line amortization of the balance. For purposes of this response, OPG has used $79.8M (EB-2013-0321 Ex. G2-2-1 Table 8 line 15 col. c) less tax thereon at 25% for a net of $59.9M for the year 2015.

- All other balances are recovered over 12 months.

Using the hypothetical scenario set out in the question, the proposed base payment amounts in EB-2013-0321, Ex. N2-1-1, and the assumptions outlined in EB-2013-0321 Ex I1-1-2, the estimated impact of this hypothetical scenario on the bill of a typical residential consumer during 2014 and 2015 vs 2013 rates and riders would have been $7.01/month or 5.9%.

b) OPG has calculated the hypothetical impact set out in this question using the same amortization assumptions as in part a) with one exception.

The exception is that the Capacity Refurbishment Variance Account – Hydroelectric is amortized over 12 months as directed by the OEB in the EB-2013-0321 Decision.

Using the hypothetical scenario set out in this question, the estimated impact on the bill of a typical residential consumer during 2014 and 2015 vs 2013 rates and riders would have been $4.22/month or 3.6%.

OPG notes that the hypothetical impacts in both a) and b) fall well short of the OEB's 10% threshold for mitigation.

OPG also notes that the total estimated impact on the bill of a typical residential consumer of the EB-2013-0321 Decision with Reasons and the current application, which proposes disposition of 2014 account balances rather than 2013 balances, is $5.53/month or 4.4% on the bill. This combined impact still falls well short of of the OEB's 10% threshold for mitigation.