EB-2013-0321

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act 1998*, Schedule B to the *Energy Competition Act*, 1998, S.O. 1998, c.15;

AND IN THE MATTER OF an Application Ontario Power Generation Inc. for an order or orders approving payment amounts for prescribed generating facilities commencing January 1, 2014.

SCHOOL ENERGY COALITION CROSS-EXAMINATION COMPENDIUM
(Panel 7 – Volume 2)

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Numbers may not add due to rounding.

Revised Ex.F4-2-1 Table 6
Reconciliation of Tax Return to Regulatory Tax Calculation ($M)
Year Ending December 31, 2012

Line No.	Particulars	2012 Tax Return					Adjustments		(5) - (6) - (7)
		OPG Parent[i]	Subsidiaries[ii]	(1) + (2) Total[iii]	Unregulated[iv]	(3) - (4) Regulated[v]	Bruce Lease[vi]	Other Adjustments[vii]	Regulatory Tax Calc'n[viii]
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Determination of Taxable Income								
1	**Earnings (Loss) Before Tax**	486.1	(51.9)	434.2	(140.6)	574.8	(164.0)	543.6	195.2
	Additions for Tax Purposes:								
2	**Depreciation and Amortization**	540.7	81.1	621.8	135.0	486.8	78.9	94.3	313.6
3	**Nuclear Waste Management Expenses (incl Accretion Expense)**	864.9	0.0	864.9	0.0	864.9	375.3	458.9	30.7
4	**Receipts from Nuclear Segregated Funds**	69.7	0.0	69.7	0.0	69.7	28.1	0.0	41.6
5	**Pension and OPEB/SPP Accrual**	640.4	0.0	640.4	126.2	514.2	0.0	238.5	275.7
6	**Regulatory Asset Amortization - Nuclear Development and Capacity Refurbishment Variance Accounts**	(65.0)	0.0	(65.0)	0.0	(65.0)	0.0	(65.0)	0.0
7	**Regulatory Asset Amortization - Nuclear Liability Deferral Account**	21.4	0.0	21.4	0.0	21.4	0.0	0.0	21.4
8	**Regulatory Asset and Liability Amortization - Other Variance Accounts**	(33.6)	0.0	(33.6)	0.0	(33.6)	0.0	(33.6)	0.0
9	**Regulatory Liability Amortization - Income and Other Taxes Variance Account**	(21.7)	0.0	(21.7)	0.0	(21.7)	0.0	(6.3)	(15.4)
10	**Regulatory Asset Amortization - Bruce Lease Net Revenues Variance Account**	136.1	0.0	136.1	0.0	136.1	0.0	0.1	136.0
11	**Regulatory Asset Amortization - Tax Loss Variance Account**	128.5	0.0	128.5	0.0	128.5	0.0	128.5	0.0
12	**Reversal of Bruce Lease Net Revenues Variance Account Additions**	(336.2)	0.0	(336.2)	0.0	(336.2)	0.0	(333.8)	(2.4)
13	**Adjustment Related to Financing Cost for Nuclear Liabilities**	0.0	0.0	0.0	0.0	0.0	0.0	(78.7)	78.7
14	**Taxable SR&ED Investment Tax Credits**	32.0	0.0	32.0	4.2	27.8	0.0	(21.7)	49.5
15	**Materials and Supplies Inventory Obsolescence**	50.7	0.0	50.7	10.5	40.2	0.0	0.0	40.2
16	**Other**	309.6	0.0	309.6	34.1	275.5	249.0	7.6	18.9
17	**Total Additions**	2,337.5	81.1	2,418.6	310.0	2,108.6	731.3	388.8	988.5
	Deductions for Tax Purposes:								
18	**CCA**	477.7	6.0	483.7	175.0	308.7	6.1	(0.1)	302.7
19	**Cash Expenditures for Nuclear Waste & Decommissioning**	199.6	0.0	199.6	0.4	199.2	83.7	0.0	115.5
20	**Contributions to, and Earnings on Nuclear Segregated Funds**	888.5	0.0	888.5	0.0	888.5	425.8	355.6	107.1
21	**Pension Plan Contributions**	370.0	0.0	370.0	72.9	297.1	0.0	0.0	297.1
22	**OPEB/SPP Payments**	98.5	0.0	98.5	19.4	79.1	0.0	0.0	79.1
23	**Reversal of Nuclear Liability Deferral Account Additions**	147.7	0.0	147.7	0.0	147.7	0.0	143.1	4.6
24	**Reversal of Pension and OPEB Cost Variance Account Additions**	194.7	0.0	194.7	0.0	194.7	0.0	194.7	0.0
25	**Reversal of Impact of USGAAP Deferral Account Additions**	47.5	0.0	47.5	0.0	47.5	0.0	47.5	0.0
26	**Reversal of Other Variance Account Additions**	50.9	0.0	50.9	0.0	50.9	0.0	50.9	0.0
27	**Reversal of Nuclear Development and Capacity Refurbishment Variance Account Additions**	34.0	0.0	34.0	0.0	34.0	0.0	34.0	0.0
28	**SR&ED Qualifying Capital Expenditures**	24.9	0.0	24.9	4.3	20.6	0.0	0.0	20.6
29	**Construction In Progress Interest Capitalized**	81.7	0.0	81.7	5.4	76.3	0.0	76.3	0.0
30	**Other**	173.8	0.0	173.8	129.6	44.2	14.2	25.3	4.7
31	**Total Deductions**	2,789.5	6.0	2,795.5	407.0	2,388.5	529.8	927.3	931.4
32	**Taxable Income** (line 1 + line 17 - line 31)	34.1	23.2	57.3	(237.6)	294.9	37.5	5.1	252.3

Notes:

i Amounts are per the OPG Inc. legal entity income tax return.

ii Amounts are per the income tax returns for OPG Inc. subsidiaries.

iii Represents the OPG consolidated amounts. Earnings Before Tax at line 1 is as reported in OPG's 2012 audited consolidated financial statements (Ex. A2-1-1, Attachment 1, p. 78).

iv Represents amounts relating to OPG's unregulated operations. Newly regulated hydroelectric amounts are included in this column, while Bruce Lease net revenue items are not.

v Represents amounts reported in the "regulated" segments of OPG's audited consolidated financial statements in accordance with generally accepted accounting principles. For financial reporting purposes, the "regulated" segments include the prescribed facilities as well as the Bruce facilities.

vi Represents Bruce Lease net revenue items included in col. (5). Bruce Lease income tax details are provided in Ex G2-2-1 Table 7 and are included in Bruce Lease net revenues; therefore Bruce Lease income tax amounts are removed in determining income taxes for prescribed facilities.

vii Represents the following:

- items of income and expense reflected in OPG's income tax returns that do not form part of the regulatory income tax calculation as per the OEB-approved methodology, and vice versa. Examples include: accretion expense for nuclear waste management and decommissioning liabilities and earnings on related segregated funds which do not form part of the OEB-approved recovery methodology for these liabilities, and deemed interest expense that replaces OPG's actual interest expense for regulatory purposes.
- line item presentation differences between OPG's income tax returns and the regulatory income tax calculation at Ex. F4-2-1 Table 4 that do not impact the resulting taxable income.

viii Amounts are as shown in Ex. F4-2-1 Table 4, col. (c).

Chart 3

Updated Forecast of Pension and OPEB Costs – Drivers of Change ($M)

	2014			2015			Test Period		
	Pension	OPEB	Total	Pension	OPEB	Total	Pension	OPEB	Total
2013-2015 Business Plan*	394.8	287.2	682.0	380.9	291.8	672.7	775.7	579.0	1,354.7
Updated Mortality Assumptions	116.3	30.2	146.5	114.5	30.0	144.5	230.8	60.2	291.0
Higher Discount Rates	(90.8)	(15.5)	(106.3)	(85.0)	(14.7)	(99.7)	(175.8)	(30.2)	(206.0)
Lower Health Care Benefit Costs	-	(66.0)	(66.0)	-	(65.0)	(65.0)	-	(131.0)	(131.0)
Updated Membership Data	42.5	13.1	55.6	45.9	15.1	61.0	88.4	28.2	116.6
Other Changes	53.5	(3.6)	49.9	32.4	(6.8)	25.6	85.9	(10.4)	75.5
2014-2016 Business Plan	516.3	245.4	761.7	488.7	250.4	739.1	1,005.0	495.8	1,500.8

* From Ex. F4-3-1, pp 36 - 37.
Numbers may not add due to rounding.

2.2.2 Mortality Assumptions

There are two key components to the determination of the best estimate mortality assumptions for valuing obligations of a post retirement benefit plan:

- Base mortality table – gender-specific tables that estimate the probability of death based on the age of plan members at a point in time, based on historical experience.
- Future improvements in mortality – estimates of future improvements in longevity that will reduce mortality rates over time.

Prior to the comprehensive accounting valuation, OPG's mortality assumptions were based on the industry standard actuarial 1994 Uninsured Pensioner ("UP94") mortality table, as adjusted by a factor of 85 per cent, and the standard future mortality improvement Scale AA.[2,3] These assumptions were reflected in the pension and OPEB costs in the 2013 - 2015

[2] Scale AA has been the most commonly used basis for mortality improvements assumptions in Canada and the United States. The scale was published by the U.S. Society of Actuaries in 1995 and was based on U.S mortality experience between 1977 and 1993. Scale AA is a non-gender specific set of assumed life expectancy improvement factors at different ages. The improvement factors at a particular age do not distinguish between individuals with different years of birth.

Therefore, the income tax impact of updated pension and OPEB information is calculated in Chart 4 below using the net amount of additions or deductions to earnings before tax, based on the difference between the original and updated forecasts of pension and OPEB costs, and contributions and payments. The income tax impact is a reduction to the revenue requirement of $3.9M.

Chart 4

Income Tax Impact of Updated Pension and OPEB Forecasts ($M)

Line	Particulars	2014	2015	Total
1	Updated Forecast of Pension and OPEB Costs	761.7	739.1	1,500.8
2	Less: Original Forecast of Pension and OPEB Costs	682.0	672.7	1,354.7
3	Increase in Regulatory Taxable Income for Pension and OPEB Costs (line 1 - line 2)	79.7	66.4	146.2
4	Updated Forecast of Pension Plan Contributions	355.3	401.8	757.1
5	Updated Forecast of OPEB Payments	89.3	95.8	185.1
6	Less: Original Forecast of Pension Plan Contributions[6]	238.0	340.2	578.2
7	Less: Original Forecast of OPEB Payments[6]	99.7	106.5	206.2
8	Decrease in Regulatory Taxable Income for Pension Plan Contributions and OPEB Payments (lines 4 + 5 - 6 - 7)	106.9	50.9	157.8
9	Net (Decrease) Increase in Regulatory Taxable Income (line 3 - line 8)	(27.2)	15.5	(11.6)
10	(Decrease) Increase in Regulatory Income Taxes (line 9 x 25% / (1 - 25%))	**(9.1)**	**5.2**	**(3.9)**

[6] From Ex. F4-2-1, Table 5, lines 15 and 16

Updated Ex F4-2-1 Table 5 for Impact Statement Ex N2-1-1 for 2014 and 2015
Calculation of Regulatory Income Taxes for Prescribed Facilities ($M)
Years Ending December 31, 2013, 2014 and 2015

Line No.	Particulars	Note	2013 Budget[1]	2014 Plan[2]	2015 Plan[2]
			(a)	(a)	(b)
	Determination of Regulatory Taxable Income				
1	**Regulatory Earnings Before Tax**	3	88.4	598.6	517.1
	Additions for Regulatory Tax Purposes:				
2	**Depreciation and Amortization**		305.9	418.0	433.6
3	**Nuclear Waste Management Expenses**		28.8	59.3	62.2
4	**Receipts from Nuclear Segregated Funds**		53.3	62.6	116.5
5	**Pension and OPEB/SPP Accrual**	4	314.0	675.8	618.1
6	**Regulatory Asset Amortization - Bruce Lease Net Revenues Variance Account**		62.9	41.9	0.0
7	**Regulatory Liability Amortization - Income and Other Taxes Variance Account**		(18.7)	(12.4)	0.0
8	**Adjustment Related to Financing Cost for Nuclear Liabilities**		76.9	74.6	70.3
9	**Taxable SR&ED Investment Tax Credits**		21.4	14.8	10.4
10	**Other**		33.4	45.9	49.7
11	**Total Additions**		878.0	1,380.5	1,360.8
	Deductions for Regulatory Tax Purposes:				
12	**CCA**		316.7	419.0	467.0
13	**Cash Expenditures for Nuclear Waste & Decommissioning**		131.6	148.8	197.5
14	**Contributions to Nuclear Segregated Funds**		98.1	170.1	172.8
15	**Pension Plan Contributions**	5	305.7	357.6	407.6
16	**OPEB/SPP Payments**	6	85.4	89.6	95.8
17	**Reversal of Return on Rate Base Recorded in Capacity Refurbishment Variance Account**		53.3	0.0	0.0
18	**SR&ED Qualifying Capital Expenditures**		14.3	0.0	0.0
19	**Other**		0.5	0.5	0.5
20	**Total Deductions**		1,005.6	1,185.6	1,341.2
21	**Regulatory Taxable Income** (line 1 + line 11 - line 20)		(39.2)	793.5	536.6
22	**Regulatory Income Taxes - Federal** (line 21 x line 26)		(5.9)	119.0	80.5
23	**Regulatory Income Taxes - Provincial** (line 21 x (line 27 + line 28))		(3.9)	79.3	53.7
24	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		(14.8)	(10.4)	(10.4)
25	**Total Regulatory Income Taxes** (line 22 + line 23 + line 24)		(24.6)	188.0	123.8
	Income Tax Rate:				
26	**Federal Tax**		15.00%	15.00%	15.00%
27	**Provincial Tax**		11.00%	11.00%	11.00%
28	**Provincial Manufacturing & Processing Profits Deduction**		-1.00%	-1.00%	-1.00%
29	**Total Income Tax Rate**		25.00%	25.00%	25.00%

Notes:

1 From Ex. F4-2-1 Table 5, col. (a)

2 The regulatory income tax calculation for 2014 and 2015 is as shown at Ex. N2-1-1, Att. 5, p. 9, cols. (b) and (f), respectively. With the exception of lines 1, 5, 11, 15, 16, 20, 21 and 25, amounts are also as shown at corresponding lines of Ex. F4-2-1, Table 5, col. (b) for 2014 and col. (c) for 2015.

3 Regulatory Earnings Before Tax for are calculated as follows:

Table to Note 3 - Calculation of Regulatory EBT for 2014 and 2015 ($M)

Line No.	Item	Reference	2014	2015
			(a)	(b)
1a	Requested After Tax Return on Equity	Ex. N2-1-1, Att. 5, p. 8, line 52, cols. (b) and (f)	438.0	446.3
2a	Less: Bruce Lease Net Revenues	Ex. G2-2-1 Table 1, line 3	39.7	40.6
3a	Single Payment Amounts Adjustment		12.3	(12.3)
4a		line 1a - line 2a + line 3a	410.6	393.3
5a	Additions for Regulatory Tax Purposes	line 11	1,380.5	1,360.8
6a	Deductions for Regulatory Tax Purposes	line 20	1,185.6	1,341.2
7a		line 4a+ line 5a - line 6a	605.5	412.9
8a	Regulatory Income Taxes - Federal	(lines 7a + 24) x line 26 / (1 - line 29)	119.0	80.5
9a	Regulatory Income Taxes - Provincial	(lines 7a + 24) x (lines 27 + 28) / (1 - line 29)	79.3	53.7
10a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 24	(10.4)	(10.4)
11a	Total Regulatory Income Taxes	line 8a + line 9a + line 10a	188.0	123.8
12a	Requested After Tax Return on Equity	line 1a	438.0	446.3
13a	Less: Bruce Lease Net Revenues	line 2a	39.7	40.6
14a	Add: Total Regulatory Income Taxes	line 11a	188.0	123.8
15a	Single Payment Amounts Adjustment		12.3	(12.3)
16a	Regulatory Earnings Before Tax	lines 12a - 13a + 14a + 15a	598.6	517.1

4 For 2014 and 2015, from Ex. N2-1-1 Chart 2, line 1

5 For 2014 and 2015, from Ex. N2-1-1 Chart 2, line 4

6 For 2014 and 2015, from Ex. N2-1-1 Chart 2, line 5

Schedule 2—Summary of Estimated 2014 US GAAP Results

The following table provides a summary of the estimated US GAAP results for 2014 for the post employment benefit plans sponsored by OPG. The estimated net periodic pension/benefit cost for the period January 1, 2014 to December 31, 2014 is determined based on the projected balance sheet items at January 1, 2014.

(in Canadian $ 000's)	RPP	SPP	OPRB	LTD
Projected Net Asset (Liability) Recognized as at January 1, 2014				
Projected Benefit Obligation	$ (13,971,270)	$ (307,880)	$ (3,007,952)	$ (297,431)
Fair Value of Plan Assets	10,794,263	0	0	0
Net Asset (Liability) Recognized	$ (3,177,007)	$ (307,880)	$ (3,007,952)	$ (297,431)
Estimated Amounts Recognized in Accumulated Other Comprehensive Income as at January 1, 2014				
Unrecognized Past Service Costs (Credits)	$ 0	$ 0	$ 3,438	$ 0
Unrecognized Net Actuarial Loss (Gain)	4,274,226	95,289	894,301	0
Unrecognized Transition Obligation (Asset)	0	0	0	0
Total Accumulated Other Comprehensive Loss (Income)	$ 4,274,226	$ 95,289	$ 897,739	$ 0
Components of Estimated Net Periodic Pension/Benefit Cost, January 1, 2014 to December 31, 2014				
Employer Current Service Cost	$ 295,529	$ 9,887	$ 78,815	$ 25,420
Interest Cost	602,290	13,489	134,156	10,799
Expected Return on Plan Assets	(674,099)	0	0	0
Amortization of Past Service Cost	0	0	535	0
Amortization of Net (Gain) Loss	220,778	5,420	44,963	0
Total Cost	$ 444,498	$ 28,796	$ 258,469	$ 36,219
2014 Estimated Employer Pension Contributions / Benefit Payments	$ 268,000	$ 8,159	$ 75,511	$ 28,644

Schedule 3—Summary of Estimated 2015 US GAAP Results

The following table provides a summary of the estimated US GAAP results for 2015 for the post employment benefit plans sponsored by OPG. The estimated net periodic pension/benefit cost for the period January 1, 2015 to December 31, 2015 is determined based on the projected balance sheet items at January 1, 2015.

(in Canadian $ 000's)	**RPP**	**SPP**	**OPRB**	**LTD**
Projected Net Asset (Liability) Recognized as at January 1, 2015				
Projected Benefit Obligation	$ (14,341,560)	$ (323,097)	$ (3,143,307)	$ (305,006)
Fair Value of Plan Assets	11,208,910	0	0	0
Net Asset (Liability) Recognized	$ (3,132,650)	$ (323,097)	$ (3,143,307)	$ (305,006)
Estimated Amounts Recognized in Accumulated Other Comprehensive Income as at January 1, 2015				
Unrecognized Past Service Costs (Credits)	$ 0	$ 0	$ 2,903	$ 0
Unrecognized Net Actuarial Loss (Gain)	4,053,371	89,869	847,233	0
Unrecognized Transition Obligation (Asset)	0	0	0	0
Total Accumulated Other Comprehensive Loss (Income)	$ 4,053,371	$ 89,869	$ 850,136	$ 0
Components of Estimated Net Periodic Pension/Benefit Cost, January 1, 2015 to December 31, 2015				
Employer Current Service Cost	$ 297,539	$ 10,134	$ 78,658	$ 26,068
Interest Cost	618,101	14,134	139,987	11,074
Expected Return on Plan Assets	(698,581)	0	0	0
Amortization of Past Service Cost	0	0	535	0
Amortization of Net (Gain) Loss	209,485	4,837	41,310	0
Total Cost	$ 426,544	$ 29,105	$ 260,490	$ 37,142
2015 Estimated Employer Pension Contributions / Benefit Payments	$ 381,000	$ 9,057	$ 80,875	$ 29,374

7

of the company. For the nuclear business the evidence is clear that overall performance is poor in comparison to its peers and the staffing levels and compensation exceed the comparators. On this basis an adjustment is necessary to ensure the payment amounts are just and reasonable.

Lastly, the Board directs OPG to conduct an independent compensation study to be filed with the next application. As noted above, OPG's compensation benchmarking analysis to date has not been comprehensive. The Board remains concerned about compensation costs, in light of the company's overall poor nuclear performance, and would be assisted by a comprehensive benchmarking study comparing OPG's total compensation with broadly comparable organizations. The study should cover a significant proportion of its positions. Compensation costs are a signification proportion of the total revenue requirement; OPG's position that such a study would be too expensive and of little value is therefore not reasonable. Consultation with Board staff and stakeholders concerning the scope of the study, in advance of issuing a Terms of Reference, is advised. The costs of the study are to be absorbed within the overall revenue requirement allowed for in this Decision. This has been already accounted for in the Regulatory Affairs budget, which anticipates studies in support of the company's next application.

6.2 Pension and Other Post Employment Benefits

Costs related to Pension and Other Post Employment Benefits ("OPEB") for the test period were forecast based on discount rates and assumptions in OPG's 2010-2014 business plan. The total amount requested for the test period is approximately $633 million. On September 30, 2010, OPG filed an Impact Statement in which it identified a significant decline in discount rates causing an increase in forecast pension and OPEB costs for the test period. Rather than revising the proposed revenue requirement, OPG requested approval for a variance account, "to record the revenue requirement impact of differences between forecast and actual pension and OPEB costs." The total forecast increase as a result of the update is $264.2 million, as summarized in the following table.

Table 18: Updated Pension and OPEB Costs ($ million)

	Nuclear		Regulated Hydroelectric	
	2011	2012	2011	2012
Pension Cost				
As per Chart 9, Exh.F4-3-1	$114.0	$162.8	$5.8	$8.1
Projection as of August 2010	210.2	245.9	10.6	12.3
Increase	96.2	83.1	4.8	4.2
OPEB Cost[1]				
As per Chart 9, Exh.F4-3-1	159.3	166.7	8.0	8.3
Projection as of August 2010	196.5	201.7	9.9	10.1
Increase	37.2	35.0	1.9	1.8
Total Test Period Increase		**$251.5**		**$12.7**

Note 1: Supplementary pension plans costs are included with OPEB costs
Source: Exh. N-1-1

Board staff submitted that it would be more appropriate for OPG to determine pension and OPEB costs on a cash basis because costs determined on that basis are more stable for ratemaking purposes than those calculated on an accounting basis. In support of its position, Board staff provided a table in its submission that illustrated pension and OPEB payments on an accounting basis as well as a cash basis. On a cash basis, the table identified a total amount of $568 million. This position was supported by CCC, CME, and SEC.

In reply, OPG noted that the Board had approved the accrual method in the previous case and argued that no evidence had been introduced on the cash method in the current proceeding. OPG pointed out that the Board staff tables did not reflect updated pension contributions for 2011 and 2012, as provided by Mercer. OPG maintained that including the updates demonstrates that the cash basis is no more stable than the accounting basis. As noted in OPG's reply submission, there are utilities regulated by the Board using the cash basis and others using the accounting basis.

Board staff further submitted that the variance account request should be denied, and its position was supported by CCC, CME, SEC and VECC. Board staff raised two materiality arguments in its submission. Staff noted that OPG had not informed its shareholder of the increased forecast cost as OPG suggested the increase was not material, and that balances in the Hydro One transmission pension variance account for the last two proceedings have not been material. On the first point, OPG replied that seeking shareholder approval before applying for a variance account is not an established requirement. On the second point, OPG maintained that there is no evidence that OPG's variances will be similar to the immaterial balances recorded by Hydro One.

VECC submitted that the Hydro One pension and OPEB variance accounts for its distribution business and its transmission business were established under specific and unique circumstances and should not be accepted as precedents by the Board. VECC maintained that the accounts are "not the result of decisions wherein the Board actually turns its mind to the appropriateness of allowing HONI to be fully protected from the risk associated with its pension cost forecasts."[42] OPG challenged this view and argued that the Hydro One decision confirmed that balances in the variance account would be subject to a prudence review.

In the previous proceeding the Board denied OPG's request for a pension and OPEB variance account. Board staff submitted that had the account been approved, an estimated $314 million credit to ratepayers would have been recorded for the period 2008 to 2010. This led staff to conclude that the request in the current proceeding should be denied because the pension and OPEB amounts included in the current application are lower than what OPG now believes it will incur in the test period. OPG responded that staff's conclusion amounts to retroactive ratemaking and further, that the staff analysis is not correct. Staff's analysis reflects a full year for 2008, but in OPG's view should reflect only 9 months. OPG also argued that staff has grossly overestimated the 2010 variance.

OPG also disagreed with the Board staff submission on pension and OPEB in three other areas:

- Board staff submitted that if the Board allows OPG to collect the forecast accounting OPEB costs, the variance should be placed in a segregated fund. OPG doubted whether the Board has jurisdiction to implement the proposal. SEC also disagreed with staff, expressing its concern with the precedent;
- Staff submitted that the undisclosed tax impact related to the amount to be tracked in the variance account is approximately $91 million. OPG responded that Board staff is incorrect in submitting that the consequences of taxes

[42] VECC Argument, para. 134.

regarding the update have not been identified, citing updates to the pre-filed evidence; and

- Board staff submitted that OPG should provide evidence that discusses alternatives to AA bond yields to forecast discount rates. In reply, OPG cited sections of the CICA handbook and asserted that the use of AA bond yields was appropriate.

Board Findings

OPG correctly points out that there is currently no consistency amongst utilities in the use of either the cash or accrual method to setting pension and other post employment benefit expenses. Both methodologies have been approved by the Board. The Board in this case sees no compelling reason to change OPG's existing approach of using the accrual method. Consistency in accounting treatment, in order to compare results year to year, is advantageous for purposes of assessing the level of costs for reasonableness. A consistent approach over time also ensures a greater level of fairness for ratepayers and the company.

The request for a variance account is denied. Pension and OPEB costs should be included in the forecast of expenses in the same way as other OM&A expenses, and then managed by the company within its overall operations. The Board finds that the forecast included in the pre-filed evidence was more rigorous because it was based on a set of internally consistent assumptions, while the update is based on the AA bond yields which will change. Accordingly, the Board finds that the allowance for pension and OPEB expenses in the pre-filed evidence is appropriate, as it is the best evidence on this matter.

The Board is reluctant to make selective updates to the evidence. The bond yields have changed, and will continue to change, as noted by the actuary in the updated statement. Further, the Board notes that the financial market conditions are variable and have indeed improved since the impact statement was filed. The Board concludes that an adjustment to the allowance is not warranted.

The Board sees no reason to depart from the use of AA bond yields at this time, with the exception of using more current data. However, OPG is directed to provide a fuller range and discussion of alternatives to the use of AA bond yields to forecast discount rates in its next application.

Schedule 3—Summary of Estimated 2014 US GAAP Results

The following table provides a summary of the estimated US GAAP results for 2014 for the post employment benefit plans sponsored by OPG. The estimated net periodic pension/benefit cost for the period January 1, 2014 to December 31, 2014 is determined based on the projected balance sheet items at January 1, 2014.

(in Canadian $ 000's)	RPP	SPP	OPRB	LTD
Projected Net Asset (Liability) Recognized as at January 1, 2014				
Projected Benefit Obligation	$ (14,159,373)	$ (306,662)	$ (2,646,977)	$ (288,223)
Fair Value of Plan Assets	10,551,892	0	0	0
Net Asset (Liability) Recognized	$ (3,607,481)	$ (306,662)	$ (2,646,977)	$ (288,223)
Estimated Amounts Recognized in Accumulated Other Comprehensive Income as at January 1, 2014				
Unrecognized Past Service Costs (Credits)	$ 0	$ 0	$ 3,438	$ 0
Unrecognized Net Actuarial Loss (Gain)	4,704,700	98,789	533,326	0
Unrecognized Transition Obligation (Asset)	0	0	0	0
Total Accumulated Other Comprehensive Loss (Income)	$ 4,704,700	$ 98,789	$ 536,764	$ 0
Components of Estimated Net Periodic Pension/Benefit Cost, January 1, 2014 to December 31, 2014				
Employer Current Service Cost	$ 272,040	$ 9,568	$ 62,500	$ 24,059
Interest Cost	666,703	14,654	125,865	11,918
Expected Return on Plan Assets	(646,743)	0	0	0
Amortization of Past Service Cost	0	0	535	0
Amortization of Net (Gain) Loss	289,317	6,029	21,152	0
Total Cost	$ 581,317	$ 30,251	$ 210,052	$ 35,977
2014 Estimated Employer Pension Contributions / Benefit Payments				
Amounts used for developing estimated net periodic pension/benefit cost	$ 277,000	$ 8,883	$ 62,974	$ 28,644

Schedule 4—Summary of Estimated 2015 US GAAP Results

The following table provides a summary of the estimated US GAAP results for 2015 for the post employment benefit plans sponsored by OPG. The estimated net periodic pension/benefit cost for the period January 1, 2015 to December 31, 2015 is determined based on the projected balance sheet items at January 1, 2015.

(in Canadian $ 000's)	RPP	SPP	OPRB	LTD
Projected Net Asset (Liability) Recognized as at January 1, 2015				
Projected Benefit Obligation	$ (14,645,795)	$ (322,001)	$ (2,770,317)	$ (295,556)
Fair Value of Plan Assets	10,989,154	0	0	0
Net Asset (Liability) Recognized	$ (3,656,641)	$ (322,001)	$ (2,770,317)	$ (295,556)
Estimated Amounts Recognized in Accumulated Other Comprehensive Income as at January 1, 2015				
Unrecognized Past Service Costs (Credits)	$ 0	$ 0	$ 2,903	$ 0
Unrecognized Net Actuarial Loss (Gain)	4,449,543	92,760	510,123	0
Unrecognized Transition Obligation (Asset)	0	0	0	0
Total Accumulated Other Comprehensive Loss (Income)	$ 4,449,543	$ 92,760	$ 513,026	$ 0
Components of Estimated Net Periodic Pension/Benefit Cost, January 1, 2015 to December 31, 2015				
Employer Current Service Cost	$ 267,757	$ 9,807	$ 62,460	$ 24,671
Interest Cost	688,558	15,360	131,545	12,222
Expected Return on Plan Assets	(676,412)	0	0	0
Amortization of Past Service Cost	0	0	535	0
Amortization of Net (Gain) Loss	267,469	5,359	18,499	0
Total Cost	$ 547,372	$ 30,526	$ 213,039	$ 36,893
2015 Estimated Employer Pension Contributions / Benefit Payments				
Amounts used for developing estimated net periodic pension/benefit cost	$ 429,000	$ 10,012	$ 67,872	$ 29,374

2.2 Pension and OPEB Costs

Relative to the amounts reflected in the first Impact Statement, OPG is forecasting an overall decrease of $278.7M in its test period revenue requirement related to pension and OPEB, inclusive of the related income taxes. This consists of a $206.9M decrease in forecast pension and OPEB costs for the prescribed facilities as shown on Chart 1, which has been reproduced from Ex. L, Tab 6.8, Schedule 1 Staff-112, and a $71.8M decrease in income taxes as presented in Chart 2, also reproduced from Ex. L, Tab 6.8, Schedule 1 Staff-112. The income tax impact of the updated pension and OPEB forecast is calculated in the same manner as discussed in Ex. N1-1-1, section 2.2.4.

Chart 1

Updated Forecast of Pension and OPEB Costs ($M)[1]

	Nuclear		Previously Regulated Hydroelectric		Newly Regulated Hydroelectric		Total Prescribed Assets		
	2014	**2015**	**2014**	**2015**	**2014**	**2015**	**2014**	**2015**	**Total**
Pension Costs									
December 31, 2013 Update	406.9	348.5	22.4	20.1	42.0	36.7	471.3	405.3	876.6
Impact Statement[2]	448.0	425.1	24.5	23.1	43.8	40.5	516.3	488.7	1,005.1
Decrease	(41.1)	(76.6)	(2.1)	(3.0)	(1.8)	(3.8)	(45.0)	(83.4)	(128.5)
OPEB Costs									
December 31, 2013 Update	176.6	182.9	9.7	10.6	18.2	19.3	204.6	212.8	417.4
Impact Statement[2]	212.9	217.8	11.7	11.8	20.8	20.8	245.4	250.4	495.8
Decrease	(36.3)	(34.9)	(2.0)	(1.2)	(2.6)	(1.5)	(40.8)	(37.6)	(78.4)
Total Decrease	**(77.4)**	**(111.5)**	**(4.1)**	**(4.2)**	**(4.4)**	**(5.3)**	**(85.8)**	**(121.0)**	**(206.9)**

1 Reproduced from Ex. L, Tab 6.8, Schedule 1 Staff-112. Numbers may not add due to rounding.
2 From Ex. N1-1-1 Chart 2.

Chart 2

Income Tax Impact of Updated Pension and OPEB Forecasts[1] ($M)

Line	Particulars	2014	2015	Test Period
1	Updated Forecast of Pension and OPEB Costs	675.9	618.1	1,294.0
2	Less: Impact Statement Forecast of Pension and OPEB Costs[2]	761.7	739.1	1,500.8
3	Decrease in Regulatory Taxable Income for Pension and OPEB Costs (line 1 - line 2)	(85.8)	(121.0)	(206.8)
4	Updated Forecast of Pension Plan Contributions	357.6	407.6	765.2
5	Updated Forecast of OPEB Payments	89.6	95.8	185.4
6	Less: Impact Statement Forecast of Pension Plan Contributions[3]	355.3	401.8	757.1
7	Less: Impact Statement Forecast of OPEB Payments[4]	89.3	95.8	185.1
8	Decrease in Regulatory Taxable Income for Pension Plan Contributions and OPEB Payments (lines 4 + 5 - 6 - 7)	2.6	5.8	8.4
9	(Decrease) Increase in Regulatory Taxable Income (line 3 - line 8)	(88.4)	(126.8)	(215.2)
10	Decrease in Regulatory Income Taxes (line 9 x 25% / (1-25%))	**(29.5)**	**(42.3)**	**(71.8)**

1 Reproduced from Ex. L, Tab 6.8, Schedule 1 Staff-112. Numbers may not add due to rounding.
2 From Ex. N1-1-1 Chart 4, line 1.
3 From Ex. N1-1-1 Chart 4, line 4.
4 From Ex. N1-1-1 Chart 4, line 5.

The updated forecast of OPG's total pension and OPEB costs was determined by OPG's independent actuary, AON Hewitt ("AON"), using the same methodology applied in determining the costs reflected in the pre-filed evidence and the first Impact Statement. The economic assumptions and pension plan asset values underpinning the updated forecast reflect market conditions as at December 31, 2013. AON's report on the updated estimates of OPG's 2014 and 2015 pension and OPEB costs is provided in Attachment 1.

The main drivers of change to the pension and OPEB costs compared to the first Impact Statement are higher discount rates as at December 31, 2013 and the adoption of a new scale for future mortality improvement issued by the Canadian Institute of Actuaries ("CIA") in February 2014. The updated forecast of 2014 and 2015 costs reflects the results of a comprehensive accounting valuation of OPG's post employment benefit plan obligations, as explained in Ex. N1-1-1, section 2.2.1.

As the final assumptions as of December 31, 2013 were used to project the 2014 and 2015 costs, the 2014 forecast costs are expected to be close to the actual costs for the year, with the exception of the long-term disability benefit plan ("LTD") costs which will be calculated using information as of year-end 2014.

As discussed in detail in Ex. L, Tab 6.8, Schedule 1 Staff-112, discount rates have increased between those determined as of June 30, 2013 used for the first Impact Statement and the December 31, 2013 rates used for this update, reflecting the impact of financial market conditions on long-term bond rates. This has caused a decline in the projected pension and OPEB costs for the test period. Specifically, the discount rates used to project pension, OPEB and LTD costs have increased from 4.70 per cent, 4.70 per cent and 4.00 per cent, respectively, to 4.90 per cent, 5.00 per cent and 4.10 per cent, respectively. The updated discount rates were provided by Mercer and calculated in the same way as those reflected in the original pre-filed evidence and the first Impact Statement.

Also as discussed in Ex. L, Tab 6.8, Schedule 1 Staff-112, AON recommended an updated assumption for future mortality improvement, replacing the one used in the projection provided in Ex. N1-1-1. Specifically, AON recommended the use of the Canadian Pensioners Mortality Improvement Scale B ("CPM-B") released by the CIA on February 13, 2014 in the "CIA Final Report: Canadian Pensioners' Mortality" ("CIA Mortality Report"). The CPM-B scale reflects Canadian experience specific to pensioners (rather than the Canadian population in general), and is expected to be widely adopted by pension plan sponsors in Canada. The CIA Mortality Report is provided in Ex. L, Tab 6.8, Schedule 1 Staff-112, Attachment 2.

The CPM-B scale was adopted for purposes of valuing the obligations of OPG's post employment benefit plans as at December 31, 2013, which were reported in OPG's 2013 audited consolidated financial statements, and consequently updated projections of 2014 and 2015 costs.

2.3 Deferral and Variance Accounts

The audited actual 2013 deferral and variance account balances for the four accounts that OPG is proposing to recover through new riders beginning in 2015 are as detailed in Ex. L, Tab 9.1, Schedule 17 SEC-132.

As OPG does not propose to clear balances in all deferral and variance accounts in this application, the stand-alone audit of the December 31, 2013 account balances by OPG's auditor, Ernst & Young LLP, was limited to the accounts proposed to be cleared. The auditors' report is included as Attachment 2.

The net impact of reflecting the final balances is a small change to the riders, from $2.99/MWh in the first Impact Statement to $3.36/MWh for the output from the previously regulated hydroelectric facilities, and from $1.59/MWh in the first Impact Statement to $1.35/MWh for the output from the nuclear facilities. Details of the deferral and variance account amounts and resulting riders are provided in Chart 3.

Chart 3

Summary of Deferral and Variance Account Amounts and Riders[1]

		Sep. 2013 Application		Dec. 2013 Impact Stmt		May 2014 Impact Stmt	
Line No.	**Previously Regulated Hydroelectric Facilities**	Projected Balance ($M)	2015 Amortization ($M)	Projected Balance ($M)	2015 Amort ($M)	Actual Balance ($M)	2015 Amortization ($M)
1	Capacity Refurbishment Variance Account	114.4	57.2	114.4	57.2	112.7	56.4
2	Hydroelectric Incentive Mechanism Variance Account	(2.4)	(2.4)	(2.4)	(2.4)	(5.0)	(5.0)
3	Surplus Baseload Generation Variance Account	8.1	8.1	8.1	8.1	19.2	19.2
4	Total	120.1	62.9	120.1	62.9	127.0	70.6
5	Forecast Production (TWh)		20.2		21.0		21.0
6	Rider ($/MWh) (line 4 / line 5)		3.11		2.99		3.36
	Nuclear Facilities						
7	Capacity Refurbishment Variance Account - Capital Portion	3.7	3.7	3.7	3.7	5.7	5.7
8	Nuclear Development Variance Account	69.4	69.4	69.4	69.4	56.5	56.5
9	Total	73.1	73.1	73.1	73.1	62.2	62.2
10	Forecast Production (TWh)		48.0		46.1		46.1
11	Rider ($/MWh) (line 9 / line 10)		1.52		1.59		1.35

1 Numbers may not add due to rounding.

Schedule 2—Summary of Estimated 2014 US GAAP Results

The following table provides a summary of the estimated US GAAP results for 2014 for the post employment benefit plans sponsored by OPG. The estimated net periodic pension/benefit cost for the period January 1, 2014 to December 31, 2014 is determined based on the projected balance sheet items at January 1, 2014.

(in Canadian $ 000's)	RPP	SPP	OPRB	LTD
Projected Net Asset (Liability) Recognized as at January 1, 2014				
Projected Benefit Obligation	$ (13,368,826)	$ (285,169)	$ (2,439,305)	$ (267,830)
Fair Value of Plan Assets	10,893,428	0	0	0
Net Asset (Liability) Recognized	$ (2,475,398)	$ (285,169)	$ (2,439,305)	$ (267,830)
Estimated Amounts Recognized in Accumulated Other Comprehensive Income as at January 1, 2014				
Unrecognized Past Service Costs (Credits)	$ 0	$ 0	$ 950	$ 0
Unrecognized Net Actuarial Loss (Gain)	3,492,617	78,721	319,518	0
Unrecognized Transition Obligation (Asset)	0	0	0	0
Total Accumulated Other Comprehensive Loss (Income)	$ 3,492,617	$ 78,721	$ 320,468	$ 0
Components of Estimated Net Periodic Pension/Benefit Cost, January 1, 2014 to December 31, 2014				
Employer Current Service Cost	$ 235,496	$ 7,437	$ 51,620	$ 11,517
Interest Cost	655,696	14,110	122,963	10,887
Expected Return on Plan Assets	(624,026)	0	0	0
Amortization of Past Service Cost	0	0	120	0
Amortization of Net (Gain) Loss	259,998	4,291	5,952	0
Total Cost	$ 527,164	$ 25,838	$ 180,655	$ 22,404
2014 Estimated Employer Pension Contributions / Benefit Payments				
Amounts used for developing estimated net periodic pension/benefit cost	$ 400,000	$ 9,278	$ 63,336	$ 27,644

Schedule 3—Summary of Estimated 2015 US GAAP Results

The following table provides a summary of the estimated US GAAP results for 2015 for the post employment benefit plans sponsored by OPG. The estimated net periodic pension/benefit cost for the period January 1, 2015 to December 31, 2015 is determined based on the projected balance sheet items at January 1, 2015.

(in Canadian $ 000's)	**RPP**	**SPP**	**OPRB**	**LTD**
Projected Net Asset (Liability) Recognized as at January 1, 2015				
Projected Benefit Obligation	$ (13,792,082)	$ (297,438)	$ (2,549,220)	$ (262,590)
Fair Value of Plan Assets	11,527,305	0	0	0
Net Asset (Liability) Recognized	$ (2,264,777)	$ (297,438)	$ (2,549,220)	$ (262,590)
Estimated Amounts Recognized in Accumulated Other Comprehensive Income as at January 1, 2015				
Unrecognized Past Service Costs (Credits)	$ 0	$ 0	$ 830	$ 0
Unrecognized Net Actuarial Loss (Gain)	3,154,832	74,430	312,234	0
Unrecognized Transition Obligation (Asset)	0	0	0	0
Total Accumulated Other Comprehensive Loss (Income)	$ 3,154,832	$ 74,430	$ 313,064	$ 0
Components of Estimated Net Periodic Pension/Benefit Cost, January 1, 2015 to December 31, 2015				
Employer Current Service Cost	$ 238,024	$ 7,623	$ 53,861	$ 11,291
Interest Cost	675,765	14,698	128,442	10,673
Expected Return on Plan Assets	(675,198)	0	0	0
Amortization of Past Service Cost	0	0	120	0
Amortization of Net (Gain) Loss	208,890	3,755	4,478	0
Total Cost	$ 447,481	$ 26,076	$ 186,901	$ 21,964
2015 Estimated Employer Pension Contributions / Benefit Payments				
Amounts used for developing estimated net periodic pension/benefit cost	$ 450,000	$ 10,208	$ 68,480	$ 27,115

The table below shows the various assumptions used in the current valuation in comparison with those used in the previous valuation.

Assumption	Current valuation	Previous valuation
Discount rate:	6.30%	6.00%
Inflation:	2.50%	2.25%
Expenses	Implicit provision reflected in the discount rate	Implicit provision reflected in the discount rate
ITA limit / YMPE increases:	3.50%	3.25%
Pensionable earnings increases:	3.50% [16] plus PPM	3.25% plus PPM
Movement within the salary structure (PPM)	Age and service related table	Age and service related table
Indexation of deferred pensions and pensions in payment	2.50%	2.25%
Interest on employee contributions:	5.30%	5.00%
Retirement rates:	Age related table	Age related table
Termination rates:	Age related table	Age related table
Mortality rates:	85% of the rates of the 1994 Uninsured Pensioner Mortality Table	85% of the rates of the 1994 Uninsured Pensioner Mortality Table
Mortality improvements:	Fully generational using Scale AA	Fully generational using Scale AA
Disability rates:	Age related table	Age related table
Eligible spouse at retirement:	90%	90%
Spousal age difference:	Male 4 years older	Male 4 years older
Commencement of deferred pensions	For members eligible for unreduced pension or who have 25 yrs of continuous service, assume to retire at earliest possible date. For all other members, assume age 65.	For members eligible for unreduced pension or who have 25 yrs of continuous service, assume to retire at earliest possible date. For all other members, assume age 65.
Retirement date for disabled members	Age 65	Age 65
Service accrual after 35 years	Assume members contribute past 35 years of pensionable service, unless members already have 35 years and have elected not to contribute.	Assume members contribute past 35 years of pensionable service, unless members already have 35 years and have elected not to contribute.

The assumptions are best-estimates and do not include a margin for adverse deviations.

[16] With adjustments in 2010, 2011, and 2012 as outlined below.

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EB-2013-0321
Exhibit L
Tab 6.8
Schedule 17 SEC-103
Attachment 1

Age Related Tables

Sample rates from the age related tables are summarized in the following table:

Age	Termination		Disability	Retirement		
			Rate per 1000 Employee Members	If Eligible for Reduced Pension		If Eligible for Unreduced Pension
	Males	Females		Males	Females	
20	2.9%	4.4%	1.00	0.0%	0.0%	n/a
25	2.2%	3.3%	1.00	0.0%	0.0%	n/a
30	1.6%	2.4%	1.05	0.0%	0.0%	n/a
35	1.1%	1.7%	1.10	0.0%	0.0%	n/a
40	0.8%	1.2%	1.15	0.0%	0.0%	n/a
45	0.7%	1.1%	1.20	0.0%	0.0%	n/a
50	0.7%	1.1%	2.95	0.0%	0.0%	20.0%
55	0.0%	0.0%	10.00	2.0%	5.0%	20.0%
56	0.0%	0.0%	12.00	2.0%	5.0%	20.0%
57	0.0%	0.0%	13.00	2.0%	5.0%	20.0%
58	0.0%	0.0%	14.75	2.0%	5.0%	20.0%
59	0.0%	0.0%	16.37	2.0%	5.0%	20.0%
60	0.0%	0.0%	18.78	2.0%	5.0%	20.0%
61	0.0%	0.0%	21.14	7.0%	10.0%	25.0%
62	0.0%	0.0%	24.70	7.0%	10.0%	25.0%
63	0.0%	0.0%	28.40	7.0%	10.0%	25.0%
64	0.0%	0.0%	30.62	7.0%	10.0%	25.0%
65	0.0%	0.0%	0.00	100.0%	100.0%	100.0%

Pensionable Earnings

The benefits ultimately paid will depend on each member's final average earnings. To calculate the pension benefits payable upon retirement, death or termination of employment, we have taken 2009 earnings and assumed that such pensionable earnings will increase at the assumed rates shown in the table below, plus increases due to movement within the salary structure:

	Management	PWU	Society
2010	0.00%	3.00%	3.00%
2011	3.50%	3.00%	3.00%
2012	3.50%	3.50%	3.00%
thereafter	3.50%	3.50%	3.50%

Even if the salary structure doesn't change from year to year, members' salaries increase due to promotions, the accumulation of seniority and movement within and between salary bands. The following table summarizes the assumed salary increases due to these movements within the salary structure.

Salary Increases Due to Movement Within the Salary Structure[17]

Age	First 4 Years of Employment	Subsequent Years
Under 25	9.0%	2.5%
25 – 29	6.5%	2.5%
30 – 34	5.0%	2.0%
35 – 39	4.5%	1.5%
40 – 44	4.0%	1.0%
45 – 49	3.0%	1.0%
50 – 54	2.0%	1.0%
55 – 59	2.0%	0.6%
60 & over	1.5%	0.6%

Rationale for Assumptions

A rationale for each of the assumptions used in the current valuation is provided below.

Discount Rate

We have discounted the expected benefit payment cash flows using the expected investment return on the market value of the fund. Other bases for discounting the expected benefit payment cash flows may be appropriate, particularly for purposes other than those specifically identified in this valuation report.

The discount rate is comprised of the following:

- Estimated returns for each major asset class consistent with market conditions on the valuation date and the target asset mix specified in the Plan's investment policy.
- Implicit provision for investment and administrative expenses determined as the average rate of investment and administrative expenses paid from the fund over the last 3 years.

The discount rate was developed as follows:

Assumed investment return	6.60%
Investment and administrative expenses provision	(0.30%)
Margin for adverse deviation	0.00%
Net discount rate	6.30%

[17] Over and above any increase in salaries due to adjustments to the salary structure itself.

Inflation	
The inflation assumption is based on the spread between the yields on nominal and real return bonds at the valuation date of 2.50%.	
Income Tax Act Pension Limit and Year's Maximum Pensionable Earnings	
The assumption is based on historical real economic growth and the underlying inflation assumption.	
Pensionable Earnings	
The assumption is based on general wage growth assumptions. The increase in pensionable earnings assumption is adjusted to include increases due to movement within the salary structure based on an experience study considering pay adjustments over the years 1989 to 1995.	
Post retirement pension increases	
The assumption is based on a formula related to the increases in the Consumer Price Index (CPI). We have assumed that CPI will increase at the inflation assumption above.	
Retirement rates	
Because early retirement pensions are reduced in accordance with a formula, the retirement age of plan members has an impact on the cost of the Plan. The assumed retirement rates used in this valuation are based on a study of the Plan's retirement experience between 2004 and 2007 (inclusive).	
Termination rates	
The assumption is based on experience over the years 2004 to 2007.	
Mortality rates	
The assumption is based on experience from 2004 to 2007. Based on the results of this study, mortality rates were approximately 85% of those expected based on the generational UP94 table.	
Interest on employee contributions	
The assumption is based on plan terms and the underlying investment return assumption.	
Disability rates	
The assumption is based on experience of plans with similar benefits. Disabled employees are assumed to remain disabled until age 65, as few recoveries have been recorded.	
Eligible spouse	
The assumption is based on plan experience for non-retired members (actual status used for retirees).	
Spousal age difference	
The assumption is based on plan experience showing males are typically 4 years older than their spouse.	

Chart 1

Pension and OPEB Cost Assumptions						
	2010 Actual	2011 Actual	2012 Actual	2013 Projection[10]	2014 Plan[4]	2015 Plan[4]
Discount rate for pension	6.80% per annum	5.80% per annum	5.10% per annum	4.30% per annum	4.30% per annum	4.30% per annum
Discount rate for other post retirement benefits	6.90% per annum	5.80% per annum	5.20% per annum	4.40% per annum	4.40% per annum	4.40% per annum
Discount rate for long-term disability[11]	5.40% per annum	4.00% per annum	3.50% per annum	3.50% per annum	3.50% per annum	3.50% per annum
Expected long-term rate of return on pension fund assets	7.0% per annum	6.5% per annum	6.5% per annum	6.25% per annum	6.25% per annum	6.25% per annum
Inflation rate	2.0% per annum	2.0% per annum	2.0% per annum	2.0% per annum	2.0% per annum	2.0% per annum
Salary schedule escalation rate	3.0% per annum	3.0% per annum	3.0% per annum	2.5% per annum	2.5% per annum	2.5% per annum
Rate of return used to project year-end pension fund asset values	N/A	N/A	N/A	N/A	6.25% per annum in 2013	6.25% per annum in 2013 and 2014

Projections of rates of return to determine year-end pension fund asset values are not required for the calculation of the 2010-2013 costs because the actual prior year-end asset values are known. The actual returns on pension fund assets were 12.2 per cent in 2010, 6.9

[10] The assumptions for 2013-2015 can also be found at pages 4-5 of Aon Hewitt's report in Attachment 2.

[11] As the costs for 2010 are presented under Canadian GAAP, the discount rate assumption used to determine LTD costs for 2010 represents the rate as at December 31, 2009. In accordance with USGAAP, the discount rates for 2011-2015 are actual (2011-2012) or projected (2013-2015) rates at December 31 of those years.

Numbers may not add due to rounding.

Table 1
Revenue Requirement Impact of OPG's Nuclear Liabilities ($M)
Years Ending December 31, 2010 to 2015

Line No.	Description	Note or Reference	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2014 Plan	2015 Plan
			(a)	(b)	(c)	(d)	(e)	(f)
	PRESCRIBED FACILITIES							
1	**Depreciation of Asset Retirement Costs**	Ex. C2-1-1 Table 2	26.3	29.0	127.2	80.7	80.7	80.7
2	**Used Fuel Storage and Disposal Variable Expenses**	Ex. C2-1-1 Table 2	23.5	26.0	51.9	52.7	56.1	56.7
3	**Low & Intermediate Level Waste Management Variable Expenses**	Ex. C2-1-1 Table 2	1.1	0.9	3.8	3.3	3.1	5.5
	Return on ARC in Rate Base:							
4	**Return on Rate Base at Weighted Average Accretion Rate**	Ex. C1-1-1 Tables 1-6	84.7	83.1	100.5	78.9	74.6	70.3
5	**Return on Rate Base at Weighted Average Cost of Capital**	Note 1	0.0	0.0	0.0	0.0	0.0	0.0
6	**Pre-Tax Revenue Requirement Impact**		135.5	139.1	283.5	215.6	214.6	213.2
7	**Income Tax Impact**	Note 2	(6.0)	(2.1)	58.8	39.2	14.8	13.5
8	**Total Revenue Requirement Impact** (line 6 + line 7)		129.5	137.0	342.3	254.8	229.4	226.6
	BRUCE FACILITIES							
9	**Depreciation of Asset Retirement Costs**	Ex. C2-1-1 Table 3	26.1	23.9	69.6	100.6	100.6	100.6
10	**Used Fuel Storage and Disposal Variable Expenses**	Ex. C2-1-1 Table 3	17.8	27.0	44.5	51.6	54.3	56.4
11	**Low & Intermediate Level Waste Management Variable Expenses**	Ex. C2-1-1 Table 3	0.9	1.0	1.8	2.8	2.4	3.8
12	**Accretion Expense**	Ex. C2-1-1 Table 3	283.1	296.6	327.8	367.8	382.9	397.3
13	**Less: Segregated Fund Earnings (Losses)**	Ex. C2-1-1 Table 3	418.0	240.1	350.9	330.8	347.0	359.8
14	**Impact on Bruce Facilities' Income Taxes**	Note 3	21.5	(27.5)	(23.2)	(48.0)	(48.3)	(49.6)
15	**Pre-Tax Revenue Requirement Impact (Impact on Bruce Lease Net Revenues)**		(68.6)	81.0	69.6	143.9	144.9	148.7
16	**Income Tax Impact on Revenue Requirement** (line 15 x tax rate / (1-tax rate))	Note 4	(28.0)	29.2	23.2	48.0	48.3	49.6
17	**Total Revenue Requirement Impact** (line 15 + line 16)		(96.6)	110.2	92.9	191.9	193.2	198.3
18	**Total Revenue Requirement Impact - Prescribed and Bruce Faciliites**		32.9	247.2	435.1	446.7	422.6	424.9
	(line 8 + line 17)							

See Ex. C2-1-1 Table 1a for notes

Table 2
Prescribed Facilities - Asset Retirement Obligation, Nuclear Segregated Funds, and Asset Retirement Costs ($M)
Years Ending December 31, 2010 to 2015

Line No.	Description	Note	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2014 Plan	2015 Plan
			(a)	(b)	(c)	(d)	(e)	(f)
	ASSET RETIREMENT OBLIGATION							
1	**Opening Balance**	1	6,391.2	7,174.5	7,935.9	8,034.1	8,400.6	8,772.2
2	**Darlington Refurbishment Adjustment**	2	497.4	0.0	0.0	0.0	0.0	0.0
3	**Adjusted Opening Balance** (line 1 + line 2)		6,888.6	7,174.5	7,935.9	8,034.1	8,400.6	8,772.2
4	**Used Fuel Storage and Disposal Variable Expenses**		23.5	26.0	51.9	52.7	56.1	56.7
5	**Low & Intermediate Level Waste Management Variable Expenses**		1.1	0.9	3.8	3.3	3.1	5.5
6	**Accretion Expense**		382.2	399.0	432.6	442.1	461.3	479.8
7	**Expenditures for Used Fuel, Waste Management & Decommissioning**		(122.0)	(104.0)	(115.5)	(131.6)	(148.8)	(197.6)
8	**Consolidation and Other Adjustments**		1.2	0.3	0.9	0.0	0.0	0.0
9	**Closing Balance Before Year-End Adjustments** (lines 3 through 8)		7,174.5	7,496.7	8,309.7	8,400.6	8,772.2	9,116.7
10	**Current Approved ONFA Reference Plan Adjustment**	3	0.0	439.2	(276.9)	0.0	0.0	0.0
11	**New CNSC Requirements Adjustment**	4	0.0	0.0	1.3	0.0	0.0	0.0
12	**Closing Balance** (line 9 + line 10 + line 11)		7,174.5	7,935.9	8,034.1	8,400.6	8,772.2	9,116.7
13	**Average Asset Retirement Obligation** ((line 3 + line 9)/2)		7,031.6	7,335.6	8,122.8	8,217.3	8,586.4	8,944.4
	NUCLEAR SEGREGATED FUNDS BALANCE							
14	**Opening Balance**	1	5,058.7	5,564.9	5,895.3	6,316.5	6,687.8	7,142.4
15	**Earnings (Losses)**		417.7	220.7	355.7	326.5	347.2	369.3
16	**Contributions**		150.2	145.0	107.1	98.1	170.1	172.8
17	**Disbursements**		(61.8)	(35.3)	(41.6)	(53.3)	(62.6)	(116.5)
18	**Closing Balance** (line 14 + line 15 + line 16 + line 17)		5,564.9	5,895.3	6,316.5	6,687.8	7,142.4	7,568.0
19	**Average Nuclear Segregated Funds Balance** ((line 14 + line 18)/2)		5,311.8	5,730.1	6,105.9	6,502.1	6,915.1	7,355.2
	UNFUNDED NUCLEAR LIABILITY BALANCE (UNL)							
20	**Opening Balance** (line 3 - line 14)		1,829.9	1,609.6	2,040.6	1,717.6	1,712.8	1,629.8
21	**Closing Balance** (line 9 - line 18)		1,609.6	1,601.4	1,993.2	1,712.8	1,629.8	1,548.7
22	**Average Unfunded Nuclear Liability Balance** ((line 20 + line 21)/2)		1,719.8	1,605.5	2,016.9	1,715.2	1,671.3	1,589.2
	ASSET RETIREMENT COSTS (ARC)							
23	**Opening Balance**	1	1,098.0	1,504.5	1,914.7	1,510.5	1,429.8	1,349.1
24	**Reconciliation Adjustment**	5	(42.7)	0.0	0.0			
25	**Darlington Refurbishment Adjustment**	2	475.5	0.0	0.0	0.0	0.0	0.0
26	**Adjusted Opening Balance** (line 23 + line 24 + line 25)		1,530.8	1,504.5	1,914.7	1,510.5	1,429.8	1,349.1
27	**Depreciation Expense**		(26.3)	(29.0)	(127.2)	(80.7)	(80.7)	(80.7)
28	**Closing Balance Before Year-End Adjustments** (line 26 + line 27)		1,504.5	1,475.4	1,787.5	1,429.8	1,349.1	1,268.4
29	**Current Approved ONFA Reference Plan Adjustment**	3	0.0	439.2	(276.9)	0.0	0.0	0.0
30	**Closing Balance** (line 28 + line 29)		1,504.5	1,914.7	1,510.5	1,429.8	1,349.1	1,268.4
31	**Average Asset Retirement Costs** ((line 26 + line 28)/2)		1,517.6	1,490.0	1,851.1	1,470.2	1,389.5	1,308.8
32	**LESSER OF AVERAGE UNL OR ARC** (lesser of line 22 or line 31)		1,517.6	1,490.0	1,851.1	1,470.2	1,389.5	1,308.8

Notes:

1 Opening balances in col. (a) from EB-2010-0008, Ex. C2-1-1 Table 1.

2 Adjustment recorded on January 1, 2010 associated with the changes to the end-of-life date assumptions underlying the ARO calculation, as a result of the approval of the definition phase of the Darlington Refurbishment project.

3 Adjustments recorded on December 31, 2011 and December 31, 2012, as per Ex. C2-1-1 Table 4, associated with the current approved ONFA Reference Plan effective January 1, 2012.

4 Represents implementation, in accordance with GAAP, of new CNSC requirements in 2012 to include certain facilites with Waste Nuclear Substance Licenses not included in the 2012 ONFA Reference Plan due to timing of notification by the CNSC. As a result, ARO increased by $2.4M to include a legacy facility not used to support OPG's current operations, of which $1.3M is atttributed to prescribed facilities and $1.1M is attributed to Bruce facilities. In accordance with GAAP, this amount was expensed (i.e., not included in ARC) in 2012.

5 Adjustment to remove from the ARC continuity amounts reflected in the non-ARC portion of PP&E in rate base. Total rate base is not impacted.

Table 3
Bruce Facilities - Asset Retirement Obligation, Nuclear Segregated Funds, and Asset Retirement Costs ($M)
Years Ending December 31, 2010 to 2015

Line No.	Description	Note	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2014 Plan	2015 Plan
			(a)	(b)	(c)	(d)	(e)	(f)
	ASSET RETIREMENT OBLIGATION							
1	**Opening Balance**	1	5,315.0	5,357.0	6,107.7	7,125.5	7,434.8	7,745.5
2	**Darlington Refurbishment Adjustment**	2	(204.4)	0.0	0.0	0.0	0.0	0.0
3	**Adjusted Opening Balance** (line 1 + line 2)		5,110.7	5,357.0	6,107.7	7,125.5	7,434.8	7,745.5
4	**Used Fuel Storage and Disposal Variable Expenses**		17.8	27.0	44.5	51.6	54.3	56.4
5	**Low & Intermediate Level Waste Management Variable Expenses**		0.9	1.0	1.8	2.8	2.4	3.8
6	**Accretion Expense**		283.1	296.6	327.8	367.8	382.9	397.3
7	**Expenditures for Used Fuel, Waste Management & Decommissioning**		(57.5)	(68.1)	(83.7)	(112.8)	(128.9)	(172.7)
8	**Consolidation and Other Adjustments**		1.9	(1.0)	0.6	0.0	0.0	0.0
9	**Closing Balance Before Year-End Adjustments** (lines 3 through 8)		5,357.0	5,612.6	6,398.7	7,434.8	7,745.5	8,030.3
10	**Current Approved ONFA Reference Plan Adjustment**	3	0.0	495.1	706.1	0.0	0.0	0.0
11	**New CNSC Requirements Adjustment**	4	0.0	0.0	20.6	0.0	0.0	0.0
12	**Closing Balance** (line 9 + line 10 + line 11)		5,357.0	6,107.7	7,125.5	7,434.8	7,745.5	8,030.3
13	**Average Asset Retirement Obligation** ((line 3 + line 9)/2)		5,233.8	5,484.8	6,253.2	7,280.1	7,590.2	7,887.9
	NUCLEAR SEGREGATED FUNDS BALANCE							
14	**Opening Balance**	1	5,187.2	5,680.9	6,002.5	6,400.1	6,779.6	7,045.2
15	**Earnings (Losses)**		418.0	240.1	350.9	330.8	347.0	359.8
16	**Contributions**		113.9	105.5	74.9	85.9	(31.3)	(29.4)
17	**Disbursements**		(38.2)	(24.0)	(28.1)	(37.2)	(50.1)	(89.3)
18	**Closing Balance** (line 14 + line 15 + line 16 + line 17)		5,680.9	6,002.5	6,400.1	6,779.6	7,045.2	7,286.3
19	**Average Nuclear Segregated Funds Balance** ((line 14 + line 18)/2)		5,434.0	5,841.7	6,201.3	6,589.9	6,912.4	7,165.8
	ASSET RETIREMENT COSTS (ARC)							
20	**Opening Balance**	1	1,035.8	817.6	1,288.8	1,944.8	1,844.2	1,743.6
21	**Reconciliation Adjustment**	5	(9.6)	0.0	0.0			
22	**Darlington Refurbishment Adjustment**	2	(182.4)	0.0	0.0	0.0	0.0	0.0
23	**Adjusted Opening Balance** (line 20 + line 21 + line 22)		843.7	817.6	1,288.8	1,944.8	1,844.2	1,743.6
24	**Depreciation Expense**		(26.1)	(23.9)	(69.6)	(100.6)	(100.6)	(100.6)
25	**Closing Balance Before Year-End Adjustments** (line 23 + line 24)		817.6	793.7	1,219.2	1,844.2	1,743.6	1,643.0
26	**Current Approved ONFA Reference Plan Adjustment**	3	0.0	495.1	706.1	0.0	0.0	0.0
27	**New CNSC Requirements Adjustment**	4	0.0	0.0	19.5	0.0	0.0	0.0
28	**Closing Balance** (line 25 + line 26 + line 27)		817.6	1,288.8	1,944.8	1,844.2	1,743.6	1,643.0
29	**Average Asset Retirement Costs** ((line 23 + line 25)/2))		830.7	805.7	1,254.0	1,894.5	1,793.9	1,693.3

Notes:

1 Opening balances in col. (a) from EB-2010-0008, Ex. C2-1-1 Table 2.

2 Adjustment recorded on January 1, 2010 associated with the changes to the end-of-life date assumptions underlying the ARO calculation, as a result of the approval of the definition phase of the Darlington Refurbishment project.

3 Adjustments recorded on December 31, 2011 and December 31, 2012, as per Ex. C2-1-1 Table 4, associated with the current approved ONFA Reference Plan effective January 1, 2012.

4 Represents implementation, in accordance with GAAP, of new CNSC requirements in 2012 to include certain facilites with Waste Nuclear Substance Licenses not included in the 2012 ONFA Reference Plan due to timing of notification by the CNSC. As a result, ARO increased by $2.4M to include a legacy facility not used to support OPG's current operations, of which $1.3M is atttributed to prescribed facilities and $1.1M is attributed to Bruce facilities. In accordance with GAAP, this amount was expensed (i.e., not included in ARC) in 2012. ARO increased by a further $19.5M to include a facility dedicated to supporting the Bruce facilities. In accordance with GAAP, this amount was included in ARC.

5 Adjustment to remove from the ARC continuity amounts reflected in the non-ARC portion of PP&E. Total Bruce Lease net revenues are not impacted.

Table 1

Calculation of Weighted Average Accretion Rate for 20013-2015[1]

Line No.	Asset Retirement Obligation Tranche[2]	Year-end Balance ($M) (a)	Weighting (b)	Accretion Rate[3] (c)	Weighted Average Accretion Rate (d) = (b) x (c)
	2013 Budget - As of December 31, 2012[4]				
1	Tranche 1	11,584.4	76.4%	5.75%	4.40%
2	Tranche 2	1,726.5	11.4%	4.60%	0.52%
3	Tranche 3	398.6	2.6%	4.80%	0.13%
4	Tranche 4	994.0	6.6%	3.43%	0.22%
5	Tranche 5	451.1	3.0%	3.50%	0.10%
6	**Total/Weighted average as at year-end[5]**	15,154.5	100.0%		**5.37%**
	2014 Plan - As of December 31, 2013				
7	Tranche 1	12,058.4	76.2%	5.75%	4.38%
8	Tranche 2	1,777.4	11.2%	4.60%	0.52%
9	Tranche 3	411.1	2.6%	4.80%	0.12%
10	Tranche 4	1,011.8	6.4%	3.43%	0.22%
11	Tranche 5	571.7	3.6%	3.50%	0.13%
12	**Total/Weighted average as at year-end[5]**	15,830.4	100.0%		**5.37%**
13	**2015 Plan - As of December 31, 2014**				
14	Tranche 1	12,534.0	75.9%	5.75%	4.36%
15	Tranche 2	1,827.3	11.1%	4.60%	0.51%
16	Tranche 3	423.5	2.6%	4.80%	0.12%
17	Tranche 4	1,028.4	6.2%	3.43%	0.21%
18	Tranche 5	699.6	4.2%	3.50%	0.15%
19	**Total/Weighted average as at year-end[5]**	16,512.8	100.0%		**5.36%**

Notes:

1 Numbers may not calculate due to rounding

2 Tranches correspond to the following: Tranche 1 = ARO recorded prior to December 31, 2006; Tranche 2 = ARO recorded on December 31, 2006 arising from the approved 2006 ONFA Reference Plan; Tranche 3 = ARO recorded on December 31, 2010 in relation to the decision related to the Darlington refurbishment project; Tranche 4 = ARO recorded on December 31, 2011 arising from the approved 2012 ONFA Reference Plan; Tranche 5 = ARO recorded on December 31, 2012 arising from the approved 2012 ONFA Reference Plan.

3 As shown in EB-2012-0002, Ex. M1-1, Attachment 3, Table 1a, Note 1, col. (c)

4 As shown in EB-2012-0002, Ex. M1-1, Attachment 3, Table 1a, Note 1

5 Represents OPG's total nuclear ARO excluding consolidation adjustments

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

(millions of dollars)	**2013**	**2012**
Cash flow hedges		
Gain (loss) in OCI	**17**	(12)
Reclassification of losses to net interest expense	**18**	12
Reclassification of gains to fuel expense	**(3)**	7
Commodity derivatives		
Realized losses in revenue	**(7)**	(2)
Unrealized losses in revenue	**(4)**	(2)
Embedded derivative		
Unrealized losses in revenue [1]	**(33)**	(284)

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

Existing net losses of $19 million deferred in AOCL as at December 31, 2013 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:

(millions of dollars except where noted)	Fair Value	Carrying Value [1]	Balance Sheet Line Item
As at December 31, 2013			
Commodity derivative instruments	**10**	**10**	Other accounts receivable and prepaid expenses
Investment in OPG Ventures Inc.	**9**	**9**	Other long-term assets
Nuclear fixed asset removal and nuclear waste management funds (includes current portion)	**13,496**	**13,496**	Nuclear fixed asset removal and nuclear waste management funds
Foreign exchange derivative instruments	**1**	**1**	Other accounts receivable and prepaid expenses
Commodity derivative instruments	**(11)**	**(11)**	Accounts payable and accrued charges
Cash flow hedges - Forward start interest rate swaps	**(8)**	**(8)**	Long-term accounts payable and accrued charges
Payable related to cash flow hedges	**(56)**	**(56)**	Long-term accounts payable and accrued charges
Derivative embedded in the Bruce Lease	**(346)**	**(346)**	Long-term accounts payable and accrued charges
Long-term debt (includes current portion)	**(5,955)**	**(5,625)**	Long-term debt
As at December 31, 2012			
Commodity derivative instruments	7	7	Other accounts receivable and prepaid expenses
Investment in OPG Ventures Inc.	10	10	Other long-term assets
Nuclear fixed asset removal and nuclear waste management funds (includes current portion)	12,717	12,717	Nuclear fixed asset removal and nuclear waste management funds
Foreign exchange derivative instruments	(1)	(1)	Accounts payable and accrued charges
Commodity derivative instruments	(4)	(4)	Accounts payable and accrued charges
Cash flow hedges - Forward start interest rate swaps	(66)	(66)	Long-term accounts payable and accrued charges
Payable related to cash flow hedges	(24)	(24)	Long-term accounts payable and accrued charges
Derivative embedded in the Bruce Lease	(392)	(392)	Long-term accounts payable and accrued charges
Long-term debt (includes current portion)	(5,751)	(5,114)	Long-term debt

[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 financial assets and liabilities measured at fair value in accordance with the fair value hierarchy:

	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**
Commodity derivative instruments	**5**	**2**	**3**	**10**
Investment in OPG Ventures Inc.	**-**	**-**	**9**	**9**
Foreign exchange derivative instruments	**-**	**1**	**-**	**1**
Total	**3,536**	**9,679**	**301**	**13,516**
Liabilities				
Derivative embedded in the Bruce Lease	**-**	**-**	**(346)**	**(346)**
Forward start interest rate swaps	**-**	**(8)**	**-**	**(8)**
Commodity derivative instruments	**(8)**	**(3)**	**-**	**(11)**
Total	**(8)**	**(11)**	**(346)**	**(365)**
Net assets (liabilities)	**3,528**	**9,668**	**(45)**	**13,151**

	December 31, 2012			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Decommissioning Fund	2,596	2,948	163	5,707
Used Fuel Fund	212	6,785	13	7,010
Commodity derivative instruments	2	2	3	7
Investment in OPG Ventures Inc.	-	-	10	10
Total	2,810	9,735	189	12,734
Liabilities				
Derivative embedded in the Bruce Lease	-	-	(392)	(392)
Forward start interest rate swaps	-	(66)	-	(66)
Commodity derivative instruments	(3)	(1)	-	(4)
Foreign exchange derivative instruments	-	(1)	-	(1)
Total	(3)	(68)	(392)	(463)
Net assets (liabilities)	2,807	9,667	(203)	12,271

During the year ended December 31, 2013, 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:

	For the year ended December 31, 2013				
(millions of dollars)	**Decom-missioning Fund**	**Used Fuel Fund**	**Investment in OPG Ventures Inc.**	**Derivative Embedded in the Bruce Lease** [1]	**Commodity Derivative Instruments**
Opening balance, January 1, 2013	**163**	**13**	**10**	**(392)**	**3**
Unrealized gains included in earnings on nuclear fixed asset removal and nuclear waste management funds[1]	**18**	**3**	**-**	**-**	**-**
Unrealized losses included in revenue	**-**	**-**	**(1)**	**(33)**	**-**
Realized losses included in revenue	**(1)**	**-**	**-**	**-**	**(2)**
Purchases	**83**	**14**	**-**	**-**	**2**
Sales	**(3)**	**-**	**-**	**-**	**-**
Settlements	**(13)**	**12**	**-**	**79**	**-**
Closing balance, December 31, 2013	**247**	**42**	**9**	**(346)**	**3**

[1] Total gains (losses) exclude the impact of regulatory assets and liabilities.

	For the year ended December 31, 2012				
(millions of dollars)	**Decom-missioning Fund**	**Used Fuel Fund**	**Investment in OPG Ventures Inc.**	**Derivative Embedded in the Bruce Lease** [1]	**Commodity Derivative Instruments**
Opening balance, January 1, 2012	98	6	16	(186)	2
Unrealized gains included in earnings on nuclear fixed asset removal and nuclear waste management funds[1]	11	1	-	-	-
Unrealized losses included in revenue	-	-	(5)	(284)	(1)
Realized losses included in revenue	-	-	-	-	(5)
Purchases	58	6	-	-	7
Sales	(2)	-	-	-	-
Settlements	(2)	-	(1)	78	-
Closing balance, December 31, 2012	163	13	10	(392)	3

[1] Total gains (losses) exclude the impact of regulatory assets and liabilities.

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, 2013:

(millions of dollars except where noted)	**Fair Value**	**Valuation Technique**	**Unobservable Input**	**Range**
Derivative embedded in the Bruce Lease	(346)	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. In 2012, the service life of these Bruce units was extended to 2019. The service life extension accounted for $249 million of the total increase in the derivative liability during 2012. 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 pre-tax income statement impact, as a result of changes in the derivative liability, is offset by the pre-tax 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, 2013:

(millions of dollars except where noted)	**Fair Value**	**Unfunded Commitments**	**Redemption Frequency**	**Redemption Notice**
Infrastructure	312	241	n/a	n/a
Real Estate	286	373	n/a	n/a
Pooled Funds				
Short-term Investments	27	-	Daily	1 - 5 Days
Fixed Income	519	-	Daily	1 - 5 Days
Equity	1,627	-	Daily	1 - 5 Days
Total	2,771	614		

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

Infrastructure

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.

Real Estate

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 US and Emerging Market listed equity and fixed income securities. 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.

Investment in OPG Ventures Inc.

Significant Level 3 inputs used in the fair value measurement of the OPG Ventures Inc. investments include recent comparable transactions, comparable benchmark information, bid/ask spread of similar transactions, and other relevant factors. Significant increases (decreases) in any of those inputs in isolation would result in significantly higher (lower) fair value measurement.

14. COMMON SHARES

As at December 31, 2013 and 2012, 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 on OPG and Bruce Power L.P. by British Energy Limited and British Energy International Holdings Limited (together British Energy). The British Energy claim against OPG pertains to corrosion in the Bruce Unit 8 Steam Generators, in particular, erosion of the support plates through which the boiler tubes pass. The claim amount includes $65 million due to an extended outage to repair some of the alleged damage. The balance of the amount claimed is based on an increased probability the steam generators will have to be replaced or