OPG

EB-2013-0321

Board Staff Compendium

Panel 7

Total benefit costs, including the impact of the Pension and OPEB Cost Variance Account and Impact for USGAAP Deferral Account, for the years ended December 31 are as follows:

(millions of dollars)	**2013**	**2012**
Registered pension plans	**476**	358
Supplementary pension plans	**29**	27
Other post-employment benefits	**262**	260
Pension and OPEB Cost Variance Account *(Note 5)*	**(312)**	(192)
Impact for USGAAP Deferral Account *(Note 5)*	**-**	(47)
Pension and other post-employment benefit costs	**455**	406

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)	**2013**	**2012**	**2013**	**2012**	**2013**	**2012**
Change in Plan Assets						
Fair value of plan assets at beginning of year	**10,337**	9,604	**-**	-	**-**	-
Contributions by employer	**306**	375	**14**	16	**87**	83
Contributions by employees	**74**	77	**-**	-	**-**	-
Actual return on plan assets, net of expenses	**923**	898	**-**	-	**-**	-
Benefit payments	**(679)**	(617)	**(14)**	(16)	**(87)**	(83)
Fair value of plan assets at end of year	**10,961**	10,337	**-**	-	**-**	-
Change in Projected Benefit Obligations						
Projected benefit obligations at beginning of year	**13,669**	12,197	**297**	261	**3,174**	2,708
Employer current service costs	**291**	264	**10**	9	**86**	78
Contributions by employees	**74**	77	**-**	-	**-**	-
Interest on projected benefit obligation	**589**	618	**13**	14	**138**	139
Benefit payments	**(679)**	(617)	**(14)**	(16)	**(87)**	(83)
Past service credits	**-**	-	**-**	-	**(2)**	(7)
Net actuarial (gain) loss	**(522)**	1,130	**(17)**	29	**(590)**	339
Projected benefit obligations at end of year	**13,422**	13,669	**289**	297	**2,719**	3,174
Funded status – deficit at end of year	**(2,461)**	(3,332)	**(289)**	(297)	**(2,719)**	(3,174)

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

	Registered Pension Plans		**Supplementary Pension Plans**		**Other Post-Employment Benefits**	
(millions of dollars)	**2013**	**2012**	**2013**	**2012**	**2013**	**2012**
Current liabilities	**-**	-	**(9)**	(8)	**(91)**	(98)
Non-current liabilities	**(2,461)**	(3,332)	**(280)**	(289)	**(2,628)**	(3,076)
Total liabilities	**(2,461)**	(3,332)	**(289)**	(297)	**(2,719)**	(3,174)

The accumulated benefit obligations for the registered pension plans and supplementary pension plans as at December 31, 2013 are $12,242 million and $237 million, respectively (2012 – $12,366 million and $242 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.

pension plan will be determined as part of the funding valuation which is required to be filed by September 30, 2014. 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, 2013, there was a surplus on a going-concern basis of $14 million and a deficiency on a wind-up basis of $15 million. In the previously filed actuarial valuation, as at January 1, 2012, there was a surplus on a going-concern basis of $8 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, 2014.

The supplementary pension plans are not funded, but are secured by Letters of Credit totalling $302 million as at December 31, 2013 (2012 – $332 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, 2013 are as follows:

(millions of dollars)	Registered Pension Plans	Supplementary Pension Plans	Other Post-Employment Benefits
2014	521	9	91
2015	551	10	96
2016	582	11	100
2017	589	12	105
2018	634	13	110
2019 through 2023	3,658	79	625

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 2013 OPEB cost recognized of $54 million (2012 – $48 million) or a decrease in the service and interest components of the 2013 OPEB cost recognized of $39 million (2012 – $36 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, 2013 of $472 million (2012 – $604 million) or a decrease in the projected OPEB obligation at December 31, 2013 of $360 million (2012 – $456 million).

12. 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.

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 other contractual arrangements for a significant portion of OPG's business. The majority of this exposure should be mitigated with the implementation of a

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Undertaking

To add a "total" column to the table in response to board staff interrogatory 124, removes the "2007" column, and cross-add from 2008 to 2015 to the "total" column.

Response

A modified version of Ex. L-6.8-1 Staff-124, Chart 1 is provided below. In addition to removing the "2007 column" and incorporating the requested "total" column, the modified chart also reflects the updated forecast of 2014 - 2015 pension and OPEB costs presented in Ex. L-6.8-1 Staff-112.

In the EB-2010-0008 Decision With Reasons (page 91), the OEB approved the continued use of the accrual method for determining supplementary pension plan ("SPP") and other post retirement benefit ("OPRB") costs in setting OPG's payment amounts. The circumstances with respect to OPG's SPP and OPRB costs and their recovery have not changed since EB-2010-0008.

On an accrual basis, SPP and OPRB costs are incurred and recognized in accordance with generally accepted accounting principles when the related employee service is considered to be rendered and the benefit is considered to be earned, not when the actual benefit payments are made to retirees in the future. It is the earning of the benefit which results in the cost. Reflecting these costs in payment amounts at the time the costs arise results in an appropriate matching of costs and benefits, thereby avoiding intergenerational equity issues as consistent with generally accepted regulatory principles.

Modified Chart 1
OPRB and SPP Amounts[1]

$M	2008 Actual[2]	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan	Total
Actual/Projected Costs	157.9	120.4	136.1	175.6	203.0	231.3	184.6	192.9	1,401.7
Recoverable Costs	119.2	162.5	161.0[3]	173.2[4]	203.0	231.3	184.6	192.9	1,427.7
Actual/Projected Benefit Payments	44.2	43.1	43.4	48.4	57.9	61.2	64.9	71.3	434.4
Recoverable Costs Less Actual/Projected Benefit Payments	75.0	119.4	117.6	124.8	145.1	170.1	119.7	121.6	993.3

[1] Amounts for 2008-2013 exclude those for the newly regulated hydroelectric assets; amounts for 2014 and 2015 include them. Amounts for all years do not include those related to the Nuclear Waste Management Organization.
[2] Amount for recoverable costs represents 9/12 of the annual amount, as the EB-2007-0905 payment amounts came into effect on April 1, 2008. Amounts for actual costs and benefit payments are for the full year.
[3] Represents 12/21 of the sum of 2008 and 2009 amounts, as the EB-2007-0905 payment amounts became effective April 1, 2008 and applied throughout 2010.
[4] Represents 2/21 of the sum of 2008 and 2009 amounts, plus 10/12 of the 2011 amount, as the EB-2010-0008 payment amounts were effective March 1, 2011

MR. KOGAN: Yes, it is, again exclusive of tax impacts. And in fact, you can see that by virtue of the first and second lines being the same. The reason they are the same in 2013 is because it reflects the actuals, including variance account entries.

MR. SKINNER: So in order to get the total recoverable amount, would we have to take the OPEBs and SPP amounts out of the variance account by year it arose, and add it to the amounts on chart 1?

MR. KOGAN: Sorry if I wasn't clear. I meant to say that we actually would have done that.

MR. SKINNER: I'm sorry?

MR. KOGAN: That's why you see that the recoverable number and the actual number are the same. Normally, in the absence of a variance account, you would expect those to be different by virtue of forecast variances, but we have taken into account the variance account.

MR. SKINNER: Okay. Do you know what the average remaining service lives of your employees are? I had a look at the actuarial valuation and I couldn't see that number.

MR. KOGAN: I don't know the exact number right now, but I would expect it to be more or less in the range of the 12 years that we have, I think, roughly talked about in the EB-2012 hearing, plus or minus a couple of years.

MR. SKINNER: Okay. The reason I ask, if I take that billion dollar number from chart 1 that I have added up, that when you complete the table you will probably see as

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		Other Post-Employment Benefits	
	2013	2012	2013	2012
Weighted Average Assumptions – Benefit Obligations at Year-End				
Rate used to discount future benefits	**4.90%**	4.30%	**4.91%**	4.32%
Salary schedule escalation rate	**2.50%**	2.50%	**-**	-
Rate of cost of living increase to pensions	**2.00%**	2.00%	**-**	-
Initial health care trend rate	**-**	-	**6.19%**	6.38%
Ultimate health care trend rate	**-**	-	**4.34%**	4.38%
Year ultimate health care trend rate reached	**-**	-	**2030**	2030
Rate of increase in disability benefits	**-**	-	**2.00%**	2.00%

	Registered and Supplementary Pension Plans		Other Post-Employment Benefits	
	2013	2012	2013	2012
Weighted Average Assumptions – Costs for the Year				
Expected return on plan assets, net of expenses	**6.25%**	6.50%	**-**	-
Rate used to discount future benefits	**4.30%**	5.10%	**4.32%**	5.07%
Salary schedule escalation rate	**2.50%**	3.00%	**-**	-
Rate of cost of living increase to pensions	**2.00%**	2.00%	**-**	-
Initial health care trend rate	**-**	-	**6.38%**	6.48%
Ultimate health care trend rate	**-**	-	**4.38%**	4.38%
Year ultimate health care trend rate reached	**-**	-	**2030**	2030
Rate of increase in disability benefits	**-**	-	**2.00%**	2.00%
Expected average remaining service life for employees (years)	**13**	12	**14**	13

(millions of dollars)	Registered Pension Plans		Supplementary Pension Plans		Other Post-Employment Benefits	
	2013	2012	2013	2012	2013	2012
Components of Cost Recognized						
Current service costs	**291**	264	**10**	9	**86**	78
Interest on projected benefit obligation	**589**	618	**13**	14	**138**	139
Expected return on plan assets, net of expenses	**(648)**	(668)	**-**	-	**-**	-
Amortization of past service costs [1]	**-**	-	**-**	-	**1**	2
Amortization of net actuarial loss [1]	**244**	144	**6**	4	**48**	31
Recognition of LTD net actuarial (gain) loss	**-**	-	**-**	-	**(11)**	10
Cost recognized [2]	**476**	358	**29**	27	**262**	260

[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] These pension and OPEB costs exclude the reduction of costs resulting from the recognition of additions to the regulatory assets for the Pension and OPEB Cost Variance Account and the Impact for USGAAP Deferral Account. The Pension and OPEB Cost Variance Account and the Impact for USGAAP Deferral Account are discussed in Note 5.

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

In the event that the OEB determines that OPG's pension and OPEB costs should be determined on a cash basis for ratemaking purposes, OPG's request for the Pension and Other Post Employment Benefits Cost Variance Account would remain unchanged. A variance account is required for recovery of costs on a cash basis because, as noted above, OPG is forecasting a significant variance in its test period cash amounts over those presented in its pre-filed evidence and further changes may arise in subsequent funding valuations, particularly if OPG is required to move to annual valuations, while continuing to use a multi-year test period for setting the payment amounts.

Proposal for a "Segregated Fund" for OPEB Costs

Board staff submits that under the accrual method, the OEB should consider a segregated fund to deal with the differences between the amount collected in rates and the cash OPEB payments made by OPG (Board staff argument, p.99). OPG supports the submissions of SEC in disagreeing with this request on the basis that any segregated fund would have to address situations when accrual costs were both higher and lower than cash costs (SEC argument, para. 10.6.5). In addition, OPG submits that it is doubtful whether the OEB has the jurisdiction to mandate OPG to set cash payments aside in a segregated fund for a specific use. Board staff's argument is silent on this question as well as on how such a fund would be structured, managed and paid for. Finally, at least for the supplementary pension plan component of OPEB, there likely would be adverse tax consequences to OPG under the *Income Tax Act* that would have to be passed on to ratepayers, if the OEB required such an arrangement. For all of these reasons, the proposal for a segregated fund for OPEB costs should be denied.

Approval of the Pension and Other Post Employment Benefits Cost Variance Account

In its Impact Statement (Ex. N-T1-S1), OPG provided updated forecasts of its pension and OPEB costs for 2011 and 2012 as projected by external actuaries as of the end of August 2010. Compared to OPG's original evidence, the total projected increase over the two test years is $251.5M for Nuclear and $12.7M for Regulated Hydroelectric have an economic effect on regulated enterprises and requires accounting that may be different than that required to be followed by a non-regulated enterprise if certain criteria are met.

On October 16, 1992, the Interstate Natural Gas Association of America (INGAA) filed a petition for issuance of a policy statement addressing the appropriate rate and accounting treatment of PBOPs. INGAA maintained in its petition that the change in accounting required by SFAS 106 will result in a reduction in income and equity for natural gas pipelines unless the Commission acts expeditiously to remove regulatory uncertainty regarding rate treatment of PBOPs and to allow regulated entities to recover PBOP accruals in rates on a current basis.

On October 21, 1992, the Commission issued a Request for Public Comments generally on the INGAA petition. Public comments were requested by November 12, 1992, and 77 comments were received. 3/ The Commission has reviewed those comments and is issuing this policy statement to address the concerns raised by the commenters.

II. The Policy

It shall be the policy of the Commission to recognize, as a component of jurisdictional cost-based rates of natural gas pipeline companies and public utilities under its jurisdiction, and oil pipelines should they elect to comply with this

3/ See the Appendix for a list of comments received.

statement, allowances for prudently incurred costs of PBOPs of company employees when determined on an accrual basis (and supported by independent actuarial studies) that are consistent with the accounting principles set forth in SFAS 106 provided that the following conditions are met:

(1) The company must agree to make cash deposits to an irrevocable external trust fund, 4/ no less frequently than quarterly, in amounts that are proportional and, on an annual basis equal, to the annual test period allowance for PBOPs. The trust must provide that any disbursements made from the trust are limited to payments for the benefit of employees pursuant to the company's postretirement plans, payments for expenses of the trust, and refunds to customers pursuant to a Commission approved refund plan in the event the funds are not to be paid to employees. The trustee must be independent of the company and authorized to make only those investments which are consistent with sound investment policies for funds of this nature.

(2) The company must agree, when it is consistent with good business practices to do so, to maximize the use of income tax deductions for contributions to funds of this nature. If tax deductions are not available for some portion of currently funded amounts, deferred income tax accounting must be followed for the tax effects of such transactions.

4/ An "external trust fund," or "external funding," used herein means a fund under the direction of a trustee independent of and external to the company. Contrast this with establishing an internal reserve account, or "internal funding."

Board Staff Interrogatory #123

Ref: Exh F4-3-1, FERC Policy: 61FERC61 330 PL63-1-000

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

Interrogatory

a) Does OPG have a separate fund, or irrevocable trust (as noted in FERC policy 61FERC61,330), into which OPEB and SPP recoveries that exceed payments to retirees are deposited and managed to earn a return on behalf of ratepayers?

b) Please provide the legal rationale and/or explanation that support OPG's statement from page 129 of its reply argument in EB-2010-0008.

> "In addition, OPG submits that it is doubtful whether the OEB has the jurisdiction to mandate OPG to set cash payments aside in a segregated fund for a specific use. Board staff's argument is silent on this question as well as on how such a fund would be structured, managed and paid for."

c) Has OPG undertaken a review of what would be required to set up and manage such a segregated fund or irrevocable trust similar to that in the FERC guidelines as provided?

d) If OPG has not undertaken this review, please explain why OPG believes that the Board should allow OPG to continue to use ratepayer money, recovered for OPEBs decades in advance of the cash requirement, for general corporate purposes.

e) Please provide OPG's estimate of the costs that would be incurred to create an irrevocable trust for OPEBs and SPP and what the annual operating costs would be following the FERC guidelines as provided.

Response

a) No.

b) The OEB's jurisdiction is derived from statute. The submission reflects OPG's view that there is no provision in *the Ontario Energy Board Act, 1998*, which would permit the OEB to mandate OPG to set cash payments aside in a segregated fund for a specific use.

c) No.

d) In the EB-2010-0008 Decision with Reasons (page 91) the OEB approved the continued use of the accrual method of setting pension and other post employment benefit costs. On an accrual basis, OPEB cost is incurred and recognized when related employee service is rendered, not when the actual benefit payment is made to retirees in the future. The circumstances with respect to OPG's OPEB costs and their recovery have not changed since EB-2010-0008. Therefore, OPG continues to believe that it is appropriate to continue with the accounting (accrual) method, as approved by the OEB.

e) OPG has no estimate of the costs to create or operate such a fund.

structured, managed and paid for."

In response to your concern, we asked if you could provide the costs to create and operate such a fund, and you replied you don't have a cost estimate.

And I was wondering if you would be willing to undertake on a best-efforts basis to find out what it would cost to set up such a fund, to operate it, and what the operating costs would be.

MR. BARRETT: We're going to decline, because we have no plans to set up such a fund.

MR. SKINNER: You may not be aware in the Enbridge case this issue came up in the oral part of the hearing, and Enbridge replied to the Board that they felt a generic proceeding would be better than trying to do it on a company-by-company basis.

Do you think a generic proceeding is a better way to do this than within the context of your proceeding?

MR. SMITH: And I guess our answer to that is if it were to be considered by the Board, then it would be better to consider it in a generic form.

MR. SKINNER: Okay. Issue 6.8, Staff 124, you gave us a table in answer to our interrogatory, and I was wondering if you could undertake to add a "Total" column, drop the "2007" column, because it's got two N/As in it, cross-add from 2008 to 2015, and foot that "Total" column?

And I have done it manually, and the sum of the recoverable costs, minus the benefit payments, is a total of 1 billion, 28 million?

A portion of OPG's total pension and OPEB costs continues to be charged directly to the business units as part of standard labour rates. The portion of pension and OPEB costs included in standard labour rates is based on an estimate of the current service cost for pension and OPEB. The remainder of pension and OPEB costs, which includes interest costs on the obligations, the expected return on pension plan assets, amounts for past service costs and actuarial gains and losses, and any current service cost variance from the estimate reflected in the standard labour rates, continues to be recorded as a centrally-held cost (presented in Ex. F4-4-1, Section 3.0).

The centrally-held costs for pension and OPEB are directly assigned and allocated to the regulated business units in proportion to the amount of pension and OPEB costs directly charged to the regulated business units plus the costs assigned and allocated from the support services groups. The same methodology was used in EB-2010-0008 and EB-2012-0002. It has been reviewed by HSG Group, Inc. in the cost allocation study presented in Ex. F5-5-1, as well as by Black & Veatch Corporation Inc. in the cost allocation study filed in EB-2010-0008.

The costs associated with plans that provide benefits to OPG's employees during their employment continue to be charged to regulated business units largely via standard labour rates with a small portion included in centrally-held costs.

6.3.5 Comparison of Pension and OPEB Costs

Charts 2, 3 and 4 below present pension and OPEB costs attributed to nuclear, previously regulated hydroelectric and newly regulated hydroelectric operations, respectively, for the 2010-2015 period.[23] The 2011 and 2012 amounts for the nuclear and previously hydroelectric operations were reflected in the December 31, 2012 balances of the Pension and OPEB Cost Variance Account (on a Canadian GAAP basis) and the Impact for USGAAP Deferral Account approved in EB-2012-0002. Actuarial and audit reports in support of the 2011 and

[23] The figures in these Charts differ from those used in Table 1 and Attachment 6 because the amounts here include total pension and OPEB costs (i.e., all components) while Table 1 and Attachment 6 include only the current service cost component of pension and OPEB costs.

Board Staff Interrogatory #113

Ref: Exh A2-1-1 Attachment 1 page 117

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

Interrogatory

a) Please provide the tables similar to note 10 in OPG Inc.'s audited financial statements that will show the funded status as at December 31, 2013 using the updated evidence requested above for discount rate and actual returns both as of December 31, 2013.
b) Please provide a similar updated table for the regulated business as at December 31, 2013 and describe how the allocations from OPG Inc. to the regulated business were prepared.

Response

a) The equivalent table as at December 31, 2013 is found in Note 11 to OPG's 2013 audited consolidated financial statements, at page 42 of Ex. L-2,1-6 ED-003, Attachment 1. The table reflects all the applicable actual information and assumptions as at December 31, 2013, including discount rates and actual pension fund returns.

b) The requested table provides an annual continuity for each of fund assets and projected benefit obligation for the registered pension plans ("RPP"), supplementary pension plans ("SPP") and other post employment benefit ("OPEB") plans, with a net funded status (asset or liability), for accounting purposes, at the end of the year. OPG does not allocate most of the line items making up the continuity between its regulated and unregulated operations, as this information is not required for any purpose and would not be meaningful. This is because there is no separate RPP, SPP or OPEB plan for OPG's regulated business and the OPG pension fund is managed on an aggregate basis for all of OPG's operations. The financial statements for the prescribed facilities are required to reflect on the balance sheet an amount for the portion of OPG's RPP, SPP, and OPEB liabilities (i.e., the funded status for accounting purposes) attributed to the regulated operations.

While OPG is of the view that this allocated figure is not meaningful for the reasons outlined above, it is included in order to prepare a full balance sheet in accordance with generally accepted accounting principles. Using the allocation methodology described in Note 10 to the 2012 audited financial statements for the prescribed facilities (Ex. A2-1-1, Attachment 2b, page 41), OPG is able to approximate that $2.0B of OPG's total accounting RPP liability and $2.4B of OPG's total accounting SPP and OPEB liabilities would be attributed to the prescribed facilities (excluding newly regulated hydroelectric assets) as at December 31, 2013.

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.

Board Staff Interrogatory #116

Ref: Exh F4-3-1 page 31, Mercer Press Release January 2014

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

Interrogatory

In the pre-filed evidence OPG disclosed that the return on the plan assets was 1.7% at the end of August 2013. As noted in the Mercer Press Release, other pension plans in Canada have reported much higher returns than OPG for the entire year 2013.

a) What was the return on plan assets for the entire year ended December 31, 2013?
b) If OPG's return on plan assets was lower than other plans (as identified in the Mercer press release) have reported for 2013, please explain why OPG's returns lagged behind the other pension plans. Please refer to analysis published by Mercer and other experts where possible.
c) What steps has OPG taken to improve the returns on the plan assets in the test period 2014-2015?

Response

a) The return on the plan assets for the calendar year ended December 31, 2013 was 9.2%.

b) The Mercer press release states that "A typical balanced pension portfolio returned 12.8 per cent in 2013." However, the press release does not discuss actual returns of other Canadian pension plans; rather it describes a sample portfolio that is not identified with any specific pension plan. This hypothetical portfolio also appears to exclude alternative assets (real estate, infrastructure, etc.) and real return bonds which are important components of OPG's pension fund; therefore it is not comparable to OPG's pension plan return.

   Pension plan returns are driven by the strategic asset allocation for each pension plan. Each pension plan will have a unique asset allocation to reflect its unique liability profile. OPG does not have the details of other pension plans' liability profiles and investment strategies and cannot, therefore, comment on the relative returns of other Canadian pension plans.

   OPG takes part in an annual third party analysis that evaluates the performance, risk and cost effectiveness of the pension fund relative to other Canadian pension funds. The 2013 analysis is currently underway; however, the results from 2012 indicated that OPG's pension fund was in the top quartile relative to its Canadian peers and the Canadian universe between 2008 and 2012.

c) As noted in Part a) the return for one year period ending December 31, 2013, the OPG pension plan assets returned 9.2%. This exceeds its benchmark return of 8.5%. OPG is satisfied with the performance of the pension fund and continues to review and evaluate the investment strategy. There is a plan to add additional diversifying strategies to the portfolio with a focus on managing downside risk and the funded status of the pension plan.

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

Actuarial Methods and Assumptions

The same actuarial methodology and accounting policies, as set out in the Report, were used in the development of the updated estimates of costs.

- The discount rates have been determined in accordance with US GAAP. The discount rates have been set with reference to that representative of AA corporate bond yields in Canada as at December 31, 2013 having duration similar to the liabilities of the plans. The discount rates used are 4.90% per annum for determining the estimated 2014 and 2015 RPP and SPP costs, 5.00% per annum for determining the estimated 2014 and 2015 OPRB costs and 4.10% per annum for determining the estimated 2014 and 2015 LTD costs;

- The asset value for the RPP as at December 31, 2013 is based on the actual asset value at December 31, 2013 for the pension fund;

- Mortality rates are expected to improve in the future based on observed Canadian pensioner population data. The assumed mortality improvement rates have been updated to reflect the improvement scale developed by the Canadian Institute of Actuaries ("CIA") based on a comprehensive study of observed Canadian pensioner experience. The Canadian Pensioners Mortality Improvement Scale B (CPM-B) was released by the CIA on February 13, 2014 in the CIA Final Report: Canadian Pensioners' Mortality. This improvement scale was developed by the CIA for use by Canadian pension and benefit plan sponsors.

  The CPM-B improvement scale applies improvement rates, by age, that decrease in a linear fashion for year 2012 – 2030 and ultimate rates applicable for all years after 2030. It reflects Canadian experience specific to pensioners and was developed to become the de facto standard for pension plan mortality in Canada. The CPM-B improvement scale is expected to be widely adopted by pension plan sponsors in Canada, and is a best estimate of mortality improvement assumption for the Canadian pensioner population. We will recommend the use of this assumption for the purposes of OPG's next RPP funding valuation effective no later than January 1, 2014;

- The spousal age assumption for active members at retirement has been updated to reflect the demographics of the plan membership. Female spouses are assumed to be three, instead of four, years younger than their male spouses;

- Health care benefit claims costs for the LTD plan have been updated to reflect actual plan experience in 2011 and 2012; and,

- The active membership headcount is first calculated for each business unit based on the assumed decrements and then compared to the estimated active December 31, 2013 and December 31, 2014 headcounts for each business unit. As the calculated headcounts exceed the estimated headcounts, additional employees are assumed to retire to reduce the headcounts. The estimated December 31, 2013 active headcount used is 10,393 (i.e., 6,223 for Nuclear, 1,865 for Hydro / Thermal and 2,305 for Corporate). The estimated December 31, 2014 active headcount used is 10,274 (i.e., 6,282 for Nuclear, 1,717 for Hydro / Thermal and 2,275 for Corporate). For the purposes of projecting membership data from December 31, 2012 to December 31, 2013, base salary in 2013 is assumed to increase by 0% for Management members, 2.75% for the Power Workers' Union ("PWU") members, and 0.75% for the Society of Energy Professionals ("Society") members.

Headcount, FTE and Employee Costs for OPG's Regulated Facilities

Line #		2010 Actual	2011 Actual	2012 Actual	2013 Plan	2013 Actual	2014 Plan	2015 Plan
	Headcount							
1	Nuclear Operations & Projects	8,246	7,901	6,556	6,542	6,362	6,329	6,210
2	DRP and New Nuclear	153	241	227	270	198	266	276
3	Allocated Corporate Support to Nuclear	871	857	1,941	1,880	1,883	1,759	1,683
4	Previously Reg Hydro Operations	365	376	343	342	319	339	337
5	Allocated Corp Support to Previously Reg Hydro	87	79	103	102	102	102	96
6	Newly Reg Hydro Operations	609	617	589	584	571	591	573
7	Allocated Corp Support to Newly Reg Hydro	127	113	143	129	128	144	138
8	Total (Regular and Non-Regular Staff)	10,458	10,184	9,902	9,850	9,563	9,529	9,314
9	Less DRP And New Nuclear Regular Staff (Incl Allocated Corp Support)	176	283	290	365	276	367	378
10	Less All Non-Regular Staff (incl DRP & New Nuclear)	496	463	449	539	551	464	460
11	Regular Staff in Ongoing Operations	9,786	9,438	9,163	8,946	8,736	8,698	8,475
	FTE							
12	Nuclear Operations & Projects	8,292.5	7,988.6	6,536.7	6,547.8	6,353.6	6,315.6	6,243.9
13	DRP and New Nuclear	152.9	226.5	225.1	259.4	200.6	264.1	276.0
14	Allocated Corporate Support to Nuclear	875.0	876.1	2,037.2	1,903.2	1,910.6	1,790.6	1,714.1
15	Previously Reg Hydro Operations	359.7	369.4	343.8	346.8	321.5	343.1	340.9
16	Allocated Corp Support to Previously Reg Hydro	88.7	80.8	108.9	104.7	103.0	104.6	97.8
17	Newly Reg Hydro Operations	584.3	617.4	600.9	596.8	584.0	599.5	582.2
18	Allocated Corp Support to Newly Reg Hydro	127.7	115.6	152.8	132.5	129.1	148.6	140.8
19	Total (Regular and Non-Regular Staff)	10,480.8	10,274.4	10,005.5	9,891.2	9,602.5	9,566.1	9,395.6
20	Less DRP And New Nuclear Regular Staff (Incl Allocated Corp Support)	178.3	268.6	290.7	355.4	280.2	368.1	380.4
21	Less All Non-Regular Staff (incl DRP & New Nuclear)	787.2	698.6	635.0	485.9	676.2	423.8	475.4
22	Regular Staff in Ongoing Operations	9,515.3	9,307.2	9,079.8	9,049.8	8,646.0	8,774.3	8,539.8
	Headcount (regular and non regular)							
23	Management	1,067	1,039	1,015	1,108	978	1,084	1,063
24	Society	3,292	3,198	3,066	3,101	2,876	2,995	2,937
25	PWU	5,603	5,484	5,372	5,102	5,159	4,986	4,853
26	Sub Total - Regular	9,961	9,721	9,453	9,311	9,012	9,065	8,853
27	Non-Regular	496	463	449	539	551	464	460
28	Total (Regular and Non-Regular Staff)	10,458	10,184	9,902	9,850	9,563	9,529	9,314
	FTE (regular and non-regular)							
29	Management	1,101.7	1,099.2	1,095.6	1,124.5	1,091.0	1,101.0	1,076.3
30	Society	3,269.0	3,254.6	3,112.6	3,146.9	2,909.2	3,043.3	2,965.6
31	PWU	6,012.9	5,840.7	5,711.0	5,564.7	5,542.0	5,371.7	5,300.3
32	EPSCA	97.2	79.8	86.3	55.1	60.2	50.1	53.4
33	Total (Regular and Non-Regular Staff)	10,480.8	10,274.4	10,005.5	9,891.2	9,602.5	9,566.1	9,395.6
	Employee Costs ($million)							
34	Nuclear Operations & Projects	1,274.6	1,281.5	1,135.7	1,166.1	1,202.3	1,143.6	1,163.9
35	DRP and New Nuclear	23.1	36.3	37.6	49.5	40.3	52.2	55.2
36	Allocated Corporate Support to Nuclear	122.4	129.1	268.2	297.8	291.7	290.1	280.5
37	Previously Reg Hydro Operations	50.4	54.5	51.8	57.1	53.7	58.4	59.0
38	Allocated Corp Support to Previously Reg Hydro	12.7	13.1	15.9	17.7	17.4	17.9	16.8
39	Newly Reg Hydro Operations	79.2	87.9	91.5	102.1	96.1	105.8	104.1
40	Allocated Corp Support to Newly Reg Hydro	18.6	18.7	23.0	23.6	22.5	26.4	25.3
41	Total	1,581.0	1,621.0	1,623.7	1,713.8	1,724.0	1,694.4	1,704.9
	Employee Costs ($million)							
42	Management	222.8	230.9	220.8	238.5	233.1	238.2	233.5
43	Society	522.9	541.0	543.4	570.1	568.4	556.7	551.5
44	PWU	820.9	837.9	847.6	897.6	911.1	893.0	912.8
45	EPSCA	14.4	11.3	11.9	7.6	11.3	6.6	7.1
46	Total	1,581.0	1,621.0	1,623.7	1,713.8	1,724.0	1,694.4	1,704.9

Notes

1. Employee Costs: Total of Base Salary & Wages, Overtime, Incentive Pay, Fiscal Year Adjustment and Total Benefits
2. Plan figures for 2013, 2014 and 2015 are based on 2013-15 Business Plan
3. Headcount, FTE and Employee Cost plan figures and 2013 actuals exclude New Nuclear since the proposed revenue requirement excludes New Nuclear costs as discussed in Ex F2-8-1.

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Contribution Requirements

Considering the funding and solvency status of the Plan, the Company contributions with effect for the first plan year following January 1, 2014, and those at January 1, 2011, both of which are within the range outlined in Section 5 and in accordance with legislative requirements, are as follows:

($000's)	January 1, 2014	January 1, 2011
Company normal cost	$ 227,389	$ 217,621
Special payments	130,848	64,837
Total Company Contribution	**$ 358,237**	**$ 282,458**

Key Assumptions

The principal assumptions to which the valuation results are most sensitive are outlined in the following table.

Going Concern Assumptions	January 1, 2014	January 1, 2011
Discount rate	5.60% per year	6.30% per year
Inflation rate	2.00% per year	2.50% per year
Increase in pensionable earnings (Active members)	2.50% per year for 3 years, 3.00% per year thereafter; plus promotional scale	3.50% per year, plus promotional scale
Increase in pensionable earnings (Disabled members)	2.00% per year	2.50% per year
Increase in year's maximum pensionable earnings ("YMPE")	2.50% per year for 3 years, 3.00% per year thereafter	3.50% per year
Increase in *Income Tax Act* maximum pension	2.50% per years for 3 years, 3.00% per year thereafter	3.50% per year
Mortality table	OPG-specific mortality table and mortality improvements based on Canadian Pensioner Mortality Improvement Scale CPM-B Table B in Appendix D	85% of 1994 Uninsured Pensioner Mortality table with fully generational mortality improvements at Scale AA
Promotional increases	Table A in Appendix D	Table A in Appendix D
Retirement rates	Table C in Appendix D	Table C in Appendix D
Withdrawal rates	Table D in Appendix D	Table D in Appendix D

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- As part of this valuation, a full review of all assumptions and methods was performed.
- Effective with this valuation, a number of changes have been made to the going concern assumptions including:
  - Lowering of key economic assumptions (e.g. discount rate, inflation, etc.);
  - Adoption of a new base mortality table and improvement scale as described above; and
  - Changes to certain demographic assumptions (e.g. spouse age difference) to better reflect observed data.
- In conjunction with the adoption of the changes in assumptions, the actuarial value of assets has been reset to market value at January 1, 2014. This change results in the immediate recognition of deferred equity gains which serves as an offset to the increase in liability resulting from the changes in assumptions described above.
- The smoothing adjustment applied to solvency assets and liabilities for the purpose of determining the solvency special payments has been removed effective January 1, 2014.

Company Information and Inputs

In order to prepare our valuation, we have relied upon the following information:

- A copy of the previous valuation report prepared by Mercer (Canada) Limited as at January 1, 2011;
- Membership data compiled as at January 1, 2014 by the Company;
- Asset data taken from the Plan's audited financial statements; and
- A copy of the latest plan text and amendments up to and including December 31, 2013.

Furthermore, our actuarial assumptions and methods have been chosen with due respect to accepted actuarial practice and regulatory constraints.

The Company has not elected to defer the commencement of new Special Payments by 12 months as permitted by the *Pension Benefits Act* (Ontario).

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Discussion of Changes in Assumptions and Methods

Effective January 1, 2014, the following assumptions and methods have been changed (all figures in $000's):

Economic Assumptions

- The assumed increase in Consumer Price Index has been changed from 2.50% per year to 2.00% per year.
- The nominal discount rate has been changed from 6.30% per year to 5.60% per year.
- The net impact of the change in the assumed inflation rate and the nominal discount rate is a change in the real discount rate from 3.80% per year to 3.60% per year.
- The assumed increase in pensionable earnings for active members has been changed from 3.50% per year plus promotional scale to 2.50% per year for three years, 3.00% per year thereafter, plus promotional scale. The assumed increase in pensionable earnings for disabled members has been changed from 2.50% per year to 2.00% per year.
- The assumed increase in the YMPE and in the maximum pension under the *Income Tax Act* has been changed from 3.50% per year to 2.50% for three years, 3.00% per year thereafter.

In combination, these changes in assumptions increased the going concern liabilities by $220,044 and the total normal cost by $6,564.

Demographic Assumptions

- The mortality rates have been changed from 85% of 1994 Uninsured Pensioner Mortality Table with fully generational mortality improvements at Scale AA to an OPG-Specific Mortality Table with future mortality improvements at Scale CPM-B.
- The assumed spousal age difference has been changed from a male assumed to be four years older than a female spouse, to a male assumed to be three years older than a female spouse.
- A margin of $100 million has been added to the liability in anticipation of higher than expected retirements in the short-term before the next valuation.

In combination, these changes in assumptions increased the going concern liabilities by $504,876 and the total normal cost by $8,914.

Asset Valuation Method

- The actuarial value of assets has been reset to equal the market value of assets at January 1, 2014. This reset results in the recognition of $891,630 in asset gains which would otherwise have been deferred.
- The resetting of the actuarial value of assets has been done at this time to offset the impact of the adoption of certain changes in economic and demographic assumptions which had a significant increase in the liability. It is expected that an asset smoothing approach will continue to be used in the future although alternate smoothing approaches will be examined.

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Justification of Actuarial Assumptions and Methods

Economic Assumptions

Discount Rate

We have used a discount rate of 5.60% per year developed as follows:

Development of Discount Rate				
Overall expected return				6.40%
Non-investment expenses				(0.20)%
Investment expenses				
Passive	(1)	(0.16)%		
Actively managed	(2)	0.00%		
			(1)+(2)	(0.16)%
Additional returns due to active management				0.00%
Margin for adverse deviations				(0.44)%
Discount Rate				**5.60%**

The overall expected return ("best-estimate") is 6.40% per year, which is based on an inflation rate of 2.00% per year, yielding an expected real rate of return on the pension fund assets of 4.40% per year. This overall expected return was developed using best-estimate returns for each major asset class in which the pension fund is invested. A Monte Carlo simulation is performed over 30 years where the portfolio returns are projected assuming annual rebalancing. The average of the 30-year geometric return is used to develop an overall best estimate rate of return for the entire pension fund. Gains from rebalancing and diversification are implicit in this return.

The above determined rate of return has been established based on the Company's investment policy. There may be some barriers to achieving this return such as inflation higher than expected, asset returns lower than expected, and assets and liabilities that are mismatched. We have derived a going concern discount rate which reflects the Company's investment policy combined with a margin for adverse deviation so as to account for the variables mentioned above.

3.7 Capacity Refurbishment Variance Account

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

For ease of record keeping and tracking OPG will use the following sub-accounts to make entries into the account, as applicable: Nuclear Sub-Account, Previously Regulated Hydroelectric Sub-Account and Newly Regulated Hydroelectric Sub-Account.

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

3.8 Pension and OPEB Cost Variance Account

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

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

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

Pursuant to the EB-2012-0002 Payment Amount Order, the balance in this account as at December 31, 2012, including interest accrued to that date, was split into the Historic Recovery and Future Recovery components. The Historic Recovery component was set at 2/12ths of the total December 31, 2012 balance. The Future Recovery component was set at 10/12ths of the total December 31, 2012 balance. The EB-2012-0002 Payment Amounts Order reflected the terms of the approved Settlement Agreement, which specified that no interest is to be recorded on the Future Recovery component of the December 31, 2012 approved balance during the period from January 1, 2013 to December 31, 2014. Additionally, during this period, OPG is not recording interest on account additions arising during 2013 or 2014.

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

As noted in Ex. H1-1-1, Section 4.8, in order to facilitate the presentation of entries into the account, OPG has shown in Ex. H1-1-1 Table 1 the projected account additions for 2013 as a separate component. For administrative purposes, OPG will use the following sub-accounts for the three components of the account, effective December 31, 2013: the Historic basis of forecast numbers is a departure from the Board's standard practice. However, the Board recognizes that this is a unique account, which is "cleared" through an adjustment to rate base, which itself includes components that are forecasted for the bridge and test years, for example capital additions and working capital allowance.

The Board approves the disposition of $16,474,719 in Account 1575 to be amortised over four years to align with Enersource's expected rebasing cycle. The period of amortization may be revisited by a subsequent panel should Enersource chose to rebase under an alternative cycle under the Board's Renewed Regulatory Framework for Electricity.

The Board directs Enersource to adjust depreciation expense, the weighted average cost of capital and the revenue requirement in the manner as specified by the Board policy.

Issue 9.2 – Are the proposed new MIFRS deferral and variance accounts appropriate?

Enersource requested that the Board approve one new deferral account related to MIFRS: MIFRS Other Post-Employment Benefits Adjustment Account. This account would be used for future re-measurements of the defined benefit obligation which will be recorded in other comprehensive income instead of being amortized in OM&A.

Enersource proposed that this deferral account would capture the impact of other post-employment benefits ("OPEB") adjustments related to future transactions, as described below, and also past transactions.

Regarding past transactions, the proposed deferral account would capture:

1. The impact from the other post-employment benefits adjustment resulting from the transition to MIFRS. The net impact of this adjustment at the date of transition of January 1, 2011 was a reduction of the other post-employment benefits accrued liability of $150,000. This amount would be returned to ratepayers through Enersource's proposal to record a credit in the requested deferral account.

2. The recognition of actuarial gains and losses which would be recorded in Other Comprehensive Income ("OCI") under IFRS. Under CGAAP, these amounts would have been amortized in OM&A using the corridor approach.

Enersource early adopted the amended IFRS standard, IAS 19, which eliminates the corridor approach. The 2011 actuarial loss relating to the other post-employment benefits obligation was $769,000. The amount would be collected from ratepayers through Enersource's proposal to record a debit to the requested deferral account.

If the account is established, Enersource would record a net amount of $619,000 debit balance in the account and proposes to recover the amount from customers over one year.

Board Staff noted that the Addendum Report requires utilities to demonstrate the likelihood of a large cost impact upon transition to IFRS when seeking an individual account for IFRS related impacts. Board Staff submitted that the requested amount for recovery is below Enersource's materiality threshold of $658,000 and that Enersource has not demonstrated a large cost impact. SEC and Energy Probe agreed with Board Staff. Board Staff and SEC further submitted that the requested recovery should not include any amounts in relation to 2011 during which Enersource was under IRM as this would constitute an inclusion of "out of period" amounts and be contrary to the rule against retroactive rate making.

Enersource also proposed to accumulate all future re-measurements of OCI in the requested deferral account and proposed to dispose the cumulative balance in future cost of service rate applications if the balance reaches the materiality threshold. Enersource indicated that it was unable to forecast whether any actuarial gain or loss will be recognized in any given year. Board Staff submitted that though it is difficult to forecast future actuarial gains and losses, demonstrating materiality is one of the tests for establishing a new deferral or variance account and Enersource has not done so in this case. Enersource also indicated that given the amount requested for disposition, a recovery period of longer than one year would result in a $0.00/kWh rate rider for certain customer classes. As a result, Board staff submitted that Enersource was unable to demonstrate that there is a large cost impact.

Staff suggested that it is open to Enersource to file an application in the future to recover/refund future actuarial gains or losses from the other post-employment benefits, if the amount is material.

SEC supported the establishment of the variance account going forward to deal with annual fluctuations in the accounting charges for pensions and OPEBs, using a relatively long disposition period so that the effect is to smooth the impacts over time. SEC noted that the Board approved a similar variance account for Hydro Ottawa in EB-2011-0054. SEC acknowledged that Enersource did not provide any evidence that the entries in this account would be material, and in the normal course should therefore not be approved. However, SEC submitted that a variance account should be established as annual adjustments in pension and OPEBs are very unpredictable, and are sensitive to small changes in long-term interest and discount rates. In the event that amounts accumulating in the account turn out not to be material, SEC argued that the Board could deal with that at the time disposition is being proposed.

Enersource responded that its request for a deferral account is reasonable because actuarial gains and losses are unpredictable and the net actuarial loss incurred is close to the materiality threshold. In its Reply Argument, Enersource sought approval to carry the balance in a proposed new OCI deferral account if the Board did not approve the disposition of the $619,000 in the P&OPEB transition account. Enersource asserted that as a result the balance would not be considered an out period adjustment. Enersource confirmed that it would only seek disposition of future cumulative balances only if the materiality threshold is met.

Board Findings

Enersource's request can be separated into two components: a request to recover or carry forward $619,000 related to 2011, which results from a reduction in the accrued liability for other post-employment benefits and a recognition of actuarial gains and losses in Other Comprehensive Income; and a deferral account going forward to capture annual fluctuations in the accounting charges for OPEB.

The Board agrees with SEC that in the absence of an existing deferral or variance account, and given that the amount cannot be treated as a Z factor due to materiality, the recovery of $619,000 from ratepayers for 2011 would be retroactive ratemaking.

In its Addendum Report, the Board indicated that distributors could seek approval to establish an individual account if they can demonstrate the likelihood of a large cost impact upon transition to IFRS. The Board will therefore approve the establishment of a prospective OPEB deferral account, which will capture the actuarial gains and losses related to OPEB, effective in 2013 subject to the materiality threshold being met. The

Board notes however, that Enersource did not include any amounts for actuarial gains and losses related to the OPEB in its base rates. Therefore, the Board is authorizing the establishment of a deferral account rather than a variance account for Enersource to record and track the cumulative actuarial gains and losses related to OPEB as they are incurred. Given that actuarial gains and losses are non-cash items, interest carry charges shall not apply to the balance in this account. The Board agrees with SEC that annual adjustments in OPEB can be unpredictable and sensitive to changes in various factors. To be eligible for clearance in a future rate proceeding, the OPEB amount must be material. Enersource may come forward for disposition in a future application for the amount accumulated in the deferral account, if any.

The Board further notes that this deferral account is being established in the absence of Board policy on the OPEB issue. The account will therefore continue until the earlier of:

- A decision by the Board to implement a policy respect to the OPEB which differs from the approach approved here, and
- The next rebasing application for Enersource

Issue 9.3 – Have all impacts of the transition to MIFRS been properly identified, and is the treatment of each of those impacts appropriate?

Enersource submitted that it has used the Board Report for policy guidance on the transition to IFRS, and specifically its requirements for regulatory accounting, regulatory reporting, and the filing requirements.

SEC and Energy Probe submitted that Enersource has identified and provided for all of the material impacts of IFRS.

Board Findings

The Board agrees that subject to the findings above, all MIFRS transition impacts have been property identified and the treatments of those impacts have been addressed appropriately.

10 Smart Meters

Issue 10.1 – Are the proposed quanta and nature of smart meter costs, including the allocation and recovery methodologies appropriate?

ENBRIDGE

72 ;and 76 to 91	
JT2.2 to 2.5 and 2.10 to 2.11	Undertakings from Technical Conference (September 6, 2012)

4. Is the forecast of Employee Future Benefit costs which will be incurred under USGAAP appropriate, including the request to recover Pension Expense and Other Post-Employment Benefits ("OPEB") Expense on an accrual basis commencing January 1, 2013?

[Complete Settlement]

All parties agree that the recovery of Pension and Other Post-Employment Benefits expense on an accrual basis commencing January 1, 2013 is appropriate. All parties further agree that Enbridge shall recover the Other Post-Employment Benefits (OPEB) expenses described at Exhibit A2, Tab 3, Schedule 1 equally over a twenty year period commencing January 1, 2013. The OPEB expenses of $90 million will be recorded in the Transition Impact of Accounting Changes Deferral Account (TIACDA), and will be cleared to the credit of Enbridge at the rate of $4.5 million per year (no interest will be applicable to the amounts recorded in the TIACDA).

Evidence: The evidence in relation to this issue includes the following:

A2-3-1	Change in Accounting Methodology – Other Post Employment Benefits ("OPEB")
A2-3-2	Change in Accounting Methodology – Pension Expense
I-D1-1.6	Board Staff Interrogatory #6
I-D4-1.1 to 14.2	Interrogatories on Issue D4
I-DV2-1.1 to 4.1	Interrogatories on Issue DV2
I TR 138 to 153	Evidence at Technical Conference (September 5, 2012)
T1.23	Undertaking from Technical Conference (September 5, 2012)

5. Is the corporate cost allocation ("RCAM") appropriate?

[Complete Settlement]

See Issue D1, above. The RCAM corporate cost allocation for 2013 is part of the overall agreed-upon "All other O&M budget" of $256.8 million. It is agreed that no party will raise any procedural objection if any party requests changes to RCAM in Enbridge's 2014 rates proceeding (which is anticipated to be an application for approval of an IR methodology, which is not the type of case where such issues would ordinarily be raised). All parties are free to take whatever positions they determine with respect to this issue at that time.

Evidence: The evidence in relation to this issue includes the following:

D1-4-1	Corporate Cost Allocation ("CAM")
D1-4-2	Updated Corporate Cost Allocation ("CAM")
D1-24-1	Regulatory Adjustments and Eliminations – CAM Elimination to Adjust for RCAM
D1-24-2	Updated Regulatory Adjustments and Eliminations - CAM Elimination to Adjust for RCAM

in the Province'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 current 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*. Variance accounts capture differences between actual costs and revenues, and the corresponding forecast amounts approved in the setting of 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 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 asset 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 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 authorized by the OEB, OPG recognizes regulatory assets 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 refund of the 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.

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 variable 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.

The changes in the regulatory assets and liabilities during 2013 and 2012 are as follows:

(millions of dollars)	**Pension and OPEB Cost Variance**	**Bruce Lease Net Revenues Variance**	**Nuclear Liability Deferral**	**Tax Loss Variance**	**Capacity Refurbish -ment Variance**	**Nuclear Develop-ment Variance**	**Pension and OPEB Regulatory Asset**	**Deferred Income Taxes**	**Other Variance and Deferral (net)**
Net regulatory assets (liabilities), January 1, 2012	96	196	22	425	(1)	(55)	3,553	699	(72)
Change during the year	225	248	206	-	10	25	941	(31)	107
Interest	3	3	1	5	-	-	-	-	-
Amortization during the year	-	(136)	(21)	(128)	5	60	-	-	51
Net regulatory assets December 31, 2012	324	311	208	302	14	30	4,494	668	86
Change during the year	402	110	123	-	93	26	(1,336)	(109)	68
Interest	1	(5)	(2)	3	-	1	-	-	-
Amortization during the year	(60)	(63)	(75)	(181)	(7)	-	-	-	(50)
Net regulatory assets, December 31, 2013	**667**	**353**	**254**	**124**	**100**	**57**	**3,158**	**559**	**104**

Pension and OPEB Cost Variance Account

The OEB established the Pension and OPEB Cost Variance Account in its June 2011 decision and order. The variance account records the difference between actual pension and OPEB costs for the regulated business and related tax impacts, and the corresponding amounts reflected in the current regulated prices. The OEB's June 2011 decision and order established the account for the period from March 1, 2011 to December 31, 2012. In approving the Settlement Agreement, the OEB authorized the continuation of the variance account.

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 the 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 payment to

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BY E-MAIL AND WEB POSTING

November 25, 2013

To: All Licensed Electricity Distributors and Transmitters
All Gas Distributors
Ontario Power Generation Inc.
All Registered Intervenors in 2014 Cost of Service Applications

Re: Cost of Capital Parameter Updates for 2014 Cost of Service Applications

The Ontario Energy Board (the "Board") has determined the values for the Return on Equity ("ROE") and the deemed Long-Term ("LT") and Short-Term ("ST") debt rates for use in the 2014 cost of service applications. The ROE and the LT and ST debt rates are collectively referred to as the Cost of Capital parameters. The updated Cost of Capital parameters are calculated based on the formulaic methodologies documented in the *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* (the "Cost of Capital Report"), issued December 11, 2009.

Cost of Capital Parameters for 2014 Rates

For rates with effective dates in 2014, the Board has updated the Cost of Capital parameters based on: (i) the September 2013 survey from Canadian banks for the spread over the Bankers' Acceptance rate of 3-month short-term loans for R1-low or A:-(A-stable) commercial customers, for the Short-Term debt rate; and (ii) data three months prior to January 1, 2014 from the Bank of Canada, *Consensus Forecasts*, and Bloomberg LLP, for all Cost of Capital parameters.

The Board has determined that the updated Cost of Capital parameters for 2014 cost of service rate applications for rates with effective in 2014 are:

Cost of Capital Parameter	Value for 2014 Cost of Service Applications for rate changes in 2014
ROE	9.36%
Deemed LT Debt rate	4.88%
Deemed ST Debt rate	2.11%

Detailed calculations of the Cost of Capital parameters are attached.

The Board considers the Cost of Capital parameter values shown in the above table, and the relationships between them, to be reasonable and representative of market conditions at this time.

As documented in the *Report of the Board on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors* (EB-2010-0379) issued November 21, 2013, the Board intends to update Cost of Capital parameters for setting rates in cost of service applications only once per year. For this reason, the Cost of Capital parameters above will be applicable for all cost of service applications with rates effective in the 2014 calendar year.

The Board monitors macroeconomic conditions and may issue updated parameters if economic conditions materially change. An applicant or intervenors can also file evidence in support of different Cost of Capital parameters due to the specific circumstances in individual rate hearings, but must provide strong rationale for deviating from the Board's policy.

All queries on the Cost of Capital parameters should be directed to the Board's Market Operations hotline, at 416 440-7604 or market.operations@ontarioenergyboard.ca.

Yours truly,

Original Signed By

Kirsten Walli
Board Secretary

Attachment

Board Staff Interrogatory #015

Ref: Exh C1-1-1 page 2

Issue Number: 3.1
Issue: What is the appropriate capital structure and rate of return on equity for the currently regulated facilities and newly regulated facilities?

Interrogatory

In the application filed on September 27, 2013, OPG proposed that the ROE be updated based on Consensus Forecasts [and other Statistics Canada/Bank of Canada and Bloomberg LLP] data for three months prior to the effective date of the payment rates order, in accordance with the Cost of Capital Report and with the Decisions in its previous payment order EB-2010-0008.

On November 21, 2013, the Board issued the *Report of the Board on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors* (EB-2010-0379), in which the Board stated that the Cost of Capital parameters would normally be updated once a year.[1] This was repeated in the letter issued November 25, 2013 announcing the Cost of Capital parameters effective for cost of service rates applications effective January 1, 2014.

a) In light of the Board's process to calculate the Cost of Capital parameters only once annually, does OPG intend to change its proposal and adopt the 2014 ROE as announced in the Board's letter of November 25, 2013?
b) If OPG proposes an alternative, including updating the ROE based on data three months prior to the effective date of the payments order, please provide OPG's rationale for doing so, and why it does not consider the 2014 Cost of Capital parameters issued by the Board on November 25, 2013 to be suitable for setting its 2014-2015 payments.

Response

a) No, OPG is not planning on changing its proposal in the Application as OPG is using the cost of capital methodology approved by the Board in its last payments amounts application. This methodology is described at Ex. C1-1-1 page 2, lines 19-29.

   For 2014, OPG is proposing to use data three months prior to the effective date of the payment amounts order, proposed to be January 1, 2014, from the Bank of Canada, *Consensus Forecasts*, and Bloomberg LLP. For 2015, OPG is proposing that the ROE be set at the same time as the first year but using data from Global Insight because *Consensus Forecasts* data is only projected for 12 months and thus would not cover 2015.

[1] *Report of the Board on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors* (EB-2010-0379), November 21, 201, page 10

b) In OPG's last payment amounts application (EB-2010-0008), the issue of whether one ROE should be set for both years of OPG's application was specifically addressed by the Board. SEC argued that the ROE for the two years should be set "at the same level, an approach that is consistent with that used under IRM[2]". This is the regulatory approach used to set rates for electricity distributors in the report identified by Board Staff. However, the OEB found that it was "...appropriate to set separate ROEs for each year of the test period. The issue is what data should be used for establishing the 2012 ROE.[3]" OPG's proposal for setting its ROE for 2015 is in accordance with the approach approved by the OEB. No alternative to the Board-approved methodology for OPG is being proposed in this Application.

[2] EB-2010-0008, Decision With Reasons, Page 121
[3] EB-2010-0008, Decision With Reasons, Page 122

Tech Conf
April 23, 2014

MR. RITCHIE: Okay. Thank you.

And then I think really I just have one final question, and it is referring to Board Staff Interrogatory 3.1, Staff 15, and that would be at pages 431, 432.

MR. BARRETT: Yes, we have that.

MR. RITCHIE: Okay. And in this response -- just one second here.

Basically OPG has responded that it's basically wanting to maintain the approach that was approved in the previous payments orders of updating the ROE with data three months in advance of the effective date, rather than sort of going to the new Board policy that was announced in the Board's letter of 25th November, 2013, whereby, say for 2014, there would be the one ROE for rates effective in the 2014 test year.

MR. BARRETT: By happy coincidence, three months prior to the effective date would be that same number.

MR. RITCHIE: Yes, that is for the -- actually I guess for the existing hydroelectric and the nuclear.

But isn't -- under your application, you have a -- also a different payment order for the newly regulated hydroelectric of July 1, 2014?

MR. BARRETT: I wouldn't describe it as a different payment order. There is the regulation of the newly regulated hydroelectric assets starts on July 1st.

But for purposes of simplicity, we would be fine to adopt the same methodology for establishing a 2014 ROE for those set of assets, that is the three months prior to

January 1st, 2014.

MR. RITCHIE: Okay. And I guess for the 2015 estimate -- no, I guess they use -- you're using the same -- no. You actually are using a different data source?

MR. BARRETT: We're using the Global Insight information, as we did in the last case, and it would be the information, again, that would be available at that same time as the 2014 information was established, or the 2014 number was established.

MR. RITCHIE: Okay. Thank you. That is all of my questions.

MR. MILLAR: Thank you, Mr. Ritchie.

Mr. Skinner?

MR. SKINNER: Good afternoon, panel. My name is Duncan Skinner, Board Staff. Could you go to Issue 6.8, Staff No. 112, which is at PDF page 2,452?

You have provided an updated forecast of pension and OPEB costs in answer to this interrogatory. Am I right in the assuming -- or the fact that the current payment amounts include the impact statement pension and OPEB dollars?

MR. BARRETT: Could you rephrase that question, please?

MR. SKINNER: Sure. The current payment amounts, do they include the impact statement pension and OPEB costs?

MR. BARRETT: They do.

MR. SKINNER: And you have called this an update to those costs. When would you expect to include those in

MS. McSHANE: Absolutely.

MR. SHEPHERD: That is a financial risk, right?

MS. McSHANE: Yes.

MR. SHEPHERD: It is right, isn't it, that this was discussed in EB-2010-0008, this very question?

MS. McSHANE: The question, yes, because in EB-2010-0008, as I recall, OPG applied to include construction work and progress related to Darlington in rate base and the Board decided to -- not to allow that.

MR. SHEPHERD: But it is also true, isn't it, that it was discussed in the context of what's the appropriate equity thickness for nuclear. Right? Do you recall that?

MS. McSHANE: No. I don't recall that that specific connection was made.

MR. SHEPHERD: I just had to put that to you.

Okay. I have no further questions --

MS. HARE: Thank you.

MR. SHEPHERD: -- Madam Chair.

MS. HARE: Mr. Millar, do you have any questions?

CROSS-EXAMINATION BY MR. MILLAR:

MR. MILLAR: Madam Chair, I have one question that I think is probably for panel 7, but I would hate to lose my chance while we have Ms. McShane here, so I will shoot it at her here, and if this is the wrong panel, that's fine.

Ms. McShane, as you are aware, the payment amounts have been calculated on the basis of a 47 percent equity thickness; is that right?

MS. McSHANE: That's my understanding, yes.

MR. MILLAR: From what we have heard earlier today, we can assume or at least anticipate that some parties may argue that a different equity thickness should be applied in the final analysis.

I guess my question to you -- and as I say, this may be for panel 7 -- is, do you know what impact that has on the revenue requirement in terms of number? For example, if we switched to 45 instead of 47, would you know what that impact would be on the revenue requirement?

MS. McSHANE: I have no looked at those numbers. I have proceeded on the assumption that the fair return is the fair return, as determined by the Supreme Court of Canada and accepted by the Ontario Energy Board, and I have not specifically looked at what the revenue impacts would be of a change.

MR. MILLAR: Mr. Keizer, if we wanted that information, panel 7 would be able to help us?

MR. KEIZER: Panel 7 would be the place to ask that question.

MR. MILLAR: Thank you, those are my questions.

MS. HARE: Thank you.

I think the Panel has some questions.

QUESTIONS BY THE BOARD:

MS. LONG: Hello, Ms. McShane. I just had two questions for you. One, to follow up on a question that Mr. Shepherd asked you with respect to whether or not there was any business risk associated with a disallowance on

Board Staff Interrogatory #166

Ref: Exh. F4-2-1 and Table 5

Issue Number: 6.13
Issue: Are the amounts proposed to be included in the test period revenue requirement for income and property taxes appropriate?

Interrogatory

Table 5 at Line 21 in "Regulatory Taxable Income" shows a negative amount of $39.2M (net loss) for 2013 Budget.

a) Please update the 2013 Budget amount to reflect the actual amount for 2013 as at December 31.

b) If the actual amount for 2013 remains as a net loss, is the amount being applied as a loss carry forward to reduce the Regulatory Taxable Income for 2014? If not, please explain.

Response

a) The 2013 actual regulatory tax loss is $153.8M, as shown at Ex. L-1.0-1 Staff-002, Table 29, line 21.

b) No. The 2013 regulatory tax loss is not applied to reduce the forecast 2014 regulatory taxable income because the loss arises as a result of a 2013 nuclear operating loss, as discussed below. As OPG incurred the operating loss, it should receive the benefit of the associated tax loss. This principle of attributing the tax cost or benefit between the ratepayers and OPG's Shareholder was established by the Board in EB-2007-0905 (Decision with Reasons, page 170) and applied in OPG's analysis of tax losses reflected in the balance of the Tax Loss Variance Account approved by the Board in EB-2010-0008 (EB-2010-0008, Ex. F4-2-1, section 4.3.3).

   As determined below, the shortfall in 2013 nuclear production is approximately $325M, which is substantially higher than the regulatory tax loss of $153.8M. Most of the operating loss is related to production. OPG is at risk for production variances. A comparison of actual 2013 nuclear production of 44.7 TWh (Ex. L-1.0-1 Staff-002, Table 14, line 3, col. (d)) to the average of approximately 51.0 TWh of 2011 and 2012 production (50.4 TWh and 51.5 TWh, respectively), approved by the OEB in EB-2010-0008 Payment Amounts Order, Appendix A, Table 3 results in a production shortfall of approximately 6.3 TWh. Using the nuclear base payment amount of $51.52/MWh, the shortfall in production results in a reduction to revenue in 2013 of approximately $325M. As OPG has incurred the operating loss it should retain the benefit of the associated tax losses.

Witness Panel: Finance, D&V Accounts, Nuclear Liabilities

Although the Board is not convinced that regulatory tax loss carry forwards existed at the end of 2007, or that OPG's treatment of taxes is appropriate, the Board is not making a finding that all of the tax benefits of pre-2008 tax losses should accrue to OPG's shareholder. The Board believes that the benefit of tax deductions and losses that arose before the date of the Board's first order should be apportioned between electricity consumers and OPG based on the principle that the party who bears a cost should be entitled to any related tax savings or benefits. The Board has adopted this principle in other cases where a company owns both regulated and unregulated businesses.

The practical consequences of this principle can be illustrated by reference to two of the items that OPG cites as causes for the 2005 to 2007 regulatory tax loss.

- In 2005, OPG deducted $258 million of Pickering A return to service costs in computing taxable income for that year. For accounting purposes, OPG recorded those costs in the PARTS deferral account. As noted in Chapter 7 of this decision, the remaining deferral account balance at December 31, 2007 of $183.8 million will be recovered through future payment amounts for the nuclear facilities. In the Board's view, the majority of the tax benefit realized by OPG in 2005 should be for the account of consumers given that the nuclear revenue requirement after 2007 will include $183.8 million to recover the deferral account balance.
- OPG's evidence indicated that in 2007 its regulated operations incurred an $84 million loss before income taxes (how much of that loss, if any, that relates to Bruce is unclear). It would appear that the operating loss in 2007 was borne completely by OPG's shareholder. Consumers have not been required to absorb that loss because the payment amounts for 2007 were set in 2005 and did not change. Accordingly, in the Board's view, none of the tax benefit of that loss should accrue to consumers.

The Board does not have the information necessary to determine the tax benefits which should be carried forward to offset payment amounts in 2008 and later periods. The Board has therefore examined the proposed level of mitigation within the context of OPG's overall application.

With respect to 2008 and 2009, the Board is not able to agree, for the reasons outlined above, with OPG's position that "regulatory tax losses" permit it to eliminate an income

Numbers may not add due to rounding.

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	Subsidiaries	(1) + (2) Total	Unregulated	(3) - (4) Regulated	Bruce Lease	Other Adjustments	Regulatory Tax Calc'n[1]
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Determination of Taxable Income								
1	Earnings 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 fo 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:
1 Amounts are as shown in Ex. F4-2-1 Table 4, col. (c).

Ontario Energy Board
Commission de l'Énergie de l'Ontario

2006 ELECTRICITY DISTRIBUTION RATE HANDBOOK

May 11, 2005

7.2.2 Capital tax exemptions

i) Federal Large Corporation Tax (LCT) Exemption

Where the applicant is the only regulated entity in a corporate group, the full LCT exemption must be claimed by the applicant for purposes of its 2006 OEB tax calculation.

Where the distributor is a member of a larger corporate group that includes other regulated entities, the exemptions will be prorated among the regulated entities.

ii) Ontario Capital Tax Exemption

Where the applicant is the only regulated entity in a corporate group, the full OCT exemption must be claimed by the applicant for purposes of its 2006 OEB tax calculation.

Where the applicant is a member of a larger corporate group, the full provincial capital tax exemption will be prorated among the regulated entities in that group.

iii) Non-distribution activities within an applicant

When distribution and non-distribution functions are being undertaken in the same legal entity by an applicant, the full federal LCT exemption and provincial capital tax exemptions must be claimed by the applicant for purposes of its 2006 OEB tax calculation.

7.2.3 Loss carry-forwards

A distributor expecting to have any loss carry-forwards still available on December 31, 2005 must disclose the amount of those loss carry-forwards in the 2006 application, and apply them in full to reduce the taxable income calculated in the 2006 regulatory tax calculation. These amounts are to be entered in the 2006 OEB Tax Model.

If a distributor has within its legal entity a business other than a distribution business, loss carry-forwards must be allocated between the distribution and the non-distribution business on a reasonable basis. The applicant shall include in Schedule 7-1 a description and justification of that allocation method and calculation.

Exhibit

Sample of electricity distributors that have used their non-capital loss carry-forwards to reduce regulatory income tax/PILs provisions

No.	EB No.	Distributor	Non-Capital Loss carry-forward applied to rates	Notes
1)	RP 2005-0020/EB-2005-0428	Welland Hydro-Electric System Corp	**$733,628** Non-Capital Loss carry forward was used to reduce PILs expense / provision in its 2006 electricity distribution rate ("EDR") application.	The 2006 rates reflected an amount for a loss carry-forward and a remaining amount of $255,942 was available for carry forward to 2007.
2)	RP-2005-0020/EB-2005-0412	PUC Distribution Inc.	The 2006 rates incorporated a reduced PILs expense due to the use of a **$255,942** loss carry-forward	This resulted in a reduction to its income tax/PILs expense/ provision in 2006.
3)	EB-2007-0879	Veridian Connections Inc. re Scugog	**$174,599** of non-capital loss carry-forward was used by Scugog to reduce its 2006 regulatory taxable income and thus its income tax /PILs provision.	Board's Decision EB-2007-0879 (page 4) addressed Veridian's 2008 IRM application request for rates harmonization to its main service area and Scugog service area, but it also discussed the loss carry-forward issue.
4)	EB-2009-0056	Espanola Regional Hydro Distribution Corporation	Loss carry-forward as of December 31, 2006 of **$457,257** was applied to eliminate income tax /PILs expense and thus no	The amount of the loss carry-forward available at December 31, 2006 was subsequently

			income tax/ PILs provision was included in 2007 and 2008 rate years.	adjusted to $115,272 per the EB-2009-0056 Board's Decision.
5)	EB-2011-0177 (2012 IRM3 Application)	Kenora Hydro Electric Corporation Ltd.	Board Staff Submission (page 9): Board staff notes that during the period 2001 through 2005, Kenora paid no income tax PILs. As at December 31, 2005, Kenora had a remaining tax loss carry-forward balance of **$273,129** to shelter taxable income for the tax years after 2005.	Reference provided of Loss carry-forwards applied to 2001 to 2005 rate years thus no income tax/ PILs provisions were included in rates. Application / 2005 T2 tax return, Sch. 4 Loss Continuity/ PDF pages 487-491.
6)	EB-2005-0418	Terrace Bay Superior Wires Inc.	Terrace Bay's loss carry-forward of over **$20,000** was applied by the Board to adjust and reduce its 2006 PILs provision included in rates.	Decision and Order (page 5) states that Terrace Bay should have adjusted its 2006 PILs liability by the loss carry-forward that it has available. The Board has therefore corrected the February 16, 2006 PILs spreadsheet for this omission.

Note:

The above-noted information was compiled by Board Staff.

Income Tax/PILs
Workform for 2014 Filers

Corporation Loss Continuity and Application

Schedule 7-1 Loss Carry Forward - Bridge Year

Non-Capital Loss Carry Forward Deduction	**Total**
Actual Historic	0
Application of Loss Carry Forward to reduce taxable income in Bridge Year	
Other Adjustments Add (+) Deduct (-)	
Balance available for use in Test Year	0
Amount to be used in Bridge Year	
Balance available for use post Bridge Year	0

Net Capital Loss Carry Forward Deduction	**Total**
Actual Historic	0
Application of Loss Carry Forward to reduce taxable income in Bridge Year	
Other Adjustments Add (+) Deduct (-)	
Balance available for use in Test Year	0
Amount to be used in Bridge Year	
Balance available for use post Bridge Year	0

in -- the residual amount is within the CCA?

MR. KOGAN: Yes. Any of these eligible expenses are within CCA --

MR. BAKSH: Okay. Thank you.

Could I ask you to go to 6.13, Staff 170?

MR. KOGAN: I have that.

MR. BAKSH: Now, in light of the changes OPG has made to the newly regulated hydroelectric 2014 UCC, opening balance from 1,277.8 million to 1,590.9 million -- an increase of 113 million to UCC -- did OPG make adjustments to increase CCA for the 2014 and 2015 test years in respect to this increase in the UCC?

MR. KOGAN: I don't think we have in general made any changes based on our date for actual 2013 information. And as Mr. Barrett indicated, we are canvassing for information that would be part of an update that exceeds certain thresholds, so presumably that would be part of that consideration.

MR. BAKSH: Okay. Thank you.

Can you please go to Exhibit 9.7, Staff 195, as well as Exhibit H-1-3-1, page 3?

MR. KOGAN: Sorry, what was the second reference?

MR. BAKSH: Yes, it's Exhibit H-1-3-1, page 3. So I realize we are getting closer to the end of time. I will try and -- this is the last question. I will try to be quick.

It's the -- you have indicated in terms of the proposed sub-account for the newly regulated hydroelectric

Board Staff Interrogatory #170

Ref: Exh. F4-2-1 Table 9

Issue Number: 6.13
Issue: Are the amounts proposed to be included in the test period revenue requirement for income and property taxes appropriate?

Interrogatory

Table 9 (col. c) includes $1,227.8M under Net Adjustment and related Note 3 states that these amounts represent the inclusion of the Undepreciated Capital Cost for the newly regulated hydroelectric facilities effective in 2014.

Please provide a schedule (in the format of Table 9) detailing the derivation of the Undepreciated Capital Cost for the newly regulated hydroelectric facilities by year from 2007 to 2013.

Response

OPG notes that the total Net Adjustment amount in Ex. F4-2-1, Table 9, col. (c) is $1,277.8M, not $1,227.8M. The amount represents the forecast 2014 opening Undepreciated Capital Cost ("UCC") for the newly regulated hydroelectric facilities.

Attachment 1, Tables 1 and 2 (in the format of Ex. F4-2-1 Table 9) detail the Undepreciated Capital Cost ("UCC") for the newly regulated hydroelectric facilities for the same years (2012 and 2013) for which equivalent information was provided for the previously regulated facilities in Ex. F4-2-1, Tables 7 and 8.

The attached tables reflect an updated 2013 closing balance of UCC of $1,390.9M for the newly regulated hydroelectric facilities. This amount reflects actual information for 2013.

Numbers may not add due to rounding.

Table 1
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Newly Regulated Hydroelectric Facilities ($M)
Year Ending December 31, 2012

Line No.	Class	Undepreciated Capital Cost at Beginning of Year	Cost of Acquisitions	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	1	544.9	13.2	0.0	0.0	558.1	6.6	551.5	0.0	0.0	22.1	536.0
2	1-rolling start	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	1.1	0.0	2.6	0.0	0.0	2.6	1.3	1.3	0.1	0.0	0.1	2.5
4	1.1-rolling start	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0
5	2	750.3	0.0	0.0	0.0	750.3	0.0	750.3	0.1	0.0	45.0	705.3
6	3	0.4	0.0	0.0	0.0	0.4	0.0	0.4	0.1	0.0	0.0	0.4
7	8	20.3	2.4	0.0	0.0	22.6	1.2	21.5	0.2	0.0	4.3	18.3
8	10	0.8	0.2	0.0	0.0	1.0	0.1	0.9	0.3	0.0	0.3	0.7
9	12	0.1	1.1	0.0	0.0	1.3	0.6	0.7	1.0	0.0	0.7	0.6
10	13	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A	0.0	0.0	0.0
11	17	127.3	20.6	0.0	0.0	147.9	10.3	137.6	0.1	0.0	11.0	136.9
12	17-rolling start	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0
13	38	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0
14	42	3.1	0.0	0.0	0.0	3.1	0.0	3.1	0.1	0.0	0.4	2.8
15	43.1	0.6	0.0	0.0	0.0	0.6	0.0	0.6	0.3	0.0	0.2	0.4
16	43.2	10.0	3.1	0.0	0.0	13.1	1.6	11.6	0.5	0.0	5.8	7.3
17	45	0.5	0.0	0.0	0.0	0.5	0.0	0.5	0.5	0.0	0.2	0.2
18	50	0.0	0.3	0.0	0.0	0.3	0.1	0.1	0.6	0.0	0.1	0.2
19	52	0.8	0.0	0.0	0.0	0.8	0.0	0.8	1.0	0.0	0.8	0.0
20	Total	1,459.1	43.5	0.0	0.0	1,502.6	21.8	1,480.9		0.0	90.9	1,411.7

Numbers may not add due to rounding.

Table 2
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Newly Regulated Hydroelectric Facilities ($M)
Year Ending December 31, 2013

Line No.	Class	Undepreciated Capital Cost at Beginning of Year	Cost of Acquisitions	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	1	536.0	39.1	0.0	0.0	575.1	19.5	555.6	0.0	0.0	22.2	552.9
2	1-rolling start	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	1.1	2.5	1.3	0.0	0.0	3.8	0.6	3.1	0.1	0.0	0.2	3.6
4	1.1-rolling start	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0
5	2	705.3	0.0	0.0	0.0	705.3	0.0	705.3	0.1	0.0	42.3	663.0
6	3	0.4	0.0	0.0	0.0	0.4	0.0	0.4	0.1	0.0	0.0	0.4
7	8	18.3	1.2	0.0	0.0	19.6	0.6	18.9	0.2	0.0	3.8	15.8
8	10	0.7	0.2	0.0	0.0	1.0	0.1	0.9	0.3	0.0	0.3	0.7
9	12	0.6	0.0	0.0	0.0	0.6	0.0	0.6	1.0	0.0	0.6	0.0
10	13	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A	0.0	0.0	0.0
11	17	136.9	17.0	0.0	0.0	153.9	8.5	145.4	0.1	0.0	11.6	142.3
12	17-rolling start	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0
13	38	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0
14	42	2.8	0.0	0.0	0.0	2.8	0.0	2.8	0.1	0.0	0.3	2.4
15	43.1	0.4	0.0	0.0	0.0	0.4	0.0	0.4	0.3	0.0	0.1	0.3
16	43.2	7.3	7.6	0.0	0.0	15.0	3.8	11.2	0.5	0.0	5.6	9.4
17	45	0.2	0.0	0.0	0.0	0.2	0.0	0.2	0.5	0.0	0.1	0.1
18	50	0.2	0.0	0.0	0.0	0.2	0.0	0.2	0.6	0.0	0.1	0.1
19	52	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0
20	Total	1,411.7	66.4	0.0	0.0	1,478.1	33.2	1,444.9		0.0	87.2	1,390.9

Numbers may not add due to rounding.

Table 9
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Operations ($M)
Year Ending December 31, 2014

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions[2]	Net Adjustments[3]	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	1,861.9	88.2	537.4	0.0	2,487.6	44.1	2,443.5	4%	0.0	97.7	2,389.9
2	**1-rolling start**	337.5	0.0	0.0	0.0	337.5	0.0	337.5	4%	0.0	13.5	324.0
3	**1.1**	182.3	78.4	2.4	0.0	263.1	39.2	223.9	6%	0.0	13.4	249.7
4	**1.1-rolling start**	36.9	61.8	0.0	0.0	98.7	0.0	98.7	6%	0.0	5.9	92.8
5	**2**	1,113.7	0.0	557.0	0.0	1,670.7	0.0	1,670.7	6%	0.0	100.2	1,570.4
6	**3**	0.0	0.0	0.8	0.0	0.8	0.0	0.8	5%	0.0	0.0	0.8
7	**8**	265.1	55.4	22.7	0.0	343.2	27.7	315.5	20%	0.0	63.1	280.1
8	**10**	23.0	11.7	2.9	0.0	37.7	5.9	31.8	30%	0.0	9.6	28.2
9	**12**	8.2	21.3	3.0	0.0	32.5	10.7	21.8	100%	0.0	21.8	10.7
10	**13**	3.0	0.0	0.0	0.0	3.0	0.0	3.0	N/A	0.0	0.7	2.4
11	**17**	621.9	219.6	142.3	0.0	983.8	109.8	874.0	8%	0.0	69.9	913.9
12	**17-rolling start**	73.4	126.4	0.0	0.0	199.7	0.0	199.7	8%	0.0	16.0	183.7
13	**38**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
14	**42**	0.6	0.5	2.2	0.0	3.3	0.2	3.1	12%	0.0	0.4	2.9
15	**43.1**	0.0	0.0	0.4	0.0	0.4	0.0	0.4	30%	0.0	0.1	0.3
16	**43.2**	0.0	0.0	6.1	0.0	6.1	0.0	6.1	50%	0.0	3.1	3.1
17	**45**	0.0	0.0	0.2	0.0	0.2	0.0	0.2	45%	0.0	0.1	0.1
18	**50**	4.3	3.3	0.3	0.0	7.9	1.7	6.2	55%	0.0	3.4	4.5
19	**Total**	4,531.9	666.6	1,277.8	0.0	6,476.3	239.2	6,237.1		0.0	419.0	6,057.3

Notes:
1 Amounts are from Ex. F4-2-1 Table 8, col. (k) and are for the previously regulated hydroelectric facilities and nuclear facilities.
2 Amounts are for previously and newly regulated hydroelectric facilities and nuclear facilities.
3 Amounts represent the inclusion of the Undepreciated Capital Cost for the newly regulated hydroelectric facilities effective in 2014.

Numbers may not add due to rounding.

Table 10
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Operations ($M)
Year Ending December 31, 2015[1]

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[2]	Cost of Acquisitions	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	2,389.9	86.6	0.0	0.0	2,476.4	43.3	2,433.1	4%	0.0	97.3	2,379.1
2	**1-rolling start**	324.0	0.0	0.0	0.0	324.0	0.0	324.0	4%	0.0	13.0	311.1
3	**1.1**	249.7	174.7	0.0	0.0	424.4	87.4	337.0	6%	0.0	20.2	404.2
4	**1.1-rolling start**	92.8	138.7	0.0	0.0	231.5	0.0	231.5	6%	0.0	13.9	217.6
5	**2**	1,570.4	0.0	0.0	0.0	1,570.4	0.0	1,570.4	6%	0.0	94.2	1,476.2
6	**3**	0.8	0.0	0.0	0.0	0.8	0.0	0.8	5%	0.0	0.0	0.7
7	**8**	280.1	63.7	0.0	0.0	343.8	31.8	312.0	20%	0.0	62.4	281.4
8	**10**	28.2	13.2	0.0	0.0	41.4	6.6	34.8	30%	0.0	10.4	31.0
9	**12**	10.7	23.3	0.0	0.0	34.0	11.7	22.3	100%	0.0	22.3	11.7
10	**13**	2.4	0.0	0.0	0.0	2.4	0.0	2.4	N/A	0.0	0.7	1.7
11	**17**	913.9	416.2	0.0	0.0	1,330.0	208.1	1,122.0	8%	0.0	89.8	1,240.3
12	**17-rolling start**	183.7	283.6	0.0	0.0	467.3	0.0	467.3	8%	0.0	37.4	429.9
13	**38**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
14	**42**	2.9	0.5	0.0	0.0	3.4	0.3	3.2	12%	0.0	0.4	3.1
15	**43.1**	0.3	0.0	0.0	0.0	0.3	0.0	0.3	30%	0.0	0.1	0.2
16	**43.2**	3.1	0.0	0.0	0.0	3.1	0.0	3.1	50%	0.0	1.5	1.5
17	**45**	0.1	0.0	0.0	0.0	0.1	0.0	0.1	45%	0.0	0.1	0.1
18	**50**	4.5	3.3	0.0	0.0	7.8	1.7	6.1	55%	0.0	3.4	4.4
19	**Total**	6,057.3	1,203.8	0.0	0.0	7,261.1	390.8	6,870.3		0.0	467.0	6,794.0

Notes:

1 All amounts are for previously and newly regulated hydroelectric facilities and nuclear facilities.

2 Amounts are from Ex. F4-2-1 Table 9, col. (k).

these wastes. The current assumptions used to establish the accrued L&ILW management costs include a L&ILW deep geologic repository (L&ILW DGR). 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 pending receipt of the site preparation and construction licence which is expected in the first half of 2015.

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. The liability is based on third-party cost estimates after an in-depth review of active plant sites and an assessment of required clean-up and restoration activities. As at December 31, 2013, the estimated retirement dates of the thermal stations for the purposes of this liability are between 2014 and 2030. The discount rates range from 1.5 percent to 5.8 percent. The undiscounted amount of estimated future cash flows associated with the non-nuclear liabilities is $491 million in 2013 dollars.

As at December 31, 2013, in addition to the $134 million liability for active sites, OPG has an ARO of $220 million for decommissioning and restoration costs associated with plant sites that are no longer 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 a portion of used fuel storage costs after station life. As at December 31, 2013, 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 $12.9 billion in present value dollars as at December 31, 2013, 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 2013 under the ONFA was $184 million (2012 – $182 million), including a contribution to the Ontario NFWA Trust (the Trust) of $154 million (2012 – $149 million). Based on the approved 2012 ONFA Reference Plan, OPG is required to contribute annual amounts to the Used Fuel Fund, ranging from $139 million to $193 million over the years 2014 to 2018 (Refer to Note 15).

The NFWA was proclaimed into force in November 2002. As required under the NFWA, OPG established the Trust in November 2002 and made an initial deposit of $500 million into the Trust. The NFWA required OPG to make annual contributions of $100 million to the Trust, until such time that the NWMO proposed funding formula, designed to address the future financial costs of implementing the Adapted Phase Management approach, was approved by the Federal Minister of Natural Resources. In 2009, this funding formula was approved. 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.

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 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 2013 and 2014, 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 funding in the Decommissioning Fund, which is the excess of the fair market value of the Decommissioning Fund 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.

The Decommissioning Fund's asset value on a fair value basis was $5,967 million as at December 31, 2013, which was net of the due to the Province of $624 million, as the asset value of the fund was higher than the liability per the approved 2012 ONFA Reference Plan. As at December 31, 2012, the Decommissioning Fund's asset value on a fair value basis was $5,707 million, also higher than the liability per the 2012 ONFA Reference Plan. 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. 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 of 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, based on the fair value of the Used Fuel Fund's assets, which includes realized and unrealized returns, is recorded as due to or due from the Province. The due to or due from the Province represents the amount the fund 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 incremental fuel bundles are not subject to the Province's guaranteed rate of return, but rather earn a return based on changes in the market value of the assets of the Used Fuel Fund.

As at December 31, 2013, the Used Fuel Fund asset value on a fair value basis was $7,529 million. The Used Fuel Fund value included a due to the Province of $990 million related to the committed return adjustment. As at December 31, 2012, the Used Fuel Fund asset value on a fair value basis was $7,010 million, including a due to the Province of $235 million related to the committed return adjustment.

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.

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

	Fair Value	
(millions of dollars)	**2013**	**2012**
Decommissioning Fund	**6,591**	5,771
Due to Province – Decommissioning Fund	**(624)**	(64)
	5,967	5,707
Used Fuel Fund [1]	**8,519**	7,245
Due to Province – Used Fuel Fund	**(990)**	(235)
	7,529	7,010
Total Nuclear Funds	**13,496**	12,717
Less: current portion	**25**	27
Non-current Nuclear Funds	**13,471**	12,690

[1] The Ontario NFWA Trust represented $2,668 million as at December 31, 2013 (2012 – $2,559 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:

	Fair Value	
(millions of dollars)	**2013**	**2012**
Cash and cash equivalents and short-term investments	**262**	335
Alternative investments	**598**	362
Pooled funds	**2,173**	2,093
Marketable equity securities	**7,332**	5,670
Fixed income securities	**4,713**	4,523
Net receivables/payables	**32**	41
Administrative expense payable	**-**	(8)
	15,110	13,016
Due to Province	**(1,614)**	(299)
	13,496	12,717

The bonds and debentures held in the Used Fuel Fund and the Decommissioning Fund as at December 31 mature according to the following schedule:

	Fair Value	
(millions of dollars)	**2013**	**2012**
1 – 5 years	**1,334**	1,151
5 – 10 years	**871**	631
More than 10 years	**2,508**	2,741
Total maturities of debt securities	**4,713**	4,523
Average yield	**3.2%**	2.7%

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

	Fair Value	
(millions of dollars)	**2013**	**2012**
Decommissioning Fund, beginning of year	**5,707**	5,342
Increase in fund due to return on investments	**854**	469
Decrease in fund due to reimbursement of expenditures	**(34)**	(40)
Increase in due to Province	**(560)**	(64)
Decommissioning Fund, end of year	**5,967**	5,707
Used Fuel Fund, beginning of year	**7,010**	6,556
Increase in fund due to contributions made	**184**	182
Increase in fund due to return on investments	**1,131**	584
Decrease in fund due to reimbursement of expenditures	**(41)**	(30)
Increase in due to Province	**(755)**	(282)
Used Fuel Fund, end of year	**7,529**	7,010

The earnings from the Nuclear Funds during 2013 and 2012 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)	**2013**	**2012**
Decommissioning Fund	**294**	405
Used Fuel Fund	**376**	302
Bruce Lease Net Revenues Variance Account *(Note 5)*	**(42)**	(56)
Total earnings	**628**	651

9. INCOME TAXES

OPG follows the liability method of tax accounting for all of 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 2013, 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 $109 million (2012 – $31 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 2013 and 2012 was not impacted.

The amount of taxes paid during 2013 was $14 million (tax refund received net of taxes paid during 2012 – $7 million).

MR. CROCKER: Yes.

MR. MAUTI: That's the change in the -- due to the province for recognition of those amounts that are over and above the target return for the year.

MR. CROCKER: We'll talk about whether that is due to the province or not in a sec.

If that amount were included in -- if we go back to the table on page 39 -- if it were included on earnings for the period that -- I'm correct, am I not, in assuming that the average unfounded -- unfunded nuclear liability balance would go down by an equivalent amount? Correct?

MR. KOGAN: Obviously, as we've discussed, we don't at all agree with the premise, but sure, if you want to do the math and you adjusted the earnings number at line 15, more earnings means more funds, means lower unfunded liability at line 22.

MR. CROCKER: Right. And then -- I'm not going to do the math, but the -- then the amount that you would need to recover in revenue for the test period would then be significantly lower than the average asset retirement costs at line 31. Correct?

MR. KOGAN: That's absolutely incorrect.

MR. CROCKER: Well, explain to me why.

MR. KOGAN: Because if you increase using the Board's methodology the amount of the segregated funds and you decrease the unfunded nuclear liability, you are, if anything, going to be possibly in a situation where the unfunded nuclear liability will be lower than the asset retirement cost, so the amount at line 32 will be lower --

MR. CROCKER: That's what I wanted you to agree with.

MR. KOGAN: No, but if you let me finish, please.

And as per the Board's methodology, the difference between the asset retirement costs and the unfunded nuclear liability receives the weighted average cost of capital.

So whereas right now the entire amount is at the weighted average accretion rate, which is lower than the weighted average cost of capital, you will now be exposing some of that amount to the weighted average cost of capital, which would increase the revenue requirement.

MR. CROCKER: How much of that is sum?

MR. KOGAN: Well, I'm sorry I haven't done the math to run through the -- you know, what the new "lower of" number would be, but directionally it can only go up; it won't go down, is what I'm trying to say.

MR. MAUTI: Any time you reduce the unfunded nuclear liability, it can only cause an amount to be exposed to the weighted average cost of capital to be a greater risk, not a lower risk.

MR. CROCKER: Are you suggesting, then, that by including that amount in earnings, you would not be reducing the amount that would be -- that you would need to be recovered -- that would need to be recovered for -- the revenue requirement that you would need pursuant to the Board's formula?

MR. KOGAN: The revenue requirement would go up pursuant to the Board's formula for the prescribed

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 Facililites**		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 1a
Revenue Requirement Impact of OPG's Nuclear Liabilities ($M)
Years Ending December 31, 2010 to 2015
Notes to Ex. C2-1-1, Table 1

Notes:

1 If average UNL is less than average ARC for the prescribed facilities, the funded portion of average ARC (i.e. the amount by which average ARC exceeds average UNL) earns WACC as follows:

Table to Note 1

Line No.	Year	(from Ex. C2-1-1 Table 2, line 31) Average ARC ($M)	(from Ex. C2-1-1 Table 2, line 22) Average UNL ($M)	(a)-(b) ARC-UNL ($M)	Annual WACC	(c) x (d) if >0 Return on Rate Base ($M)	WACC Reference
		(a)	(b)	(c)	(d)	(e)	
1a	2010	1,517.6	1,719.8	(202.1)	7.19%	0.0	EB-2007-0905 Payment Amounts Order, App. A, Table 5b
2a	2011	1,490.0	1,605.5	(115.6)	7.31%	0.0	EB-2010-0008 Payment Amounts Order, App. A, Table 4b
3a	2012	1,851.1	2,016.9	(165.9)	7.40%	0.0	EB-2010-0008 Payment Amounts Order, App. A, Table 5b
4a	2013	1,470.2	1,715.2	(245.0)	7.40%	0.0	EB-2010-0008 Payment Amounts Order, App. A, Table 5b
5a	2014	1,389.5	~~1,671.3~~ 816	~~(281.9)~~	6.77%	~~0.0~~	Ex. C1-1-1 Table 2
6a	2015	1,308.8	~~1,589.2~~ 734	~~(280.5)~~	6.79%	~~0.0~~	Ex. C1-1-1 Table 1

2 The income tax impact for prescribed facilities is calculated as follows:

Table to Note 2 ($M)

Line No.	Item	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1b	Increase in Regulatory Taxable Income Before Impact of Segregated Fund Contributions (Ex. C2-1-1, Table 1, line 6)	135.5	139.1	283.5	215.6	214.6	213.2
2b	Contributions to Nuclear Segregated Funds for Prescribed Facilities (Ex. C2-1-1 Table 2, line 16)	150.2	145.0	107.1	98.1	170.1	172.8
3b	Net Increase in Regulatory Taxable Income (line 1b - line 2b)	(14.7)	(5.9)	176.4	117.5	44.5	40.4
4b	Income Tax Rate (Ex. F4-2-1 Table 4 line 33 and Ex. F4-2-1 Table 5 line 29)	29.00%	26.50%	25.00%	25.00%	25.00%	25.00%
5b	Income Tax Impact (line 3b x line 4b / (1 - line 4b))	(6.0)	(2.1)	58.8	39.2	14.8	13.5

3 The impact on Bruce facilities' income taxes relates to higher deductible temporary differences associated with the expenses at Ex. C2-1-1 Table 1, lines 9-13, which are not deductible for tax purposes. The impact is calculated as follows:

Table to Note 3 ($M)

Line No.	Item	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	Short-Term Temporary Differences:						
1c	Increase in Short-Term Temporary Differences - Depreciation Expense (Ex. C2-1-1 Table 1, line 9)	26.1	23.9	69.6	100.6	100.6	100.6
2c	Income Tax Rate - Current (Ex. G2-2-1 Tables 7 and 8, line 50)	29.00%	26.50%	25.00%	25.00%	25.00%	25.00%
3c	Increase in Deferred Income Taxes - Short-Term	(7.6)	(6.3)	(17.4)	(25.1)	(25.1)	(25.1)
	Long-Term Temporary Differences:						
4c	Increase in Long-Term Temporary Differences - All Other Expenses (Ex. C2-1-1 Table 1, lines 10 through 13)	(116.2)	84.5	23.3	91.3	92.6	97.7
5c	Income Tax Rate - Long-Term (Ex. G2-2-1 Tables 7 and 8, line 54)	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
6c	Increase in Deferred Income Taxes - Long-Term	29.0	(21.1)	(5.8)	(22.8)	(23.2)	(24.4)
7c	Impact on Bruce Facilities' Income Taxes (line 3c + line 6c)	21.5	(27.5)	(23.2)	(48.0)	(48.3)	(49.6)

4 Income tax rates are from Ex. F4-2-1 Table 4, line 33 and Ex. F4-2-1 Table 5, line 29.

Numbers may not add due to rounding.

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 5
Impact of Current Approved ONFA Reference Plan on Nuclear Liabilities Costs ($M)
Years Ending December 31, 2014 and 2015

Line No.	Description	Note or Reference (for cols. (a) and (b))	With Current Approved ONFA Reference Plan 2014 Plan	With Current Approved ONFA Reference Plan 2015 Plan	Note or Reference (for cols. (c) and (d))	Without Current Approved ONFA Reference Plan[1] 2014 Plan	Without Current Approved ONFA Reference Plan[1] 2015 Plan	(a)-(c)+(b)-(d) Impact on Nuclear Liabilities Costs
			(a)	(b)		(c)	(d)	(e)
	PRESCRIBED FACILITIES							
1	**Depreciation of Asset Retirement Costs**	Ex. C2-1-1 Table 1	80.7	80.7	Note 2	29.0	29.0	103.3
2	**Used Fuel Storage and Disposal Variable Expenses**	Ex. C2-1-1 Table 1	56.1	56.7		31.1	31.8	49.9
3	**Low & Intermediate Level Waste Management Variable Expenses**	Ex. C2-1-1 Table 1	3.1	5.5		1.4	2.5	4.8
	Return on ARC in Rate Base:							
4	**Return on Rate Base at Weighted Average Accretion Rate**	Ex. C2-1-1 Table 1	74.6	70.3	Note 2	78.3	76.7	(10.0)
5	**Return on Rate Base at Weighted Average Cost of Capital**	Ex. C2-1-1 Table 1	0.0	0.0	Note 2	0.0	0.0	0.0
6	**Pre-tax Revenue Requirement Impact**		214.6	213.2		139.8	140.0	148.0
7	**Income Tax Impact on Revenue Requirement**	Ex. C2-1-1 Table 1	14.8	13.5	Note 3	20.3	19.7	(11.6)
8	**Total Impact on Nuclear Liabilities Costs - Prescribed Facilities**		229.4	226.6		160.0	159.6	136.4
	(line 6 + line 7)							
	BRUCE FACILITIES							
9	**Depreciation of Asset Retirement Costs**	Ex. C2-1-1 Table 1	100.6	100.6		26.7	26.7	147.8
10	**Used Fuel Storage and Disposal Variable Expenses**	Ex. C2-1-1 Table 1	54.3	56.4		26.9	28.3	55.5
11	**Low & Intermediate Level Waste Management Variable Expenses**	Ex. C2-1-1 Table 1	2.4	3.8		1.0	1.6	3.5
12	**Accretion**	Ex. C2-1-1 Table 1	382.9	397.3		337.8	350.8	91.5
13	**Less: Segregated Fund Earnings (Losses)**	Ex. C2-1-1 Table 1	347.0	359.8		349.4	365.0	(7.6)
14	**Bruce Facilities' Income Tax Impact**	Ex. C2-1-1 Table 1	(48.3)	(49.6)	Note 4	(10.8)	(10.6)	(76.5)
15	**Pre-Tax Revenue Requirement Impact (Impact on Bruce Lease Net Revenues)**		144.9	148.7		32.3	31.9	229.4
16	**Income Tax Impact on Revenue Requirement**	Ex. C2-1-1 Table 1	48.3	49.6	Note 5	10.8	10.6	76.5
17	**Total Impact on Nuclear Liabilities Costs - Bruce Facilities**		193.2	198.3		43.1	42.5	305.9
	(line 15 + line 16)							
18	**Total Test Period Impact of Current Approved ONFA Reference Plan on Nuclear Liabilities Costs** (col. (e): line 8 + line 17)							442.3

See Ex. C2-1-1 Table 5a for notes

special payments, special cash payments, right?

MR. KOGAN: Again, it is an apples-to-oranges, because one is a cash amount and one is an accounting amount. So there are no cash amounts at all in these dollars, because they're all determined in accordance with GAAP.

MR. SHEPHERD: Well, it is interesting you say that, because you also have an accrued number, which is what you're asking the ratepayers to pay, right?

And that is $1,294,000,000 over the test period; isn't that right?

MR. KOGAN: Could you point me to where you are looking at?

MR. SHEPHERD: Yes, it is actually N2-1-1, page 3.

We talked about this number at some length. $675 million in 2014 and $618 million in 2015; isn't that right?

MR. KOGAN: So all of the numbers you're citing, as per Exhibit N2-1-1, is the total accounting pension and OPEB costs that we're seeking for recovery.

An element of those costs are the numbers that you were referring to earlier at the bottom of, I believe, page 1, J3.5.

MR. SHEPHERD: Okay. So what is the difference between those?

MR. KOGAN: Other components of pension and OPEB costs determined in accordance with GAAP, and --

MR. SHEPHERD: Let me just stop you. You said the ones on page 2 of our materials in J3.5 were the accounting instruction, and the reason I say that is I took from Mr. Kogan's answer that it may not be done. It may be, but it may not be, and --

MS. DUFF: We also have the July 2nd filing that you are planning to do, so that provides some time.

MR. SMITH: It does. I think I have to stick with what I said before, which is I can look at it, and if it is going to be available, then we will certainly report back on how we propose to deal with it.

MS. HARE: But if it's not available, how are we going to reconcile the numbers with the new information?

MR. SMITH: I'm --

MS. LADAK: Can I just say that this is the funding valuation. It is not flowing through -- our revenue requirement is based on our pension expense and accounting expense. It is not cash. So it wouldn't really impact the revenue requirement. It won't be an impact statement, because this is what we pay out in cash. It is not what we recover through rates.

MR. SHEPHERD: May I comment, Madam Chair?

MS. HARE: Yes, please.

MR. SHEPHERD: It actually will, of course, impact on the revenue requirement, because it will change the tax number. If nothing else, it will change the tax number.

Isn't that right, Mr. Kogan?

MR. KOGAN: It will. I just wanted to clarify that is a funding valuation, as Ms. Ladak said, and it -- yes, that it will change the funding number, which will therefore and you would have an accrual basis? You're both under US GAAP, right? And so is Enbridge?

MR. KOGAN: US GAAP governs accounting for your financial reporting. I understand this Board sets how the amounts are included in the requirement.

MR. SHEPHERD: So does US GAAP require cash or accrual?

MR. KOGAN: US GAAP requires accrual, like, accrual accounting.

MR. SHEPHERD: So then Hydro One and Enbridge are doing it wrong, or they have an exception from the Board, right?

MR. KOGAN: No. I think we are -- we're missing each other here. I think, as we alluded to in our reply argument in the last application and I think it was acknowledged in the EB-2010 decision, there is a variety of recovery methods for pension and OPEB costs that I understand are applied to various utilities.

For us, pension and other post-employment benefit costs are calculated in rates on an accounting -- on an accrual accounting basis, i.e., the same way that an unregulated utility out there who calculates their pension and OPEB costs in accordance with US GAAP would do.

That's the amount we've got and that's the amount in our rates and that have been proposed in this test period.

MR. SHEPHERD: It's correct, isn't it, that for 2014 you're asking the ratepayers to pay you $70,656 per employee for pension and other post-employment benefit