IMPACT STATEMENT

1.0 PURPOSE

The purpose of this exhibit is to show the impact of certain material changes resulting from OPG's 2014 - 2016 Business Plan. The 2014 - 2016 Business Plan was approved by OPG's Board of Directors ("OPG Board") on November 14, 2013. The prefiled evidence in this Application was based on OPG's 2013 - 2015 Business Plan.

2.0 SUMMARY

The update to the Application is required to reflect material changes in costs and production forecasts for the 2014 - 2015 period that are included in the 2014 - 2016 Business Plan. Specifically, OPG is proposing to update its Application in three areas that affect revenue requirement and payment amounts/riders. These are: (1) changes to forecast pension and OPEB costs, including the related tax effects; (2) production forecast changes for nuclear and the previously regulated hydroelectric assets, including the related impacts on nuclear fuel costs and gross revenue charge ("GRC"); and, (3) a change in forecast ancillary service revenues for the previously regulated hydroelectric assets.

The change in forecast pension and OPEB costs (an increase of $142.3M, inclusive of the related income taxes) is driven by a number of factors, including changes in mortality assumptions, and updated plan membership data, partially offset by the impact of higher discount rates and lower forecast health care benefit costs.

The change in the previously regulated production forecast reflects an increase in water availability resulting in an overall increase of 1.8 TWh over the test period. Forecast nuclear production has decreased by 2.6 TWh over the test period as a result of increased outage days. The production forecast for newly regulated hydroelectric is essentially unchanged. Consistent with these forecast production changes, fuel costs and GRC costs have also been updated for nuclear and previously regulated hydroelectric, respectively.

Finally, forecast ancillary service revenues for previously regulated hydroelectric have increased by $28.5M over the previous business plan. This change is primarily due to higher forecasted revenues for operating reserve ("OR") and regulation service.

The updated costs and production forecasts were determined using the same methodologies and with the same rigour and level of review and approval as the original pre-filed evidence.

Using the same assumptions as described at Ex. I1-1-2, page 1, these changes result in a revised total customer impact, inclusive of the newly regulated hydroelectric facilities, of approximately $5.94/month on a typical consumer's monthly bill. This is an increase from the $5.36/month impact calculated as part of the September filing.

The main remaining changes from the 2014 - 2016 Business Plan, which net to an approximate $33.0M increase in revenue requirement over 2014 - 2015, are identified below. However, OPG is not seeking to recover these amounts in the revised payment amounts and riders. In order to minimize the impact on the proceeding schedule and to keep the Impact Statement to a manageable size, OPG is limiting the update to just the largest changes.

Chart 1 below shows the changes, plan-over-plan that OPG is not seeking to recover.

Chart 1

BP2013 - 2015 vs. BP2014 - 2016 Changes

Not Included in Impact Statement ($M) *

	Test Period
Revenue Requirement Items	
OM&A	26
Asset Service Fees	(1)
Nuclear Fuel Costs – Non Fuel Bundle Costs	(4)
Ancillary Service Revenue	(8)
Bruce Lease Net Revenues	20
Other Revenues	7
Depreciation & Amortization	9
Property Taxes-Nuclear	(3)
Cost of Capital	(6)
Income Taxes - Excluding Pension&OPEB	(6)
Total (Net)	33
Production Forecast Item	
Newly Regulated Hydroelectric	1

* Positive numbers indicate increase to revenue requirement; negatives indicate decreases

2.1 Items Included in the Impact Statement

This section provides additional detail on the specific cost items and production changes that have been reflected in the revised payment amounts and riders for the test period. Each of the following sections will cover the amount of the plan-over-plan change and the reason(s) for the change.

Sections 2.2 through 2.4 set out changes that affect revenue requirement and payment amounts/riders. Section 2.5 discusses certain changes that have occurred in the Darlington Refurbishment Project. While these changes impact the specific approvals that OPG has requested from the OEB, OPG has not included the impact of these changes in the proposed revenue requirement for 2014 - 2015 or the revised payment amounts and riders.

2.2 Pension and OPEB Costs

2.2.1 Introduction

OPG is forecasting an overall increase of $142.3M in its test period revenue requirement related to pension and OPEB, inclusive of the related income taxes. The updated forecast of the pension and OPEB costs for the prescribed assets is shown in Chart 2. The change in the income taxes is presented in Chart 4.

Chart 2

Updated Forecast of Pension and OPEB Costs ($M)

	Nuclear		Previously Regulated Hydroelectric		Newly Regulated Hydroelectric		Total Prescribed Assets		
	2014	2015	2014	2015	2014	2015	2014	2015	Total
Pension Costs									
2014-2016 Business Plan	448.0	425.1	24.5	23.1	43.8	40.5	516.3	488.7	1,005.1
2013-2015 Business Plan*	342.6	331.3	18.8	18.0	33.4	31.6	394.8	380.9	775.7
Increase	105.4	93.8	5.7	5.1	10.4	8.9	121.5	107.8	229.4
OPEB Costs									
2014-2016 Business Plan	212.9	217.8	11.7	11.8	20.8	20.8	245.4	250.4	495.8
2013-2015 Business Plan*	249.3	253.7	13.6	13.8	24.3	24.3	287.2	291.8	579.0
Decrease	(36.4)	(35.9)	(1.9)	(2.0)	(3.5)	(3.5)	(41.8)	(41.4)	(83.2)
Net Increase	**69.1**	**57.9**	**3.8**	**3.1**	**6.9**	**5.4**	**79.7**	**66.5**	**146.2**

* From Ex. F4-3-1, pp 36 - 37.

The updated forecast of OPG's total pension and OPEB costs was determined by OPG's independent actuary, AON Hewitt ("AON"), using the same methodology applied in determining the costs reflected in the pre-filed evidence. The economic assumptions and pension plan asset values underpinning the updated forecast reflect market conditions as at June 30, 2013. AON's report on the updated estimates of OPG's 2014 and 2015 pension and OPEB costs is provided in Attachment 1.

The updated forecast of OPG's pension and OPEB costs reflects an estimate of the impact of a comprehensive accounting valuation of the plan obligations. A comprehensive accounting valuation incorporates current demographics of the plan membership, and updates to applicable assumptions to represent the current best estimate based on plan experience and current expectations.

In accordance with generally accepted actuarial practice, periodic comprehensive accounting valuations are performed typically at least every three years. OPG's last comprehensive accounting valuation was performed using data as at December 31, 2009. Therefore, given the passage of time, AON and OPG determined that a new comprehensive accounting valuation should be conducted to determine the year-end 2013 obligations and, consequently, the costs for 2014 and 2015.[1] The new comprehensive accounting valuation ensures that OPG's pension and OPEB obligations are not materially misstated. Changes arising from the comprehensive accounting valuation of OPG's plans include updated mortality assumptions, lower health care benefit costs, and updated membership.

The main drivers of change to the pension and OPEB costs from the 2013 - 2015 Business Plan are shown in Chart 3. New mortality assumptions, reflected as part of the comprehensive accounting valuation, are the most significant driver of the increased pension costs. These assumptions are discussed in section 2.2.2. For OPEB, the forecast of lower per capita health care benefit costs is the most significant factor. The lower per capita costs result primarily from the increased use and reduced pricing of generic drugs. The update of plan membership data to December 31, 2012 as part of the comprehensive accounting valuation increases the forecast pension and OPEB costs.

In addition to changes arising from the comprehensive accounting valuation, higher discount rates due to higher representative AA corporate bond yields, discussed in section 2.2.3, work to decrease the updated forecast of pension and OPEB costs. Other factors include the impact of pension fund asset returns.

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[1] The new comprehensive accounting valuation uses data as of December 31, 2012, as this is the date of the most recent year-end of OPG's registered pension plan.

Chart 3

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

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

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

2.2.2 Mortality Assumptions

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

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

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

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

Business Plan. The adjustment factor of 85 per cent reflected the results of the last review of OPG pensioners' mortality experience that showed that OPG pensioners were living longer than predicted by the UP94 table.

As part of the current comprehensive accounting valuation for OPG's plans, AON has recommended updates to both base mortality rates and future mortality improvement assumptions (Attachment 1, pp. 3-4). AON's recommendation is based on its analysis of recent mortality experience information for OPG retirees and current expectations of future mortality improvement specific to the Canadian populations.

OPG adopted AON's recommendation, as this information represents a better estimate for purposes of determining OPG's obligations under the plan. In adopting the recommendation, OPG concluded that the continued use of the previous mortality assumptions would result in a material understatement of its pension and OPEB obligations and costs, and would not be in accordance with US GAAP. In accounting for pension and OPEB, US GAAP requires the use of best estimate assumptions for future events.[4] The role of Ernst & Young ("E&Y") is to provide an opinion on whether OPG's financial statements are in accordance with US GAAP in all material aspects. Given the significance of the mortality assumption with respect to the actuarial valuations of OPG's pension and OPEB plans, E&Y agrees that the use of the available updated mortality is required under US GAAP.

AON determined that OPG's plans are large enough to develop base mortality assumptions specific to OPG's employee and pensioner base population. This approach reflects the actuarial best practice of using plan-specific information, rather than standard mortality tables, in developing mortality assumptions. This best practice was recently affirmed by the Canadian Institute of Actuaries ("CIA") in an educational note supplement issued in October

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[3] The Canadian Institute of Actuaries has not previously published mortality improvement assumptions specific to the Canadian population.

[4] United States Financial Accounting Standards Board Accounting Standards Codification Topic 715-30-35-42

2013 entitled "Educational Note Supplement: Canadian Pensioners Mortality" (the "CIA Educational Note Supplement") (see Attachment 2).[5]

AON also recommended updated assumptions for future mortality improvement to replace Scale AA. These assumptions were developed by AON based on an analysis of the actual mortality experience of the Canadian population to 2007. The recommended mortality improvement assumptions represent a better estimate for purposes of valuing OPG's plans than Scale AA, as they use more recent data, reflect experience specific to Canada, and are gender and birth-year specific. AON's discussion of the recommended future mortality improvement assumptions is found at pages 11 and 12 of Attachment 1.

AON's recommendations to update OPG's mortality assumptions are consistent with recent conclusions by the CIA. The CIA has concluded that the UP94 table and Scale AA produce significantly higher mortality rates than actual experience. For example, in a July 2013 draft report entitled "Canadian Pensioners Mortality" (Attachment 3), the CIA stated:

> The results of the RPP and CPP/QPP Studies indicate that the overall level of recent mortality experience is significantly lower than that anticipated by UP-94 with Scale AA and exhibits a different shape by age. The CPP/QPP Study also shows that mortality improvement rates experienced in recent years have been substantially higher than indicated by Scale AA.
>
> The experience illustrated by both the CPP/QPP Study and RPP Study indicates that adoption of tables and scales reflecting Canadian mortality experience is warranted.
>
> […]
>
> The adoption of the [draft CIA] proposed tables [based on the experience observed in the RPP and CPP/QPP Studies] will result in an increase in recognized costs for Canadian pension plans and their sponsors to the extent that the mortality tables and improvement scales used in recent valuations have not reflected recent experience." (Attachment 3, p. 19, clarifications added.)

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[5] The CIA Educational Note Supplement states: "In establishing a best estimate mortality assumption, it would always be preferable to reflect actual credible experience of the plan under review, rather than to rely solely on published mortality studies or adjustments." (Attachment 2, p. 2)

The CIA's July 2013 draft report was issued as part of the CIA's ongoing initiative to develop a Canadian pension mortality table and improvement scale. While the CIA is currently in the process of reviewing comments on its draft report, it has stated the following regarding the use of the UP94 table and Scale AA in the CIA Educational Note Supplement:

> The use of the unadjusted UP94 table projected to the valuation date using Scale AA as a best estimate of current mortality rates; and/or
>
> The use of an unadjusted Scale AA as a best estimate of future mortality improvement rates would only be appropriate if supported by credible evidence, the characteristics of the specific plan under review, or other quantifiable evidence. (Attachment 2, p. 2).

AON's use of recent, OPG-specific data in developing base mortality rate assumptions and their use of an analysis of recent Canadian population experience to project mortality improvement assumptions are in line with the CIA's conclusions.

2.2.3 Discount Rates

The pension and OPEB costs forecasts in OPG's original pre-filed evidence were based on December 31, 2012 discount rates, as discussed in Ex. F4-3-1, section 6.3.2 and presented in Ex. F4-3-1, Chart 1. The forecast of these costs from the 2014 - 2016 Business Plan is based on discount rates as at June 30, 2013. The increase in discount rates between December 31, 2012 and June 30, 2013 has caused a decline in the forecast pension and OPEB costs for the test period. Specifically, the discount rates used to project pension, other post retirement benefits and the long-term disability plan costs have increased from 4.30 per cent, 4.40 per cent and 3.50 per cent, respectively, as at December 31, 2012, to 4.70 per cent, 4.70 per cent and 4.00 per cent, respectively, as at June 30, 2013 (see Attachment 1, p 4).

As discussed in detail in Ex. F4-3-1 (pp. 31-34), the discount rates used in determining pension and OPEB costs are based on AA corporate bond yields for bonds with durations similar to those of OPG's obligations. The updated discount rates were provided by Mercer and calculated in the same way as those in the original pre-filed evidence.

2.2.4 Income Tax Impact

As discussed in Ex. F4-2-1, section 3.3.5, pension and OPEB accounting costs are not deductible for income tax purposes and are added back to earnings before tax in computing taxable income. Conversely, pension plan contributions and OPEB payments are deductible for income tax purposes and are deducted from earnings before tax in computing taxable income.

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

2.3 Production Forecast (Previously Regulated Hydro and Nuclear)

2.3.1 Nuclear Production

The nuclear production forecast for 2014 and 2015 in the 2014 - 2016 Business Plan is 2.6 TWh lower than the 2013 - 2015 Business Plan, primarily due to the addition of 148.5 planned outage days over the two years. As a result, the forecast production levels for 2014 and 2015 are 49.0 TWh and 46.1 TWh, respectively.

Chart 5

OPG Nuclear Plan over Plan Changes

OPG Nuclear		**2014**	**2015**	**Total Variance**
Generation - TWH	2014-2016 Nuclear Business Plan	49.0	46.1	
	2013-2015 Nuclear Business Plan	49.7	48.1	
	Variance (BP2014-16 vs 2013-2015)	-0.6	-2.0	**-2.6**
FLR %	2014-2016 Nuclear Business Plan	4.1	3.1	
	2013-2015 Nuclear Business Plan	4.1	3.1	
	Variance (BP2014-16 vs 2013-2015)	0.0	0.0	**0.0**
Planned Outage Days	2014-2016 Nuclear Business Plan	409.3	585.1	
	2013-2015 Nuclear Business Plan	370.0	475.9	
	Variance (BP2014-16 vs 2013-2015)	39.3	109.2	**148.5**

Numbers may not add due to rounding

OPG's Nuclear Generation Plan identifies the number of outage days required for inspections and maintenance activities to ensure continued safe, reliable, and long-term operation. The planned outage schedule is prepared in accordance with OPG's aging and lifecycle management programs and in compliance with OPG's nuclear operating licences issued by the CNSC. Planned outages are complex, requiring the coordination of a number of divisions and many specialized individuals working together. The planning and coordination effort typically exceeds that of a major construction project due to the highly technical nature of the work, the complexity and the constraints on work execution. Because of the complexity and the execution of non-routine tasks included in a planned outage, OPG's generation planning includes station and fleet level allowances (Ex. E2-1-1, p. 6) to accommodate risks that can result in an extension of the outage.

As part of the 2014 - 2016 Business Plan review process (see Ex A2-2-1), OPG's senior management directed generation planning staff to reassess the plan based on OPG's historical performance in which significant production forecast variances have occurred (i.e., actual generation has been lower than forecast over the past nine years including 2013). The reassessment revisited both outage scope along with the allowances, with the objective of establishing a more realistic and accurate nuclear production forecast for 2014 - 2015.

2.3.1.1 Pickering

The Pickering production forecast for 2014 and 2015 in the 2014 - 2016 Business Plan shows a 1.0 TWh reduction in generation compared to the 2013 - 2015 Business Plan.

Chart 6
Pickering NGS Plan over Plan Changes

Pickering NGS		**2014**	**2015**	**Total Variance**
Generation - TWH	2014-2016 Nuclear Business Plan	20.9	21.3	
	2013-2015 Nuclear Business Plan	21.3	21.9	
	Variance (BP2014-16 vs 2013-2015)	-0.4	-0.6	**-1.0**
FLR %	2014-2016 Nuclear Business Plan	7.8	5.5	
	2013-2015 Nuclear Business Plan	7.8	5.5	
	Variance (BP2014-16 vs 2013-2015)	0.0	0.0	**0.0**
Planned Outage Days	2014-2016 Nuclear Business Plan	327.9	339.5	
	2013-2015 Nuclear Business Plan	292.9	287.9	
	Variance (BP2014-16 vs 2013-2015)	35.0	51.6	**86.6**

Numbers may not add due to rounding

This is due to an increase of 86.6 planned outage days over the two-year period, as follows:

- An additional 23 day mid-cycle Unit 5 outage in 2014. In the 2013 Unit 5 outage, unexpected reductions in pressure tube to calandria tube gaps were noted. The 2014 mid-cycle planned outage is therefore required to measure the gap and to perform maintenance as required. Monitoring and maintaining the gap between calandria and pressure tubes is critical since there is the potential for blistering if the pressure tube and calandria tube touch which can result in failure of the pressure tube.
- The 2013 Unit 4 outage was deferred to January 2014. This resulted in the timing of all future Unit 1 and 4 planned outages being similarly deferred (e.g., the 2014 Unit 1 outage is deferred to 2015; and, the 2015 Unit 4 outage is deferred until 2016). The deferral of the 2013 Unit 4 fall outage into 2014 results in an additional seven planned outage days over the test period due to additional scope.
- An additional 28 day 2015 mid-cycle outage has been added to the 2014 - 2016 Business Plan in support of OPG's 2016 targeted reduction in FLR to 5.0 per cent. Pickering has a two year planned outage cycle (i.e., each Pickering unit is subject to a planned outage once every two years). However, starting in 2012, OPG began implementing short duration, mid-cycle planned outages (i.e., an additional planned outage within the two year cycle) for Pickering Units 1 and 4 to focus on preventative maintenance and to lessen the risk of future forced outages thereby improving reliability and reducing the FLR.
- OPG's generation plan includes allowances (Ex. E2-1-1, p. 6) to account for risks that can result in an extension of an outage. The reassessment increased the allowance for Pickering planned outages by a total of 28.6 outage days (0.30 TWh) over the two-year test period. This increase is based on an assessment of historical performance which showed that over the period 2005 to 2013, the average annual forced extension to planned outages at Pickering was 82.5 days (0.87 TWh per year).

2.3.1.2 <u>Darlington</u>

The Darlington production forecast for 2014 and 2015 in the 2014 - 2016 Business Plan has a 1.6 TWh reduction in generation compared to the 2013 - 2015 Business Plan.

Chart 7

Darlington NGS Plan over Plan Changes

Darlington NGS		**2014**	**2015**	**Total Variance**
Generation - TWH	2014-2016 Nuclear Business Plan	28.1	24.7	
	2013-2015 Nuclear Business Plan	28.4	26.1	
	Variance (BP2014-16 vs 2013-2015)	-0.2	-1.4	**-1.6**
FLR %	2014-2016 Nuclear Business Plan	1.3	1.0	
	2013-2015 Nuclear Business Plan	1.3	1.0	
	Variance (BP2014-16 vs 2013-2015)	0.0	0.0	**0.0**
Planned Outage Days	2014-2016 Nuclear Business Plan	81.4	245.6	
	2013-2015 Nuclear Business Plan	77.1	188.0	
	Variance (BP2014-16 vs 2013-2015)	4.3	57.6	**61.9**

Numbers may not add due to rounding

This is due to:

- A reduction of 0.28 TWh to reflect the expectation of higher lake water temperatures than assumed in the 2013 - 2015 Business Plan. Higher lake water temperatures lower generation output due to reduced condenser efficiency.
- A 61.9 day increase in planned outage days. The reassessment identified a need for 39 additional planned outage days due to the vacuum building outage ("VBO") scope being of greater complexity than previously undertaken by OPG and because the VBO outage scope includes life extension activities which have not been part of prior Darlington VBO's**.** The greater scope includes a 100 per cent increase in electrical equipment maintenance, significant emergency service water ("ESW") piping replacement, a 50 per cent increase in emergency coolant injection ("ECI") valve replacement and the first time implementation of pressure relief valve ("PRV") maintenance.

Planned outages are highly complex and a VBO is one of the most complex and intricate maintenance outages undertaken. As noted in Ex. E2-1-1, p. 6, the 2015 VBO eliminates the need for the 2021 VBO, reducing the complexity and resource demands during the Darlington Refurbishment Project. It is therefore critical that all of the outage scope in the 2015 VBO be completed as there is no opportunity to defer this work. The 2015 VBO will be the last 4-unit station outage for 12 years including the term of the entire refurbishment project.

The reassessment also increased the allowances for Darlington planned outages by a total of 22.0 outage days (0.49 TWh) over the two-year test period. This increase is based on historical performance over the period 2005 - 2013. During this period the average forced extension to planned outages at Darlington was 0.24 TWH per year.

Nuclear fuel bundle costs have decreased by $19.3M over the test period (Table 4), primarily as a result of the lower forecast production.

Chart 8

Fuel Bundle Costs: Plan over Plan Changes

OPG Nuclear		**2014 ($M)**	**2015 ($M)**	**Total Variance ($M)**
Total Fuel Bundle Cost	2014-2016 Nuclear Business Plan	208.4	199.6	
	2013-2015 Nuclear Business Plan	220.3	207.0	
	Variance (BP2014-16 vs 2013-2015)	-11.9	-7.4	-19.3

2.3.2 Previously Regulated Hydroelectric

The updated previously regulated hydroelectric production forecast for 2014, included in the 2014 - 2016 Business Plan, is 20.1 TWh, or 1.0 TWh more than the forecast included in the 2013 - 2015 Business Plan. Increased production is forecast as a result of higher flows forecast for the Niagara and St. Lawrence Rivers.

Along with the higher production, the GRC costs for 2014 in the 2014 - 2016 Business Plan are $14.0M more than the original forecast. GRC costs for Niagara and Saunders increased as a result of higher forecast production.

The updated previously regulated hydroelectric production forecast for 2015, included in the 2014 - 2016 Business Plan, is 21.0 TWh, or 0.8 TWh more than the forecast included in the 2013 - 2015 Business Plan. Increased production is forecast as a result of higher flows forecast for the Niagara and St. Lawrence Rivers.

Along with the higher production, the GRC costs for 2015 in the 2014 - 2016 Business Plan are $11.3M more than the original forecast. GRC costs for Niagara and Saunders increased as a result of higher forecast production.

2.4 Ancillary Service Revenue (Previously Regulated Hydroelectric)

The test period forecast of ancillary services revenues in the 2014 - 2016 Business Plan is $28.5M higher than the prior business plan ($14.2M higher in 2014 and $14.3M higher in 2015). These changes are primarily due to higher forecasted revenues for operating reserve ("OR") and a new contract for regulation service.

The new Regulation Services Contract compensates OPG at regulated rates rather than Hourly Ontario Energy Price ("HOEP") for regulation service. Over the term of the prior contract for regulation service, OPG was paid HOEP which averaged $24.28/MWh.

The increase in ancillary services revenue results in a lowering of the test period revenue requirement.

2.5 Darlington Approvals

As planned, OPG updated its Darlington Refurbishment Program ("DRP") business case in November 2013. This updated business case, including an updated forecast of expenditures for the test period was approved by OPG Board on November 14, 2013.

The business case incorporates a change in the DRP execution phase strategy. As a result of OPG's improving confidence in the life of critical components at Darlington, OPG has decided to remove the overlap of the first and second refurbishment units. This has the effect of deferring the refurbishment outages on the 2nd, 3rd, and 4th units by about 18 months each.

This change will allow the experience gained in the refurbishment of the first unit to be assessed and applied to the work on the remaining units.

The updated business case also includes some cost flow changes. The proposed capital expenditures for 2014 have decreased from $837.4M to $765.0M, while those for 2015 have increased from $631.8M to $736.0M. The total net capital expenditure increase over the two years is $31.8M. The changes reflect a refinement of OPG's plans as a result of project development and the awarding of major contracts.

Forecast OM&A expenses have increased for 2014 from $19.6M to $23.1M and for 2015 from $18.2M to $20.4M. The total increase in OM&A over the two years is $5.6M and is mainly due to the timing of the Operations Trainee Program, deferrals from 2013 and better defined cost estimates, partly offset by lower demolition and removal activities.

The in-service additions to rate base have increased for 2014 from $18.7M to $26.1M and for 2015 from $209.4M to $310.0M. The total increase for the two year period is $108.0M.

A key driver of the higher additions to rate base is earlier assumed in-service dates for certain safety improvement projects, reflecting commitments to advance work that OPG has made to the CNSC. The projects in question are the Emergency Power Generator ("EPG") project and the Containment Filtered Venting System ("CFVS") project. The EPG project, with a projected cost of $52.0M, is required to improve the availability and reliability of the emergency power system. The project involves the installation of a third EPG that can withstand a higher level seismic event than the Design Basis Earthquake and that can operate following a severe flood. The CFVS project, with a projected cost of $39.0M, is required to prevent the loss of containment structural integrity as a result of over-pressurization. Other contributors to the change include higher in-service additions for the Heavy Water Storage and Drum Handing Facility, the Re-tube and Feeder Replacement Annex, and the Fuel Inspection Facility.

While OPG is seeking a finding of reasonability with respect to the updated test period capital expenditures, OPG is not seeking approvals of the higher levels of OM&A expense or in-service additions.

Separately, as a result of improved scope definition, the Fuel Handling Refurbishment and Balance of Plant contract strategies are currently under review; this review will be completed by December 15, 2013 and the contract strategy will be updated.

As part of the DRP's annual review of its Program Management Plans, the plans are currently being updated and will be issued by December 15, 2013. These plans will reflect the latest information on how the DRP will be managed.

3.0 SUMMARY OF IMPACTS

This section will detail the impacts on revenue requirement, rates, riders and customer impact of the three changes to the Application.

3.1 Summary of Changes to Revenue Requirement and Production Forecasts

Chart 9 below provides a breakdown of revenue requirement changes and resulting revised revenue requirements by year for each of previously regulated hydroelectric, newly regulated hydroelectric and nuclear.

Chart 9

Changes to Proposed Revenue Requirement ($M)

	Previously Regulated Hydro			Newly Regulated Hydro			Nuclear		
Revenue Requirement Items	2014	2015	Test Period	2014	2015	Test Period	2014	2015	Test Period
Change to Pension & OPEB Costs ($M)	3.8	3.1	6.9	6.9	5.4	12.3	69.1	57.9	127.0
Tax impact of Change to Pension & OPEB Costs ($M)	(0.4)	0.2	(0.2)	(0.7)	0.6	(0.1)	(7.9)	4.4	(3.6)
Previously Regulated Hydro Ancillary and Other Revenues	(14.1)	(14.4)	(28.5)	-	-	-	-	-	-
Hydro GRC costs related to change in Production Forecasts	14.0	11.3	25.2	-	-	-	-	-	-
Nuclear Fuel costs related to change in Production Forecasts	-	-	-	-	-	-	(11.9)	(7.5)	(19.3)
Total Change in 2014-2015 Revenue Requirement	3.2	0.2	3.4	6.1	6.0	12.2	49.2	54.8	104.1
Revenue Requirement Originally Proposed	**856.7**	**879.5**	**1,736.3**	**549.1**	**569.7**	**1,118.8**	**3,292.2**	**3,252.6**	**6,544.7**
Revised Revenue Requirement	860.0	879.8	1,739.7	555.2	575.8	1,131.0	3,341.4	3,307.4	6,648.8

The above changes are reflected in the updated Ex. N1-1-1 Table 1 filed as part of this update at lines 15 (OM&A, for pension and OPEB cost changes), 16 (Fuel & GRC), 21 (Ancillary and Other Revenues) and 23 (Income Tax).

Chart 10, below, provides a summary of changes to previously regulated hydroelectric and nuclear production forecasts.

Chart 10

Changes to Proposed Production Forecasts (TWh)

	Previously Regulated Hydro			Nuclear		
	2014	2015	Test Period	2014	2015	Test Period
Production Forecast Originally Proposed	19.1	20.2	39.3	49.7	48.0	97.7
Change	1.0	0.8	1.8	(0.7)	(1.9)	(2.6)
Updated Production Forecast	20.1	21.0	41.1	49.0	46.1	95.1

3.2 Resulting Rates and Riders

Revisions to revenue requirements and production forecasts result in revised payment amounts and payment amount riders as calculated in Chart 11, below.

Chart 11

Calculation of Revised Payment Amounts and Riders

	Revenue / Amortization ($M)	Production (TWh)	Payment Amounts & Riders ($/MWh)
	(a)	(b)	(c) = (a) / (b)
Previously Regulated Hydro			
Test Period Revenue Requirement	1,739.7	41.1	42.31
2015 Deferral and Variance account Amortization [1]	62.9	21.0	2.99
Newly Regulated Hydro			
18 Month Revenue Requirement [2]	853.4	17.9	47.59
Nuclear			
Test Period Revenue Requirement	6,648.78	95.1	69.91
2015 Deferral and Variance account Amortization [1]	73.1	46.1	1.59

Notes:
1 No change to proposed D&V account amortization.
2 18 month revenue requirement is 1/2 of 2014 revenue requirement plus 2015 revenue requirement.
No change to the Newly Regulated Hydroelectric production forecast.

The proposed revisions to revenue requirements and production forecasts result in revised payment amounts of $42.31/MWh for previously regulated hydroelectric, $47.59/MWh for newly regulated hydroelectric and $69.91/MWh for nuclear as calculated in updated Ex. N1-1-1 Table 6, Ex. N1-1-1 Table 7 and Ex. N1-1-1 Table 8, respectively, filed as part of this update.

Revised payment amount riders resulting from revisions to production forecasts are $2.99/MWh for previously regulated hydroelectric and $1.59/MWh for Nuclear, also as shown in updated Ex. N1-1-1 Table 6 and Ex. N1-1-1 Table 8, respectively, filed as part of this impact statement.

3.3 Resulting Customer Impact

Using the same methods as described in Ex. I1-1-2, OPG has estimated the consumer bill impact associated with the production forecast, revenue requirement and OPG's deferral and variance account proposals as revised by this impact statement to be $5.00/month on a typical consumer's monthly bill as shown in the Ex. N1-1-1, Table 5, line 4 filed with this impact statement.

Using the same assumptions as described at Ex. I1-1-2, the revised total customer impact inclusive of the newly regulated hydroelectric facilities is approximately $5.94/month on a typical consumer's monthly bill (see Ex. I1-1-2, p. 1, lines 25-29).

LIST OF ATTACHMENTS

Attachment 1	AON Hewitt Report calculating Pension and Benefit costs for 2014-16
Attachment 2	CIA issued Draft Report for comment, “Canadian Pensioners Mortality” July 2013.
Attachment 3	CIA issued educational supplement note entitled “Canadian Pensioners Mortality” issued on October 30, 2013.
Attachment 4	2014/16 OPG Corporate Business Plan
Attachment 5	2014/16 Nuclear Business Plan
Attachment 6	2014/16 HTO Business Plan
Attachment 7	Updated Revenue Requirement Work Form

Filed: 2013-12-06
EB-2013-0321
Ex. N1-1-1
Attachment 1

Actuarial Report

Ontario Power Generation Inc.

Report on the Estimated Accounting Cost for Post Employment Benefit Plans for Fiscal Years 2014 to 2015

January 1, 2014 to December 31, 2015

Contents

Introduction

This report summarizes the estimated accounting costs for fiscal years 2014 and 2015 for the post employment benefit plans sponsored by Ontario Power Generation Inc. ("OPG").

This report covers the following plans sponsored by OPG:

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

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

The results cover the fiscal years from January 1, 2014 to December 31, 2015. The results have been developed in accordance with US generally accepted accounting principles ("US GAAP") under ASC 715, 712 and 710.

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

Unless otherwise stated all assumptions, data elements, methodologies, plan provisions, and information about assets reflected in this report are the same as those underlying and/or contained in Aon Hewitt's Report on the Estimated Accounting Cost for Post Employment Benefit Plans for Fiscal Years 2013 to 2015 dated September 2013 and the December 31, 2012 disclosure reports (collectively, "the Reports") prepared by us in accordance with US GAAP for the post employment benefit plans sponsored by OPG. The December 31, 2012 disclosure reports were dated March 2013 and are titled as follows:

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

Introduction (continued)

All figures are shown in Canadian $000s.

Sincerely,

Aon Hewitt Inc.

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

Aon Hewitt Inc.

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

November 2013

Actuarial Report

Results for Fiscal Years 2014 to 2015

OPG's total estimated pension and OPEB costs for fiscal years 2014 and 2015 as determined in accordance with US GAAP are as follows:

(in Canadian $ 000's)	US GAAP	
	2014	2015
RPP	$ 581,317	$ 547,372
SPP	30,251	30,526
OPRB	210,052	213,039
LTD	35,977	36,893
Total	$ 857,597	$ 827,830

The final 2014 and 2015 costs for all plans under US GAAP will be determined based on applicable information, experience and assumptions in the future. Further details of the above OPG-wide estimated costs, by plan, as well as OPG's estimated contributions to the RPP fund and benefit payments for OPEB, are provided in Schedules 3 and 4 to this report.

In accordance with generally accepted actuarial practice, periodic comprehensive accounting valuations incorporating updated plan membership information and plan experience are typically conducted no less frequently than once every three years. Since OPG's last comprehensive accounting valuation was performed using data as of December 31, 2009, we have determined that a new comprehensive accounting valuation should be conducted in 2013 using data as of December 31, 2012, including updated plan membership information, for the purposes of establishing OPG's pension and OPRB obligations as at December 31, 2013 and, consequently, the 2014 and 2015 costs for these plans. This updated valuation is being used to establish OPG's actual RPP, SPP and OPRB obligations at December 31, 2013 and, consequently, the 2014 and 2015 costs for these plans. The estimated results of this valuation are reflected in the projected pension and OPRB obligations and estimated 2014 and 2015 costs contained in this report. Further details of the membership information as at December 31, 2012 are provided in Schedule 1. We continue to update membership for the LTD plan annually.

As part of the new comprehensive accounting valuation, we reviewed all assumptions and have recommended that updated assumptions for mortality rates, health care benefit claims costs and vision care cost trend rates be used in the calculation of OPG's pension and OPRB obligations as at December 31, 2013, and 2014 and 2015 costs for these plans. The updated assumptions reflect OPG's actual plan experience and current outlook, and, in our opinion represent a better estimate of future events. The updated assumptions are reflected in the projected pension and OPRB obligations at December 31, 2013 and the estimated costs contained in this report. The updated assumptions are detailed in the Actuarial Methods and Assumptions section of this report.

Actuarial Methods and Assumptions

The actuarial methodology and accounting policies used in the development of the estimated costs for fiscal years 2014 and 2015 under US GAAP are summarized below.

- Benefit obligations for RPP, SPP and OPRB are determined using the projected benefit method prorated on service;
- Benefit obligations for LTD are determined using the projected benefit method on a terminal basis such that the total estimated future benefit is attributed to the year of service in which a disability occurs;
- The discount rates have been determined in accordance with US GAAP. The discount rates have been set with reference to those representative of AA corporate bond yields in Canada as at June 30, 2013 having a duration similar to the liabilities of the plans. The discount rates used are 4.70% per annum for determining the estimated 2014 and 2015 RPP, SPP, and OPRB costs and 4.00% per annum for determining the estimated 2014 and 2015 LTD costs;
- A building block approach is used in determining the expected long-term rate of return on plan assets. Historical markets are studied and long-term historical relationships between equities and fixed-income are preserved consistent with the widely accepted capital market principle that assets with higher volatility generate a greater return over the long run. Current market factors such as inflation and interest rates are evaluated before long-term capital market assumptions are determined. The long-term portfolio return is established using target asset allocations, via a building block approach with proper consideration of diversification and rebalancing. An expected rate of return on assets of 6.25% per annum determined using the above approach was used for determining the estimated 2014 and 2015 RPP costs;
- The projected asset value for the RPP as at December 31, 2013 is based on the actual asset value at June 30, 2013 projected to December 31, 2013 using the expected rate of return on assets of 6.25% per annum;

- The assumed mortality rates have been updated to reflect OPG's actual experience derived from OPG pensioner data for the period 2005 to 2012, and to incorporate the current expectation of future mortality improvements based on observed Canadian population data. In accordance with best practices, as affirmed in the Canadian Institute of Actuaries Educational Note Supplement: Canadian Pensioners Mortality issued on October 30, 2013, we have used OPG-specific data to develop the assumptions for base mortality rates. As noted in this Educational Note Supplement, it is preferable to use actual experience of the plan in developing the base mortality assumptions, when sufficiently robust data is available. OPG has sufficient and credible membership data to provide an appropriate basis to develop an OPG-specific base mortality table to be used for valuation purposes. In developing the best estimate assumption for future mortality improvements, we have taken into account differences in age, gender and year of birth, as this approach is currently recognized as providing a better estimate of the rate of mortality improvement. We will use the updated mortality assumptions in measuring OPG's actual pension and OPRB obligations as at December 31, 2013 for financial reporting purposes, and also will recommend the use of these assumptions for the purposes of OPG's next RPP funding valuation effective no later than January 1, 2014. Further details of the updated mortality assumptions are provided in Schedule 2;

- Health care benefit claims costs for the OPRB valuation have been updated to reflect actual OPRB plan experience in 2011 and 2012. Overall, the updated per capita claims cost basis is lower than expected, primarily due to the impact of the increased use, and reduced pricing of generic drugs. Further details of the updated health care claims costs at age 65 are provided in Schedule 2. Age-based utilization rates (factors), as set out in the Reports, are applied to the per capita cost basis in determining the health care benefit claims costs by age;

- Health care cost trend rate for vision care for the OPRB valuation has been updated from 2.0% per annum to 0.0% per annum to reflect the maximum benefit under the plan;

- Other assumptions are management's best estimate as developed in consultation with us and are as set out in the Reports. These assumptions include the inflation rate and the salary scale increase rate, which were established at 2.00% per annum and 2.50% per annum (plus Promotion, Progression, Merit), respectively;

- 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 10,560 (i.e., 6,320 for Nuclear, 1,906 for Hydro / Thermal and 2,334 for Corporate). The estimated December 31, 2014 active headcount used is 10,261 (i.e., 6,183 for Nuclear, 1,853 for Hydro / Thermal and 2,225 for Corporate);

- Actuarial gains or losses for RPP, SPP and OPRB have been amortized using the 10% corridor method, except where immediate recognition is required under US GAAP for non-routine events during the year (none expected during 2014 through 2015);

- Past service costs for RPP, SPP and OPRB have been amortized on a straight-line basis over the expected average remaining service lifetime at the amendment date, except where immediate recognition is required under US GAAP for non-routine events during the year (none expected during 2014 through 2015);

- For LTD, all actuarial gains and losses and past service costs are required under US GAAP to be recognized immediately in the cost. Therefore, the cost is equal to the change in the benefit obligation plus benefit payments; and,

- Expected return on assets and amortization of actuarial gains/losses are based on a market-related value of assets where investment gains and losses on equity assets in excess of an expected return of 6.0% per annum plus the increase in Consumer Price Index are smoothed over five years.

OPG's latest actuarial valuation as of January 1, 2011 for funding purposes of the RPP is the basis of contributions for 2013. The next actuarial valuation for funding purposes must have an effective date no later than January 1, 2014. In order to project contributions to the RPP for 2014 and 2015, an estimate of the going concern and solvency positions of the RPP is required.

The contributions for 2014 and 2015 are estimated based on the projected going concern and solvency funded status as of January 1, 2014. In estimating the funded status, we have used the same updated RPP membership information as at December 31, 2012 (with the same adjustment for estimated active headcounts as described above), as is reflected in the estimated RPP costs for 2014 and 2015. All funding assumptions and actuarial methods used in determining the estimated going concern and solvency funded status are the same as those set out in the Report on the Actuarial Valuation for Funding Purposes as at January 1, 2011 for the OPG Pension Plan and/or the Reports, updated to reflect the following:

- For the determination of the estimated going concern funded status, the mortality assumptions have been updated to be the same as those used in the accounting valuation discussed above; and

- For the determination of the estimated solvency funded status, non-indexed discount rates are 3.10% per annum for the first 10 years and 4.30% per annum thereafter for commuted values, and 3.49% per annum for annuity purchase. The indexed discount rates are 1.70% per annum for the first 10 years and 2.20% per annum thereafter for commuted values.

Schedule 1A—Summary of Registered Pension Plan Membership at December 31, 2012

Active Members	
Number	10,847
Average Age	46.5
Average Pensionable Service (years)	15.6
Average Earnings for the Following Year	$ 103,086
Accumulated Contribution with Interest	$ 883,658,079
Members on Long-Term Disability	
Number	391
Average Age	54.3
Average Pensionable Service (years)	23.8
Average Earnings[1] for the Following Year	$ 80,763
Accumulated Contribution with Interest	$ 24,560,422
Pensioners	
Number	8,266
Average Age	69.3
Average Annual Lifetime Pension[1]	$ 42,037
Survivors (excluding children)	
Number	2,000
Average Age	76.7
Average Annual Lifetime Pension[1]	$ 22,191

[1] Includes increases for 2012 of 100% of the increase in the Consumer Price Index.

Schedule 1A—Summary of Registered Pension Plan Membership at December 31, 2012 (continued)

Children	
Number	16
Average Age	22.1
Average Annual Temporary Pension	$ 14,790
Deferred Vested Members	
Number	846
Average Age	52.0
Average Annual Lifetime Pension	$ 9,936

Schedule 1B—Summary of Supplementary Pension Plan Membership at December 31, 2012

	SPS	ESPS	DSPS	
			Canadian Obligations	Other Obligations
Active and Disabled Members				
Number	400[1]	299	3	1[2]
Average Age	50.2	50.4	59.0	*
Average Pensionable Service (years)	24.3	11.6	7.2	*
Average Pensionable Earnings	$ 169,968	$ 169,372	$ 403,119	$ *
Shift and Duty Managers				
Number	Not Applicable	Not Applicable	42	Not Applicable
Average Age			51.2	
Average Pensionable Service (years)			25.3	
Average Pensionable Earnings			$ 207,122	
Deferred Vested Members				
Number	13	42	1[2]	1[2]
Average Age	56.5	49.7	*	*
Average Monthly Pension	$ 753	$ 402	$ *	$ *
Pensioners and Survivors				
Number	489	67	42	1[2]
Average Age	63.9	65.1	62.5	*
Average Monthly Lifetime Pension	$ 705	$ 897	$ 4,546	$ *
Average Monthly Bridge Pension	$ 1	$ 0	$ 0	$ *

[1] Includes only members whose accrued benefits under the RPP as at December 31, 2012 would be limited to the projected maximum pension under the *Income Tax Act (Canada)*.
[2] Data withheld for confidentiality

Schedule 1C—Summary of Other Post Retirement Benefit Plan Membership at December 31, 2012

	PWU	Society	Management - Heritage	Management – Millennium	Total
Active Members					
Number	6,315	3,394	889	249	10,847
Average Age	45.9	46.7	51.0	46.4	46.6
Average Eligibility Service (Years)	15.4	16.5	22.6	6.1	16.1
Average Basic Earnings	$91,678	$114,709	$137,644	$110,585	$103,086
Members on Long Term Disability					
Number	314	51	24	2	391
Average Age	54.2	55.2	55.5	48.4	54.3
Average Eligibility Service (Years)	24.1	25.7	28.6	16.2	24.6
Average Deemed Basic Earnings	$75,260	$103,747	$100,311	$124,110	$80,763
RPP Retirees, Surviving Spouses and Dependent Children					
Number of Retirees	3,805	2,609	1,517	9	7,940
Average Age of Retirees	69.1	68.7	70.5	63.3	69.2
Number of Covered Spouses	3,089	2,290	1,299	9	6,687
Number of Surviving Spouses and Dependent Children	998	471	355	1[1]	1,825
Average Age of Surviving Spouses and Dependent Children	76.1	75.3	80.7	*	76.8
Non-RPP Members, Surviving Spouses and Dependent Children					
Number	55	157	64	2	278
Average Age	61.8	61.1	60.3	57.4	61.0
Deferred Vested Members—those Entitled to Coverage					
Number	8	13	10	0	31
Average Age	55.6	56.3	56.2	n/a	56.1

[1] Data withheld for confidentiality

Schedule 2—Summary of Updated Actuarial Assumptions

Mortality Rates

The OPG-specific new base mortality table is determined by applying adjustment factors, by age and gender, to the mortality rates in the 1994 Uninsured Pensioner mortality table with projected mortality improvements to 2009 (the midpoint of the OPG experience period) at Scale AA ("UP94 at 2009"). The adjustment factors are based on OPG's pensioner mortality experience for the period 2005 to 2012. The following table provides the average adjustment factors to the UP94 table at 2009 and the resulting average life expectancy at the mid-point for quinquennial age groups.

	Adjustment to UP94 at 2009		**Life Expectancy[1]**	
Age	**Male**	**Female**	**Male**	**Female**
< 55	85.00%	100.00%	33.25	35.30
55 – 59	69.90%	103.10%	31.23	33.21
60 – 64	52.00%	102.20%	26.19	28.23
65 – 69	58.30%	96.50%	21.39	23.57
70 – 74	63.50%	92.60%	16.90	19.22
75 – 79	70.00%	88.10%	12.76	15.17
80 – 84	78.20%	83.50%	9.19	11.60
85 – 89	85.70%	79.00%	6.35	8.58
90 – 94	94.20%	75.00%	4.15	6.22
95 – 99	102.00%	71.80%	2.76	4.49
>100	105.70%	70.20%	1.98	3.18

The mortality improvement assumptions applied to the above base mortality table rates from 2009 onward were developed using the mortality projection model developed by Continuous Mortality Investigation Limited (CMI), a wholly owned subsidiary of the Institute and Faculty of Actuaries of the United Kingdom, calibrated to Canadian population mortality data. This model projects future mortality improvement by commencing with current smoothed mortality improvement rates based on observed experience and then converging to a specified long term mortality improvement rate. This model is widely used - it is the de facto model for projecting pension plan mortality in the United Kingdom and was used by the U.S. Society of Actuaries to develop an interim update to its mortality improvement scale. In our opinion, this approach results in a best estimate of the mortality improvements assumptions for OPG's plans.

[1] For less than age 55 grouping, the life expectancy shown is for a 55 year-old at January 1, 2014. For the above age 100 grouping, the life expectancy shown is for a 102 year-old at January 1, 2014. For all other age groupings, the life expectancy shown is for the age at the mid-point of each grouping at January 1, 2014

Schedule 2—Summary of Updated Actuarial Assumptions (continued)

The model reflects the current actuarial best practice in developing mortality improvement assumptions because it can capture actual mortality improvement patterns for a population, such as Canada, and because it distinguishes mortality improvement rates not just by age and gender, but also the year of birth.

The following data and parameters were used by us in applying the CMI model. We determined that these data and parameters were appropriate in determining the best estimate future mortality improvement assumptions for OPG's plans:

- Canadian mortality rates for the period 1958 – 2007 obtained from the Human Mortality Database;
- Historic smoothing and fitting of Age/Period/Cohort model performed over 1957 – 2007 over age range 18 – 102;
- Assumed convergence to a long-term rate of improvement through age 90, then linear reduction of assumed long-term rates for ages between 90 and 120;
- Convergence period based on additional advanced parameter sets; and
- Convergence parameters identical to the CMI 'Core' parameters, other than cohort convergence periods by age, which are the 'Core' parameters capped to reflect the lower apparent cohort component of mortality improvement in Canada.

Schedule 2—Summary of Updated Actuarial Assumptions (continued)

Post-Retirement Health Care Claims Costs at Age 65[1]

	Society	PWU	Management (Heritage)	Management (Millennium)
Hospital	$ 90	$ 94	$ 89	$ 85
Prescription drugs[2]	505	725	484	423
Vision care	202	187	147	85
Other medical	496	396	373	83
Dental	948	828	950	658
Total	$ 2,241	$ 2,230	$ 2,043	$ 1,334

[1] Amounts shown include administration expenses and taxes
[2] Reflect drug offset assumption at age 65 and thereafter due to provincial drug plans. Additional cost of $227 to reflect Ontario Drug Deductible is included for individuals aged 65 and older.

Schedule 3—Summary of Estimated 2014 US GAAP Results

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

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

Schedule 4—Summary of Estimated 2015 US GAAP Results

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

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

Seeing Beyond Risk — Canadian Institute of Actuaries / Institut canadien des actuaires — Voir au-delà du risque

Memorandum

To: All Pension Actuaries

From: Bruce Langstroth, Chair
Practice Council

Manuel Monteiro, Chair
Committee on Pension Plan Financial Reporting

A. Kim Young, Chair
Pension Experience Subcommittee

Date: October 30, 2013

Subject: **Educational Note Supplement: Canadian Pensioners Mortality**

Document 213093

PURPOSE

The purposes of this document are for the Pension Experience Subcommittee to provide further information on the steps it is taking to finalize the Canadian Pensioners Mortality research report, and for the Committee on Pension Plan Financial Reporting (PPFRC) to provide guidance to actuaries regarding the setting of best-estimate mortality assumptions prior to the finalization of the research report.

The educational note supplement provides an update for the educational note Selection of Mortality Assumptions for Pension Plan Actuarial Valuations published on March 12, 2008.

DUE PROCESS

The Policy on Due Process for the Approval of Guidance Material Other than Standards of Practice was followed in the development of the educational note supplement.

CONTACT INFORMATION

Questions should be addressed to A. Kim Young at kim.young@sunlife.com and Manuel Monteiro at manuel.monteiro@mercer.com.

BL, MM, KY

The Pension Experience Subcommittee (PES) of the CIA Research Committee is continuing its review of the questions and comments received in response to the draft report on Canadian Pensioners Mortality issued on July 31, 2013.

For instance, the following steps have been initiated:

- The PES is soliciting additional information from participating contributors in an effort to secure the sign-off of certain excluded data sets and to enable the reclassification of pensioners by industry type, and/or as white- or blue-collar workers; and
- The PES is reviewing available information to reassess the shape and magnitude of its mortality improvement scales, and expects to coordinate this effort with the release of the December 31, 2012, actuarial valuation results of the Canada and Québec pension plans (C/QPP), which are expected to be tabled with the Government in December.

The PES believes the dataset used for the Registered Pension Plan (RPP) Study to be of high quality and credible. It is the largest Canadian RPP dataset that has yet existed, and provides useful information for establishing the best estimate mortality assumption for a Canadian pension plan. While the foregoing initiatives are expected to change the specific rates in the tables and scales provided in the draft report, the PES is of the view that the revisions will not change the overall thrust of the studies' results. In particular:

- Based on the data reviewed in the RPP Study, mortality rates for Canadian pension plan participants are significantly lower on average and exhibit a different pattern by age than the UP94 mortality rates projected forward using Scale AA; and
- Based on the data presented in the C/QPP Study, experienced mortality improvement rates have been substantially higher than those in Scale AA, particularly in the more recent periods under review.

Considering the above, it is the view of PPFRC that:

- The use of the unadjusted UP94 table projected to the valuation date using Scale AA as a best estimate of current mortality rates; and/or
- The use of an unadjusted Scale AA as a best estimate of future mortality improvement rates

would only be appropriate if supported by credible experience, the characteristics of the specific plan under review, or other quantifiable evidence.

In establishing a best estimate mortality assumption, it would always be preferable to reflect actual credible experience of the plan under review, rather than to rely solely on published mortality studies or adjustments. Where credible plan experience is not available, it may be appropriate to consider the experience of similar plans with credible experience, industry experience studies, and/or published studies, including those available from the RPP Study and the C/QPP Study.

Prior to the finalization of the Canadian pensioners mortality report, where credible experience is not available, the PPFRC believes that a reasonable approach would be for the actuary to use, or appropriately modify, published tables and improvement scales, including those available from the RPP Study and the C/QPP Study referred to in the draft report. The actuary would exercise professional judgment when making adjustments to published tables.

In addition, the actuary may refer to the educational note on the Selection of Mortality Assumptions for Pension Plan Actuarial Valuations issued on March 12, 2008. The general considerations in the educational note are still relevant, although specific references may be outdated.

The guidance provided by the PPFRC would be considered as a supplement to the 2008 educational note. Members should be familiar with educational note supplements. Educational note supplements expound or update the guidance provided in an educational note. They do not constitute standards of practice and are, therefore, not binding. They are, however, in conjunction with the source educational note, intended to illustrate the application (but not necessarily the only application) of the Standards of Practice, so there should be no conflict between them. They are intended to assist actuaries in applying standards of practice in respect of specific matters. Responsibility for the manner of application of standards of practice in specific circumstances remains that of the members.

Seeing Beyond Risk Canadian Institute of Actuaries Institut canadien des actuaires Voir au-delà du risque

Draft Report for Comments

Canadian Pensioners Mortality

Pension Experience Subcommittee – Research Committee

July 2013

Document 213059

Ce document est disponible en français

Seeing Beyond Risk Canadian Institute of Actuaries Institut canadien des actuaires Voir au-delà du risque

Memorandum

To: All Fellows, Affiliates, Associates, and Correspondents of the Canadian Institute of Actuaries

From: Marc-André Melançon, Chair
Member Services Council

Dave Dickson, Chair
Research Committee

A. Kim Young, Chair
Pension Experience Subcommittee

Date: July 31, 2013

Subject: **Draft Report: Canadian Pensioners Mortality – July 2013**

The attached document contains proposed Canadian pensioners mortality tables and improvement scales based on experience studies conducted by the Canadian Institute of Actuaries (CIA). There are a number of documents and tables referenced in this document that are available online; links are provided at the applicable reference points.

The report is being presented to the membership in the form of a draft report to obtain feedback on the content of the report and on the proposed tables and scales.

The primary objective of these studies was to build base mortality tables and mortality improvement scales that may be used for actuarial valuations for funding and/or financial reporting purposes for a broad range of Canadian pension plans. Furthermore, it was expected that such tables and scales may be considered for use under actuarial standards of practice for the determination of pension commuted values and the division of pension benefits on marriage breakdown.

Parties wishing to comment on the draft report should direct those comments to Kim Young at kim.young@sunlife.com **by September 30, 2013**. A copy should also be sent to CIA resident actuary Chris Fievoli at chris.fievoli@cia-ica.ca.

MAM, DD, AKY

INTRODUCTION

In 2008, the Research Committee of the Canadian Institute of Actuaries (CIA) formed the Pension Experience Subcommittee to:

- Review the pensioner mortality experience in Canada; and
- Develop and maintain a Canadian pension mortality table and improvement scale.

To this end, the Institute commissioned two concurrent experience studies. One study, the CPP/QPP Study, reviewed the experience of pensioners under the Canada Pension Plan, under the Québec Pension Plan, and in combination. For the purpose of developing mortality tables, the CPP/QPP Study reviewed the mortality experience of all persons receiving a retirement pension from the CPP and QPP for the calendar years 2005, 2006, and 2007 (central year 2006). The complete results of this study are provided in a report prepared by Louis Adam, FCIA, FSA, entitled "The Canadian Pensioners Mortality Table, Information on mortality for the triennial period ending December 31, 2007 with data as at December 31, 2008" (the CPP/QPP Phase II Report), which can be found here.

The CPP/QPP Study also reviewed the trends of mortality experience since 1967, the first year that pensions became payable under these programs. Results of this study are provided in the report, also prepared by Louis Adam, entitled "The Canadian Pensioners Mortality Table, Historical Trends in Mortality Improvement and a Proposed Projection Model based on CPP/QPP data as at December 31, 2007" (the CPP/QPP Phase III Report), which can be found here.

The second study, the RPP Study, reviewed the experience of a number of Canadian registered pension plans, including both public sector and private sector plans. The results of this study are provided within this report.

The primary objective of these studies was to build base mortality tables and mortality improvement scales that may be used for actuarial valuations for funding and/or financial reporting purposes for a broad range of Canadian pension plans. Furthermore, it was expected that such tables and scales may be considered for use under actuarial standards of practice for the determination of pension commuted values and the division of pension benefits on marriage breakdown.

This report presents a set of proposed mortality tables based primarily on the experience observed from the RPP Study and proposed mortality improvement scales based primarily on the experience observed from the CPP/QPP Study. The report presents gender-specific mortality tables based on the overall RPP Study data and separate tables based on public and private sector data. In addition, proposed size adjustment factors that reflect mortality differences observed by pension income level are provided. The report presents both a two-dimensional mortality improvement scale and a transitional one-dimensional scale that approximates in the near term the financial effect of the two-dimensional scale.

The subcommittee notes that the proposed tables should be used with due regard for plan-specific experience and circumstances. In many cases, adjustments to the published base table may be appropriate in specific circumstances.

The Institute thanks the 19 administrators/record-keepers (contributors) for contributing data and providing ongoing clarification to the subcommittee. The Institute appreciates the considerable effort expended by the contributors.

The Institute also thanks those members and non-members of the Institute who have dedicated significant time to this work as current and past participants of the subcommittee. In particular, the Institute thanks Louis Adam, Bob Howard, and MIB Solutions for the data compilation and analyses prepared on behalf of the Institute.

The members of the Pension Experience Subcommittee as at June 2013 are: A. Kim Young (Chair), Louis Adam, Michael Banks, Gavin Benjamin, Assia Billig, Paul Burnell, Bob Howard, Hrvoje Lakota, Scott McManus, and Catherine Robertson.

1 PROPOSED MORTALITY TABLES AND MORTALITY IMPROVEMENT SCALES

1.1 Proposed Mortality Tables

1.1.1 Introduction

In the RPP Study, the mortality experience for calendar years 1999 to 2008 of a subset of Canadian public sector and private sector registered pension plans was reviewed. Based on the results of the RPP Study, the following base male and female mortality tables for the year 2014 are provided:

- RPP 2014 Mortality Table (CPM-RPP2014)—developed from the combined experience exhibited under the public and private sector plans included in the RPP Study;
- RPP 2014 Public Sector Mortality Table (CPM-RPP2014Publ)—based on the separate experience exhibited under the public sector plans included in the RPP Study; and
- RPP 2014 Private Sector Mortality Table (CPM-RPP2014Priv)—based on the separate experience exhibited under the private sector plans included in the RPP Study.

Each of the above tables includes a set of size adjustment factors to reflect the experience exhibited at different pension income levels.

The table name abbreviations have been chosen to be consistent with the naming convention adopted in the CPP/QPP Phase II Report, where “CPM” refers to Canadian Pensioners Mortality. The tables and size adjustment factors can be found here.

1.1.2 Application

It is expected that practitioners will adopt a table and adjustment factors that are most reasonable and appropriate in the circumstances of the particular plan under review. Further details on the development of the mortality tables and adjustment factors presented with this report are provided in section 2.

1.1.2.1 Mortality Tables

The subcommittee believes that the private sector data reviewed in the RPP Study included limited or no representation from the “Finance, insurance and real estate” or from “Information and cultural” industries (Statistics Canada classifications). It is expected that both of these industries would likely exhibit mortality rates closer to those of the public sector than the private sector, as reflected in the RPP study.

The subcommittee notes that the combined RPP 2014 Mortality Table represents the experience of all registered pension plans included in the RPP Study and suggests that it could be considered suitable for use under actuarial standards of practice for the determination of pension commuted values and for the division of pension benefits on marriage breakdown.

1.1.2.2 Size Adjustment Factors

The RPP Study, and the CPP/QPP Study, identified significant experience variation by size of pension. Accordingly the subcommittee developed size adjustment factors that can be used with the base mortality tables. The subcommittee believes that it is best practice to modify the base tables to reflect actual, credible experience of the pension plan under review. However, if sufficient experience is not available, using the size adjustment factors would normally be appropriate where the average size of pensions under the particular plans is significantly larger or smaller than the average size of pensions reflected in the RPP Study data. Note that the range limits for each pension size band are as at 2014 and may require adjustment when the table is applied in subsequent years. One potential adjustment that may be appropriate is to adjust the limits to reflect changes in Average Weekly Earnings (AWE).

For reference, the average pension sizes reflected in the RPP study adjusted with AWE to 2014 are shown in table 7 provided in section 2.1.5.

The subcommittee believes that the best practice approach when applying size adjustment factors would be to group pensioner data by pension size band at the valuation date and use a separate mortality table for each band. However, a satisfactory approximation may be to determine a single size adjustment factor for each gender using the average size adjustment factor weighted by pension amount.

Table 1 illustrates the calculations using the size adjustment factors as proposed. The example is based on fictional data. For simplicity, all pensioners are assumed to be males age 70. The discount rate is 4%, and the calculations are performed as at January 1, 2014. [Note: in the tables provided in this report, sums may not add exactly due to the rounding of interim amounts.]

Table 1. Example of calculating pension values with size adjustments

Band	Monthly Pension Range	Number of Members	Total Monthly Pension	Monthly Average Pension	Size Adjust. Factor	Annuity Factor	Value
3	1000-1499	100	110,000	1,100	1.2535	11.630	15,352,098
4	1500-1999	70	115,500	1,650	1.2108	11.744	16,276,824
5	2000-2499	40	88,000	2,200	1.1532	11.903	12,569,173
8	3500-3999	25	93,750	3,750	0.9770	12.438	13,992,323
	Total	235	407,250	1,733			58,190,418
	Weighted	235	407,250	1,733	1.1560	11.895	58,128,588
	Look up	235	407,250	1,733	1.2108	11.744	57,391,659

The example assumes that pension records are first summarized into bands with increments of $500 per month. The sixth column shows values from the proposed size adjustment table. The annuity factor in the seventh column is the present value of a monthly annuity-due of $1 per annum for a male age 70. The last column is the product of 12, the monthly pension and the annuity factor.

The subcommittee believes that an acceptable alternative is suggested by the row marked "Weighted". The size adjustment factor is the weighted average of the four size adjustment factors shown in the first part of the table. That is, the fourth and sixth columns are multiplied together and the sum is divided by the sum of the fourth column. The resulting value of the pensions is close to that of the exact calculation. Further testing on more realistic datasets found the "weighted" method did not deviate from the "exact" by more than 0.15%. There may be some downward bias because in all tests "weighted" was lower, but not significantly so. The subcommittee considers the "weighted" method to be a satisfactory approximation.

The last row of table 1, marked "Look up", shows a method that, although intuitive, will rarely be satisfactory. In this case the average pension, which is $1,733, is noted to fall in the size adjustment factor band 4. Therefore, the table is adjusted using the band 4 size adjustment factor. (Note that the annuity factor is the same as on the second row of the first part of the table, 11.744.) The "look up" method is not recommended.

Because the size adjustment factors do not have a linear relationship with size, it is not enough to consider the average size of pension within a pension plan. The distribution by size adjustment band is also important. Accordingly it is not necessarily correct to assume that the value of a pension plan with an average size similar to that of the underlying data will be the same with and without size adjustments; see chart 9 in section 4.2 below.

Since the size adjustment factors are designed to apply directly to the valuation of pensions in pay, actuaries will need to consider whether it is appropriate to incorporate a comparable average size adjustment into the valuation of active members for a particular plan.

1.2 Proposed Mortality Improvement Scales

1.2.1 Introduction

The CPP/QPP Study reviewed the trends of mortality experience since 1967, the first year that pensions became payable under those programs. Based on the results of the CPP/QPP Study, the following male and female improvement scales are provided:

- CPM Improvement Scale A (CPM-A)—improvement rates by age that decrease in a linear fashion for years 2014–2030 and ultimate rates applicable for all years after 2030; and
- CPM Improvement Scale A1-2014 (CPM-A1D2014)—improvement rates by age only designed to approximate the CPM Improvement Scale A for pension valuations in 2014 and 2015.

These improvement scales can be found online here.

1.2.2 Application

The subcommittee recommends that practitioners consider adopting the proposed two-dimensional mortality improvement scale, CPM Mortality Improvement Scale A. However, the subcommittee recognizes that few pension valuation systems are currently designed to accommodate a two-dimensional scale.

Based on these considerations, the subcommittee also developed a transitional, one-dimensional (age only), gender-specific mortality improvement scale, CPM Improvement Scale A1-2014, that approximates in the near term the financial effect of the two-dimensional scale, assuming both sets of rates are applied on a generational basis.

For each age, the mortality improvement rates developed for the one-dimensional scale take into account the evolution of improvement rates anticipated over the next several decades. The two-dimensional scale assumes a slowdown in mortality improvement during years 2014 to 2030. As such, it may be inappropriate to apply the one-dimensional scale for the purpose of actuarial valuations after 2016 since it may result in an overstatement of actuarial liabilities.

It would be valid to use the CPM Mortality Improvement Scale A for valuations where the base table has been adjusted for mortality improvement or experience to 1999 or a later year. The CPM Mortality Improvement Scale A would then be applied from that particular year. However, the one-dimensional CPM Improvement Scale A1-2014 is only suitable for use with a table that has been adjusted for mortality improvement or experience to 2014.

To clarify the use of the two-dimensional improvement scale developed under this study, consider the following example:

Table 2. Example of using 2-dimensional improvement scale

Subset of CPM Improvement Scale				Subset of CPM-RPP2014	
Male	2014	2015	2016	Age	Male
80	0.02649	0.02532	0.02415	80	0.03678
81	0.02478	0.02371	0.02264	81	0.04186
82	0.02308	0.02210	0.02113	82	0.04783

Suppose it is desired to calculate the probability at the start of 2015 for a male then age 80 to survive for two years. In the notation below, "I" represents the improvement rate and a superscript is the year for the mortality rate or improvement rate, where the base year is 2014.

$${}_2p_{80}^{2015} = p_{80}^{2015}p_{81}^{2016} = (1 - q_{80}^{base}(1 - I_{80}^{2015}))\,(1 - q_{81}^{base}(1 - I_{81}^{2015})\,(1 - I_{81}^{2016}))$$

= [1-0.03678*(1-0.02532)]*[1-0.04186*(1-0.02371)*(1-0.02264)]

= 0.92564

Notation for mortality rates and improvement rates by year does not appear to be standardized within the profession. We use the following definitions, which incidentally were also used by the Society of Actuaries in connection with the two-dimensional Scale BB.

q_x^y means the probability that a person, age *x* nearest birthday at the beginning of calendar year *y*, will die before reaching the end of the calendar year. Note that both *x* and *y* are defined at the beginning of the one-year period.

I_x^y means the improvement rate in mortality for persons aged *x* nearest birthday at the start of calendar year *y*-1 to those aged *x* at the start of calendar year *y*. In this case *x* is constant through the one-year period, and *y* is defined at the end of the period.

$$q_x^y = q_x^{y-1}(1 - I_x^y)$$

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Ex. N1-1-1
Attachment 3

2 DEVELOPMENT OF MORTALITY TABLES AND SIZE ADJUSTMENT FACTORS

2.1 Data—RPP Study

2.1.1 Data Gathering

The Institute commissioned MIB Solutions to gather data from Canadian pension plan contributors on lives covered by their pension plans. The call for data went out in November 2009, and data were collected during 2010. Nineteen contributors submitted data for calendar years 1999 to 2008, from both the public and private sectors, for active lives, for pensioners and for beneficiaries after the death of pensioners. Not all contributors provided data for all years and one contributor subsequently withdrew from the study.

The data collection and validation processes are described in the MIB Solutions report, which can be found online here.

MIB Solutions provided Bob Howard, a member of the Institute and the subcommittee, with seriatim records derived from the data submitted. In particular, to protect confidentiality, member identification numbers were removed, company and plan names were replaced by codes, and dates of birth and death were replaced by age and year of death. Codes were added to indicate the status as active, pensioner or beneficiary, whether excluded, and whether unresolved. A record is marked unresolved if there was exposure for that life in some years but not in later years and no death was reported.

To ensure that the data transmitted to and assembled by Bob Howard remained consistent with that provided by MIB Solutions, the MIB Solutions report includes a table of ungraduated mortality rates based on preliminary public sector pensioner data. A comparison of those rates to similarly calculated rates prepared by Mr. Howard confirmed for the subcommittee that he and MIB Solutions were using the data in an appropriate and consistent manner. All further analyses and tables constructed for the RPP Study were prepared by Mr. Howard.

2.1.2 Data Selection and Modification

Not all data submitted by contributors were of uniformly high quality. Individual records were excluded if they had been flagged by MIB Solutions as excluded. If a record was marked as unresolved, all records for that life were excluded.

Not all contributors provided sign-off to MIB Solutions indicating their agreement that the data were sufficiently accurate. Subsequent to receiving the data from MIB Solutions, the subcommittee approached three contributors who had not signed off. One of these withdrew its data because a summary of its data was not consistent with its internal mortality study. The other two contributors provided sign-off.

The RPP Study used data only if the relevant contributor signed off. In the end, the data from 11 contributors were used for the RPP Study.

It was necessary to exclude some contributor-years of data. All records for a contributor were rejected for a particular year if any of the following criteria was met:

- Unresolved records exceeded 10% of the number of deaths in the year;
- The actual/expected ratio based on annualized pension was an outlier by more than three standard deviations; or

- The number of deaths in the year was less than 20.

For one contributor, which submitted data for all 10 years, there were so many unresolved records for the first five years of data that the subcommittee initially rejected those years of data. After examining a sample of 20 unresolved records for pensioners, it was found that all had died and 19 of them had died in the last year that the pensioner had been included in the data (but marked as alive). Therefore, for this contributor only, all unresolved records were treated as deaths in the last year reported alive and all 10 years of data were included.

It was concluded that the active life data were not sufficiently reliable for the purpose of constructing a table. Salaries were available for such a small proportion of the data that the salary information was not usable. A non-zero salary on death records was rare. The actual to expected death ratios by number of lives were very low at the younger ages and very high at the older ages, so much so that the accuracy of the active death records was in question. Furthermore, it was the subcommittee's view that the mortality rates for active lives are typically less relevant in the context of pension valuations.

The subcommittee also concluded that the beneficiary data should not be used in table construction. It would be appropriate to include beneficiary data only if the study could also include experience for these lives prior to the death of the member, but such experience was not available.

In contrast to the RPP Study, the Institute's Individual Annuitant Mortality Study tracks both lives from the outset of a joint and survivor annuity. That experience shows that mortality is lighter than for single lives while both are alive, but substantially higher after the first death. A test on that data showed that the present value of a joint and survivor annuity would be essentially the same whether calculated based on single life mortality throughout or on "joint both alive" mortality until the first death and on "joint survivor" thereafter. These observations gave the subcommittee confidence in relying on the member pensioner data only to give a satisfactory result. The subcommittee concluded that including the beneficiary data would bias mortality rates upward.

All pensioner records with a monthly income of less than $10 were excluded. A surprisingly large number of records included pensions with very low or zero income. It is not clear how there can be a pension with a zero monthly benefit; those records were considered to be unreliable. If the income is very small, there is less incentive for the contributor to seek information on the pensioner, and a death is more likely to go unreported.

The monthly income for any one record was capped at $10,000; any excess is ignored. There are a few records with very large pension amounts. Without capping the monthly income, these very large records could have too strong an influence on the experience measured by income, and their presence at the least increases the variability of the experience.

There are codes to indicate the form of benefit (e.g., life only, joint and survivor, etc.). It would have been desirable to study experience separately for each type. However, so many contributors reported the form as "unknown" that distinction by form of payment was abandoned.

Similarly, workforce characteristic (e.g., salaried, hourly, union, etc.) was reported as "unknown" so frequently that this code is ignored for table construction.

It is also important to note, based on the location of contributors participating in the RPP Study, that pensioners included are primarily located in the provinces of British Columbia, Nova Scotia and Ontario.

2.1.3 Incurred But Not Reported (IBNR)

It is probable that the data submitted misses some deaths that have occurred but were not yet reported at the time the data were submitted, referred to as incurred but not reported (IBNR) deaths. Since the most recent data are certain to have more IBNR deaths than the data for earlier years, it is important to adjust for IBNR before trying to infer the extent of improvement in mortality. This adjustment, although important, is highly subjective. The subcommittee has no pension-related information on which IBNR factors can be determined. The subcommittee used the IBNR factors of the Institute's Individual Annuitant Mortality Study as a starting point. However, it must be noted that the IBNR factors vary considerably by company, gender, duration, and form of benefit.

Since data were contributed in 2010 with 2008 as the last year of experience, it made sense to start with a factor consistent with the second duration. The subcommittee decided to adjust for IBNR by multiplying deaths in the period 2004–2008 by 1.002, 1.004, 1.008, 1.012, and 1.02, respectively; deaths for years 1999 to 2003 were taken as complete.

2.1.4 Public Sector versus Private Sector Data

The subcommittee was initially concerned that the data had a markedly higher proportion of public sector members than the proportion of public sector registered pension plan membership in Canada. The subcommittee compared our data with that of CANSIM 280-0016, which shows the number of members included in defined benefit plans split by gender and public/private sector. In addition, the subcommittee believes that the private sector data have almost no representation from "Finance, insurance and real estate" and from "Information and cultural" industries, both of which the subcommittee believed can be expected to exhibit mortality rates closer to those of the public sector than the remainder of the private sector. Therefore, for comparison purposes the subcommittee adjusted the CANSIM 280-0016 data to reflect these two industry groupings as public rather than private sector using data from CANSIM 280-0011, which provides data on defined benefit pension plan membership by gender and North American Industry Classification System categories.

After the data selection and modification described in section 2.1.2, the proportions of public sector versus private sector membership for the study data and Canadian pension plan membership were closer than initially expected. To match the proportions implied by the CANSIM data, one would need to weight the private sector data by 114% for males and 111% for females. Considering that the CANSIM data reviewed relates to current pension plan members rather than pensioners, the subcommittee concluded that the proportions from the RPP study data were close enough to the proportions from the CANSIM data to justify using the data for a composite table without applying additional weighting to the private sector data.

2.1.5 Data Summaries

Table 3 shows the data for pensioners as submitted by participating contributors and a summary for each deduction: for not signed off, excluded (as flagged by MIB), unresolved (records missing with no death reported), rejected (contributor-year of data meets one of the three criteria mentioned above related to questionable data), for small incomes (under $10 per month) and for excess incomes (over $10,000 per month). "Included" refers to the data used in the RPP Study. Data for the public and private sectors are shown separately.

In all tables, "count" means the number of life-years included, and "pension" is the sum of the annualized pensions over those same life-years.

Table 3. Summary of data for Pensioners

	Exposed		Deaths	
Public Sector				
	Count	Pension	Count	Pension
Submitted	5,152,184	107,173,848,575	99,299	1,400,807,796
Not signed off	2,060,368	39,524,681,937	38,176	464,961,117
Excluded	9,213	82,473,466	200	699,909
Unresolved	4,061	86,896,439	0	0
Rejected	389,127	6,907,378,095	5,997	27,889,458
Small	4,858	91,312	142	1,510
Excess	0	0	0	0
Included	2,684,556	60,572,327,326	54,784	907,255,803
Private Sector				
	Exposed		Deaths	
	Count	Pension	Count	Pension
Submitted	1,111,753	10,182,244,855	58,875	359,704,629
Not signed off	101,815	976,491,938	2,653	17,231,322
Excluded	158	653,914	289	1,235,865
Unresolved	5	12	0	0
Rejected	0	0	0	0
Small	90,538	4,201,957	7,160	347,927
Excess	0	7,113,552	0	127,146
Included	919,237	9,193,783,482	48,774	340,762,369
Total Included	3,603,793	69,766,110,808	103,558	1,248,018,172

Table 4 shows the data included in the RPP Study for each year of experience. The average year of experience, weighted by income exposed, is 2004.38.

Table 4. Data by year for Pensioners				
Public Sector				
	Exposed		Deaths	
Year	Count	Pension	Count	Pension
1999	165,692	3,347,669,395	3,713	52,647,662
2000	175,702	3,681,953,478	3,853	57,544,931
2001	186,443	4,081,910,146	3,786	59,480,166
2002	211,040	4,842,741,328	4,347	73,981,647
2003	224,464	5,259,922,839	4,289	72,910,072
2004	316,632	6,923,599,845	6,312	102,134,734
2005	330,716	7,389,891,130	6,795	110,404,228
2006	344,318	7,879,329,714	7,001	118,701,848
2007	357,680	8,327,830,024	7,241	124,803,514
2008	371,869	8,837,479,427	7,448	134,647,001
Public	2,684,556	60,572,327,326	54,784	907,255,803
Private Sector				
	Exposed		Deaths	
Year	Count	Pension	Count	Pension
1999	71,603	656,878,935	3,661	23,931,876
2000	70,812	664,747,000	3,464	23,613,072
2001	69,191	690,526,229	3,405	23,484,348
2002	67,273	704,584,338	3,322	25,654,980
2003	108,106	903,059,324	4,989	31,397,052
2004	105,677	914,634,897	5,897	38,221,098
2005	102,228	917,412,733	5,795	37,456,365
2006	109,966	1,198,588,542	6,204	44,509,651
2007	107,647	1,245,180,211	6,009	45,649,648
2008	106,734	1,298,171,273	6,027	46,844,279
Private	919,237	9,193,783,482	48,774	340,762,369
Total	3,603,793	69,766,110,808	103,558	1,248,018,172

Tables 5 and 6 show the data included in the RPP Study by gender. The actual to expected ratios, particularly by pension, show that UP-94 mortality rates projected with Scale AA to 2004 (UP94@2004) are significantly higher than experienced at most ages. Perhaps more significant is the fact that the slope of the experience is materially different from the slope of UP94@2004.

Table 5. Experience by quinquennial age groups for Male pensioners

Male	Exposed		Deaths		A/E on UP94@2004	
Ages	Count	Pension	Count	Pension	Count	Pension
50-54	29,746	1,030,004,756	166	3,790,036	176.2%	115.1%
55-59	212,664	7,620,906,420	1,045	30,788,358	92.1%	75.7%
60-64	300,124	9,966,329,872	2,375	66,168,769	82.8%	70.1%
65-69	328,010	7,386,420,787	4,577	86,272,644	82.5%	69.6%
70-74	317,488	5,727,082,951	7,796	118,613,577	92.6%	78.8%
75-79	291,626	4,324,456,891	12,638	163,883,284	100.6%	88.7%
80-84	211,803	2,636,662,327	15,603	173,088,151	100.3%	90.0%
85-89	107,907	1,130,218,697	13,019	128,496,678	105.4%	99.9%
90-94	33,802	321,508,686	6,799	60,348,999	111.3%	104.0%
95-99	5,682	49,708,780	1,629	13,991,351	106.6%	104.7%
100-104	570	4,872,768	181	1,646,678	88.5%	94.0%
All ages	1,843,025	40,258,370,696	65,894	848,136,491	99.2%	85.5%

Table 6. Experience by quinquennial age groups for Female pensioners

Female	Exposed		Deaths		A/E on UP94@2004	
Ages	Count	Pension	Count	Pension	Count	Pension
50-54	39,400	1,171,175,324	184	3,872,681	253.7%	177.7%
55-59	257,983	6,982,552,668	850	21,232,829	104.0%	96.4%
60-64	360,837	8,243,945,014	1,630	33,358,000	74.6%	67.8%
65-69	341,290	5,002,875,842	2,676	38,896,252	72.4%	72.2%
70-74	257,595	3,155,748,038	3,571	39,772,937	82.6%	75.6%
75-79	203,671	2,099,494,320	5,096	46,630,436	88.3%	79.0%
80-84	152,114	1,380,000,830	7,065	59,004,240	94.8%	87.4%
85-89	91,143	840,489,987	7,771	67,478,433	100.5%	94.3%
90-94	39,148	397,552,978	5,945	57,477,672	105.9%	100.4%
95-99	9,909	109,074,053	2,336	25,045,033	106.6%	103.8%
100-104	1,174	12,968,929	400	4,527,055	106.8%	109.8%
All ages	1,760,768	29,507,740,111	37,663	399,881,681	93.5%	86.2%

Table 7 shows the average monthly pension for both sectors combined and each separately. The first two columns are the average size as indicated in the data submitted. The last two columns adjust each year's amounts by Average Weekly Earnings (AWE) to 2014. Note that the average size for public sector is substantially higher than for private sector, and the average for males is higher than for females, especially in the private sector.

Table 7. Average monthly pension

	As submitted		Adjusted to 2014 by AWE	
	Male	Female	Male	Female
Combined	1,820	1,397	2,373	1,821
Public	2,348	1,540	3,058	2,007
Private	982	324	1,286	423

2.2 Table Construction Methodology—RPP Study

Bob Howard calculated the mortality tables presented in this report using a method that he developed in consultation with the subcommittee. The description of the methods, the justification for the choices of parameters, and the tables are provided in his report to the subcommittee, which is available online here.

In summary, the male and female rates in the RPP 2014 Mortality Table were constructed as follows:

- Mortality rates, weighted by amount of pension, experienced over ages 55 to 100 were determined based on the data provided by contributors, subject to the adjustments outlined in section 2.1.
- Reported deaths were adjusted to 2014 using the CPM Mortality Improvement Scale A.
- The experience demonstrated variations in mortality not only by gender, but also by employment sector (public versus private) and by pension income level. Private sector mortality rates are higher than for the public sector and mortality rates improve with high pension incomes. However, the distribution of mortality rates across sector and pension income bands was not consistent across ages.
- Mortality rates were therefore adjusted to fit a standard population so that rates for each sector-band-age were combined in such a way that varying distributions by sector-band for each age will have no effect on the observed results.
- The modified data at each age were added across all sectors and bands then graduated using the Whittaker-Henderson method.
- Mortality rates at ages below 54 were based on the ultimate, non-smoker individual Canadian life insurance mortality rates from the recently-published CIA 97–04 table, with rates from ages 54–60 obtained by fitting a 5th order polynomial to the rates already obtained for ages 51, 52, 53, 61, 62, and 63.
- Mortality rates at ages over 102 were obtained from the paper delivered by Bob Howard at the 2011 Living to 100 Symposium. Similar to the foregoing, male rates from age 95 (98 for females) to age 102 were obtained by fitting a 4th order polynomial to ages 92, 93, 94, 103, and 104 (95, 96, 97, 103, and 104 for females).

2.3 Size Adjustment Factors—RPP Study

It is always preferable to use recent, credible experience from the pension plan being reviewed to adjust a standard table. However, if the pension plan is too small or too new to have useful experience, it may be appropriate to adjust the proposed table using size adjustment factors.

It is evident from both the CPP/QPP Study and the RPP Study that mortality rates vary significantly with size of pension (other factors being equal). Size adjustment factors were derived that reflect the difference in the RPP Study experience by income band (for males and females separately) as described in Section 1.1.2.2.

2.4 Sector-Specific Mortality Tables—RPP Study

The main RPP 2014 Mortality Table is based on the combined public and private sector data and uses 2014 as a base year. Rates are provided for males and females for ages 18 to 115.

The subcommittee also produced secondary tables that were developed separately from the public sector data and from the private sector data. The male rates were developed directly from the RPP Study data with adjustments for low and high ages.

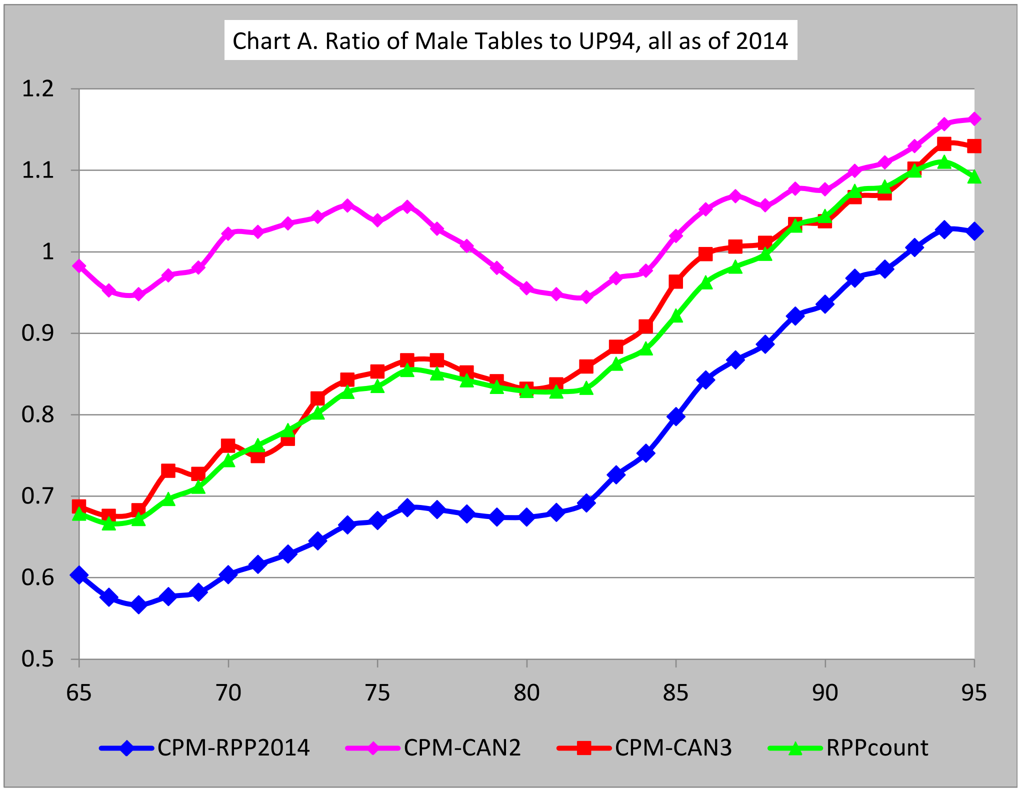
There were insufficient data for private sector females to support the direct construction of a table. However, sector-specific female tables were developed by using an appropriate multiple of the RPP 2014 Mortality Table for females.

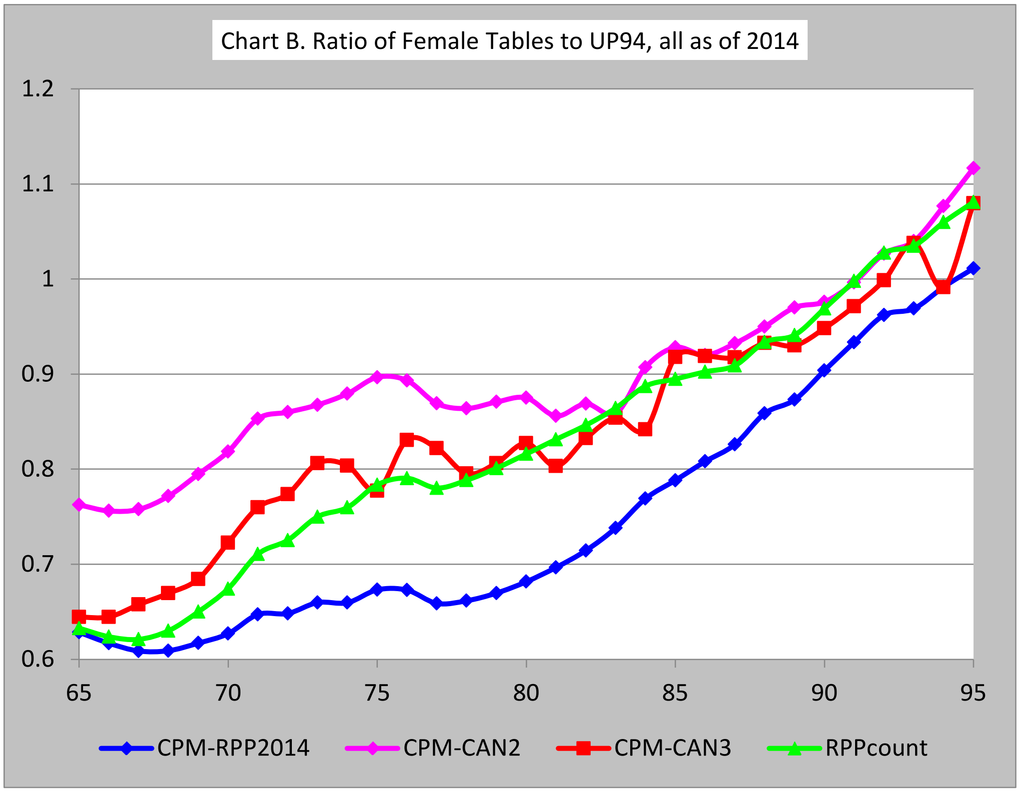
The size adjustment factors provided with the RPP 2014 Mortality Table are modified to produce sector-specific size adjustment factors by applying a common factor so that the ratio of actual deaths to expected with size adjustment for ages 65–90 is 1.0.

2.5 Comparison to UP94—RPP and CPP/QPP Studies

Charts A and B, for males and females respectively, show the ratio of mortality rates under various tables as at 2014 relative to UP94 projected to 2014 with Scale AA (UP94@2014). The tables included are:

1. CPM-RPP2014, the proposed RPP 2014 Mortality Table for combined public sector and private sector data.
2. CPM-CAN2, a table from Louis Adam's CPP/QPP Phase II Report, based on the combined CPP and QPP experience by number of deaths and pensioners exposed for those having pensions in the range of 35–94% of the maximum values. This table is projected to 2014 on the proposed CPM Improvement Scale A.
3. CPM-CAN3, as above but for pensions in the range of 95–100% of the maximum.
4. RPPcount, a table constructed similarly to RPP 2014 Mortality Table but based on experience by number of pensioners rather than on the amount of pensions. [Note: this table was developed for illustrative purposes only and is not recommended for use.]





Charts A and B indicate that the tables developed using RPP data, measured by amounts, are significantly lower than UP94@2014 and lower than the tables developed under the CPP/QPP Study.

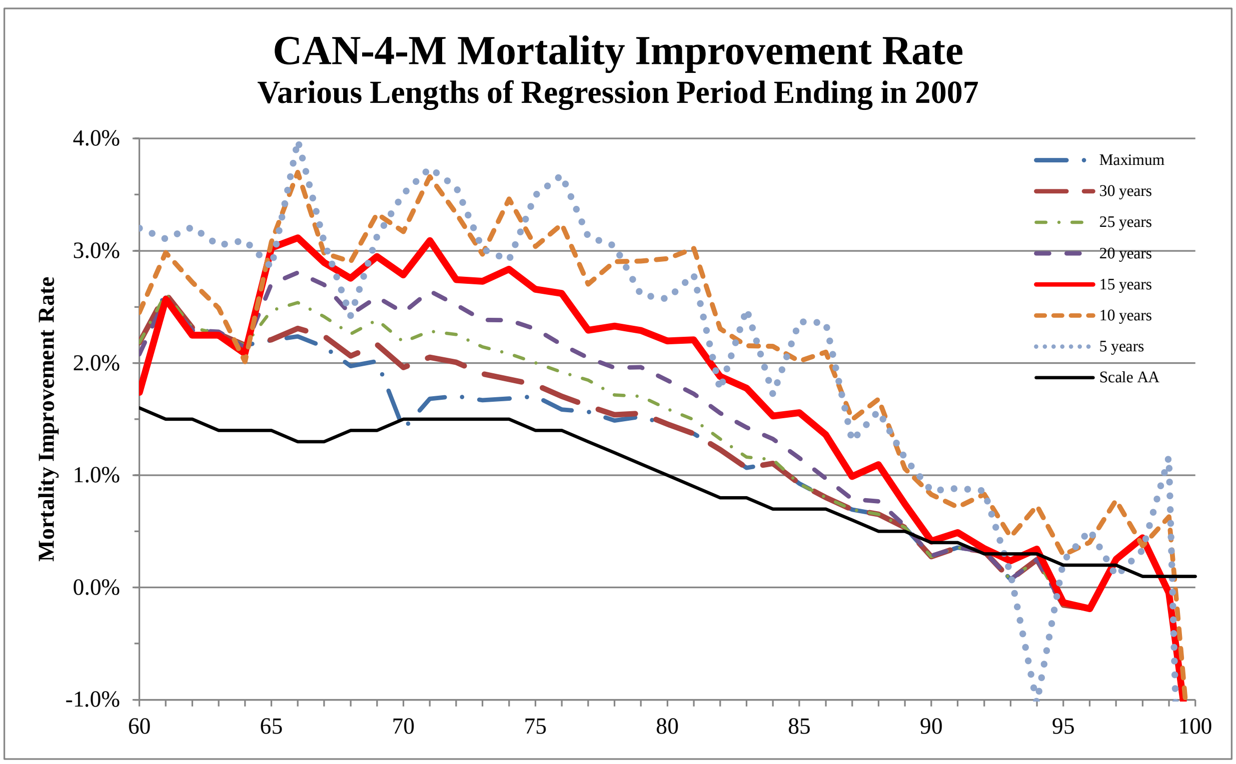
It is noteworthy that the RPP table by count is very similar to the Class 3 table developed under the CPP/QPP Study. Recall the latter was developed using data for pensioners for whom pension amounts were above 94% of the CPP/QPP maximum pensions. This observation reinforces the importance of developing mortality tables based on pension amounts. The use of the RPP Study results, by amount, is necessary to capture the effect of the range of income for RPP pensioners beyond maximum CPP/QPP benefit levels.

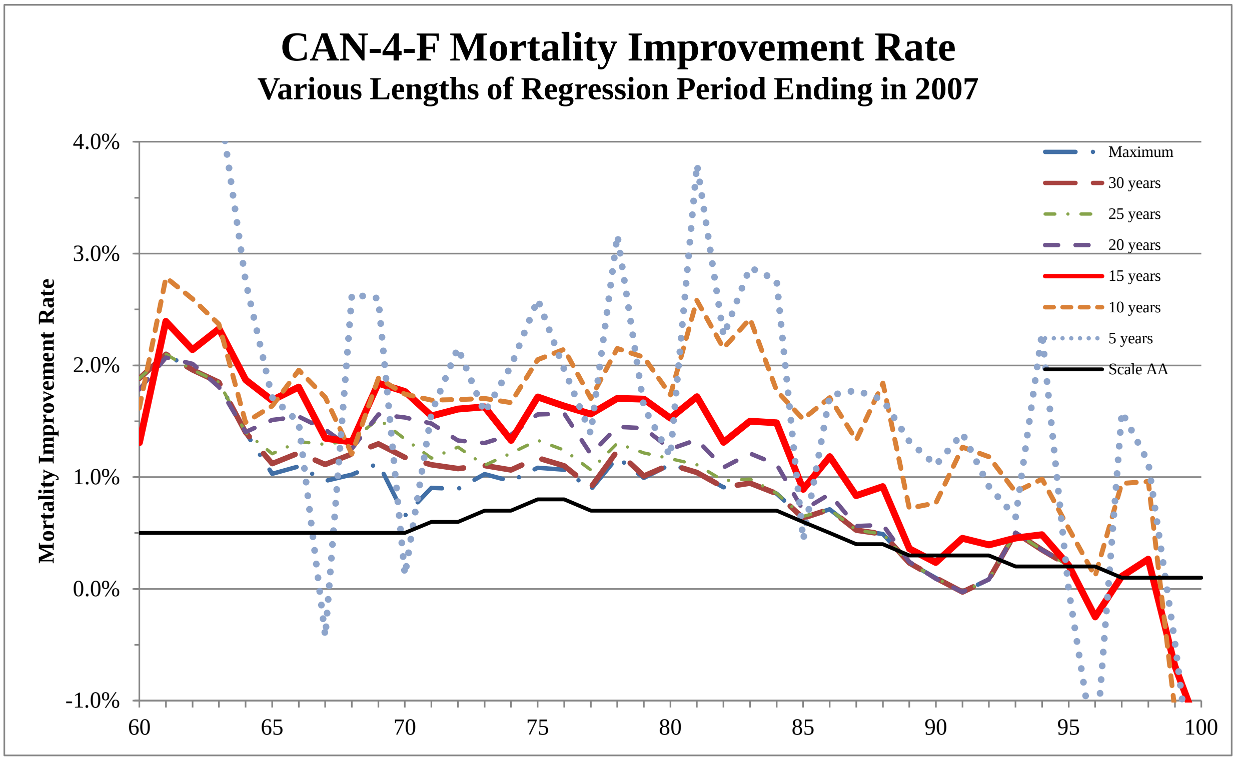
3 DEVELOPMENT OF MORTALITY IMPROVEMENT SCALES

3.1 Introduction

Assumptions in respect of future mortality improvement rates are subject to a high level of uncertainty. In addition, mortality improvement rates are affected by various socio-economic factors—e.g., income, level of education, and place of residence—and extensive data and analyses are required in order to develop scales that would reflect at least some of these factors. The RPP Study has insufficient experience, over too limited a time frame, for use in the development of mortality improvement scales. On the other hand the CPP/QPP Study provides substantive data on recent rates of improvement in the mortality of CPP/QPP pensioners. The subcommittee believes that the proposed mortality improvement scales based on the results of the CPP/QPP Phase III Report with some refinements will serve as a reasonable approximation of future mortality improvement rates of Canadian pensioners in registered pension plans.

The following charts, taken from the CPP/QPP Phase III Report, show experienced CPP/QPP mortality improvement rates for various periods ending in 2007 with Scale AA improvement rates added for reference. The data reflected in these charts are based on combined CPP and QPP data for pensions in the range of 35–100% of the maximum values. Scale AA, published by the Society of Actuaries with the UP94, is currently widely used for registered pension plan valuation purposes and is prescribed for use in the pension commuted value standards.





It can be seen that the CPP/QPP experienced improvement rates are substantially higher than Scale AA and higher for shorter, and thus more recent, periods than over longer periods.

There is broad consensus that continuation of recently-experienced rates of improvement indefinitely into the future is unlikely. Social security actuaries in various countries, including Canada, have developed ultimate improvement rate assumptions well below recently-experienced rates. There is no reliable methodology to forecast the ultimate level of mortality improvement rates or the time frame as to when such ultimate rates will be reached. As proposed in the CPP/QPP Phase III Report, the subcommittee is of the view that reference to the ultimate assumptions adopted by the CPP and QPP actuaries in their December 31, 2009, valuation reports is appropriate.

3.2 Improvement Scales

The proposed gender-specific improvement scales are as follows:

- Short-term rates applicable to years 2000–2011 equal to smoothed 10-Year experience based on the CPP/QPP income class 4 (35% of maximum pension and above) from the CPP/QPP Study for ages 65 and higher.
- Short-term rates for years 2000–2011 for ages up to age 50 are a blend of the CPP and QPP assumptions, as disclosed in the most recent actuarial reports. Note that mortality experience data are not available for CPP/QPP at these ages.
- Short-term rates for years 2000–2011 for ages 51–64 are a linear interpolation between the above rates for ages 50 and 65.
- Ultimate rates applicable for years 2031 and beyond are based on blended CPP and QPP actuarial assumptions (the “long-term scale” proposed in the CPP/QPP Phase III Report).

- Rates for years 2012 to 2030 are derived by linear interpolation between the short-term rates and the ultimate rates.

The choice of years used above is arbitrary. The year 2031 coincides with the ultimate assumption used by CPP. The year 2000 was needed for the construction of CPM-RPP2014. The year 2011 corresponds to the last year in the CPP assumption before rates began to decrease.

3.3 Transitional One-Dimensional Mortality Improvement Scale

The subcommittee believes strongly that a two-dimensional improvement scale fits the experience data better than any one-dimensional scale could and can better reflect reasonable expectations regarding the evolution of the improvement in mortality rates in future years. However, the subcommittee also recognizes that not all practitioners will have immediate access to software that can handle a two-dimensional improvement scale. Therefore, as a transitional measure, the subcommittee has developed a one-dimensional improvement scale that reasonably approximates the results of the two-dimensional scale for calculation dates that are before 2016.

The development of the one dimensional improvement scale is documented in the memo to the subcommittee from Bob Howard, which can be accessed online here.

4 FINANCIAL IMPLICATIONS

4.1 Overview

The UP-94 Mortality Table, adjusted for mortality improvement Scale AA, has been widely used for pension plan valuations and is prescribed for use in the pension commuted value standards of practice. The results of the RPP and CPP/QPP Studies indicate that the overall level of recent mortality experience is significantly lower than that anticipated by UP-94 with Scale AA and exhibits a different shape by age. The CPP/QPP Study also shows that mortality improvement rates experienced in recent years have been substantially higher than indicated by Scale AA.

The experience illustrated by both the CPP/QPP Study and RPP Study indicates that adoption of tables and scales reflecting Canadian mortality experience is warranted.

4.2 Numerical Illustrations

The adoption of the proposed tables will result in an increase in recognized costs for Canadian pension plans and their sponsors to the extent that the mortality tables and improvement scales used in recent valuations have not reflected recent experience.

Tables 8 through 13 below compare the present value of annuities on various tables. Tables 8 through 10 show monthly annuities-due and tables 11 through 13 show monthly annuities deferred to age 65. The calculations are done at 4% interest as at January 1, 2014. Each table indicates what base table and improvement scale were used in the calculation.

Table 8 shows the impact of changing from UP-94 with Scale AA to the proposed basis. Note that the increase is generally larger because of changing from UP-94 to CPM-RPP2014 than changing from Scale AA to the CPM Improvement Scale A.

Table 8. Monthly life annuities at 4% in 2014 without size adjustment					
Table	UP-94	CPM-RPP2014		CPM-RPP2014	
Scale	AA	AA		CPM-A	
	Annuity	Annuity	Incr	Annuity	Incr
M55	16.68	17.53	5.1%	17.63	5.7%
M65	13.06	14.20	8.7%	14.36	9.9%
M75	9.09	10.03	10.3%	10.17	11.8%
M85	5.38	5.68	5.6%	5.71	6.1%
F55	17.41	18.17	4.4%	18.30	5.1%
F65	14.10	15.05	6.7%	15.18	7.7%
F75	10.28	11.11	8.1%	11.23	9.2%
F85	6.25	6.61	5.8%	6.65	6.3%

Table 9 show the impact of the size adjustments. (The average size of the pensions in the RPP dataset is approximately $2,400 per month when adjusted to 2014.) Clearly the size adjustments are material, but more for males than females. Of course, in practice the actuary will adjust for recent, credible experience rather than simply for size. The size adjustment factors are useful when no such experience is available.

Table 9. Monthly life annuities on CPM-RPP2014 with CPM-A at 4% in 2014 with size adjustment for the indicated monthly pension							
Pension	Not Adjusted	$1,200		$2,400		$3,600	
	Annuity	Annuity	Incr	Annuity	Incr	Annuity	Incr
M55	17.63	17.08	-3.1%	17.29	-1.9%	17.68	0.3%
M65	14.36	13.68	-4.7%	13.93	-3.0%	14.43	0.5%
M75	10.17	9.41	-7.5%	9.69	-4.7%	10.25	0.8%
M85	5.71	5.01	-12.1%	5.26	-7.7%	5.78	1.3%
F55	18.30	18.11	-1.0%	18.28	-0.1%	18.36	0.3%
F65	15.18	14.95	-1.6%	15.16	-0.2%	15.26	0.5%
F75	11.23	10.95	-2.5%	11.20	-0.3%	11.32	0.8%
F85	6.65	6.37	-4.1%	6.62	-0.5%	6.74	1.4%

As previously noted in section 1.1.2.1 above, because the size adjustment factors do not have a linear relationship with size, it is not enough to consider the average size of pension within a pension plan.

Table 10 compares the sector-distinct tables with the combined table. The calculations are done assuming the same size annuity to make the comparison more appropriate than by using the tables without adjustment. It is clear that whether to use the combined table or a sector-distinct table is a material choice.

Table 10. Monthly life annuities at 4% in 2014 with size adjustment factor for $2400 per month					
Table	CPM-RPP2014	CPM-RPP2014Publ		CPM-RPP2014Priv	
Scale	CPM-A	CPM-A		CPM-A	
	Annuity	Annuity	Incr	Annuity	Incr
M55	17.29	17.35	0.4%	17.02	-1.5%
M65	13.93	14.01	0.6%	13.62	-2.2%
M75	9.69	9.73	0.4%	9.53	-1.6%
M85	5.26	5.22	-0.8%	5.38	2.2%
F55	18.28	18.28	0.0%	18.03	-1.4%
F65	15.16	15.17	0.1%	14.84	-2.1%
F75	11.20	11.21	0.1%	10.85	-3.1%
F85	6.62	6.62	0.1%	6.32	-4.4%

Tables 11 through 13 are analogous to tables 8 through 10 but for deferred annuities. The conclusions reached are essentially the same as mentioned for the tables above.

Table 11. Monthly life annuities deferred to age 65 at 4% in 2014 without size adjustment					
Table	UP-94	CPM-RPP2014		CPM-RPP2014	
Scale	AA	AA		CPM-A	
	Annuity	Annuity	Incr	Annuity	Incr
M25	2.82	3.01	6.8%	2.96	5.2%
M35	4.07	4.39	7.7%	4.35	6.9%
M45	5.88	6.39	8.6%	6.40	8.8%
M55	8.57	9.38	9.5%	9.48	10.6%
F25	2.93	3.13	7.0%	3.17	8.2%
F35	4.28	4.59	7.3%	4.65	8.6%
F45	6.27	6.75	7.6%	6.83	9.0%
F55	9.25	9.98	7.8%	10.10	9.1%

Table 12. Monthly life annuities on CPM-RPP2014 with CPM-A deferred to age 65 at 4% in 2014 with size adjustment for the indicated monthly pension							
Pension	Not Adjusted	$1,200		$2,400		$3,600	
	Annuity	Annuity	Incr	Annuity	Incr	Annuity	Incr
M25	2.96	2.80	-5.4%	2.86	-3.4%	2.98	0.5%
M35	4.35	4.12	-5.5%	4.21	-3.4%	4.38	0.5%
M45	6.40	6.05	-5.5%	6.18	-3.5%	6.44	0.6%
M55	9.48	8.96	-5.4%	9.16	-3.4%	9.53	0.5%
F25	3.17	3.11	-1.7%	3.16	-0.2%	3.18	0.5%
F35	4.65	4.57	-1.7%	4.64	-0.2%	4.67	0.6%
F45	6.83	6.71	-1.7%	6.82	-0.2%	6.87	0.6%
F55	10.10	9.92	-1.7%	10.08	-0.2%	10.15	0.6%

Table 13. Monthly life annuities deferred to age 65 at 4% in 2014 with size adjustment factor for $2400 per month					
Table	CPM-RPP2014	CPM-RPP2014Publ		CPM-RPP2014Priv	
Scale	CPM-A	CPM-A		CPM-A	
	Annuity	Annuity	Incr	Annuity	Incr
M25	2.86	2.88	0.6%	2.80	-2.3%
M35	4.21	4.23	0.6%	4.10	-2.4%
M45	6.18	6.22	0.6%	6.02	-2.6%
M55	9.16	9.22	0.7%	8.91	-2.7%
F25	3.16	3.16	0.1%	3.09	-2.2%
F35	4.64	4.64	0.1%	4.53	-2.3%
F45	6.82	6.83	0.1%	6.66	-2.4%
F55	10.08	10.08	0.1%	9.84	-2.3%

OPG’s 2014-2016 Business Plan

OPG Board of Directors

November 14, 2013

Donn Hanbidge, CFO

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ONTARIO POWER GENERATION

Outline

- Executive Summary
- Key Planning Assumptions
- Business Transformation Update
- Headcount Reductions and Efficiencies
- OM&A Expenses
- Capital Expenditures
- Financial Outlook
- OPG's EBT on the Province's Fiscal Basis
- Financing Outlook
- Risks and Uncertainties
- Appendix
  - Operating Statement
  - Balance Sheet
  - Financial Metrics
  - Key Business Transformation Initiatives
  - Pension and Other Post Employment Benefit Costs

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Executive Summary

- OPG's 2014-2016 Business Plan reflects its goal of being Ontario's low-cost electricity generator of choice, and its corporate strategies of financial sustainability, performance excellence, and project excellence
  - The key elements of OPG's 2014-2016 strategy to ensure financial sustainability are consistent with those included in OPG's 2013-2015 Business Plan. These key elements include: building on the business transformation achievements to-date by continuing to pursue efficiencies beyond 2015; and pursuing revenue enhancements, including new 2014/2015 base rates and riders for the currently regulated hydroelectric and nuclear assets, regulation of the currently unregulated non-contracted hydroelectric assets, and a long-term rate smoothing strategy to address nuclear rate impacts during the Darlington refurbishment.
  - Performance excellence initiatives focus on continuing to produce electricity in a safe, reliable, cost-effective, and environmentally responsible manner
  - Key project excellence initiatives include: [redacted] refurbishment of the Darlington GS; [redacted]
- In developing the business plan, OPG has recognized the impact of its operations on ratepayers by establishing challenging targets, and driving a rigorous process to identify and implement efficiencies, prioritize work, and manage costs
- As a result of above strategies and initiatives, OPG's 2014-2016 Business Plan will deliver the following results:
  - OPG will achieve the committed reduction in headcount from ongoing operations of ~2,000 employees by the end of 2015, [redacted] as efficiency targets are further realized. OM&A savings from these headcount reductions accumulate to [redacted]
  - Net income for OPG's fiscal years is forecast to [redacted] In addition, a one-time extraordinary gain of ~$300 M is expected to be realized in 2014. The gain is related to the recognition of a regulatory asset for income taxes, effective upon regulation of the unregulated hydroelectric stations.
  - OPG's earnings before tax for the Province's fiscal year are forecast to [redacted] This compares [redacted] to the Province's budgeted amount of [redacted] for 2014/2015. The extraordinary gain of ~$300 M is expected to be recognized in the Province's 2014/2015 fiscal year.
  - OPG's investment grade credit ratings can be maintained as financial metrics improve due to an increase in regulated rates, regulation of the unregulated hydroelectric assets, and [redacted]
  - OPG's liquidity improves as operating cash flow increases, and [redacted] of capital expenditures can be funded from operating cash
  - OPG will continue to moderate Ontario electricity prices, as the average revenue earned by OPG is forecast to continue to be significantly lower than revenues earned by all other generators in Ontario
- Significant risk and uncertainty remain with respect to achievement of forecast regulated revenues

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ONTARIO POWER GENERATION

Key Planning Assumptions

Production

- Nuclear production ranges from 44.6 to 49.0 TWh/yr over the 2014-2016 period, reflecting the following changes:
  - Fewer outage days in 2014, with one planned outage at Darlington compared to two in 2013
  - The Darlington Vacuum Building Outage (VBO) in 2015 reduces generation by ~3 TWh
  - In 2016, the Pickering Life Management outage and the first Darlington refurbishment outage reduce production by ~3 TWh and ~2 TWh, respectively

Production - TWh	Forecast 2013	Business Plan 2014	2015	2016
Nuclear	45.6	49.0	46.1	44.6
Previously Regulated Hydroelectric	18.9	19.5	20.4	20.2
Newly Regulated Hydroelectric	12.5	11.7	11.9	11.9
Contracted Hydroelectric	[redacted]	[redacted]	[redacted]	[redacted]
Thermal	[redacted]	[redacted]	[redacted]	[redacted]
Total OPG Production	[redacted]	[redacted]	[redacted]	[redacted]

- Previously regulated hydroelectric production increases commencing in 2014 due to an expected return to normal water levels
- Newly regulated hydroelectric production decreases by ~0.8 TWh in 2014 due to higher surplus baseload generation
- Contracted hydroelectric production [redacted]
- [redacted]

Pension and OPEB Costs

- Pension and OPEB costs reflect the impact of a comprehensive accounting valuation as at December 31, 2013, including updates to mortality and post-retirement medical and dental cost assumptions, and benefit plan membership data
- Pension fund investments are assumed to earn 6.25%/yr. A discount rate of 4.7% is used for valuing pension and other post retirement benefit costs over the 2014-2016 period.

Other

- Nuclear Funds investments are assumed to earn 5.15%/yr over the period
- Pickering units are expected to operate until ~2020
- The Darlington refurbishment execution phase (October 2016 to late 2025) reflects un-lapping of the first and second units
- [redacted]
- The Darlington nuclear new build project is not included in the capital plan, following the Province's announcement

Key Planning Assumptions

Regulated Rates and Generation Revenues

- The key elements of OPG's 2014-2016 regulatory strategy are consistent with those included in OPG's 2013-2015 Business Plan.
- New base rates for nuclear and previously regulated hydroelectric assets, effective January 1, 2014, reflect OPG's current OEB rate application based on the previous business plan, and an update to reflect significant changes from this plan for generation and pension and OPEB costs
- The increase in base rates incorporates the recovery of costs not reflected in existing base rates, such as pension and OPEB, and nuclear waste liabilities; the impact of the Darlington VBO; the current forecast of nuclear and hydroelectric production; and the impact of the Niagara Tunnel coming into service in 2013
- Rate riders in 2013/2014 reflect the OEB's decision on recovery of variance and deferral account balances at December 31, 2012

Regulated Generation Revenue Rates - $/MWh	Forecast 2013	Business Plan 2014	2015
Nuclear Base Rate	52	70	70
Nuclear Rider	6	4	7
Regulated Nuclear Rate	58	74	77
Previously Regulated Hydro Base Rate	36	42	42
Previously Regulated Hydro Rider	3	2	5
Previously Regulated Hydro Rate	39	44	47
Newly Regulated Hydro Base Rate (effective July 1, 2014)		47	47
Newly Regulated Hydro Rider		0	1
Newly Regulated Hydro Rate		47	48
Non-Contracted Hydro Market Price (prior to July 1, 2014)	[redacted]	[redacted]	

- Rate riders in 2015 include recovery, as part of the current application, of variance and deferral account balances previously deferred by the OEB, and a separate OEB application in 2014 to recover account balances at December 31, 2014
- The plan assumes regulation of the unregulated hydroelectric assets, effective July 1, 2014, at a rate of $47/MWh
- A long-term rate smoothing strategy to address nuclear rate impacts during the Darlington refurbishment is assumed to commence in 2016, subject to OEB acceptance. A regulatory asset of ~$150 M is recognized in 2016 related to deferral of nuclear rate impacts, for subsequent recovery.

Contract and Other Unregulated Generation Revenues

- [redacted]
- [redacted]
- [redacted]
- [redacted]

Business Transformation Update

OPG continues to focus on Business Transformation to deliver cost and headcount reductions as a key component of ensuring financial sustainability

Objectives

- Transform OPG by creating a scalable and sustainable organization able to adapt to changing market conditions and capitalize on future business opportunities
- Align costs with revenues by reducing headcount from ongoing operations by 2,000 over 2011-2015
- OPG is continuing to embed Business Transformation in our ongoing operations and will deliver headcount savings beyond 2015, in addition to the 2,000 already committed. [redacted] and additional cost savings have been incorporated into the plan for 2016.
- Achieve headcount reductions through attrition to lower costs, and implement initiatives to:
  - Change organization structure and modify service delivery through a centre-led model
  - Streamline and re-engineer processes, procedures, and governance
  - Eliminate lower-value work to gain efficiencies
- A key Business Transformation principle is to maintain the condition of generating stations. OPG has focused on improving the operations of its stations in recent years, and is now focused on driving further efficiencies.

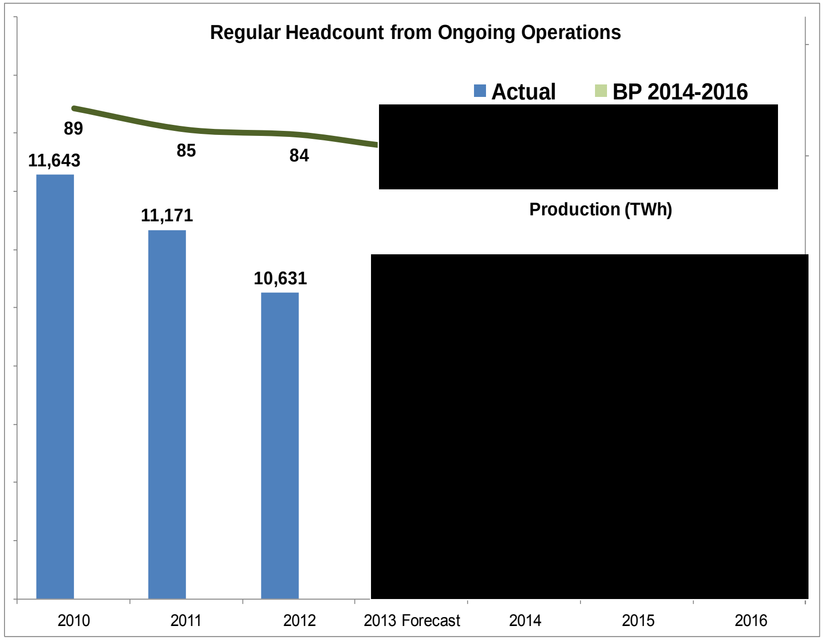
Key transformation initiatives include (see Appendix):

- Realign the organization to achieve single-point accountability and eliminate duplication
  - Merge Hydro & Thermal
  - Regionalize support services
  - Consolidate management of Pickering A & B into one organization
  - Integrate eight training organizations into one
  - Integrate five Supply Chain organizations into one
  - Consolidate two facilities organizations
- Create shared services by combining transactional work, and achieving economies of scale

Headcount Reductions and Efficiencies

OPG will achieve the committed reduction in headcount from ongoing operations of ~2,000 employees by the end of 2015, [redacted], as additional efficiencies are realized

- Through implementation of Business Transformation initiatives, aligned with attrition, headcount reductions of ~1,500 will be achieved over the 2011-2013 period
- Total committed reductions in headcount from ongoing operations of ~2,000 will be achieved by 2015 as planned
- [redacted] This includes redeployment of [redacted] operations and maintenance employees to the Darlington refurbishment organization in the fall of 2016.
- [redacted]



- OPG's productivity, as measured by GWh/headcount, improves by 17% (normalized for the Pickering Life Management outage in 2016) over the 2011-2016 period, as headcount reductions more than offset the impact of reduced production
- OPG has achieved OM&A expense savings from headcount reductions over the 2011-2013 period of ~$275 M (net of [redacted] in coal closure severance and relocation costs). Over the 2011-2016 period, OM&A savings from headcount reductions accumulate to [redacted] in coal closure severance and relocation costs), of which ~$700 M in savings will be achieved by 2015, as planned.

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2014-2016 Headcount Reductions

A reduction in headcount from ongoing operations of [redacted] over the 2014-2016 period will be achieved by aggressively pursuing further efficiencies and management of vacancies

- Nuclear Operations and Projects headcount decreases by [redacted] over the 2014-2016 period through various improvement and business transformation initiatives, and the completion of the continued operations program at Pickering. Overall reductions are net of an increase in 2016 of [redacted] employees in nuclear support divisions related to Darlington refurbishment.

- [redacted]

- Under the centre-led organizational structure, Support Services includes certain operational functions: Business and Administrative Services (BAS) includes Supply Chain and warehousing operations; Finance includes Nuclear Oversight; and People and Culture includes the Nuclear Training division. Support Services headcount decreases by [redacted] over the 2014-2016 period through Business Transformation initiatives, including standardizing, simplifying, and streamlining systems and processes

	Forecast	Business Plan		
	2013	2014	2015	2016
Nuclear Operations	5,722	5,663	5,558	5,369
Nuclear Projects	305	319	319	319
Hydro/Thermal Operations	[redacted]	[redacted]	[redacted]	[redacted]
Commercial Operations & Environment	171	172	159	152
Corporate Business Development	56	55	54	53
Total Operations	[redacted]	[redacted]	[redacted]	[redacted]
BAS (IT, Real Estate, Supply Chain)	1,026	988	932	879
Finance	370	355	322	305
People & Culture (incl. Centralized Training)	589	615	586	570
Corporate Office	93	90	86	84
Total Support Services	2,078	2,048	1,926	1,838
Ongoing Operations	[redacted]	[redacted]	[redacted]	[redacted]
Darlington Refurbishment	196	300	309	405
Total OPG	[redacted]	[redacted]	[redacted]	[redacted]

- Darlington refurbishment headcount increases by ~110 in 2014 /2015 and a further [redacted] in 2016, as engineering, operations, project management and oversight employees join the refurbishment organization during the detailed planning stage, and as Darlington operations and maintenance employees are redeployed to work on the project at the beginning of the execution phase

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OM&A Expenses

OM&A expenses from ongoing operations, excluding pension and OPEB costs, are relatively stable over 2014-2016, as the impacts of efficiencies and headcount reductions offset the impacts of inflation and other factors

- Savings from additional headcount reductions over the 2014-2016 period total [redacted]
- Savings from additional headcount reductions largely offset other cost increases, including inflation and labour cost increases primarily due to collective agreements
- Nuclear OM&A expenses fluctuate based on outage activity, including:
  - Additional outage and maintenance activities in 2014, mainly offset by the impact of a second Darlington outage in 2013 with costs of ~$75 M
  - The Darlington VBO with costs of ~ $90 M in 2015
  - Additional outage activity in 2016 with incremental costs of ~$40 M, compared to 2015 excluding the impact of the VBO in 2015, and additional maintenance and other work programs in 2016 with incremental costs of ~$ 50M, compared to 2015
- [redacted]
- [redacted]

	Forecast	Business Plan		
$ millions	2013	2014	2015	2016
Nuclear Operations	1,399	1,409	1,494	1,493
Nuclear Projects	114	113	105	100
Hydro/Thermal Operations	[redacted]	[redacted]	[redacted]	[redacted]
Commercial Operations & Environment	39	46	42	38
Corporate Business Development	13	23	23	17
Total Operations	[redacted]	[redacted]	[redacted]	[redacted]
BAS (IT, Real Estate, Supply Chain)	310	307	293	287
Finance	65	67	64	64
Insurance	26	26	37	37
People & Culture (incl. Centralized Training)	113	120	116	118
Corporate Office	39	41	38	39
Total Support Services	552	561	547	544
Total Business Unit Expenditures	[redacted]	[redacted]	[redacted]	[redacted]
Centrally Held Pension/OPEB	389	467	439	432
[redacted]				
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Ongoing Operations	[redacted]	[redacted]	[redacted]	[redacted]
OEB Variance Account Offsets	(366)	(39)	33	(141)
Darlington Refurbishment	7	23	20	31
Nuclear New Build	27	3	3	2
Total OM&A	[redacted]	[redacted]	[redacted]	[redacted]

- OM&A expenses for the Support Services groups remain stable over the period, with efficiency gains and headcount reductions offsetting inflation, labour cost escalation for unionized employees, and an increase in insurance premiums of ~$10 M in 2015 due to higher nuclear liability insurance limits from expected changes in federal legislation
- The increase in pension and OPEB costs reflects updated mortality assumptions, and other factors (see Appendix)
- [redacted]
- The decrease in the OEB variance account offsets in 2014 compared to 2013 is primarily a result of no longer deferring costs in the Pension and OPEB Cost Variance Account, upon resetting of regulated base rates. In 2016, nuclear rate impacts of ~$150 M are deferred for subsequent recovery in rates. This proposal is subject to OEB acceptance.

Capital Expenditures

OPG's capital investment program remains focused on ensuring the continued utilization of existing assets in an efficient manner through sustaining and refurbishment initiatives, and development of new hydroelectric and renewable energy investment opportunities

- Annual sustaining capital expenditures aimed at ensuring strong performance of existing assets range from [redacted] over the 2014-2016 period. This is [redacted] higher than 2013 expenditures, and higher than expenditures included in the 2013-2015 Business Plan
  - Higher sustaining nuclear expenditures relate to Fukushima projects, plant reliability improvements, and regulatory commitments
  - Sustaining expenditures for the previously regulated hydroelectric assets increase reflecting the start of the Sir Adam Beck 1 GS rehabilitation/runner upgrade program, and stator replacement at the DeCew Falls 2 GS
  - [redacted]
- Hydroelectric development expenditures primarily relate to [redacted] the start of the execution phase of the Sir Adam Beck Pump GS reservoir rehabilitation, [redacted]
- Darlington refurbishment expenditures over the planning period include:
  - Construction of facilities and infrastructure, and safety improvement projects
  - Design, fabrication, and testing of re-tube and feeder replacement tooling and mock-ups as part of the definition planning phase
  - Upon approval of the Release Quality Estimate in 2015, beginning of the execution phase in 2016 with refurbishment of Unit 2 in October 2016
- [redacted]
- Following the Province's recent announcement, the Darlington nuclear new build project is not included in planned capital expenditures. Minimal costs required to maintain the site preparation license are reflected in OM&A expenses.

	Forecast	Business Plan		
$ millions	2013	2014	2015	2016
Sustaining				
Nuclear	198	268	222	207
Hydroelectric- Regulated	26	20	32	48
Hydroelectric- Newly Regulated	65	74	78	62
Hydroelectric- Contracted	[redacted]			
Thermal				
Other				
Total Sustaining	[redacted]			
Generation Development				
Hydroelectric Development				
Niagara Tunnel	93	1		
[redacted]				
SAB PGS Reservoir Rehabilitation			8	80
[redacted]				
Darlington Refurbishment				
Facilities & Infrastructure	94	176	126	24
Definition Phase	354	589	610	
Execution Phase				583
	448	765	736	607
Renewable Energy				300
Thermal [redacted]				
[redacted]				
Total Generation Development	[redacted]			
Total Capital Expenditures	[redacted]			

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Net Income

Net income improves over the planning period mainly due to an increase in regulated base rates for the currently regulated assets and regulation of the unregulated hydroelectric stations, [redacted]

- [redacted]
  - An increase in regulated base rates to reflect OPG's updated OEB application, including the OEB approved rate of return on the Niagara Tunnel addition to the rate base
  - Higher hydroelectric revenues as the unregulated assets become regulated effective July 1, 2014, and begin to earn an appropriate rate of return
  - The impact of a two-year average regulated rate for 2014/2015, resulting in higher revenues in 2014 and lower revenues in 2015
  - These increases are partially offset by [redacted] higher interest expense in 2014 due to a regulatory variance account offset recorded in 2013 related to the Niagara Tunnel, and higher income taxes

[redacted]

- A one-time extraordinary gain of ~$300 M is expected to be realized in 2014. The gain is related to the recognition of a regulatory asset for recovery of income taxes, effective upon regulation of the unregulated hydroelectric stations.
- [redacted]
  - The full-year impact of regulating the unregulated hydroelectric assets, as regulation is assumed to be effective as of mid-2014
  - [redacted]
  - [redacted]
  - These increases are partially offset by the two-year averaging of the regulated rates for 2014/2015 resulting in lower revenues in 2015, [redacted]
- In 2016, net income improves by [redacted] primarily due to an increase in nuclear base rates. Net income in 2016 includes the establishment of a regulatory asset of ~$150 M to reflect the deferral of recovery of nuclear rate impacts to later years as part of the rate smoothing approach.

ONTARIO POWER GENERATION

Plan-Over-Plan Net Income Changes

Compared to the previous business plan, net income for 2014 and 2015 is affected by the deferral in regulating the unregulated hydroelectric assets, [redacted]

- Net income before extraordinary gain in 2014 is lower compared to the previous plan, primarily as a result of:
  - Lower revenues due to a six-month deferral in regulating the unregulated hydroelectric assets to July 1, 2014, and a detailed determination of the regulated rates for these assets as part of the 2014/2015 OEB application
  - [redacted]
  - [redacted]
- Net income in 2015 is higher compared to the previous plan, mainly due to:
  - [redacted]
  - [redacted]
  - The increase is partly offset by an increase in [redacted]
- Income in 2014 and 2015 is also affected by a change in the regulatory strategy since the previous plan, with the OEB application requesting new regulated base rates using combined, rather than single-year, cost and generation forecasts for 2014 and 2015.
- The extraordinary gain, expected to be realized in 2014, is consistent with the previous plan

[redacted]

$millions	2014	2015
[redacted]		
Change Factors:		
Deferral of Regulation of Unregulated Hydroelectic	(80)	-
Determination of Newly Regulated Hydro Rate	(74)	34
Deferral of Recovery of Variance Accounts	(19)	(29)
Two Year Averaging of Regulated Rates	92	(88)
[redacted]		
Change in Income Tax	60	1
[redacted]		
Extraordinary Gain	(16)	-
[redacted]		

ONTARIO POWER GENERATION

OPG's EBT on the Province's Fiscal Basis

- OPG's forecast earnings before tax of $195 M in 2013/2014 will exceed the Province's budget of [redacted] For 2014/2015, OPG's forecast earnings before tax are ~$405 M compared to the Province's budgeted amount of [redacted] from the 2013 Ontario Budget.

- OPG's forecast of earnings before tax on the Province's fiscal basis is highly dependant on OEB decisions, and the following assumptions of timing for regulated rates:

  - The OEB decision on the current application for new nuclear and hydroelectric rates is issued after March 31, 2014

[redacted]

  - Unregulated hydroelectric assets become regulated effective July 1, 2014

- It is further assumed that the new rates for nuclear and previously regulated hydroelectric assets are retroactive to January 1, 2014. As a result, any increase in revenue effective at the start of the year will be recognized after March 31, 2014, impacting the 2014/2015 fiscal year of the Province.

- OPG also expects to recognize an extraordinary accounting gain of ~$300 M (related to recovery of income taxes) in its 2014 fiscal year and the Province's 2014/2015 fiscal year, upon regulation of the currently unregulated hydroelectric assets

Financing Outlook

Over the 2014-2016 period, OPG has sufficient liquidity as operating cash flow increases. Long-term debt is forecast to [redacted] to support development projects.

- [redacted]
- OPG will have sufficient liquidity in 2014. Total liquidity resources are [redacted]
  - [redacted]
  - [redacted]
  - [redacted]
  - [redacted]
- OPG's long-term debt is expected to [redacted] during the 2014-2016 period
  - Net cash from operations ranges from [redacted]
  - Net cash required for investments ranges from [redacted], including expenditures for the Darlington refurbishment
  - The increase in long-term debt includes financing of [redacted] OPG will issue general corporate debt to meet financing requirements for the Darlington refurbishment project and to refinance debt retirement obligations.
  - The financing outlook is dependant on achieving the current regulatory rate forecast, with any shortfall resulting in additional borrowing requirement
- OPG will continue to finance non-nuclear development projects from the debt markets as appropriate. New debt and refinancing of debt held by OEFC can also be sourced from external markets, subject to Shareholder consent.

[redacted]

Credit Rating Metrics

Key financial metrics improve over the 2014-2016 period due to an increase in regulated rates for the currently regulated assets, the regulation of the unregulated hydroelectric assets, [redacted]

[redacted]

- OPG's objective is to improve its key credit metrics to above threshold levels in order to maintain or improve the current credit ratings [redacted]
- Both FFO and EBITDA levels improve over the 2014-2016 period compared to the 2013 levels, with modest increases in total debt
  - FFO interest coverage [redacted]
  - FFO to Total Debt [redacted]
  - Debt to EBITDA [redacted]
- The improvement in OPG's credit metrics is predicated upon:
  - Achieving new regulated rates for nuclear and previously regulated hydroelectric assets
  - Regulating the currently unregulated hydroelectric assets
  - Obtaining approvals from the OEB to recover 2013 and 2014 variance and deferral account additions starting in 2015
- In reviewing OPG's credit ratings, S&P and DBRS will assess the likelihood, as well as the degree of success in achieving planned increases in revenues and cash flow, in their determination of OPG's credit rating

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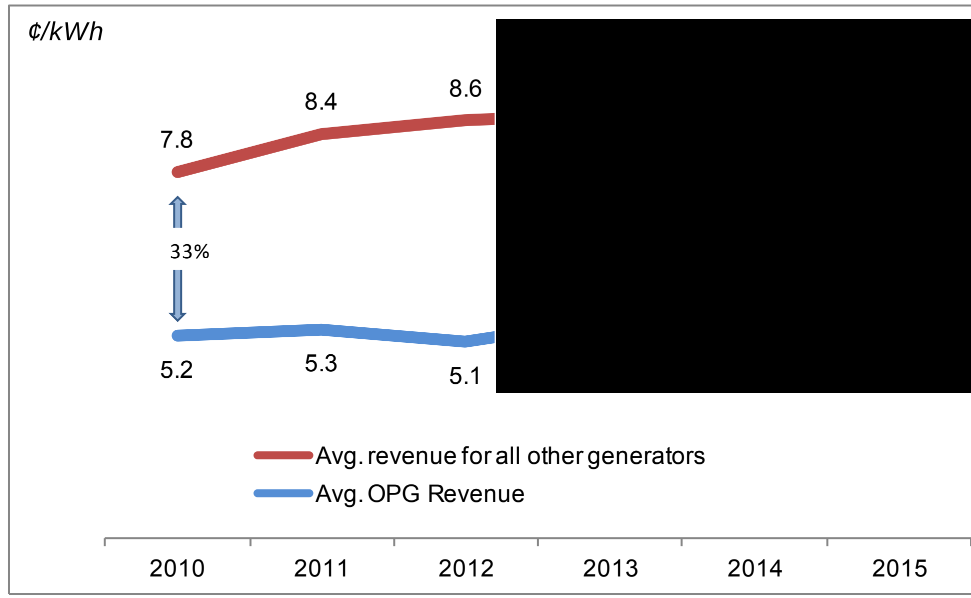
Filed: 2013-12-06
EB-2013-0321
Ex. N[illegible]-1
Attachment 4

OPG Will Remain Ontario's Low-Cost Generator

OPG's strategy to increase revenue from its regulated facilities and unregulated hydroelectric operations is critical to OPG's financial sustainability, while continuing to moderate Ontario's electricity prices

- OPG expects to continue to moderate electricity prices in Ontario after the resetting of rates for the currently regulated assets, and the implementation of regulated rates for the unregulated hydroelectric assets
- Since OPG has not received a rate increase on its regulated base rates since 2008, those rates have not kept pace with inflation
- In 2013, OPG's average price of [redacted] for generation is [redacted] than the average price received by other Ontario electricity generators of [redacted]



- OPG's average price of [redacted] in 2015 reflects the current 2014/2015 OEB rate application and the planned 2014 variance and deferral account application
- By 2015, OPG's average price of [redacted] than the average price of [redacted] paid to other Ontario based generators

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Risks and Uncertainties

OPG's 2014-2016 Business Plan is based on several strategic, operational, and financial assumptions, and as such, is subject to the following significant risks:

- OPG's inability to achieve its forecast regulated revenue levels could negatively impact income, cash flow, and borrowing requirements. Significant risk and uncertainty exist with respect to the timing and acceptance of OPG's rate proposal.
- There remains some uncertainty with respect to the finalization of changes to O. Reg. 53/05 that could impact revenues for the newly regulated hydroelectric assets
- Recovery of capital costs for the Darlington refurbishment if the project was cancelled, and determination of a long-term smoothing mechanism for recovery of rate impacts arising during the Darlington refurbishment period
- [redacted]
- While OPG's financial metrics are forecast to improve, OPG's credit rating could be downgraded as credit rating agencies will assess the likelihood, as well as the degree of success in achieving planned increases in revenues and cash flow
- If the revenue strategies do not materialize, OPG will have to implement mitigation measures to address cash flow requirements, including a reduction in project expenditures, and additional financing for development projects
- The ability to execute key operational initiatives, including:
  - Managing operational risks to ensure continued reliability of the nuclear generating stations
  - Planning and execution of work for the first Darlington refurbishment outage in 2016
  - Completion of the Darlington VBO in 2015 that is executing work critical to support the Darlington refurbishment
  - [redacted]
- Financial market performance, including:
  - Changes in long-term interest rates have a significant impact on OPG's pension and OPEB costs. A 0.25% change in the discount rate would result in a change in pension and OPEB costs of ~$60 M/yr.
  - Achieving projected returns on the Nuclear Funds
- Compensation and wage constraints may adversely affect OPG's ability to retain and attract qualified executives and employees, and as a result, may affect OPG's operations and ability to successfully implement Business Transformation initiatives
- OPG's headcount reductions, other than those related to coal closure, are based primarily on attrition. A slowdown in attrition levels could impact cost savings over the 2014-2016 period.

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Appendix

Filed: 2013-12-06
EB-2013-0321
Ex. N1-1-1
Attachment 4

Operating Statement

$ millions	
Electricity Revenues	[redacted]
Fuel & GRC	
Generation Sales Gross Margin	
Net Trading Revenue	
Non-Electricity Generation Revenue Gross Margin	
Total Gross Margin	
OM&A Expenses (Including Restructuring)	
Accretion on Nuclear Liabilities	
Earnings on Nuclear Funds	
Depreciation & Amortization	
Other Costs	
Total Other Expenses	
Income/(loss) before the following	
Interest Expense	
Other Losses/(Gains)	
Income before Tax	
Income Tax	
Net Income (Loss) Before Extraordinary Gain	
Extraordinary Gain	
Net Income (Loss)	

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Balance Sheet

[redacted]

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Financial Metrics

Business Plan 2014-2016	2013 Proj	2014	2015	2016
Earnings Before Tax- OPG Fiscal Basis $ M	[redacted]	[redacted]	[redacted]	[redacted]
Earnings Before Tax- Province's Fiscal Basis (Excluding Extraordinary Gain)- $ M	[redacted]	[redacted]	[redacted]	[redacted]
Net Income- OPG Fiscal Basis $ M	[redacted]	[redacted]	[redacted]	[redacted]
Return on Equity- %	[redacted]	[redacted]	[redacted]	[redacted]
FFO Interest Coverage	[redacted]	[redacted]	[redacted]	[redacted]
Net Cash from Operations	[redacted]	[redacted]	[redacted]	[redacted]
FFO / Total Debt- %	[redacted]	[redacted]	[redacted]	[redacted]
Debt Ratio- %	[redacted]	[redacted]	[redacted]	[redacted]
Debt / EBITDA	[redacted]	[redacted]	[redacted]	[redacted]
Nuclear Rate ($/MWh)	58	74	77	
Previously Regulated Hydro Rate ($/MWh)	39	44	47	
Newly Regulated Hydro Rate ($/MWh)		47	48	
Long Term Debt- $ M	[redacted]	[redacted]	[redacted]	[redacted]

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Key Business Transformation Initiatives

Initiative	Description
Optimization and elimination of duplicate services	Document Management: Optimize, standardize, centralize, and consolidate the Document Management , Records, and Controlled Document organizations to achieve a flexible and seamless end-to-end process, with potential for a paperless workflow. Mail/Administration Services: Optimize and increase administrative support ratio from 2:1 to 3 or 4:1.
Staff reductions through optimization of services	Reduce overall headcount in the new Facilities department by the end of 2015. Transition to a commercially driven model at nuclear stations to achieve reductions in some service levels. Streamline procedures for handling computers, recycling and waste, office moves and building maintenance activities.
Implement centre-led Environment organization	Identify and develop key processes for approved centre led organization, including OPG Environmental Management System and supporting internal service level agreements.
Phase-out analytical and market support for coal	Eliminate coal drawdown studies and coal programming analysis, market rules training , and transfer remaining training position to People & Culture . Reduce market simulation studies , and refocus and reduce market monitoring, compliance and surveillance, and project management activities.
Centralization of accounting & time reporting	Consolidate BU accounting activities into a Shared Financial Services Centre. Standardize processes to reduce low value activities, and leverage automation.
Centralize financial management reporting	Standardize a suite of reports to minimize ad-hoc reporting, consolidate standardized cost reporting systems, and utilize automated delivery of reports.
Transaction processing efficiency improvements	Centralize and standardize accounts receivables and payables transaction processing into Shared Financial Services Centre, and improve upstream procurement process. Consolidate invoice management systems, and leverage automated capabilities.
Consolidate security & emergency services	Consolidate 6 groups into the Security & Emergency Services organization. Align leadership, vision and organizational direction.

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Key Business Transformation Initiatives

Initiative	Description
Merge Hydro-Thermal business units	Reduce duplication of effort, streamline governance, and implement a centre-led engineering department to better utilize resources across the fleet and reduce engineering administrative burden on engineering staff. Management structure in place, Asset Management/Engineering risk assessment process changes complete by end of 2013, JRPT will complete movement of staff in 2014.
Create center-led Nuclear Engineering organization	Transfer line authority for 10 groups to a centre-led engineering organization with an increased span of control for managers/supervisors. The Engineering Authority will be the key driver of the new centralized matrix delivery model.
Corrective Action Program	Simplify corrective action program and centralize infrastructure. Increase individual managerial accountability for correcting problems. Improve quality of evaluations and actions by eliminate low-value process steps and consolidating 3 SCR databases into.
HR Services Centre	Establish a service centre within People & Culture to provide administrative services and advice to employees, managers and pensioners on a broad range of HR related matters.
Consolidate training organizations	Integrate training support and planning functions from Nuclear, Thermal, Hydro and Leadership training organizations. Support includes learning management system administration, learning centre coordination, content production, event planning and scheduling, reporting, measurement, business planning and learning strategy.
First Nations & Métis Relations Centre of Excellence	Enable field managers and staff to manage relationships with First Nation and Métis communities with consistency and confidence.
Health and Safety Management System	Develop a corporate level model for governance and a single Health & Safety management system to ensure a consistent approach to health and safety across OPG.
Corporate Brand Management: opg.com	Redevelop opg.com to improve alignment with current website standards and address increasing demands of social media. The new website will be a key marketing tool to illustrate OPG as Ontario's electricity generator of choice.

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Pension and OPEB Costs

- Pension and OPEB costs over the planning period reflect significant changes since the previous business plan. These include changes in economic factors, such as discount rates and fund asset performance, as well as the results of a comprehensive accounting valuation of the pension and OPEB liabilities being performed as at December 31, 2013.
- Pension and OPEB costs are projected to increase by ~$90 M in 2014 and ~$75 M in 2015, compared to the previous plan, primarily due to:
  - Updated mortality assumptions based on an evaluation of the historical experience of OPG's plans and current expectations of projected mortality improvement
  - Lower than assumed pension fund asset performance during the first half of 2013, related to low returns on fixed-income investments and reflecting the smoothing effect in recognizing the impact of returns on equity investments

Plan-Over-Plan Changes in Pension and OPEB Costs

$millions	**2014**	**2015**
Pension and OPEB Costs per 2013-2015 BP	*768*	*753*
Updated Mortality Assumptions	165	160
Lower Pension Fund Asset Performance	75	65
Higher Discount Rates	(120)	(110)
Lower Benefit Costs	(75)	(70)
Other Changes	45	30
Total Increase	90	75
Pension and OPEB Costs per 2014-2016 BP	*858*	*828*

- The above increases in pension and OPEB costs are partly offset by:
  - Higher discount rates, which increased to 4.7% from 4.3% to 4.4% in the previous plan
  - Updated post-retirement medical and dental cost assumptions reflecting historical experience for benefit claims
- The actual pension and other post retirement benefit costs for 2014 will reflect the final results of the comprehensive accounting valuation, including discount rates and asset values, at December 31, 2013

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Filed: 2013-12-06
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Ex. N1-1-1
Attachment 5





2014-2016 NUCLEAR BUSINESS PLAN

Board of Directors Meeting
November 14, 2013

Wayne Robbins – Chief Nuclear Officer
Bill Robinson – Senior Vice President, Nuclear Projects

ONTARIO POWER GENERATION

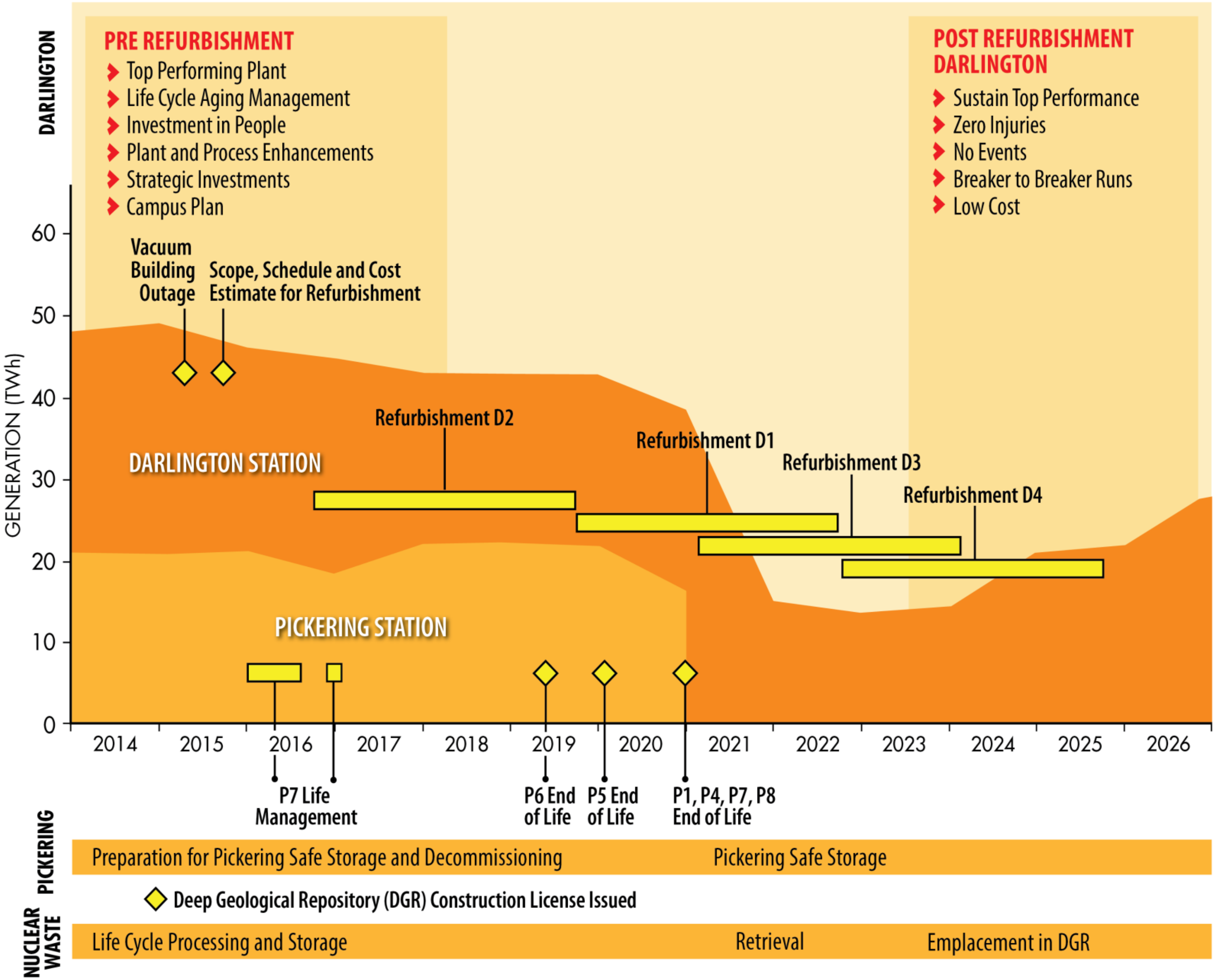
Planning Assumptions

- Pickering units will achieve 247k Equivalent Full Power Hours. Units 1, 4, 7 and 8 will operate to December 31, 2020. Unit 5 will operate to early 2020 and Unit 6 will operate to spring 2019.
- Pickering Unit 7 will be Life Managed to align with Unit 8 end of commercial operation. Pickering Unit 7 requires the unit to be Life Managed 270 days, currently distributed before and after Pickering Unit 7 outage in the fall of 2016.
- Darlington Vacuum Building Outage (VBO) to take place in spring 2015, subsequent VBOs will be on a 12 year cycle with no further Station Containment Outages.
- Nuclear Waste will maintain production of Dry Storage Containers at Darlington and Pickering Waste Management Facilities; and at a sustainable production level for Bruce Power.
- The Low and Intermediate Level Waste (L&ILW) Deep Geological Repository is expected to be placed in-service within 5 -7 years of receipt of a construction licence and OPG Board approval.
- Darlington Refurbishment outages commence in October 2016 with Unit 2. The execution phase period for each unit refurbishment is 36 months. Refurbishment duration is 108 months for all 4 units. Darlington Unit 1 refurbishment will commence upon the completion of Unit 2 refurbishment. Execution of the remaining units will have some project overlap.

ONTARIOPOWER GENERATION

Nuclear Cornerstones for Excellence

• Safety • Reliability • Value for Money • Human Performance



STRATEGIC OBJECTIVE

Operate in a safe, efficient and cost effective manner, with prudent investments to improve reliability and lower production costs.

STRATEGIC INITIATIVES

- Initiatives that close gaps to industry top performance.
- Darlington Top Performance.
- Pickering Ready and Reliable.
- Improve fleet outage performance.
- Continue to be industry leaders in Nuclear project management.
- Implement Engineering / Procurement / Construction strategy.

BEHAVIOURS

- Say It, Do It.
- Simplify It.
- Think Top and Bottom Line.
- Integrate and Collaborate.
- Tell It As It Is.

ONTARIO POWER GENERATION

Staff Plan Summary

Year End Regular Headcount	2013 Sep Forecast	2014	2015	2016
Operations				
Core Operations				
Pickering	1,942	1,915	1,902	1,899
Darlington	1,260	1,228	1,208	1,003
Fleet Operations & Maintenance	172	157	151	141
Nuclear Waste Management	213	208	207	210
Nuclear Engineering	933	927	891	883
Nuclear Services	229	222	213	213
Inspection and Maintenance Services	380	361	361	358
Security and Emergency Services	540	537	525	513
CNO Office	5	2	2	2
Subtotal - Core Operations	**5,674**	**5,557**	**5,460**	**5,222**
Refurbishment Support	59	99	91	140
Headcount funded by CNP	7	7	7	7
Operations Total	**5,740**	**5,663**	**5,558**	**5,369**
Projects				
Projects and Modifications	292	302	302	302
Contract Management	12	15	15	15
SVP - Nuclear Projects	1	2	2	2
Subtotal (excluding Refurbishment)	**305**	**319**	**319**	**319**
Nuclear Refurbishment	**196**	**300**	**309**	**405**
Total Nuclear	**6,241**	**6,282**	**6,186**	**6,093**

Highlights

- Core Operations – Reductions from:
  - Attrition and planned staff glide path enabled by Business Transformation Initiatives
  - Completion of Pickering Continued Operations program
- Planned transfer of Darlington Swing Staff (127) to Refurbishment organization by Fall 2016.
- Refurbishment Support – Higher work demands facing Nuclear Support Divisions.
- Projects and Modifications – Includes staff savings from Master Services Agreement strategy, simplification of governance, etc. Reliance on contractors to meet expanding workload.
- Refurbishment – Increases for execution of Campus Plan Projects and Definition Phase for core Refurbishment work. Updated to reflect November OPG Board submission.

ONTARIO POWER GENERATION

Financial Plan Summary

3 Year Cost Plan ($ Millions)

Cost Category / Work Program	2013 Sep Forecast	2014	2015	2016
Operations				
OM&A - Base and Outage	1,399.3	1,408.8	1,494.2	1,493.2
Provision	186.2	214.7	236.6	258.2
Fuel	250.3	267.2	257.7	251.0
Capital - MFA	13.1	37.8	21.7	17.8
Costs of Goods & Services Sold	5.7	5.5	5.2	5.8
External Revenue (Non-Electricity)	(0.6)	(0.3)	(0.3)	(0.3)
Projects				
OM&A - Base and Outage	16.7	13.0	14.9	9.5
OM&A - Projects	96.9	100.0	90.0	90.6
OM&A - Refurbishment	6.8	23.1	20.4	30.9
OM&A - New Build	26.7	3.0	3.0	1.8
Total OM&A	147.1	139.1	128.3	132.8
Capital -Project Portfolio	185.3	230.0	200.0	189.4
Capital - Refurbishment	447.6	765.0	736.0	607.0
Total Capital	633.0	995.0	936.0	796.4
Provision	25.7	64.2	59.0	59.1

Highlights

- Operations OM&A – Annual variations primarily due to Outage program changes (e.g., Darlington Vacuum Building Outage in 2015).
- Operations Provision – Increases related to planned progression on Low & Intermediate Level Waste Deep Geological Repository (e.g., construction licenses).
- Fuel – Uranium cost changes consistent with Generation Plan.
- Capital Portfolio – Increased investment for Fukushima projects, plant reliability improvements, and regulatory commitments.
- Refurbishment – Progress on project life cycle. Updated to reflect November OPG Board submission.
- Nuclear New Build – Potential activities consistent with upcoming Ontario's Long Term Energy Plan (e.g., maintaining / banking the site preparation license).
- Projects Provision – Includes: Portfolio projects; Refurbishment Retube Waste Containers; Planning for Pickering Decommissioning; and Bruce Heavy Water Plant Decommissioning.

ONTARIO POWER GENERATION

Nuclear Enterprise Risk Profile

Top, Monitored & Emerging Risks with significant impact to the Nuclear Business for Q3 2013 Reporting.

Brand/Reputation

ONTARIO POWER GENERATION

- OPG Unable to Manage Project Workload Leading up to Darlington Refurbishment
- Failure to Obtain 10 Year Licence Renewal Darlington
- Loss of AECL Capability and Knowledge
- Community and Special Interest Group Support for the L&ILW DGR Project Declines

Operational Performance

- Failure to Retain and Replace Leadership Talent
- Parts Procurement Impacting Operations
- Unexpected Fuel Channel Degradation at Darlington
- Pickering Fuel Handling Failures
- Darlington Primary Heat Transport (HT) Pump Motor Failures
- Failure to Remove Pickering Licence Hold Point
- Darlington EPG Failures Impacting Operations
- Pickering Equipment Reliability & Parts Obsolescence
- Darlington Fuel Handling Failures
- Project Leadership and Specialized Resources Not Available
- Failure to Achieve a Successful Darlington Vacuum Building Outage
- Pickering U5 L12 Channel Gap Unbudgeted SLAR Outage May 2014
- Failure of Darlington Primary HT Pump Seals
- Low and Intermediate Level Waste Equipment Failures Impacting Station Operations

Financial Sustainability

- Insufficient Revenue from OEB Rate Regulation Rulings
- Failure to Recover Darlington Refurbishment Costs
- Increase in Future Pension Plan Funding Requirements and Other Post Employment Benefit Programs

Legend:

- **Top Enterprise Risk**
- **Emerging Risk**
- OPG Centre-Led Risk
- Nuclear Owned Risk

ONTARIO POWER GENERATION

Nuclear Operations - Executive Summary

The 2014-2016 OPG Nuclear Operations Business Plan continues to improve on safety, plant reliability, and closing benchmarking gaps; while implementing the centre-led matrix business model.

Business Plan Highlights:

- Continued focus on Nuclear, Radiological, Conventional, and Environmental Safety.
- Increased outage days and focus on management of aging fleet as well as system and plant health to improve reliability.
- Additional regular staff to ensure licensed operator staff sustainability and support for Refurbishment.
- Continuation of Business Transformation enabling staff reductions.
- Improvements in outage preparation and performance as Pickering continues its execution of the Ready and Reliable Plan, and Darlington plans for the 2015 Vacuum Building Outage and the Refurbishment Project starting in October 2016.
- Continued focus by Nuclear Waste Management Division on equipment performance improvement, environmental stewardship, and long term storage projects.
- Improved Human Performance.
- Centre-Led support aligned to Nuclear's performance objectives.
- Nuclear's commitment to deliver on OPG's mission of proudly generating clean, safe, and low cost electricity through dependable performance.

ONTARIO POWER GENERATION

Nuclear Operations Initiatives and Focus Areas

Filed: 2013-12-06
EB-2013-0321
Ex. N1-1-1
Attachment 5

SAY IT, DO IT

TELL IT AS IT IS

INTEGRATE and COLLABORATE

SIMPLIFY IT

Safety Cornerstone

- Strong Nuclear Safety Culture
- Zero Lost Time Accidents
- ALARA Culture
- Environmental Stewardship
- Work Protection Program
- Nuclear Fleet Initiative to Minimize L&ILW

Human Performance / Leadership Cornerstone

- Nuclear Fleet Initiative to Improve Performance
- Licensed Operator Throughput
- Event-Free Behaviours
- Model of Accountability
- Corrective Action Plan Effectiveness

ACHIEVE 2014-2016 PERFORMANCE TARGETS

Reliability Cornerstone

- Effective Aging Management
- System and Plant Health Focus
- Fuel Handling Reliability
- Preventive Maintenance Effectiveness
- Corrective and Deficient Backlog Reduction
- Fleet Chemistry Improvement

Value for Money Cornerstone

- Business Transformation
- Outage Improvement
- Improve Parts Availability
- Leverage Days Based Maintenance

THINK TOP and BOTTOM LINE

VALUES: SAFETY, INTEGRITY, EXCELLENCE, PEOPLE & CITIZENSHIP

ONTARIO POWER GENERATION

Three Year Nuclear Operations Performance Targets

Metric	2012 Actuals (Rolling Average) Pickering	2012 Actuals (Rolling Average) Darlington	2016 Target Guidelines (Annual) Pickering	2016 Target Guidelines (Annual) Darlington
Safety				
All Injury Rate (#/200k hours worked)	0.33	0.34	0.89	0.89
Rolling Average Industrial Safety Accident Rate (#/200k hours worked)	0.03	0.10	0.15	0.15
Rolling Average Collective Radiation Exposure (Person-rem per unit)	124.06 ⇩	58.55	89.00	55.00
Airborne Tritium Emissions (Curies) per Unit[1]	2,491	973	1,800	1,000
Fuel Reliability Index (microcuries per gram)	0.000129	0.000194 ⇧	0.000500	0.000500
2-Year Reactor Trip Rate (# per 7,000 hours)	0.517 ⇧	0.208	0.50	0.50
3-Year Auxiliary Feedwater System Unavailability (#)	0.0116	0.0000	0.0200	0.0200
3-Year Emergency AC Power Unavailability (#)	0.0037	0.0000	0.0250	0.0250
3-Year High Pressure Safety Injection Unavailability (#)	0.0001	0.0000	0.0200	0.0200
Reliability				
WANO NPI (Index)	64.7	96.3 ⇩	72.8	96.3
Rolling Average Forced Loss Rate (%)	9.23	2.02 ⇩	5.00	1.00
Rolling Average Unit Capability Factor (%)	75.62	92.0 ⇧	78.4	92.0
Rolling Average Chemistry Performance Indicator (Index)	1.10	1.03	1.03	1.01
1-Year On-line Deficient Maintenance Backlog (work orders per unit)	232	203 ⇧	<197	175
1-Year On-line Corrective Maintenance Backlog (work orders per unit)	118	66	28	25
Value for Money				
3-Year Total Generating Cost per MWh ($ per Net MWh)[2]	67.16	31.67	64.78	38.16
3-Year Non-Fuel Operating Cost per MWh ($ per Net MWh)[2]	57.21	24.76	56.22	26.67
3-Year Fuel Cost per MWh ($ per Net MWh)[2]	5.00	4.69	5.96	5.38
3-Year Capital Cost per MW DER * (k$ per MW)[2]	31.84	17.66	15.60	45.26
Human Performance				
18-Month Human Performance Error Rate (# per 10k ISAR hours)	0.00800 ⇩	0.00760 ⇩	0.004	0.004

- Continue to lead industry in overall Nuclear, Conventional, and Environmental Safety. Continue fuel defect recovery plan. Improve work protection performance.
- A continued focus on equipment reliability and forced loss reductions. Improvements in work order readiness, backlog reduction, preventive maintenance, and maintenance effectiveness.
- Continuous improvement through strong work management . Realize efficiencies through Business Transformation and initiatives.
- Lower generation in 2016 due to Pickering Life Management and Darlington Refurbishment outages contributing to higher TGC/MWh and NFOC/MWh targets.
- Target top quartile performance for Event Free Day Resets through focus on improvements in operations, procedure use and adherence, and use of event free tools.

*DER - Design Electrical Rating.
1. 2011 data is used because 2012 results were unavailable at the time of benchmarking.
2. 2016 targets are preliminary and subject to updates based on final Corporate allocations. TGC/MWh and NFOC/MWh targets exclude OPEB, Pension, and Corporate Asset Service Fees to align with industry standards.

⇩ Declining Benchmark Quartile Performance vs. 2011
⇧ Improving Benchmark Quartile Performance vs. 2011

Green = max NPI points achieved (if applicable) or best quartile performance
White = 2nd quartile performance
Yellow = 3rd quartile performance
Red = worst quartile performance

ONTARIO POWER GENERATION

Nuclear Generation Plan

Generation Plan

Pickering Nuclear	2014	2015	2016
Net Generation in TWh	20.9	21.3	18.6
Planned Outage Days	327.9	339.5	342.6
Forced Loss Rate %	7.8	5.5	5.0
Unit Capability Factor %	78.4	79.9	78.4
Darlington Nuclear	**2014**	**2015**	**2016**
Net Generation in TWh	28.1	24.7	26.0
Planned Outage Days	81.4	245.6	97.0
Forced Loss Rate %	1.3	1.0	1.0
Unit Capability Factor %	93.2	82.3	92.0
OPG Nuclear	**2014**	**2015**	**2016**
Net Generation in TWh	49.0	46.1	44.6
Planned Outage Days	409.3	585.1	439.6
Forced Loss Rate %	4.1	3.1	2.7
Unit Capability Factor %	86.4	81.2	85.8

- Station plans continue to focus on improving Forced Loss Rate over the planning period.
- Generation forecast reflects expected levels of performance considering the complexity of the work program and lower production in 2016 due to the Pickering Unit 7 Life Management outage and the start of Darlington Unit 2 Refurbishment.
- Pickering Unit 7 Life Management outage and Darlington Unit 2 Refurbishment are excluded from the Planned Outage Days and Unit Capability Factor.

Generation Plan over Plan

Nuclear	2014	2015	2016	Var 2014-2015
TWh 2014-2016 Nuclear Submission	49.0	46.1	44.6	
2013-2015 Nuclear Business Plan	49.7	48.0		
	-0.6	-2.0		-2.6

Note: Numbers may not add due to rounding.

ONTARIO POWER GENERATION

Pickering Nuclear

Pickering Nuclear will continue with its vision to be "Ready & Reliable" and will focus on further performance improvements e.g. reducing generation losses. Pickering Nuclear will execute the required scope of work to ensure safe and reliable operation of the units to 2020.

Pickering Nuclear will meet its staffing, financial, and operational targets set in the business plan by:

- Extending the life of the station to 2020 by successfully completing the Continued Operations work program, scoping planned outages to End of Life and fully defining wind-up plans. This will allow Pickering to produce nominally 21 TWh of energy per year until 2020 with the exception of 2016 due to the Unit 7 Life Management outage.
- Achieving a Forced Loss Rate (FLR) of 5.0% or better by 2016 through the execution of our equipment reliability improvement plans, including targeted backlog reduction, and specific reliability projects.
- Addressing new WANO Areas For Improvement (AFIs) and gaps in performance to solidify our WANO standing, to achieve favourable 2015 WANO results, and attaining an NPI score of >72 by 2016.
- Leveraging Days Based Maintenance for lowering corrective maintenance backlogs to 28 work orders/unit by 2016.
- Achieving continuous improvement through Business Transformation initiatives.

Pickering Major Focus Areas

SAY IT, DO IT

TELL IT AS IT IS

INTEGRATE and COLLABORATE

SIMPLIFY IT

Safety Cornerstone

- Safety Culture
- Radiation Protection Performance
- Improve Work Protection
- Plant Material Condition
- Tritium Emissions Reduction

Human Performance / Leadership Cornerstone

- Leadership Effectiveness
- Focused Human Performance Improvement
- Correct Action Plan Effectiveness
- Conduct of Maintenance
- Cross Functional Team Work

READY & RELIABLE

• Zero Injuries • Human Performance Excellence • No Repeat Failures • Effective WM •

Reliability Cornerstone

- Equipment Reliability/Generation Improvement
- Continued Operations Plan
- Fuel Handling Reliability
- Preventative Maintenance (PM) Effectiveness
- Chemistry Performance Improvement

Value for Money Cornerstone

- Online Work Management Cycle Plan
- Days Based Maintenance
- Improving Outage Planning & Execution
- End of Life Outage Scoping
- Integrated Outage/IOP Schedule

THINK TOP and BOTTOM LINE

VALUES: SAFETY, INTEGRITY, EXCELLENCE, PEOPLE & CITIZENSHIP

ONTARIO POWER GENERATION

Darlington Nuclear

Darlington's goal is to be the best performing nuclear plant in the world. Darlington's objective for the 2014-2016 plan is to continue our Journey of Excellence while positioning the station for refurbishment and beyond.

Continuing improvement areas:

- Equipment reliability
- Leadership behaviours
- Vacuum Building Outage (VBO) preparation and execution
- Integration and alignment with the refurbishment project
  - Fuel Handling reliability
  - Scope rationalization
  - Strategic investments
  - Staffing

Darlington Major Focus Areas

SAY IT, DO IT

TELL IT AS IT IS

INTEGRATE and COLLABORATE

SIMPLIFY IT

Safety Cornerstone

- Tritium Emissions Reduction
- Low & Intermediate Active Waste Reduction
- Conventional Safety Improvements
- Work Protection Program
- Radiological Practices
- Fuel Defects

Human Performance / Leadership Cornerstone

- Leadership & Supervisory Development
- Focused Human Performance Improvement
- Procedure Use & Adherence
- Licensed Operator Throughput
- WANO Review

JOURNEY OF EXCELLENCE

• Zero Injuries • No Events • Breaker To Breaker Runs • Low Cost •

TO BE THE BEST PERFORMING NUCLEAR PLANT IN THE WORLD

Reliability Cornerstone

- Maintenance Backlogs
- Fuel Handling Reliability
- Preventative Maintenance (PM) Program Effectiveness
- Projects for Improved Reliability
- System Health Improvement Plans

Value for Money Cornerstone

- VBO Readiness
- Resource Strategy/Maintenance Efficiency
- Spare Parts for Critical Equipment
- Outage Improvement Strategy
- Refurbishment Integration
- 10 Year Licence in 2014

THINK TOP and BOTTOM LINE

VALUES: SAFETY, INTEGRITY, EXCELLENCE, PEOPLE & CITIZENSHIP

Nuclear Waste Management Division

Nuclear Waste Management Division continues to manage ongoing nuclear waste for Ontario's Nuclear Generating Stations (Darlington, Pickering and Bruce Power).

The scope of work continues to expand to support the following:

- **Process Equipment Performance Improvement**
  - Improve Dry Storage Container welding equipment reliability and reduce rework
  - Improve incinerator system reliability
- **Environmental Stewardship**
  - Implement low level radioactive waste minimization initiatives for reprocessing and new waste generated
- **Long Term Nuclear Waste Projects**
  - Obtain licence to construct and OPG Board approval for L&ILW DGR
  - Scope work for Pickering long term safe storage
  - Ensure alignment with Nuclear Waste Management Organization in planning long term used fuel management solution

ONTARIO POWER GENERATION

Nuclear Waste Management Major Focus Areas

SAY IT, DO IT

TELL IT AS IT IS

INTEGRATE and COLLABORATE

SIMPLIFY IT

Safety Cornerstone

- Zero High MRPH Events
- Low & Intermediate Active Waste Reduction
- Improve Fire Protection Programs & Events
- Environmental Protection
- Regulatory Compliance
- Work Protection

Human Performance / Leadership Cornerstone

- Leadership & Supervisory Development
- Focused Human Performance Improvement
- Improve Corrective Action Program Effectiveness
- Training for Improved Performance
- Aligned Message and Consistent Communication

SIMPLIFY THE BOTTOM LINE

• Waste Minimization • Volume Reduction • Equipment Reliability •

Reliability Cornerstone

- Improve System Health Reports
- Mitigate Single Point Vulnerabilities
- Projects for Improved Reliability
- Modifications for Equipment Reliability
- Develop Aging Management Plans for Used Fuel and L&ILW Systems & Structures
- Improve Overall Welding Program
- Incinerator Outage & Planning Execution

Value for Money Cornerstone

- Process and Store Annual Commitment of Dry Storage Containers (DSCs)
- Resource Strategy/Maintenance Efficiency
- Execute L&ILW Processing Strategy with a Focus on Volume Reduction and Reduction of the Environmental Footprint
- Secure Long Term Supply of DSCs

THINK TOP and BOTTOM LINE

VALUES: SAFETY, INTEGRITY, EXCELLENCE, PEOPLE & CITIZENSHIP

ONTARIO POWER GENERATION

Nuclear Engineering

Nuclear Engineering will continue to improve OPG Nuclear safety, reliability, and cost effectiveness through world class leadership, innovative solutions, and application of core competencies.

Business Plan Highlights:

- Transition to Centre-Led is essentially complete and effective
- Effective Management of Aging is maximizing generation
    - Fuel Channel Life Management
    - Neutron Over Power (NOP) Margins
- Continued Fukushima Industry Leadership
- Effective Emerging Talent program is in place
- Need to improve Component Program execution & oversight
- Implementation of Engineering, Procurement & Construction (EPC) strategy taking significant effort
- Need to mitigate known knowledge retention risks

ONTARIO POWER GENERATION

Nuclear Operations Portfolio

- Nuclear Operations Portfolio drivers include:
  - Response to Fukushima and regulatory commitments
  - Addressing vulnerabilities of aging plant and obsolescence
  - Increasing need for Capital Spares
  - Pickering End of Life – ensuring continued reliability and plant health through 2020
- Effective use of Engineering, Procurement & Construction strategy.
- Approximately $200 million of Capital growth from previous levels has been incorporated in portfolio ceilings over 2014 – 2016.
- OM&A portfolio reduced as Pickering approaches End of Life.
- Station request for projects is significantly higher than ceilings. Asset Investment Screening Committee (AISC) is actively working to meet ceilings.

Key Projects for Success

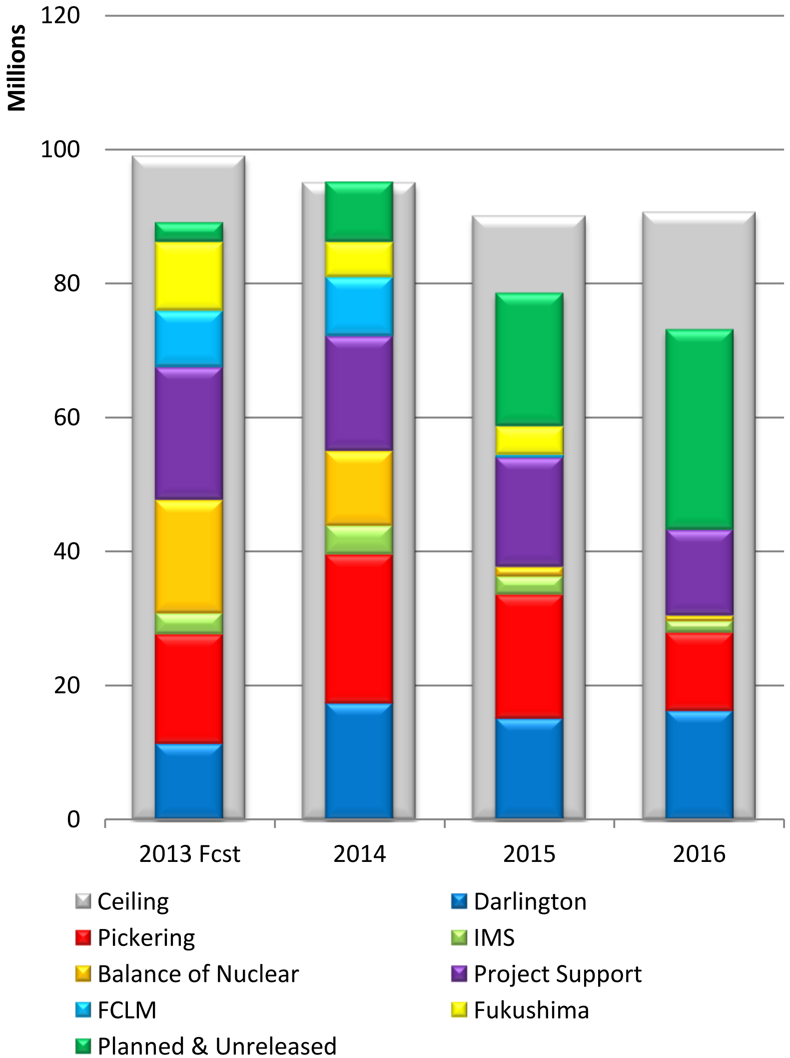
OM&A

- Fukushima support projects
  - Severe Accident Management Guidelines Implementation Improvements
  - Fukushima Oversight
  - Multi-Unit Beyond Design Basis Exercise
- Fuel Channel Life Management (FCLM) Program
- Probabilistic Risk Assessment Upgrade
- Darlington Emergency Power Generator #2 Gas Producer Engine Replacement
- Darlington Pressure – Temperature Envelope modifications
- Pickering Units 5-8 Boiler Blowdown Pipe Support Improvements

Capital

- Fukushima projects
  - Fukushima Phase 1 & 2 Emergency Mitigation Equipment for Steam Generators, Moderator & Shield Tank
  - Darlington and Pickering Passive Autocatalytic Recombiners
  - Regional Emergency Response Support Centre
  - Fukushima Telecommunications Upgrades
- Darlington and Pickering Fuel Handling Reliability Modifications
- Fire Code Compliance projects
- Darlington Restore Emergency Service Water and Firewater Margins
- Darlington Secondary Control Area Air Condition Unit Replacement

OM&A Project Portfolio Breakdown

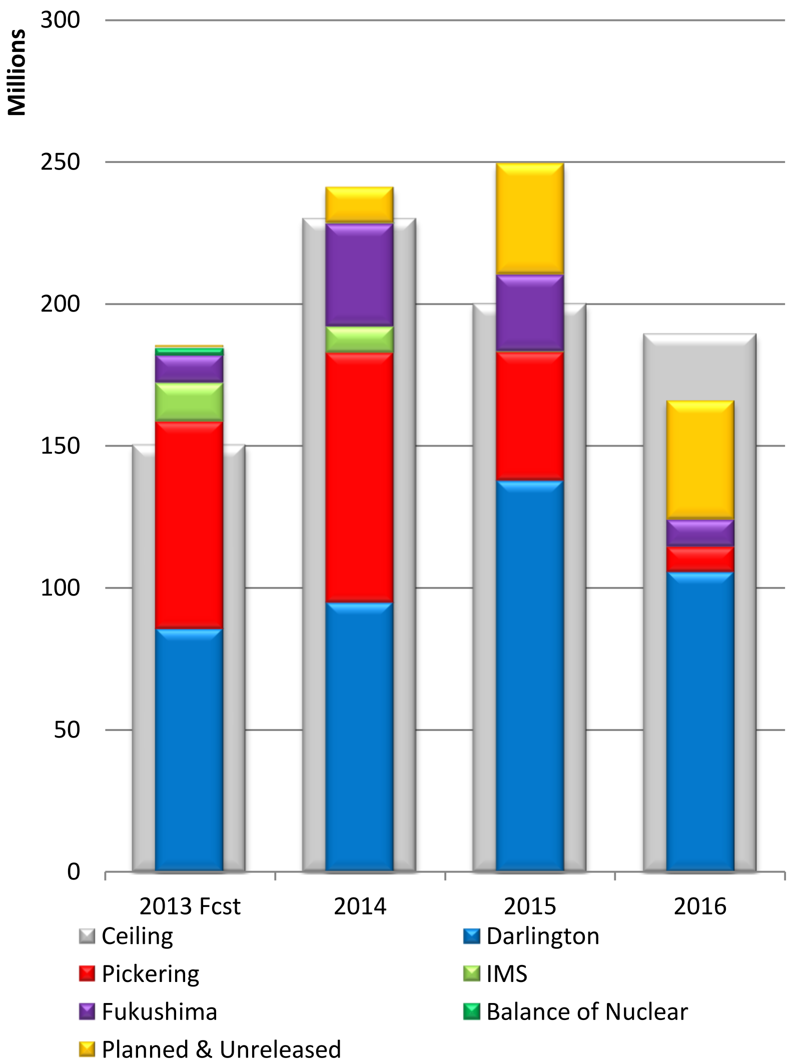


Note: Excludes Pickering Continued Operations Project.

- OM&A ceilings are reduced by $5 million year over year in 2014 and 2015. The ceiling in 2016 is essentially constant.
- The gap between the released and planned & unreleased, and the ceilings is expected to be utilized for:
  - Funding modifications at Pickering to maintain safe and reliable operation
  - Modifications to address obsolescence of Darlington equipment

ONTARIO POWER GENERATION

Capital Project Portfolio Breakdown



- In 2013, spending on Capital will exceed guideline by $35 million due to increasing demand for Capital projects and spares.
- Forecasts for planned & unreleased projects could put spending $10 million and $49 million over ceiling in 2014 and 2015 respectively. AISC is actively working to reallocate projects to eliminate over-spending in 2014 and 2015.
- Approved and forecasted unreleased spending in 2016 is $24 million under ceiling.

ONTARIO POWER GENERATION

Nuclear Projects - Executive Summary

- Nuclear Projects Organization will deliver value to the Nuclear Operations organization through Project Management Excellence.
- Nuclear Projects will:
  - Manage the Definition and Execution phases of the Darlington Refurbishment Program (DRP).
  - Complete all pre-requisite work required in order to be ready to execute the DRP, including scope definition, facility and infrastructure projects, safety improvement opportunities, and fuel handling improvements.
  - Establish an appropriate environment in order to effectively integrate and execute Engineer/Procure/Construct (EPC) contracts.
  - Implement Business Transformation initiatives to deliver projects safely, with high quality, on time and under budget.

ONTARIOPOWER GENERATION

Nuclear Projects Cornerstones

SAY IT, DO IT

TELL IT AS IT IS

INTEGRATE and COLLABORATE

SIMPLIFY IT

Safety Cornerstone

- Strengthen Safety Culture
- Zero Lost Time Accidents
- Environmental Stewardship

Human Performance / Leadership Cornerstone

- Leadership Development and Effectiveness
- Project Manager Capability
- Employee Engagement
- Contractor Management Effectiveness

ACHIEVE 2014-2016 PERFORMANCE TARGETS

Reliability Cornerstone

- Pre-requisite Projects for Refurbishment
- Fuel Handling Equipment Reliability Index
- Deliver Projects to Improve Station Reliability

Value for Money Cornerstone

- Meet Project Milestone, Cost, Schedule and Quality Targets
- Contractor Performance
- Resource Strategies
- Effective Integration with Stations

THINK TOP and BOTTOM LINE

VALUES: SAFETY, INTEGRITY, EXCELLENCE, PEOPLE & CITIZENSHIP

ONTARIO POWER GENERATION

Nuclear Refurbishment

Filed: 2013-12-06
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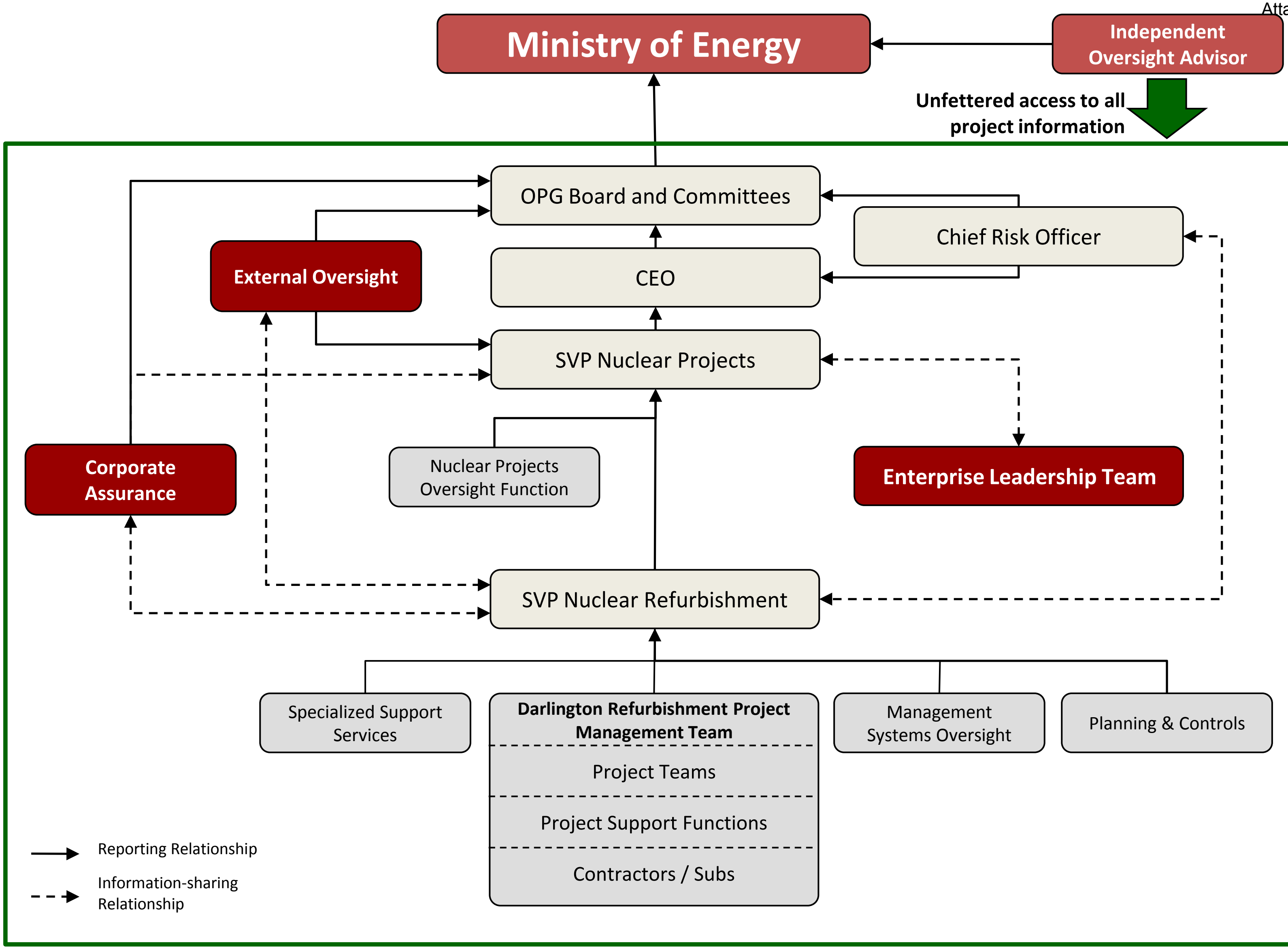
Ex. N1-1-1
Attachment 5

- Manage the Definition phase of the Darlington Refurbishment and prepare for the execution phase, starting in October 2015.
- Project schedule has been revised to reflect un-lapping of first two units.
- Scope optimization is underway in order to maximize success of Refurbishment.
- Overall project cost remains within previous estimate, including cash flow requirements for the Definition Phase.
- Business Plan reflects project cost estimate consistent with the release of funds going to the OPG Board in November 2013.
- Darlington Refurbishment has incorporated OPEX from other Refurbishment projects.

Project Oversight & Assurance Framework



Key Deliverables in Business Plan Period

- Integrated Improvement Plan (IIP) and Global Assessment Report (GAR) to support the 10 year licence application for Darlington in 2014.
- Completion of refurbishment pre-requisite work including scope defining inspections and unit islanding modifications.
- Negotiation and award of remaining major contracts.
- Completion of detailed engineering.
- Construction of facilities and infrastructure as well as safety improvement projects (e.g. Third Emergency Power Generator, Containment Filtered Venting System).
- Design, fabrication, and testing of re-tube and feeder replacement tooling and mock-ups to determine project durations for re-tube and feeder replacement activities.
- Scope finalization and development of Release Quality Estimate by October 2015.
- Development of a project agreement with the Building Trades Union through Electrical Power Systems Construction Association; discussions with the Power Workers Union regarding non-trades related Purchased Service Agreements in progress.
- Commence Unit 2 Execution Phase in October 2016 .

Projects and Modifications

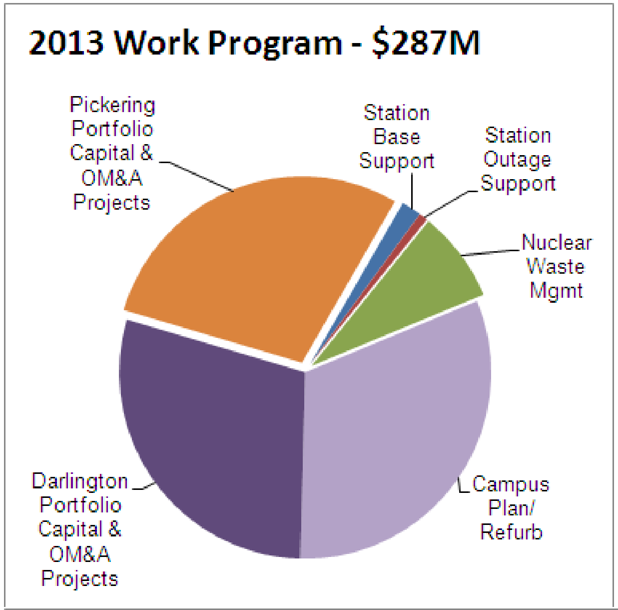
Projects and Modifications deliver projects safely, meeting quality requirements, on schedule and on budget.

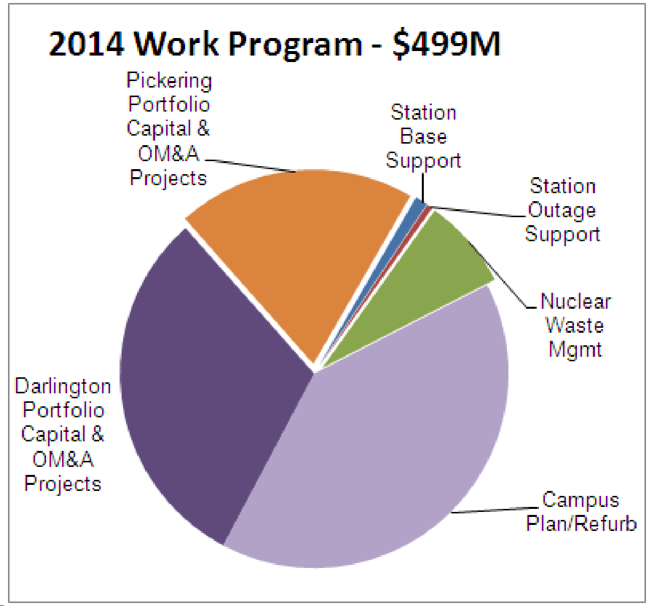
Business Plan Highlights:

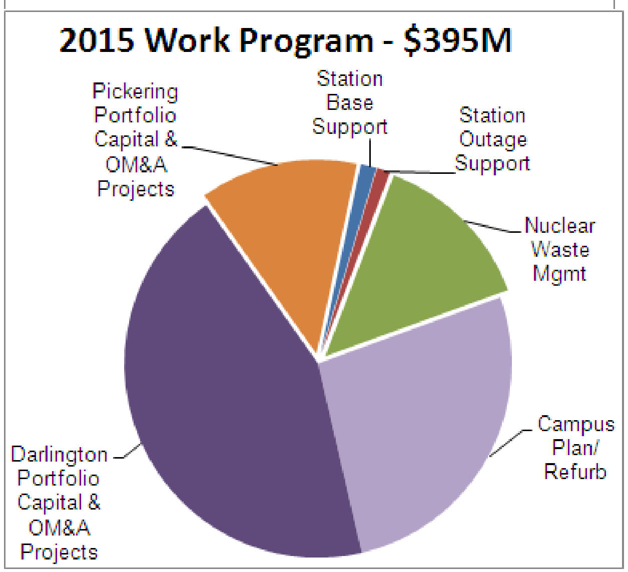
- Implement projects required to support Refurbishment (Third Emergency Power Generator, D2O Storage Facility, Containment Filter Venting, Campus Plan portfolio).
- Support an increased project work program while maintaining Safety, Quality, Schedule and Cost with current regular staff levels.
- Leverage our Extended Services-Master Service Agreement (ES-MSA) contractors.
- Utilize Engineer/Procure/Construct (EPC) contracting model where cost effective.
- Streamline Project Management governance and practices aligned with Refurbishment Program.

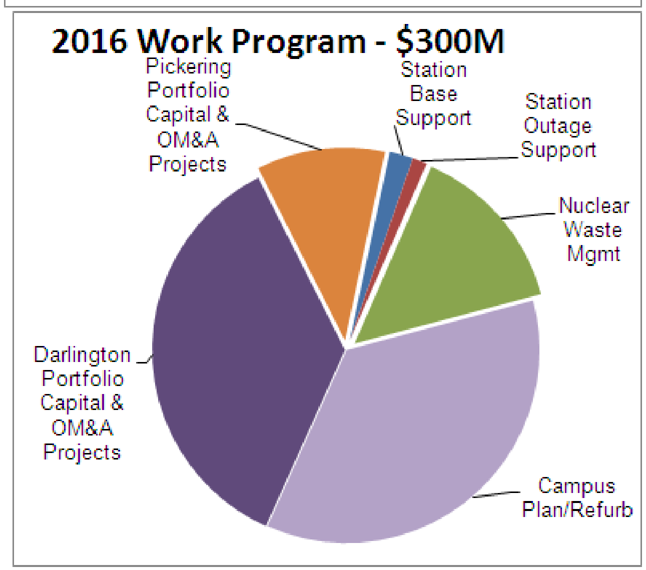
ONTARIO POWER GENERATION

Projects and Modifications Work Program









- Forecast of work to be executed by Projects & Modifications.
- Forecasts include unreleased projects and reflect support agreements.
- Forecasts subject to change pending AISC and Refurbishment gate approvals.

ONTARIO POWER GENERATION

Fleet Operations and Maintenance

Improve fleet performance in all functional areas.

Strategic Focus Required:

- On-Line and Outage Work Management
- Integrated Resource Strategy, Workforce Plan and Labour Relations Strategy
- Leadership Development and Succession Planning

Enabled By:

- Centre-Led Functional Area Manager (CFAM) Operating Model Implementation
- Cross-functional solutions that improve parts availability
- Effective Use of Extended Service Master Services Agreement

Inspection and Maintenance Services

Inspection and Maintenance Services' (IMS) objective is to provide OPG Nuclear Stations with Quality Specialized Inspection and Maintenance Services that are delivered in an effective manner.

IMS Plan is to improve the efficiency of its processes, ensure the reliability of its equipment, and execute its program with skilled staff.

Business Plan Highlights:

- Implement strategies to improve critical path performance
- Benchmark vendors to look for improvement opportunities
- Improve Equipment Reliability through tooling upgrades and improved maintenance practices
- Complete major projects and develop new tooling solutions e.g. Multiple Simultaneous Feeder Inspection tooling and Inspection Qualification project
- Effectively implement its Human Performance plan

ONTARIO POWER GENERATION

Security and Emergency Services

Security & Emergency Services (SES) organization is committed to ensuring OPG can prepare for, respond to, and recover from Emergencies.

Business Plan Highlights :

- Continued focus on Value for Money through: efficiencies and effectiveness of centre-led functions within SES, adaptive resourcing, and Life Cycle Management
- Commitment of continued high standard of operational support in all disciplines
- SES Operations regular staff headcount submitted on attrition based guideline
- Darlington Refurbishment and Campus Plan: Security head count has been agreed to by Darlington Refurbishment and SES. Fire Protection discussions on scope of work and associated head count are ongoing.

Nuclear Services

Nuclear Services' Vision: A Reliable and Responsible Resource for OPG Nuclear.

Nuclear Services delivers value to Nuclear Operations and Nuclear Projects:

- Providing effective and efficient Radiation Protection Services, Regulatory Affairs, Strategic Planning and Improvement, Environmental Assessments, and Stakeholder Relations centre-led functions;
- Maintaining regulatory relationships and influencing regulatory agencies to facilitate the needs of the Nuclear businesses, and obtaining all CNSC regulatory approvals;
- Driving fleet wide initiatives for continuous improvement;
- Driving fleet wide improvement in the Corrective Action Program;
- Safely delivering Radiation Protection services to Nuclear Operations, Nuclear Projects, and Nuclear Waste.

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Environment

Maintain environmental performance excellence and stewardship by providing leadership and support through business unit partnerships.

Business Plan Highlights:

- Complete transition to a centre-led Environment function through JRPT redeployment and change management.
- Manage Darlington refurbishment environmental assessment follow-up commitments.
- Pursue cost effective methods to achieve Pickering tritium emissions targets.
- Reduce OPG’s environmental regulatory obligations where they are assessed to be ineffective or inefficient by determining the top three advocacy areas, identifying success criteria for each, and enhancing relationships with regulators.
- Integrate program at NWMD into Nuclear environmental management program.
- Consolidate single OPG environmental management system and simplify operational control documentation.

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Learning & Development

Learning & Development Business Plan Objective: Strengthen Nuclear Fleet Training Program Quality, Effectiveness, and Efficiency.

Business Plan Highlights :

- Increase the percentage of successful graduates (through-put) from each Initial CNSC License Training Program by implementing industry benchmarked "Best Practice" improvements to both the Non-Licensed Operator Training Program (Initial and Continuing/Requalification) and to the Initial CNSC License Training Program.

- Reduce the average initial training and qualification time required for incoming temporary supplemental workers for nuclear fleet outages and projects (Building Trades Union and Appendix A workers), with more regular and effective up-front worker training and qualifications communications and collaboration with local union hiring halls , combined with implementing the EPRI Certified industry standardized task evaluations process for selected qualifications.

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Supply Chain Commitments

New centre-led Supply organization will have six focus areas to provide material and services required by the business at the right time for the best value:

1 Strategic Sourcing	2 Parts Procurement & Reliability	3 Supplier Quality & Performance	4 Projects Support	5 Warehouse Operations	6 Inventory Management
▪ $19.6M value improvement targeted in OPGN over the BP period on an addressable spend of $370.8M ▪ Leverage spend with fewer suppliers (3,000 to 1,500 by 2016) ▪ Drive "cost of quality" ▪ Pursue strategic sourcing opportunities ▪ Centres of excellence for key spend categories	▪ Parts availability to achieve Corrective and Deficient Maintenance backlog targets ▪ Improvement plans for on-line, outage, stock out, and replenishment materials ▪ Collaborate closely with Engineering on obsolescence issues ▪ Cross functional performance metrics	▪ Expand the Vendor Quality & Supplier Health Index ▪ Proactive "cost of quality" strategy ▪ Use strategic sourcing to leverage vendor quality ▪ Counterfeit, Fraudulent, and Suspect Items Program evaluation and improvements to mitigate risk exposure	▪ Meet all project schedule milestones without negative impact on scope, schedule or cost ▪ Implement and support extended Services / EPC Model ▪ Develop skill set and training for EPC SC oversight – leverage Hydro/Thermal best practices	▪ Implement the QL-4 initiative, remove non-plant equipment from Nuclear warehouses ▪ Implement a new inventory cycle count program ▪ Finalize a business case for a central warehouse at Darlington ▪ Sustain shared parts with non-OPG companies	▪ Targeted removal of $40M in QL-4 materials from Nuclear Warehouses ▪ Materials Review Board to optimize inventory levels, balancing risk and financial impacts

Note: Value improvement of $60.9M is targeted across OPG over the 2014 – 2016 period.

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Appendix A

Darlington – Refurbishment Integration

Refurbishment Integration

- Refurbishment integration team in place
- Pre-requisite work integrated into station schedules
- Integrate senior scope review results into life cycle management plans
- 10 year licence in 2014
- Top 5 focus areas developed:
  - Improve Fuel Handling reliability
  - Vacuum Building Outage preparations
  - Scope finalized
  - Develop transition plans
  - Campus Plan integration

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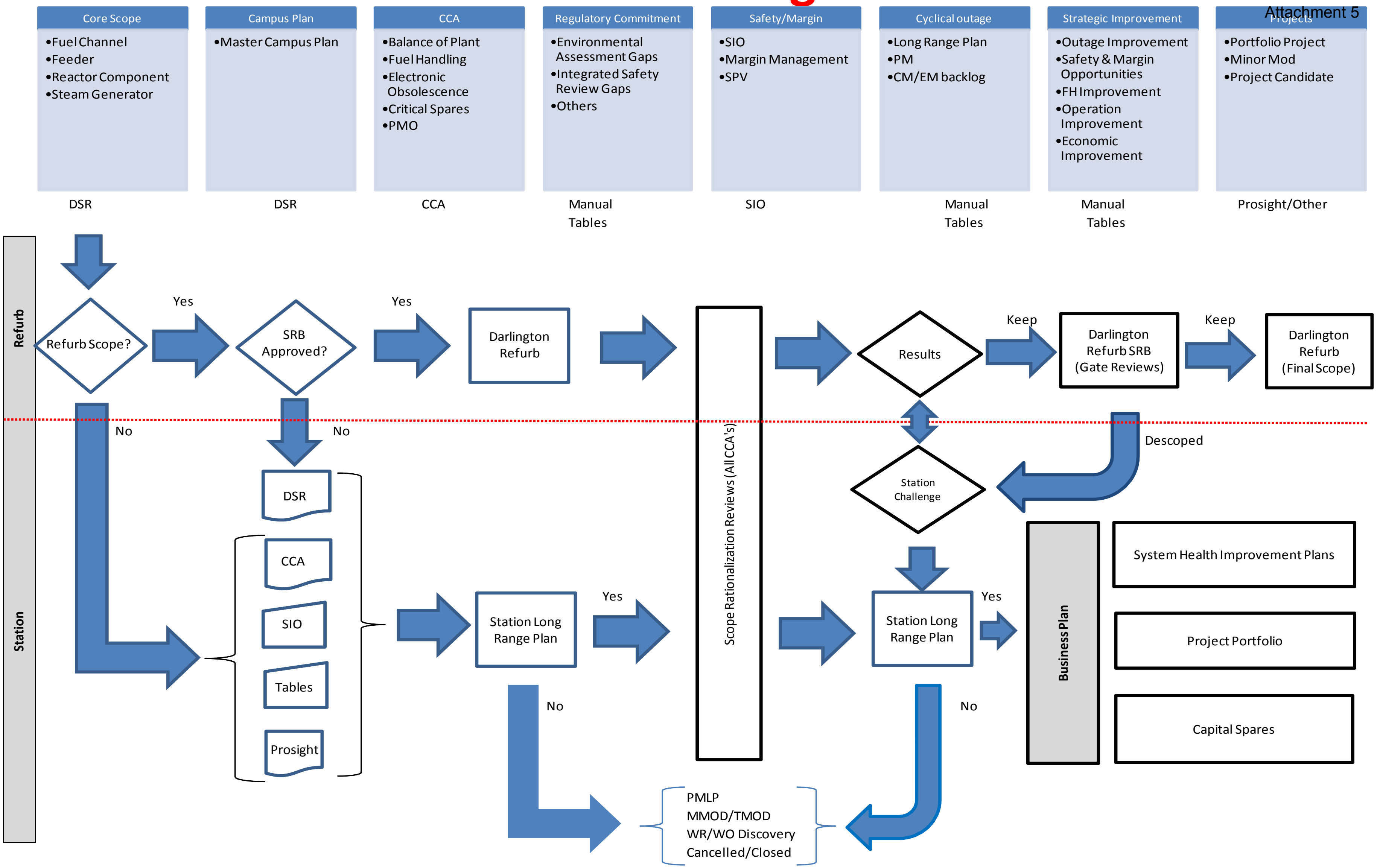
EB-2013-0321
Ex. N1-1-1
Attachment 5

Refurbishment Work Integration Process



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Attachment 6

Hydro Thermal Operations 2014-16 Business Plan Presentation to Risk Oversight Committee

November 13, 2013

Mike Martelli
SVP Hydro Thermal Operations

ONTARIO POWER GENERATION

Hydro Thermal Operations Business Plan - Outline

- Hydro Thermal Operations Business Plan Thrusts
- Planning Assumptions (2014 to 2016)
- Hydro Thermal Operations Business Plan Summary
- OM&A Plan over Plan
- Capital Plan over Plan
- Hydro Development / [redacted]
- Project Expenditures on Existing Assets
- Staffing Profile and Headcount Plan Over Plan
- Headcount vs BTS Targets & Productivity
- [redacted]
- Strategic Initiative 1 - [redacted]
- Strategic Initiative 2 - [redacted]
- Key Business Risks
- Appendices

Hydro Thermal Operations Business Plan Thrusts

<u>Operate and Maintain Hydro & Thermal Plants with Focus on Sustaining & Regulatory Work</u>

- Maintain safe and reliable plant operations through prudent investment and maintenance strategy. Utilize a risk-based approach for determining investment priorities (ie, Plant Condition/Engineering Risk Assessments) and differentiated maintenance programs
- Minimize “value enhancing” work in this plan (ie, significant reductions /deferrals made in the 2013-2015 plan and this plan)
- Maintain/improve employee safety, dam safety, environmental and reliability performance.
- [redacted]
- Continue to strengthen and develop relationships with stakeholders to sustain continued operations at existing HTO facilities and to manage local impacts of coal closure

<u>Transform Hydro Thermal Operations into a Low Cost, Agile and Variable Business Model</u>

- Continue aggressive vacancy management during Business Planning period (replace “critical” staff only)
- Complete Phase 2 implementation of BTS centre-led model, including staff reductions & initiatives
- [redacted]
- Implement new Plant Work Management and Materials System (PWMMS - SAP to Asset Suite 7)
- Develop maintenance resourcing strategy that will optimize the productivity of maintenance staff across HTO and enable additional staff reductions (aligned with BTS and PWMMS)
- [redacted]
- Communicate/Implement new OPG Business Model and Behaviors

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Hydro Thermal Operations Business Plan Thrusts (cont'd)

Optimize Costs/Revenues

- Total plan over plan OM&A **reduction** of [redacted]. [redacted], aggressive vacancy management, and deferral of lower risk OM&A projects, but partially offset by increases in labour and payroll burdens, [redacted] and new NERC CIP requirements.
- Total plan over plan Capital cost **reduction** of [redacted]. Capital expenditures on existing assets and new developments reduced by [redacted] but this was partially offset primarily by new project for NERC CIP Cyber Security V5 [redacted] capital cost portion). HTO capital expenditures on existing assets average [redacted] per year.
- Recover costs through Cost of Service application for previously regulated and newly regulated Hydro assets and Niagara Tunnel.
- Develop and implement Incentive Regulation Mechanism for Hydro regulated assets per OEB schedule
- [redacted]

Grow the Business

- Support various Corporate Business Development in new generation opportunities [redacted] Ranney Falls, [redacted]
- Develop and support new external revenue opportunities (see appendix for opportunities/initiatives)

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Planning Assumptions (2014 to 2016)

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EB-2013-0321
Ex. N1-1-1
Attachment 6

Hydro

- Focus on regulatory and sustaining work during planning period.
- Existing Unregulated Hydro Assets assumed to be regulated effective July 1, 2014
- System-impactive Hydro unit refurbishment and outage programs completed prior to Darlington refurbishment outages (eg, Lower Notch Rehabilitation, Des Joachims Rehabilitation, SAB 1 Unit 10)
- PGS Reservoir rehabilitation and full station outage planned in 2016/17 to ensure continued safe operation.
- [redacted]

General

- Labour costs for implementation of new Plant Work Maintenance and Materials System (Asset Suite 7) in HTO plan.
- Development/[redacted] projects entering Execution Phase in 2014 are included in the HTO Business Plan
- [redacted]
- Provision for unsettled Aboriginal grievances included in Corporate Business Plan

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Hydro Thermal Operations Business Plan Summary

Highlights

- Energy and capacity decrease in 2014 due to coal closure, but then increase during the planning period due to full year of production from the Niagara Tunnel and [redacted]
- Energy increases from the Niagara Tunnel and [redacted] are significantly offset by Surplus Baseload Generation [redacted] Variance account for all regulated assets proposed by OPG in 2014-2015 OEB rate application to recover SBG losses.
- Hydro availability averages just under 92% during planning period. Major planned outage program continues in 2014-2016.
- Base OM&A decreases [redacted] The decreases are partially offset by significant increases in labour rates and burdens
- Project OM&A increases primarily during planning period due to major unit overhauls/refurbishments at Lower Notch GS, SAB PGS and [redacted] units.
- Capital costs average [redacted] per year during 2014 – 2016 period [redacted] and [redacted] for Operations)
- OM&A UEC and PUEC [redacted] from 2013 to 2016
- Staff numbers decline by [redacted] aggressive vacancy management and initial BTS reductions
- **Productivity (GWh/headcount) [redacted] over planning period**

	2013 Forecast	2014	2015	2016
PRODUCTION				
Capacity (MW)	[redacted]			
Hydro	7,072	7,154	7,446	7,457
Thermal	[redacted]			
Energy (TWh)				
Hydro (including SBG)				
Hydro SBG				
Thermal				
Hydro Availability (%)	91.6	91.7	91.8	91.5
Hydro EFOR (%)	1.7	1.5	1.5	1.5
Thermal Start Guarantee (%)	[redacted]			
EFOR (OP) (%)				
RESOURCES				
Total OM&A ($M)	[redacted]			
Base OM&A ($M)				
Project OM&A ($M)				
Total Capital ($M)				
Operations ($M)				
Niagara Tunnel ($M)	93	1	0	0
[redacted]				
PGS Reservoir Rehabilitation ($M)	0	0	8	80
[redacted]				
OM&A UEC ($/MWh)	[redacted]			
PUEC ($/MWh)				
Regular Staff				
Productivity (GWH/headcount)				

ONTARIOPOWER GENERATION

OM&A Plan over Plan

[redacted]

Capital Plan over Plan

CAPITAL ($M)	2013 Proj	2014	2015	2016	2013 to 2016 Change
Approved 2016 Guideline ($M)	[redacted]				
Operations Projects Changes					
SAB I G10 Unit Rehabilitation (deferred)	-1	-10	-5	15	0
DeCew Falls ND1 Station Electrical Upgrade (cancelled)	-1	-6	-5	0	-11
NERC CIP Cyber Security Upgrade Project Version 5 (Capital Portion)	[redacted]				
OSPG Headquarters (change from own to lease strategy-project cancelled)	0	-2	-7	0	-9
[redacted]	[redacted]				
Project Schedule Change (deferred, cancelled or advanced)	[redacted]				
Project Scope Changes	[redacted]				
Project Cost Changes (escalation and revised estimates)	[redacted]				
New Projects (from Plant Condition Assessments & ERAP)	[redacted]				
Other	[redacted]				
Total Operations Capital Project Changes	[redacted]				
Destiny Project Changes					
Niagara Tunnel Project (Cost Reduction)	-66	1	0	0	-65
[redacted]					
PGS Reservoir Rehab (Transferred from CBD)	0	0	8	-8	0
Total 2013 Capital Submission	[redacted]				
2014 Capital Submission versus 2016 Guideline	[redacted]				

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Hydro Development / Thermal Repowering Projects

Projects	Capacity MW	LUEC cents/kWh	2012 LTD	2013 YE Projection $M	2014 $M	2015 $M	2016 $M	2017 $M	2018 $M	Total $M
HTO Business Plan (Execution Phase)										
Niagara Tunnel Project	n/a	6.8	1,375	119	1	0	0	0	0	1,495
[redacted]										
SAB PGS Reservoir Rehabilitation	n/a	n/a	Definition Phase by CBD		0	8	80	0	0	88
[redacted]										
Total HTO	[redacted]									
CBD Business Plan (Definition Phase)										
[redacted]										
SAB PGS Reservoir Rehabilitation	n/a	n/a	4	3	Execution Phase by HTO					6
Ranney Falls	9	10 to 12	1	0	4	4	21	14	5	49
[redacted]										
Total CBD	[redacted]									

- Projects in execution phase are included in the HTO Business Plan. Projects in Definition Phase are included in the Corporate Business Development (CBD) Plan
- [redacted]
- Cost of SAB PGS Reservoir Rehabilitation reduced from $360 M to ~$100 M due to reduced work scope based on detailed geotechnical investigation and technical assessment (including Independent panel review)
- [redacted]
- [redacted] and Ranney Falls (Defintion & Execution Phases) are included in the CBD Business Plan. Ranney Falls costs are included in Hydro Rate application
- [redacted]

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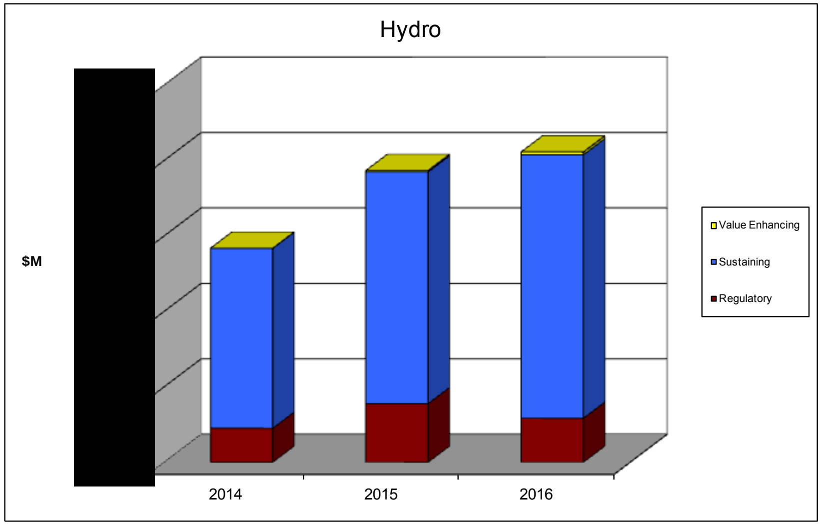
Project Expenditures on Existing Assets



[redacted]

- Continued re-investment for the long term safety and sustainment of the existing assets includes project expenditures averaging [redacted] per year (includes Capital and OM&A projects)
- Determination of investment levels and priorities are based on Plant Condition/Engineering Risk Assessments and inspections/testing, and consider station/fleet age , type of equipment, station role (peaking vs base), reliability targets, [redacted] and Joint Works with NYPA & Hydro Quebec) and business objectives and risks
- Hydro re-investment levels of ~0.5% to 1% of the "replacement cost" (excluding new facilities) are based on good utility practice, maintenance strategies, and assessment of physical composition (civil versus equipment) and remaining service lives of the assets.
- Major Hydro investments during planning period include:
  - replacement of ageing "power train components" such as turbines, generators, transformers
  - repairs, rehabilitation or replacement of ageing civil structures including powerhouses, penstocks, dams, sluiceways and bridges
  - replacement or refurbishment of sluicegates & stoplogs (regulatory/safety) and headgates
  - replacement of control equipment (automation) to improve efficiency and accommodate market dispatch requirements
- [redacted]

ONTARIO POWER GENERATION

Staffing Profile & Headcount Plan Over Plan

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EB-2013-0321
Ex. N1-1-1
Attachment 6

[redacted]

[redacted]

Headcount vs BTS Targets and Productivity

[redacted]

- [redacted]
- [redacted]
- [redacted]

ONTARIO POWER GENERATION

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

- [redacted]
- [redacted]

Strategic Initiative 1 - [redacted]

[redacted]

[redacted]

Strategic Initiative 1 - [redacted]

[redacted]

Strategic Initiative 2 - [redacted]

[redacted]

Strategic Initiative 2 - [redacted]

[redacted]

Key Business Risks

		Risk Ranking
1	Uncertainty of full cost recovery for Hydro Regulated Assets/Niagara Tunnel Project and Newly Regulated Hydro Assets	High
2	Aboriginal: Increasing complexity of role and potential cost increases for unsettled past grievances	Medium
3	[redacted]	
4	Environmental risks associated with Ontario Endangered Species Act and Federal Species at Risk Act (compliance may require physical improvement costs and/or impacts on production/revenue) ($100M)	Low
5	Implementation costs of new Provincial Dam Safety technical guidelines. Overall cost risk has been reduced compared to previously proposed MNR guidelines last year. Site specific impacts need to be assessed and could result in additional capital costs not included in plan ($100M to $400M)	Low
6	Increased cost and delayed completion of major development projects ([redacted])	Low
7	Increased costs due to new Heritage Act ($30M)	Low
8	New requirements for Permits to Take Water	Low
9	Uncertainty with future reliability of Hydro and Thermal plants associated with changing operating modes (eg, more stops and starts and gate operations due to SBG mitigation and wind integration)	Low
10	Structural and other operational risks associated with AAR induced concrete growth at Otto Holden and Saunders and ageing penstocks and other civil infrastructure (eg, bridges, sluiceways, etc.) in Hydro Fleet	Low
11	Underestimating Future Cost Escalation for Major Equipment and Civil Construction	Low
12	Cyber Security Attacks Impacting Hydro Thermal Process Control	Low

Appendices

Hydro Asset Profile

STATIONS PROFILE

NO. OF STATIONS	65
AVERAGE ENERGY	34.3 TWh/yr
CAPACITY	6996 MW
AVERAGE AGE	71 yrs
NO. OF GENERATING UNITS	234
SMALLEST / LARGEST UNIT	1 MW / 137 MW
NO. OF DAMS	228
BOOK VALUE OF ASSETS	$9 B (incl NTP)
RECONSTRUCTION COST	~40 B

PEOPLE / WORK CENTRES / LAND

PLANT GROUPS	5
WORK CENTRES	22
CONTROL CENTRES (includes International Control Dam Control Centre)	7
TOTAL STAFF (PG's only)	~980
OPERATORS	~105
NO. OF RIVER SYSTEMS	24
HYDRO OWNED LAND	~17,000 hectares
LEASED LAND (flooded)	~800, 000 hectares

ONTARIO POWER GENERATION

[redacted]

[redacted]

HTO Business Plan Summary Table

Hydro Thermal Operations Total	2013 Forecast	2014	2015	2016
Energy TW.h	[redacted]			
OM&A (M$)				
- Base				
- Projects (Totals from project listings)				
- Labour Rate & Burden Impact (WO3 - WO1)				
Capital & MFA (M$)				
- MFA				
- Projects (Totals from project listings)				
Total Regular Staff at YE				
- PWU				
- Society				
- Management Group				
Temporary Staff FTEs				
Fuel/GRC & Other Water Rentals (M$)				
Total Gross Labour ($M)				
- Total Gross Regular				
- Total Gross Temporary & Other				
- Overtime				
- Overtime (% of Gross labour)				
Incapability Factor %				
Planned Outage Factor (POF) %				
Hydro EFOR %				
Hydro Availability Factor %				
Thermal Start Guarantee %				
Thermal EFOR(Op) (%)				
OM&A UEC ($/MWh)				
GRC & Thermal Fuel UEC ($/MWh)				
PUEC ($/MW.h)				
Capacity (MW)				

ONTARIOPOWER GENERATION

Summary of Costs ($M) & Staff by Organization

Plant Group / Thermal Plant / CO Division	2014			2015			2016		
	OM&A	Capital	Staff	OM&A	Capital	Staff	OM&A	Capital	Staff
Ottawa/Madawaska	46.2	31.0	201	51.2	33.3	196	55.7	26.9	196
Saunders GS	21.0	13.0	68	23.2	8.7	68	24.1	8.1	68
Niagara PG	58.3	7.1	228	63.4	23.3	228	56.9	39.8	228
Northeast PG	[redacted]								
Central PG									
Northwest PG									
[redacted]									
Total PGs/Plants									
Engineering & Technical Services									
Dam & Public Safety									
Strategy & Bus Support (Total)									
SBS Division									
Thermal Overcomplement (SBS)									
SVP									
Total Central Office (CO)									
Total PGs/Plants/CO									
HT Project Execution									
Total HTO									

ONTARIO POWER GENERATION

Runner Replacement /Upgrade Program

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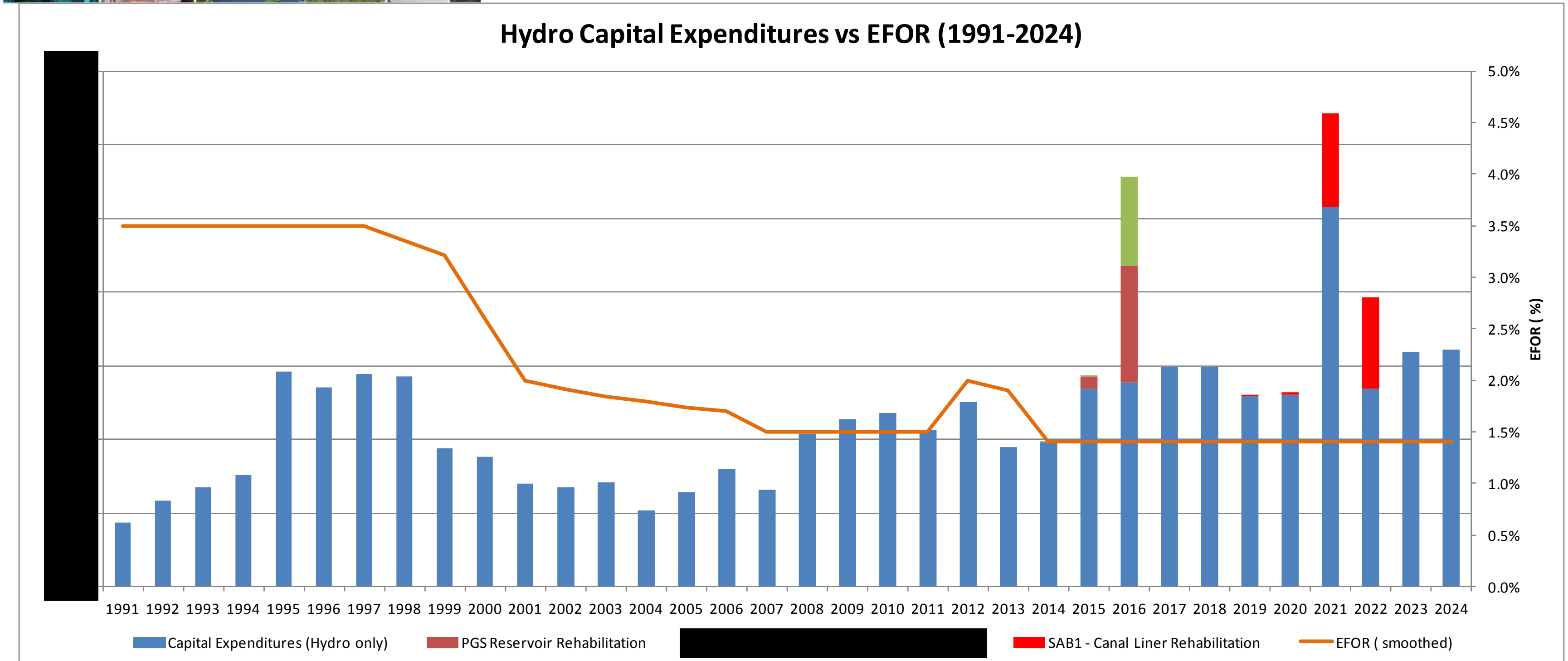
Ex. N1-1-1
Attachment 6

2014-2016 BP Runner Upgrades	Completed 1992 to 2012	2013 YE Forecast	2014	2015	2016	Total (2014 to 2016)	2017	2018	2019	2020	2021	2022	Total (2017 to 2022)
CAPACITY (MW)	464	[redacted]											
ENERGY (GWh)	887	[redacted]											
TOTAL CAPITAL COST (M$)	283	[redacted]											
OM&A COST (M$)	28	[redacted]											

1. Total Capital costs include cost of the runner plus cost of other work that is be required for sustaining purposes and to accommodate the upgraded runner during
2. OM&A costs includes all work required remove and install runner, perform mechanical overhaul, and other necessary maintenance done during outage.

- Last year, all runner replacements that were in the plan solely to enhance value (not sustaining) and had not been released, were deferred to the 2016 to 2020 period (eg Otter Rapids)
- From 2014 to 2016, capacity and energy are expected to increase by [redacted], respectively, as a result of runner upgrades
- From 1992 to the end of 2012, HTO will have realized an increase in capacity of 464 MW and 887 GWh, as a result of the runner upgrade program
- LUECs for past runner upgrades have ranged [redacted] cents/kWh. LUECs for future runner upgrades range [redacted] cents per kWh

Historical Hydro Capital vs EFOR



Note: Capital Costs in $ of the year

- From 1990 to 2003, large Hydro stations primarily built before 1958 were rehabilitated (eg, Saunders, SAB 2, Otto Holden, and Chenaux)
- From 2006 to 2020, remaining large stations have been, or will be rehabilitated (eg, Abitibi Canyon, Des Joachims, Decew Falls, Stewartville, Mountain Chute, Lower Notch, SAB 1, SAB PGS, Otto Holden)
- In addition, large civil projects (PGS Reservoir liner rehabilitation, [redacted] and SAB 1 canal rehabilitation) are planned
- The investment program, along with the Leading Edge Maintenance Program, has resulted in significant reliability (EFOR) improvements
- **With the expected increase of Surplus Baseload Generation and the resulting additional unit starts and stops, there is a risk that Hydro EFOR will exceed the target of [redacted] leading to lower than target Hydro Availability**

ONTARIO POWER GENERATION

[redacted]

[redacted]

[redacted]

[redacted]

Updated for Impact Statement Submitted December 6, 2013

EB-2013-0321
Revenue Requirement Work Form

Ontario Power Generation

Ontario Power Generation

EB-2013-0321 Revenue Requirement Work Form

Table of Contents

Worksheet

No.

Ontario Power Generation

EB-2013-0321 Revenue Requirement Work Form

Legend / Colour Scheme

(yellow)	OPG Proposed Amounts
(light blue)	Adjustment Input Cells For OEB Use
(green)	Automatically Generated Calculations

OEB Adjustment Input Sheet

Line No.	Description	Total Generating Facilities 2014 OPG Proposed (a)	2014 OEB Adjustment (b)	2014 OEB Approved (c)	2015 OPG Proposed (d)	2015 OEB Adjustment (e)	2015 OEB Approved (f)
	Capital Structure						
1	Common Equity	47.0%	0.0%	47.0%	47.0%	0.0%	47.0%
2	Debt	53.0%	0.0%	53.0%	53.0%	0.0%	53.0%
	Cost of Capital						
3	Short-Term Debt Facility Cost ($M)	3.8	-	3.8	3.8	-	3.8
4	Short-Term Debt Interest Cost ($M)	4.0	-	4.0	6.2	-	6.2
5	Short-Term Debt Cost ($M)	7.0	-	7.0	9.0	-	9.0
6	Regulated Portion of Short-Term Debt Cost Rate	89.41%	0.00%	89.41%	89.41%	0.00%	89.41%
7	Existing and Planned Long-Term Debt Cost Rate	4.85%	0.00%	4.85%	4.86%	0.00%	4.86%
8	Other Long-Term Debt Provision Cost Rate	4.85%	0.00%	4.85%	4.86%	0.00%	4.86%
9	Common Equity Cost Rate ROE	8.98%	0.00%	8.98%	8.98%	0.00%	8.98%
10	Adjustment for Lesser of UNL/ARC Cost Rate	5.37%	0.00%	5.37%	5.37%	0.00%	5.37%
	Capitalization ($M)						
11	Short-Term Debt Principal	192.2	-	192.2	192.2	-	192.2
12	Existing and Planned Long-Term Debt Principal	3,372.7	-	3,372.7	3,481.6	-	3,481.6
13	Adjustment for Lesser of UNL/ARC	1,389.5	-	1,389.5	1,308.8	-	1,308.8

Line No.	Description	Previously Regulated Hydroelectric Facilities 2014 OPG Proposed (a)	2014 OEB Adjustment (b)	2014 OEB Approved (c)	2015 OPG Proposed (d)	2015 OEB Adjustment (e)	2015 OEB Approved (f)	Total OPG Proposed (g)	Total OEB Adjustment (h)	Total OEB Approved (i)
	Rate Base ($M)									
14	Gross Plant at Cost	6,079.9	-	6,079.9	6,118.4	-	6,118.4	12,198.3	-	12,198.3
15	Accumulated Depreciation/Amortization	974.3	-	974.3	1,056.2	-	1,056.2	2,030.5	-	2,030.5
16	Cash Working Capital	21.7	-	21.7	21.7	-	21.7	43.4	-	43.4
17	Materials and Supplies	0.7	-	0.7	0.7	-	0.7	1.4	-	1.4
18	Nuclear Fuel Inventory	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
19	**Total**	**5,128.0**	**-**	**5,128.0**	**5,084.6**	**-**	**5,084.6**	**10,212.6**	**-**	**10,212.6**
	Expenses ($M)									
20	OM&A	149.2	-	149.2	144.2	-	144.2	293.5	-	293.5
21	GRC	267.2	-	267.2	280.8	-	280.8	548.0	-	548.0
22	Depreciation/Amortization	82.1	-	82.1	81.9	-	81.9	164.0	-	164.0
23	Property Taxes	0.3	-	0.3	0.3	-	0.3	0.6	-	0.6
24	**Total**	**498.8**	**-**	**498.8**	**507.2**	**-**	**507.2**	**1,006.1**	**-**	**1,006.1**
	Other Revenues ($M)									
25	Bruce Lease Revenues Net of Direct Costs	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
26	Ancillary and Other Revenue	34.0	-	34.0	34.6	-	34.6	68.6	-	68.6
27	**Total**	**34.0**	**-**	**34.0**	**34.6**	**-**	**34.6**	**68.6**	**-**	**68.6**
28	**Forecast Production** (TWh)	**20.1**	**-**	**20.1**	**21.0**	**-**	**21.0**	**41.1**	**-**	**41.1**

OEB Adjustment Input Sheet

Line No.	Description	Newly Regulated Hydroelectric Facilities 2014 OPG Proposed (a)	2014 OEB Adjustment (b)	2014 OEB Approved (c)	2015 OPG Proposed (d)	2015 OEB Adjustment (e)	2015 OEB Approved (f)	Total OPG Proposed (g)	Total OEB Adjustment (h)	Total OEB Approved (i)
	Rate Base ($M)									
29	Gross Plant at Cost	3,275.1	-	3,275.1	3,347.7	-	3,347.7	6,622.9	-	6,622.9
30	Accumulated Depreciation/Amortization	772.6	-	772.6	828.5	-	828.5	1,601.2	-	1,601.2
31	Cash Working Capital	8.3	-	8.3	8.3	-	8.3	16.5	-	16.5
32	Materials and Supplies	0.7	-	0.7	0.7	-	0.7	1.4	-	1.4
33	Nuclear Fuel Inventory	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
34	**Total**	**2,511.5**	**-**	**2,511.5**	**2,528.2**	**-**	**2,528.2**	**5,039.7**	**-**	**5,039.7**
	Expenses ($M)									
35	OM&A	239.3	-	239.3	242.6	-	242.6	482.0	-	482.0
36	GRC	75.6	-	75.6	77.5	-	77.5	153.1	-	153.1
37	Depreciation/Amortization	62.2	-	62.2	63.1	-	63.1	125.3	-	125.3
38	Property Taxes	0.1	-	0.1	0.1	-	0.1	0.2	-	0.2
39	**Total**	**377.3**	**-**	**377.3**	**383.3**	**-**	**383.3**	**760.6**	**-**	**760.6**
	Other Revenues ($M)									
40	Bruce Lease Revenues Net of Direct Costs	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
41	Ancillary and Other Revenue	22.7	-	22.7	23.1	-	23.1	45.8	-	45.8
42	**Total**	**22.7**	**-**	**22.7**	**23.1**	**-**	**23.1**	**45.8**	**-**	**45.8**
43	**Forecast Production**[1] (TWh)	**5.5**	**-**	**5.5**	**12.5**	**-**	**12.5**	**17.9**	**-**	**17.9**

Line No.	Description	Nuclear Facilities 2014 OPG Proposed (a)	2014 OEB Adjustment (b)	2014 OEB Approved (c)	2015 OPG Proposed (d)	2015 OEB Adjustment (e)	2015 OEB Approved (f)	Total OPG Proposed (g)	Total OEB Adjustment (h)	Total OEB Approved (i)
	Rate Base ($M)									
44	Gross Plant at Cost	6,262.8	-	6,262.8	6,510.7	-	6,510.7	12,773.5	-	12,773.5
45	Accumulated Depreciation/Amortization	3,299.0	-	3,299.0	3,580.1	-	3,580.1	6,879.1	-	6,879.1
46	Cash Working Capital	32.0	-	32.0	32.0	-	32.0	64.0	-	64.0
47	Materials and Supplies	427.2	-	427.2	422.0	-	422.0	849.2	-	849.2
48	Nuclear Fuel Inventory	283.6	-	283.6	274.4	-	274.4	558.0	-	558.0
49	**Total**	**3,706.7**	**-**	**3,706.7**	**3,659.0**	**-**	**3,659.0**	**7,365.7**	**-**	**7,365.7**
	Expenses ($M)									
50	OM&A	2,491.8	-	2,491.8	2,531.3	-	2,531.3	5,023.0	-	5,023.0
51	Fuel	268.6	-	268.6	260.5	-	260.5	529.0	-	529.0
52	Depreciation/Amortization	273.7	-	273.7	288.5	-	288.5	562.3	-	562.3
53	Property Taxes	15.9	-	15.9	16.4	-	16.4	32.4	-	32.4
54	**Total**	**3,050.0**	**-**	**3,050.0**	**3,096.7**	**-**	**3,096.7**	**6,146.7**	**-**	**6,146.7**
	Other Revenues ($M)									
55	Bruce Lease Revenues Net of Direct Costs	39.7	-	39.7	40.6	-	40.6	80.3	-	80.3
56	Ancillary and Other Revenue	33.2	-	33.2	30.5	-	30.5	63.7	-	63.7
57	**Total**	**72.9**	**-**	**72.9**	**71.1**	**-**	**71.1**	**144.0**	**-**	**144.0**
58	**Forecast Production** (TWh)	**49.0**	**-**	**49.0**	**46.1**	**-**	**46.1**	**95.1**	**-**	**95.1**

OEB Adjustment Input Sheet

Line No.	Description	Total Generating Facilities 2014 OPG Proposed	2014 OEB Adjustment	2014 OEB Approved	2015 OPG Proposed	2015 OEB Adjustment	2015 OEB Approved	Total OPG Proposed	Total OEB Adjustment	Total OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Rate Base ($M)									
59	Gross Plant at Cost	15,617.8	-	15,617.8	15,976.9	-	15,976.9	31,594.7	-	31,594.7
60	Accumulated Depreciation/Amortization	5,045.9	-	5,045.9	5,464.8	-	5,464.8	10,510.7	-	10,510.7
61	Cash Working Capital	62.0	-	62.0	62.0	-	62.0	123.9	-	123.9
62	Materials and Supplies	428.6	-	428.6	423.4	-	423.4	852.0	-	852.0
63	Nuclear Fuel Inventory	283.6	-	283.6	274.4	-	274.4	558.0	-	558.0
64	**Total**	**11,346.1**	**-**	**11,346.1**	**11,271.8**	**-**	**11,271.8**	**22,617.9**	**-**	**22,617.9**
	Expenses ($M)									
65	OM&A	2,880.3	-	2,880.3	2,918.1	-	2,918.1	5,798.4	-	5,798.4
66	Fuel and GRC	611.4	-	611.4	618.8	-	618.8	1,230.2	-	1,230.2
67	Depreciation/Amortization	418.0	-	418.0	433.6	-	433.6	851.6	-	851.6
68	Property Taxes	16.3	-	16.3	16.8	-	16.8	33.2	-	33.2
69	**Total**	**3,926.1**	**-**	**3,926.1**	**3,987.3**	**-**	**3,987.3**	**7,913.4**	**-**	**7,913.4**
	Other Revenues ($M)									
70	Bruce Lease Revenues Net of Direct Costs	39.7	-	39.7	40.6	-	40.6	80.3	-	80.3
71	Ancillary and Other Revenue	89.8	-	89.8	88.2	-	88.2	178.0	-	178.0
72	**Total**	**129.5**	**-**	**129.5**	**128.8**	**-**	**128.8**	**258.3**	**-**	**258.3**
73	**Forecast Production** (TWh)	**74.6**	**-**	**74.6**	**79.6**	**-**	**79.6**	**154.2**	**-**	**154.2**

Line No.	Description	Regulatory Income Taxes 2014 OPG Proposed	2014 OEB Adjustment	2014 OEB Approved	2015 OPG Proposed	2015 OEB Adjustment	2015 OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)
	Applicable Tax Rates						
74	Federal Rate	15.00%	0.00%	15.00%	15.00%	0.00%	15.00%
75	Provincial Rate	11.00%	0.00%	11.00%	11.00%	0.00%	11.00%
76	Provincial Manufacturing & Processing Profits Deduction	-1.00%	0.00%	-1.00%	-1.00%	0.00%	-1.00%
77	**Total Tax Rate**	**25.00%**	**0.00%**	**25.00%**	**25.00%**	**0.00%**	**25.00%**
	Tax Credits and Payment Adjustments ($M)						
78	SR&ED Investment	(10.4)	-	(10.4)	(10.4)	-	(10.4)
79	Single Payments Amount Adjustment	12.3	-	12.3	(12.3)	-	(12.3)
	Taxable Income Adjustments ($M)						
	Additions						
80	Depreciation and Amortization	418.0	-	418.0	433.6	-	433.6
81	Nuclear Waste Management Expenses	59.3	-	59.3	62.2	-	62.2
82	Receipts from Nuclear Segregated Funds	62.6	-	62.6	116.5	-	116.5
83	Pension and OPEB/SPP Accrual	682.0	-	682.0	672.7	-	672.7
84	Regulatory Asset Amortization - Bruce Lease Net Revenues Variance	41.9	-	41.9	-	-	-
85	Regulatory Liability Amortization - Income and Other Taxes Variance	(12.4)	-	(12.4)	-	-	-
86	Adjustment Related to Financing Cost for Nuclear Liabilities	74.6	-	74.6	70.3	-	70.3
87	Taxable SR&ED Investment Tax Credits of Prior Periods	14.8	-	14.8	10.4	-	10.4
88	Other	45.9	-	45.9	49.7	-	49.7
89	**Total Additions**	**1,386.7**	**-**	**1,386.7**	**1,415.4**	**-**	**1,415.4**
	Deductions						
90	CCA	419.0	-	419.0	467.0	-	467.0
91	Cash Expenditures for Nuclear Waste & Decommissioning	148.8	-	148.8	197.6	-	197.6
92	Contributions to Nuclear Segregated Funds	170.1	-	170.1	172.8	-	172.8
93	Pension Plan Contributions	238.0	-	238.0	340.2	-	340.2
94	OPEB/SPP Payments	99.7	-	99.7	106.5	-	106.5
95	Other	0.5	-	0.5	0.5	-	0.5
96	**Total Deductions**	**1,076.1**	**-**	**1,076.1**	**1,284.6**	**-**	**1,284.6**

OEB Adjustment Input Sheet

Line No.	Description	Deferral and Variance Account Recovery 2015					
		Projected Balance at December 31, 2013			Recovery Period (Months)		
		OPG Proposed	OEB Adjustment	OEB Approved	OPG Proposed	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)
	Previously Regulated Hydroelectric Facilities ($M)						
97	Capacity Refurbishment Variance	114.4	-	114.4	24	-	24
98	Hydroelectric Incentive Mechanism Variance	(2.4)	-	(2.4)	12	-	12
99	Surplus Baseload Generation Variance	8.1	-	8.1	12	-	12
100	**Total**	120.1	-	120.1	n/a	n/a	n/a
	Nuclear Facilities ($M)						
101	Capacity Refurbishment Variance - Capital Portion	3.7	-	3.7	12	-	12
102	Nuclear Development Variance	69.4	-	69.4	12	-	12
103	**Total**	73.1	-	73.1	n/a	n/a	n/a

1 Newly Regulated Hydroelectric Facilities 18 month (July 2014 - December 2015) test period forcast production

OPG Rate Base and Cost of Capital

Line No.	Description	Total Generating Facilities 2014 OPG Proposed	2014 OEB Adjustment	2014 OEB Approved	2015 OPG Proposed	2015 OEB Adjustment	2015 OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)
1	Previously Regulated Hydroelectric Rate Base ($M)	5,128.0	-	5,128.0	5,084.6	-	5,084.6
2	Newly Regulated Hydroelectric Rate Base ($M)	2,511.5	-	2,511.5	2,528.2	-	2,528.2
3	Nuclear Rate Base Financed by Capital Structure ($M)	2,317.2	-	2,317.2	2,350.2	-	2,350.2
4	Previously Regulated Hydroelectric Allocation factor	51.50%	0.00%	51.50%	51.03%	0.00%	51.03%
5	Newly Regulated Hydroelectric Allocation Factor	25.22%	0.00%	25.22%	25.38%	0.00%	25.38%
6	Nuclear Allocation Factor	23.27%	0.00%	23.27%	23.59%	0.00%	23.59%

Line No.	Description	Previously Regulated Hydroelectric Facilities 2014 OPG Proposed	2014 OEB Adjustment	2014 OEB Approved	2015 OPG Proposed	2015 OEB Adjustment	2015 OEB Approved	Total OPG Proposed	Total OEB Adjustment	Total OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Capitalization ($M)									
7	Total Rate Base	5,128.0	-	5,128.0	5,084.6	-	5,084.6	10,212.6	-	10,212.6
8	Adjustment for Lesser of UNL/ARC	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
9	**Rate Base Financed by Capital Structure**	**5,128.0**	**-**	**5,128.0**	**5,084.6**	**-**	**5,084.6**	**10,212.6**	**-**	**10,212.6**
10	**Common Equity**	**2,410.1**	**-**	**2,410.1**	**2,389.8**	**-**	**2,389.8**	**4,799.9**	**-**	**4,799.9**
11	Total Debt	2,717.8	-	2,717.8	2,694.8	-	2,694.8	5,412.7	-	5,412.7
12	Short-Term Debt	99.0	-	99.0	98.1	-	98.1	197.1	-	197.1
13	Existing and Planned Long-Term Debt	1,737.0	-	1,737.0	1,776.8	-	1,776.8	3,513.8	-	3,513.8
14	**Other Long-Term Debt Provision**	**881.8**	**-**	**881.8**	**819.9**	**-**	**819.9**	**1,701.7**	**-**	**1,701.7**
	Cost of Capital ($M)									
15	Adjustment for Lesser of UNL/ARC	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
16	**Common Equity**	**216.4**	**-**	**216.4**	**214.6**	**-**	**214.6**	**431.0**	**-**	**431.0**
17	Existing and Planned Long-Term Debt	84.2	-	84.2	86.4	-	86.4	170.6	-	170.6
18	Other Long-Term Debt Provision	42.8	-	42.8	39.8	-	39.8	82.6	-	82.6

Line No.	Description	Newly Regulated Hydroelectric Facilities 2014 OPG Proposed	2014 OEB Adjustment	2014 OEB Approved	2015 OPG Proposed	2015 OEB Adjustment	2015 OEB Approved	Total OPG Proposed	Total OEB Adjustment	Total OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Capitalization ($M)									
19	Total Rate Base	2,511.5	-	2,511.5	2,528.2	-	2,528.2	5,039.7	-	5,039.7
20	Adjustment for Lesser of UNL/ARC	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
21	**Rate Base Financed by Capital Structure**	**2,511.5**	**-**	**2,511.5**	**2,528.2**	**-**	**2,528.2**	**5,039.7**	**-**	**5,039.7**
22	**Common Equity**	**1,180.4**	**-**	**1,180.4**	**1,188.2**	**-**	**1,188.2**	**2,368.6**	**-**	**2,368.6**
23	Total Debt	1,331.1	-	1,331.1	1,339.9	-	1,339.9	2,671.0	-	2,671.0
24	Short-Term Debt	48.5	-	48.5	48.8	-	48.8	97.3	-	97.3
25	Existing and Planned Long-Term Debt	850.7	-	850.7	883.5	-	883.5	1,734.2	-	1,734.2
26	**Other Long-Term Debt Provision**	**431.9**	**-**	**431.9**	**407.7**	**-**	**407.7**	**839.6**	**-**	**839.6**
	Cost of Capital ($M)									
27	Adjustment for Lesser of UNL/ARC	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
28	**Common Equity**	**106.0**	**-**	**106.0**	**106.7**	**-**	**106.7**	**212.7**	**-**	**212.7**
29	Existing and Planned Long-Term Debt	41.3	-	41.3	42.9	-	42.9	84.2	-	84.2
30	Other Long-Term Debt Provision	20.9	-	20.9	19.8	-	19.8	40.8	-	40.8

OPG Rate Base and Cost of Capital

Line No.	Description	Nuclear Facilities 2014 OPG Proposed	2014 OEB Adjustment	2014 OEB Approved	2015 OPG Proposed	2015 OEB Adjustment	2015 OEB Approved	Total OPG Proposed	Total OEB Adjustment	Total OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Capitalization ($M)									
31	Total Rate Base	3,706.7	-	3,706.7	3,659.0	-	3,659.0	7,365.7	-	7,365.7
32	Adjustment for Lesser of UNL/ARC	1,389.5	-	1,389.5	1,308.8	-	1,308.8	2,698.2	-	2,698.2
33	**Rate Base Financed by Capital Structure**	**2,317.2**	**-**	**2,317.2**	**2,350.2**	**-**	**2,350.2**	**4,667.4**	**-**	**4,667.4**
34	**Common Equity**	**1,089.1**	**-**	**1,089.1**	**1,104.6**	**-**	**1,104.6**	**2,193.7**	**-**	**2,193.7**
35	Total Debt	1,228.1	-	1,228.1	1,245.6	-	1,245.6	2,473.7	-	2,473.7
36	Short-Term Debt	44.7	-	44.7	45.3	-	45.3	90.1	-	90.1
37	Existing and Planned Long-Term Debt	784.9	-	784.9	821.3	-	821.3	1,606.2	-	1,606.2
38	**Other Long-Term Debt Provision**	**398.5**	**-**	**398.5**	**379.0**	**-**	**379.0**	**777.5**	**-**	**777.5**
	Cost of Capital ($M)									
39	Adjustment for Lesser of UNL/ARC	74.6	-	74.6	70.3	-	70.3	144.9	-	144.9
40	**Common Equity**	**97.8**	**-**	**97.8**	**99.2**	**-**	**99.2**	**197.0**	**-**	**197.0**
41	Existing and Planned Long-Term Debt	38.1	-	38.1	39.9	-	39.9	78.0	-	78.0
42	Other Long-Term Debt Provision	19.3	-	19.3	18.4	-	18.4	37.7	-	37.7

Line No.	Description	Total Generating Facilities 2014 OPG Proposed	2014 OEB Adjustment	2014 OEB Approved	2015 OPG Proposed	2015 OEB Adjustment	2015 OEB Approved	Total OPG Proposed	Total OEB Adjustment	Total OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Capitalization ($M)									
43	Total Rate Base	11,346.1	-	11,346.1	11,271.8	-	11,271.8	22,617.9	-	22,617.9
44	Adjustment for Lesser of UNL/ARC	1,389.5	-	1,389.5	1,308.8	-	1,308.8	2,698.2	-	2,698.2
45	**Rate Base Financed by Capital Structure**	**9,956.7**	**-**	**9,956.7**	**9,963.0**	**-**	**9,963.0**	**19,919.7**	**-**	**19,919.7**
46	**Common Equity**	**4,679.6**	**-**	**4,679.6**	**4,682.6**	**-**	**4,682.6**	**9,362.2**	**-**	**9,362.2**
47	Total Debt	5,277.0	-	5,277.0	5,280.4	-	5,280.4	10,557.4	-	10,557.4
48	Short-Term Debt	192.2	-	192.2	192.2	-	192.2	384.4	-	384.4
49	Existing and Planned Long-Term Debt	3,372.7	-	3,372.7	3,481.6	-	3,481.6	6,854.2	-	6,854.2
50	**Other Long-Term Debt Provision**	**1,712.1**	**-**	**1,712.1**	**1,606.6**	**-**	**1,606.6**	**3,318.8**	**-**	**3,318.8**
	Cost of Capital ($M)									
51	Adjustment for Lesser of UNL/ARC	74.6	-	74.6	70.3	-	70.3	144.9	-	144.9
52	**Common Equity**	**420.2**	**-**	**420.2**	**420.5**	**-**	**420.5**	**840.7**	**-**	**840.7**
53	Existing and Planned Long-Term Debt	163.6	-	163.6	169.2	-	169.2	332.8	-	332.8
54	Other Long-Term Debt Provision	83.0	-	83.0	78.1	-	78.1	161.1	-	161.1

OPG Regulatory Income Taxes

Line No.	Description	Total Generating Facilities 2014 OPG Proposed	2014 OEB Adjustment	2014 OEB Approved	2015 OPG Proposed	2015 OEB Adjustment	2015 OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)
	Applicable Tax Rates						
1	Federal Rate	15.00%	0.00%	15.00%	15.00%	0.00%	15.00%
2	Provincial Rate	11.00%	0.00%	11.00%	11.00%	0.00%	11.00%
3	Provincial Manufacturing & Processing Profits Deduction	-1.00%	0.00%	-1.00%	-1.00%	0.00%	-1.00%
4	**Total Tax Rate**	**25.00%**	0.00%	**25.00%**	**25.00%**	0.00%	**25.00%**
	Taxable Income ($M)						
5	Earnings Before Tax	613.5	-	613.5	519.8	-	519.8
6	Adjustments: Additions	1,386.7	-	1,386.7	1,415.4	-	1,415.4
7	Adjustments: Deductions	1,076.1	-	1,076.1	1,284.6	-	1,284.6
8	**Total Taxable Income**	**924.1**	**-**	**924.1**	**650.6**	**-**	**650.6**
	Income Taxes ($M)						
9	Federal Income Taxes	138.6	0.0	138.6	97.6	0.0	97.6
10	Provincial Income Taxes	92.4	0.0	92.4	65.1	0.0	65.1
11	Tax Credits (SR&ED Investment)	(10.4)	0.0	(10.4)	(10.4)	0.0	(10.4)
12	**Total Income Taxes**	**220.6**	**0.0**	**220.6**	**152.3**	**0.0**	**152.3**
	Earnings Before Tax ($M)						
13	**Requested After Tax ROE**	**420.2**	**-**	**420.2**	**420.5**	**-**	**420.5**
14	Bruce Lease Net Revenues	39.7	-	39.7	40.6	-	40.6
15	Income Taxes	220.6	-	220.6	152.3	-	152.3
16	Single Payments Amount Adjustment	12.3	-	12.3	(12.3)	-	(12.3)
17	**Total Earnings Before Tax**	**613.5**	**-**	**613.5**	**519.8**	**-**	**519.8**
	Adjustments ($M)						
	Additions						
18	Depreciation and Amortization	418.0	-	418.0	433.6	-	433.6
19	Nuclear Waste Management Expenses	59.3	-	59.3	62.2	-	62.2
20	Receipts from Nuclear Segregated Funds	62.6	-	62.6	116.5	-	116.5
21	Pension and OPEB/SPP Accrual	682.0	-	682.0	672.7	-	672.7
22	Regulatory Asset Amortization - Bruce Lease Net Revenues Variance	41.9	-	41.9	-	-	-
23	Regulatory Liability Amortization - Income and Other Taxes Variance	(12.4)	-	(12.4)	-	-	-
24	Adjustment Related to Financing Cost for Nuclear Liabilities	74.6	-	74.6	70.3	-	70.3
25	Taxable SR&ED Investment Tax Credits of Prior Periods	14.8	-	14.8	10.4	-	10.4
26	Other	45.9	-	45.9	49.7	-	49.7
27	**Total Additions**	**1,386.7**	**-**	**1,386.7**	**1,415.4**	**-**	**1,415.4**
	Deductions						
28	CCA	419.0	-	419.0	467.0	-	467.0
29	Cash Expenditures for Nuclear Waste & Decommissioning	148.8	-	148.8	197.6	-	197.6
30	Contributions to Nuclear Segregated Funds	170.1	-	170.1	172.8	-	172.8
31	Pension Plan Contributions	238.0	-	238.0	340.2	-	340.2
32	OPEB/SPP Payments	99.7	-	99.7	106.5	-	106.5
33	Other	0.5	-	0.5	0.5	-	0.5
34	**Total Deductions**	**1,076.1**	**-**	**1,076.1**	**1,284.6**	**-**	**1,284.6**

OPG Revenue Requirement

Line No.	Description	Previously Regulated Hydroelectric Facilities								
		2014			2015			Total		
		OPG Proposed	OEB Adjustment	OEB Approved	OPG Proposed	OEB Adjustment	OEB Approved	OPG Proposed	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Cost of Capital ($M)									
1	Short-term Debt	3.6	0.0	3.6	4.6	0.0	4.6	8.2	0.0	8.2
2	Long-Term Debt	127.0	0.0	127.0	126.2	0.0	126.2	253.2	0.0	253.2
3	ROE	216.4	0.0	216.4	214.6	0.0	214.6	431.0	0.0	431.0
4	Adjustment for Lesser of UNL/ARC	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
5	**Total**	**347.1**	0.0	**347.1**	**345.4**	0.0	**345.4**	692.4	0.0	692.4
	Expenses ($M)									
6	OM&A	149.2	0.0	149.2	144.2	0.0	144.2	293.5	0.0	293.5
7	GRC	267.2	0.0	267.2	280.8	0.0	280.8	548.0	0.0	548.0
8	Depreciation/Amortization	82.1	0.0	82.1	81.9	0.0	81.9	164.0	0.0	164.0
9	Property Taxes	0.3	0.0	0.3	0.3	0.0	0.3	0.6	0.0	0.6
10	**Total**	**498.8**	0.0	**498.8**	**507.2**	0.0	**507.2**	**1,006.1**	0.0	**1,006.1**
	Other Revenues ($M)									
11	Bruce Lease Net Revenues	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
12	Ancillary and Other Revenue	34.0	0.0	34.0	34.6	0.0	34.6	68.6	0.0	68.6
13	**Total**	**34.0**	0.0	**34.0**	**34.6**	0.0	**34.6**	**68.6**	0.0	**68.6**
14	**Regulatory Income Tax** ($M)	**48.0**	0.0	**48.0**	**61.8**	0.0	**61.8**	**109.8**	0.0	**109.8**
15	**Revenue Requirement** ($M)	**860.0**	0.0	**860.0**	**879.8**	0.0	**879.8**	**1,739.7**	0.0	**1,739.7**

Line No.	Description	Newly Regulated Hydroelectric Facilities								
		2014			2015			Total		
		OPG Proposed	OEB Adjustment	OEB Approved	OPG Proposed	OEB Adjustment	OEB Approved	OPG Proposed	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Cost of Capital ($M)									
16	Short-term Debt	1.8	0.0	1.8	2.3	0.0	2.3	4.0	0.0	4.0
17	Long-Term Debt	62.2	0.0	62.2	62.7	0.0	62.7	125.0	0.0	125.0
18	ROE	106.0	0.0	106.0	106.7	0.0	106.7	212.7	0.0	212.7
19	Adjustment for Lesser of UNL/ARC	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
20	**Total**	**170.0**	0.0	**170.0**	**171.7**	0.0	**171.7**	**341.7**	0.0	**341.7**
	Expenses ($M)									
21	OM&A	239.3	0.0	239.3	242.6	0.0	242.6	482.0	0.0	482.0
22	GRC	75.6	0.0	75.6	77.5	0.0	77.5	153.1	0.0	153.1
23	Depreciation/Amortization	62.2	0.0	62.2	63.1	0.0	63.1	125.3	0.0	125.3
24	Property Taxes	0.1	0.0	0.1	0.1	0.0	0.1	0.2	0.0	0.2
25	**Total**	**377.3**	0.0	**377.3**	**383.3**	0.0	**383.3**	**760.6**	0.0	**760.6**
	Other Revenues ($M)									
26	Bruce Lease Net Revenues	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	Ancillary and Other Revenue	22.7	0.0	22.7	23.1	0.0	23.1	45.8	0.0	45.8
28	**Total**	**22.7**	0.0	**22.7**	**23.1**	0.0	**23.1**	**45.8**	0.0	**45.8**
29	**Regulatory Income Tax** ($M)	**30.6**	0.0	**30.6**	**43.8**	0.0	**43.8**	**74.5**	0.0	**74.5**
30	**Revenue Requirement** ($M)	**555.2**	0.0	**555.2**	**575.8**	0.0	**575.8**	**1,131.0**	0.0	**1,131.0**

OPG Revenue Requirement

Line No.	Description	Nuclear Facilities 2014 OPG Proposed (a)	2014 OEB Adjustment (b)	2014 OEB Approved (c)	2015 OPG Proposed (d)	2015 OEB Adjustment (e)	2015 OEB Approved (f)	Total OPG Proposed (g)	Total OEB Adjustment (h)	Total OEB Approved (i)
	Cost of Capital ($M)									
31	Short-term Debt	1.6	0.0	1.6	2.1	0.0	2.1	3.7	0.0	3.7
32	Long-Term Debt	57.4	0.0	57.4	58.3	0.0	58.3	115.7	0.0	115.7
33	ROE	97.8	0.0	97.8	99.2	0.0	99.2	197.0	0.0	197.0
34	Adjustment for Lesser of UNL/ARC	74.6	0.0	74.6	70.3	0.0	70.3	144.9	0.0	144.9
35	**Total**	**231.4**	0.0	**231.4**	**229.9**	0.0	**229.9**	**461.4**	0.0	**461.4**
	Expenses ($M)									
36	OM&A	2,491.8	0.0	2,491.8	2,531.3	0.0	2,531.3	5,023.0	0.0	5,023.0
37	Fuel	268.6	0.0	268.6	260.5	0.0	260.5	529.0	0.0	529.0
38	Depreciation/Amortization	273.7	0.0	273.7	288.5	0.0	288.5	562.3	0.0	562.3
39	Property Taxes	15.9	0.0	15.9	16.4	0.0	16.4	32.4	0.0	32.4
40	**Total**	**3,050.0**	0.0	**3,050.0**	**3,096.7**	0.0	**3,096.7**	**6,146.7**	0.0	**6,146.7**
	Other Revenues ($M)									
41	Bruce Lease Net Revenues	39.7	0.0	39.7	40.6	0.0	40.6	80.3	0.0	80.3
42	Ancillary and Other Revenue	33.2	0.0	33.2	30.5	0.0	30.5	63.7	0.0	63.7
43	**Total**	**72.9**	0.0	**72.9**	**71.1**	0.0	**71.1**	**144.0**	0.0	**144.0**
44	**Regulatory Income Tax** ($M)	**132.8**	0.0	**132.8**	**51.9**	0.0	**51.9**	**184.7**	0.0	**184.7**
45	**Revenue Requirement** ($M)	**3,341.4**	0.0	**3,341.4**	**3,307.4**	0.0	**3,307.4**	**6,648.8**	0.0	**6,648.8**

Line No.	Description	Total Generating Facilities 2014 OPG Proposed (a)	2014 OEB Adjustment (b)	2014 OEB Approved (c)	2015 OPG Proposed (d)	2015 OEB Adjustment (e)	2015 OEB Approved (f)	Total OPG Proposed (g)	Total OEB Adjustment (h)	Total OEB Approved (i)
	Cost of Capital ($M)									
46	Short-term Debt	7.0	0.0	7.0	9.0	0.0	9.0	16.0	0.0	16.0
47	Long-Term Debt	246.6	0.0	246.6	247.3	0.0	247.3	493.9	0.0	493.9
48	ROE	420.2	0.0	420.2	420.5	0.0	420.5	840.7	0.0	840.7
49	Adjustment for Lesser of UNL/ARC	74.6	0.0	74.6	70.3	0.0	70.3	144.9	0.0	144.9
50	**Total**	**748.5**	0.0	**748.5**	**747.0**	0.0	**747.0**	**1,495.5**	0.0	**1,495.5**
	Expenses ($M)									
51	OM&A	2,880.3	0.0	2,880.3	2,918.1	0.0	2,918.1	5,798.4	0.0	5,798.4
52	Fuel and GRC	611.4	0.0	611.4	618.8	0.0	618.8	1,230.2	0.0	1,230.2
53	Depreciation/Amortization	418.0	0.0	418.0	433.6	0.0	433.6	851.6	0.0	851.6
54	Property Taxes	16.3	0.0	16.3	16.8	0.0	16.8	33.2	0.0	33.2
55	**Total**	**3,926.1**	0.0	**3,926.1**	**3,987.3**	0.0	**3,987.3**	**7,913.4**	0.0	**7,913.4**
	Other Revenues ($M)									
56	Bruce Lease Net Revenues	39.7	0.0	39.7	40.6	0.0	40.6	80.3	0.0	80.3
57	Ancillary and Other Revenue	89.8	0.0	89.8	88.2	0.0	88.2	178.0	0.0	178.0
58	**Total**	**129.5**	0.0	**129.5**	**128.8**	0.0	**128.8**	**258.3**	0.0	**258.3**
59	**Regulatory Income Tax** ($M)	**211.5**	0.0	**211.5**	**157.5**	0.0	**157.5**	**369.0**	0.0	**369.0**
60	**Revenue Requirement** ($M)	**4,756.6**	0.0	**4,756.6**	**4,762.9**	0.0	**4,762.9**	**9,519.5**	0.0	**9,519.5**

OPG Revenue Requirement Deficiency / (Sufficiency)

Line No.	Description	Previously Regulated Hydroelectric Facilities 2014 OPG Proposed	2014 OEB Adjustment	2014 OEB Approved	2015 OPG Proposed	2015 OEB Adjustment	2015 OEB Approved	Total Test Period OPG Proposed	Total Test Period OEB Adjustment	Total Test Period OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Production & Revenue									
1	Forecast Production (TWh)	20.1	0.0	20.1	21.0	0.0	21.0	41.1	0.0	41.1
2	Current Payment Rate ($/MWh)	35.78	n/a	35.78	35.78	n/a	35.78	n/a	n/a	n/a
3	**Revenue From Current Payment Rate ($M)**	**718.6**	**0.0**	**718.6**	**752.4**	**0.0**	**752.4**	**1,471.1**	**0.0**	**1,471.1**
	Revenue Requirement									
4	Revenue Requirement ($M)	860.0	0.0	860.0	879.8	0.0	879.8	1,739.7	0.0	1,739.7
5	**Revenue Requirement Deficiency (Sufficiency)** ($M)	**141.3**	0.0	**141.3**	**127.3**	0.0	**127.3**	**268.6**	0.0	**268.6**

Line No.	Description	Nuclear Facilities 2014 OPG Proposed	2014 OEB Adjustment	2014 OEB Approved	2015 OPG Proposed	2015 OEB Adjustment	2015 OEB Approved	Total Test Period OPG Proposed	Total Test Period OEB Adjustment	Total Test Period OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Production & Revenue									
6	Forecast Production (TWh)	49.0	0.0	49.0	46.1	0.0	46.1	95.1	0.0	95.1
7	Current Payment Rate ($/MWh)	51.52	n/a	51.52	51.52	n/a	51.52	n/a	n/a	n/a
8	**Revenue From Current Payment Rate ($M)**	**2,526.8**	**0.0**	**2,526.8**	**2,373.4**	**0.0**	**2,373.4**	**4,900.2**	**0.0**	**4,900.2**
	Revenue Requirement									
9	Revenue Requirement ($M)	3,341.4	0.0	3,341.4	3,307.4	0.0	3,307.4	6,648.8	0.0	6,648.8
10	**Revenue Requirement Deficiency (Sufficiency)** ($M)	**814.6**	0.0	**814.6**	**934.0**	0.0	**934.0**	**1,748.6**	0.0	**1,748.6**

Line No.	Description	Total Previously Regulated Hydroelectric and Nuclear Generating Facilities 2014 OPG Proposed	2014 OEB Adjustment	2014 OEB Approved	2015 OPG Proposed	2015 OEB Adjustment	2015 OEB Approved	Total Test Period OPG Proposed	Total Test Period OEB Adjustment	Total Test Period OEB Approved
		(a)	(b)	(c)	(a)	(b)	(c)	(a)	(b)	(c)
	Production & Revenue									
12	Forecast Production (TWh)	69.1	0.0	69.1	67.1	0.0	67.1	136.2	0.0	136.2
12	Current Payment Rate ($/MWh)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
13	**Revenue From Current Payment Rate ($M)**	**3,245.4**	**0.0**	**3,245.4**	**3,125.8**	**0.0**	**3,125.8**	**6,371.2**	**0.0**	**6,371.2**
	Revenue Requirement									
14	Revenue Requirement ($M)	4,201.4	0.0	4,201.4	4,187.1	0.0	4,187.1	8,388.5	0.0	8,388.5
15	**Revenue Requirement Deficiency (Sufficiency)** ($M)	**955.9**	0.0	**955.9**	**1,061.3**	0.0	**1,061.3**	**2,017.3**	0.0	**2,017.3**

OPG Requested Payment Amounts

Line No.	Description	Previously Regulated Hydroelectric Facilities								
		2014			2015			2014 - 2015 Test Period		
		OPG Proposed	OEB Adjustment	OEB Approved	OPG Proposed	OEB Adjustment	OEB Approved	OPG Proposed	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Revenue Requirement ($M)	860.0	0.0	860.0	879.8	0.0	879.8	1,739.7	0.0	1,739.7
2	Forecast Production (TWh)	20.1	0.0	20.1	21.0	0.0	21.0	41.1	0.0	41.1
3	**Requested Payment Amount ($/MWh)** (line 1 / line 2)	n/a	n/a	n/a	n/a	n/a	n/a	**42.31**	**-**	**42.31**

Line No.	Description	Newly Regulated Hydroelectric Facilities								
		July 1, 2014 - December 31, 2014			2015			July 1, 2014 - 2015 Test Period		
		OPG Proposed	OEB Adjustment	OEB Approved	OPG Proposed	OEB Adjustment	OEB Approved	OPG Proposed	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
4	Revenue Requirement[1] ($M)	277.6	0.0	277.6	575.8	0.0	575.8	853.4	0.0	853.4
5	Forecast Production[2] (TWh)	5.5	0.0	5.5	12.5	0.0	12.5	17.9	0.0	17.9
6	**Requested Payment Amount ($/MWh)** (line 4 / line 5)	n/a	n/a	n/a	n/a	n/a	n/a	**47.59**	**-**	**47.59**

Line No.	Description	Nuclear Facilities								
		2014			2015			2014 - 2015 Test Period		
		OPG Proposed	OEB Adjustment	OEB Approved	OPG Proposed	OEB Adjustment	OEB Approved	OPG Proposed	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
7	Revenue Requirement ($M)	3,341.4	0.0	3,341.4	3,307.4	0.0	3,307.4	6,648.8	0.0	6,648.8
8	Forecast Production (TWh)	49.0	0.0	49.0	46.1	0.0	46.1	95.1	0.0	95.1
9	**Requested Payment Amount ($/MWh)** (line 7 / line 8)	n/a	n/a	n/a	n/a	n/a	n/a	**69.91**	**-**	**69.91**

Line No.	Description	Total Generating Facilities								
		2014			2015			2014 - 2015 Test Period		
		OPG Proposed	OEB Adjustment	OEB Approved	OPG Proposed	OEB Adjustment	OEB Approved	OPG Proposed	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
10	Revenue Requirement ($M)	4,479.0	0.0	4,479.0	4,762.9	0.0	4,762.9	9,241.9	0.0	9,241.9
11	Forecast Production (TWh)	74.6	0.0	74.6	79.6	0.0	79.6	154.2	0.0	154.2
12	**Requested Payment Amount ($/MWh)**	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

1 Amount represents 50% of 2014 revenue requirement
2 Newly Regulated Hydroelectric Facilities 18 month (July 2014 - December 2015) test period forcast production

OPG Recovery of Deferral and Variance Accounts and Riders

Line No.	Description	Previously Regulated Hydroelectric Facilities Amortization 2015 OPG Proposed	 OEB Adjustment	 OEB Approved
		(a)	(b)	(c)
	Variance Accounts ($M)			
1	Capacity Refurbishment Variance	57.2	0.0	57.2
2	Hydroelectric Incentive Mechanism Variance	(2.4)	0.0	(2.4)
3	Surplus Baseload Generation Variance	8.1	0.0	8.1
4	**Total**	**62.9**	0.0	**62.9**
5	**Forecast Production** (TWh)	**21.0**	0.0	**21.0**
6	**Rider** ($/MWh) (line 4 / line 5)	**2.99**	-	**2.99**

Line No.	Description	Nuclear Facilities Amortization 2015 OPG Proposed	 OEB Adjustment	 OEB Approved
		(a)	(b)	(c)
	Variance Accounts ($M)			
7	Capacity Refurbishment Variance	3.7	0.0	3.7
8	Nuclear Development Variance	69.4	0.0	69.4
9	**Total**	**73.1**	0.0	**73.1**
10	**Forecast Production** (TWh)	**46.1**	0.0	**46.1**
11	**Rider** ($/MWh) (line 9 / line 10)	**1.59**	-	**1.59**

OPG 2014-2015 Test Period Consumer Impact

Line No.	Description	Residential Consumers EB-2010-0008 / EB-2012-0002 >> EB-2013-0321 Previously Regulated Hydroelectric & Nuclear Facilities OPG Proposed	 OEB Adjustment	 OEB Approved
		(a)	(b)	(c)
	Production and Demand			
1	Typical Usage, including Line Losses[1] (kWh/Month)	842.3	n/a	842.3
2	Forecast Production (TWh)	136.2	-	136.2
3	IESO Forecast Provincial Demand[2] (TWh)	282.4	n/a	282.4
4	OPG Proportion of Consumer Usage (line 2 / line 3)	48.24%	0.00%	48.24%
5	Typical Usage of OPG Generation (kWh/Month) (line 1 x line 4)	406.3	-	406.3
6	**Typical Bill[1] ($/Month)**	**118.69**	n/a	**118.69**
	Production-Weighted Average Rates			
7	EB-2010-0008 / EB-2012-0002 Production-Weighted Average Rate ($/MWh) (line 23)	52.06	-	52.06
8	EB-2013-0321 Production-Weighted Average Rate ($/MWh) (line 41)	64.38	-	64.38
	Impact			
9	**Typical Bill Impact[3]** ($/Month)	**5.00**	**-**	**5.00**
10	**Percentage Change of Typical Bill** (line 9 / line 6)	**4.2%**	**0.0%**	**4.2%**

Line No.	Description	EB-2010-0008 / EB-2012-0002 Current Rates Previously Regulated Hydroelectric & Nuclear Facilities OPG Proposed	 OEB Adjustment	 OEB Approved
		(a)	(b)	(c)
	Payment Amounts ($MWh)			
11	Previously Regulated Hydroelectric	35.78	n/a	35.78
12	Nuclear	51.52	n/a	51.52
	Riders ($MWh)			
13	Previously Regulated Hydroelectric	3.04	n/a	3.04
14	Nuclear	6.27	n/a	6.27
	Total Annual Rates ($MWh)			
15	Previously Regulated Hydroelectric	38.82	n/a	38.82
16	Nuclear	57.79	n/a	57.79
	Forecast Production EB-2013-0321 (TWh)			
17	Previously Regulated Hydroelectric	41.1	-	41.1
18	Nuclear	95.1	-	95.1
19	**Total**	**136.2**	**-**	**136.2**
	Production-Weighted Average Rates ($MWh)			
20	Previously Regulated Hydroelectric	11.72	-	11.72
21	Nuclear	40.35	-	40.35
22	**Total** (line 20 + line 21)	**52.06**	**-**	**52.06**
23	**Total Production-Weighted Average Rate** ($MWh)	**52.06**	**-**	**52.06**

OPG 2014-2015 Test Period Consumer Impact

Line No.	Description	EB-2013-0321 Test Period Revenue Previously Regulated Hydroelectric & Nuclear Facilities		
		OPG Proposed	OEB Adjustment	OEB Approved
		(a)	(b)	(c)
	EB-2012-0002 2014 Approved Riders and Forecasted Revenue ($M)			
24	Previously Regulated Hydroelectric Rider	2.02	n/a	2.02
25	Previously Regulated Hydroelectric Rider Revenue	40.57	-	40.57
26	Nuclear Rider	4.18	n/a	4.18
27	Nuclear Rider Revenue	205.01	-	205.01
28	**Total Revenue**	**245.58**	**-**	**245.58**
	EB-2013-0321 2015 Proposed Riders and Forecasted Revenue ($M)			
29	Previously Regulated Hydroelectric Rider	2.99	-	2.99
30	Previously Regulated Hydroelectric Rider Revenue	62.88	-	62.88
31	Nuclear Rider	1.59	-	1.59
32	Nuclear Rider Revenue	73.07	-	73.07
33	**Total Revenue**	**135.95**	**-**	**135.95**
	EB-2013-0321 2014-2015 Test Period Revenue Requirement ($M)			
34	Previously Regulated Hydroelectric Revenue	1,739.7	-	1,739.7
35	Nuclear Revenue	6,648.8	-	6,648.8
36	**Total Revenue**	**8,388.5**	**-**	**8,388.5**
37	**Total Test Period Revenue** ($M) (line 28 + line 33 + line 36)	**8,770.0**	**-**	**8,770.0**
	Forecast Production EB-2013-0321 (TWh)			
38	Previously Regulated Hydroelectric	41.11	-	41.11
39	Nuclear	95.11	-	95.11
40	**Total**	**136.23**	**-**	**136.23**
41	**Total Production-Weighted Average Rate** ($/MWh) (line 37 / line 40)	**64.38**	**-**	**64.38**

1 Average monthly consumption (800 kWh) and average monthly bill are based on the OEB "Bill Calculator" for estimating monthly electricity bills (using Tiered pricing). Typical Consumption includes line losses.

2 Based on IESO May 24, 2013 18 Month Outlook. As the 18 Month Outlook did not provide a demand forecast for 2014 or 2015, OPG used the IESO Energy demand forecast for 2013 (141.2 TWh) and assumed the 2014 and 2015 forecasts to be equal to the 2013 forecast (141.2 TWh + 141.2 TWh = 282.4 TWh).

3 Typical Bill Impact is line 2 x increase (in $/MWh) in average OPG rates (payment amounts including riders) from Board Approved EB-2010-0008/EB-2012-0002 to proposed EB-2013-0321. Average Board Approved rates are payment amounts for Prev. Reg. Hydro and Nuclear, respectively, from EB-2010-0008 Payment Amounts Order (Prev. Reg. Hydro from App. B, Table 1, line 3; Nuclear from App. C, Table 1, line 3) plus riders from EB-2012-0002 Payment Amounts Order (Hydroelectric Rider 2013-A from pg. 4, para. 3; Nuclear Rider 2013-A from pg. 5, para. 6), prorated for respective Prev. Reg. Hydro and Nuclear production in 2014-15 Test Period (from Ex. E1-1-1 Table 1, line 3 (Prev. Reg. Hydro) and Ex. E2-1-1 Table 1, line 3 (Nuclear)).
Average proposed rates are Test Period amounts for Prev. Reg. Hydro revenue requirement plus Nuclear revenue requirement (from Ex. I1-1-1 Table 1, line 24), plus Test Period amounts for Deferral & Variance Account recovery (from Ex. I1-1-1 Table 1, line 25), plus Test Period revenue from Hydroelectric Rider 2014-A and Nuclear Rider 2014-A, all divided by total Test Period Prev. Reg. Hydro and Nuclear production (from Ex. E1-1-1 Table 1, line 3 (Prev. Reg. Hydro) and Ex. E2-1-1 Table 1, line 3 (Nuclear)). Hydroelectric Rider 2014-A is $2.02/MWh from EB-2012-0002 Payment Amounts Order, pg. 5, para. 5; Nuclear Rider 2014-A is $4.18/MWh from EB-2012-0002 Payment Amounts Order, pg. 5, para. 8.

Numbers may not add due to rounding.

Table 1
(Updated version of Ex. I1-1-1 Table 1)
Summary of Revenue Requirement ($M)
Years Ending December 31, 2014 and 2015

Line No.	Description	Note	Previously Regulated Hydroelectric 2014	Previously Regulated Hydroelectric 2015	Previously Regulated Hydroelectric Total	Newly Regulated Hydroelectric 2014[1]	Newly Regulated Hydroelectric 2015	Newly Regulated Hydroelectric Total	Nuclear 2014	Nuclear 2015	Nuclear Total
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Rate Base										
1	**Net Fixed Assets**	2	5,105.6	5,062.2	N/A	2,502.5	2,519.2	N/A	2,963.8	2,930.6	N/A
2	**Working Capital**	2	0.7	0.7	N/A	0.7	0.7	N/A	710.8	696.4	N/A
3	**Cash Working Capital**	2	21.7	21.7	N/A	8.3	8.3	N/A	32.0	32.0	N/A
4	**Total Rate Base**		5,128.0	5,084.6	N/A	2,511.5	2,528.2	N/A	3,706.7	3,659.0	N/A
	Capitalization										
5	**Short-term Debt**	3	99.0	98.1	N/A	48.5	48.8	N/A	44.7	45.3	N/A
6	**Long-Term Debt**	3	2,618.8	2,596.7	N/A	1,282.6	1,291.1	N/A	1,183.4	1,200.3	N/A
7	**Common Equity**	3	2,410.1	2,389.8	N/A	1,180.4	1,188.2	N/A	1,089.1	1,104.6	N/A
8	**Adjustment for Lesser of UNL or ARC**	3	N/A	N/A	N/A	N/A	N/A	N/A	1,389.5	1,308.8	N/A
9	**Total Capital**		5,128.0	5,084.6	N/A	2,511.5	2,528.2	N/A	3,706.7	3,659.0	N/A
	Cost of Capital										
10	**Short-term Debt**	4	3.6	4.6	8.2	1.8	2.3	4.0	1.6	2.1	3.7
11	**Long-Term Debt**	4	127.0	126.2	253.2	62.2	62.7	125.0	57.4	58.3	115.7
12	**Return on Equity**	4	216.4	214.6	431.0	106.0	106.7	212.7	97.8	99.2	197.0
13	**Adjustment for Lesser of UNL or ARC**	4	N/A	N/A	N/A	N/A	N/A	N/A	74.6	70.3	144.9
14	**Total Cost of Capital**		347.1	345.4	692.4	170.0	171.7	341.7	231.4	229.9	461.4
	Expenses:										
15	**OM&A**	5	149.2	144.2	293.5	239.3	242.6	482.0	2,491.8	2,531.3	5,023.0
16	**Fuel and GRC**	6	267.2	280.8	548.0	75.6	77.5	153.1	268.6	260.5	529.0
17	**Depreciation & Amortization**	7	82.1	81.9	164.0	62.2	63.1	125.3	273.7	288.5	562.3
18	**Property Tax**	8	0.3	0.3	0.6	0.1	0.1	0.2	15.9	16.4	32.4
19	**Total Expenses**		498.8	507.2	1,006.1	377.3	383.3	760.6	3,050.0	3,096.7	6,146.7
	Less:										
	Other Revenues										
20	**Bruce Lease Revenues Net of Direct Costs**	9	N/A	N/A	N/A	N/A	N/A	N/A	39.7	40.6	80.3
21	**Ancillary and Other Revenue**	10	34.0	34.6	68.6	22.7	23.1	45.8	33.2	30.5	63.7
22	**Total Other Revenues**		34.0	34.6	68.6	22.7	23.1	45.8	72.9	71.1	144.0
23	**Income Tax**	8	48.0	61.8	109.8	30.6	43.8	74.5	132.8	51.9	184.7
24	**Revenue Requirement**		860.0	879.8	1,739.7	555.2	575.8	1,131.0	3,341.4	3,307.4	6,648.8
	(line 14 + line 19 - line 22 + line 23)										
25	**Amortization of Variance & Deferral Account Amounts**	11	0.0	62.9	62.9	N/A	N/A	N/A	0.0	73.1	73.1
26	**Revenue Requirement Plus Variance & Deferral Account Amounts** (line 24 + line 25)		860.0	942.6	1,802.6	555.2	575.8	1,131.0	3,341.4	3,380.4	6,721.9

Notes:
1 Although regulation of Newly Regulated Hydroelectric facilities is expected to begin on July 1, 2014, full year amounts are shown for comparison purposes.
2 From Ex. B2-1-1 Table 1 (Prev. Reg. Hydro and Newly Reg. Hydro), Ex. B1-1-1 Table 2 (Nuclear).
3 Totals from Exhibit C1-1-1 Tables 1 and 2 (col. (a)).
Capitalization is allocated to Previously Regulated Hydroelectric, Newly Regulated Hydroelectric and Nuclear operations using rate base financed by capital structure.
Capital Structure for OPG's combined regulated operations is provided in Ex. C1-1-1 Tables 1 and 2.
4 Totals from Exhibit C1-1-1 Tables 1 and 2 (col. (d)).
Cost of Capital is allocated to Previously Regulated Hydroelectric, Newly Regulated Hydroelectric and Nuclear operations using rate base financed by capital structure.
Capital Structure for OPG's combined regulated operations is provided in Ex. C1-1-1 Tables 1 and 2.
5 From Ex. F1-1-1 Table 1 (Prev. Reg. Hydro), Ex. F1-1-1 Table 2 (Newly Reg. Hydro), Ex. F2-1-1 Table 1 (Nuclear), updated to reflect changes described in Ex. N1-1-1.
6 From Ex. F1-4-1 Table 1 (Prev. Reg. Hydro and Newly Reg. Hydro), Ex. F2-5-1 Table 1 (Nuclear), updated to reflect changes described in Ex. N1-1-1.
7 From Ex. F4-1-1 Table 1 (Prev. Reg. Hydro and Newly Reg. Hydro); Ex. F4-1-1 Table 2 (Nuclear).
8 Ex. F4-2-1 Table 1 (Prev. Reg. Hydro), Ex. F4-2-1 Table 2 (Newly Reg. Hydro), Ex. F4-2-1 Table 3 (Nuclear), updated to reflect changes described in Ex. N1-1-1.
9 From Ex. G2-2-1 Table 1.
10 From Ex. G1-1-1 Table 1 (Prev. Reg. Hydro and Newly Reg. Hydro), Ex. G2-1-1 Table 1 (Nuclear), updated to reflect changes described in Ex. N1-1-1.
Other Revenues included in the determination of the Nuclear revenue requirement are adjusted for sharing of 50 percent of
net revenue from sales of heavy water per the OEB Decision in EB-2010-0008, (see Ex. G2-1-2 Table 1, Note 1).
11 From Ex. H1-2-1 Table 1 (Prev. Reg. Hydro) and Ex. H1-2-1 Table 2 (Nuclear).

Table 2
(Updated version of Ex. I1-1-1 Table 2)
Comparison of Revenue Requirement to Board Approved - Previously Regulated Hydroelectric ($M)
Years Ending December 31, 2011, 2012, 2013, 2014 and 2015

Line			Board Approved[1]		Actual		Forecast		
No.	Description	Note	2011	2012	2011	2012	2013	2014	2015
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Total Cost of Capital**	2	278.2	280.4	181.6	186.9	398.3	347.1	345.4
	Expenses:								
2	**OM&A**	3	128.2	125.9	96.3	119.7	141.3	149.2	144.2
3	**GRC**	4	263.7	263.7	259.4	244.5	243.5	267.2	280.8
4	**Depreciation & Amortization**	5	65.6	65.0	65.6	70.0	79.0	82.1	81.9
5	**Property Tax**	6	0.0	0.0	0.2	0.2	0.3	0.3	0.3
6	**Total Expenses**		457.5	454.6	421.4	434.3	464.2	498.8	507.2
	Less:								
	Other Revenues								
7	**Ancillary and Other Revenue**	7	[redacted]		31.5	21.6	31.8	34.0	34.6
8	**Total Other Revenues**				31.5	21.6	31.8	34.0	34.6
9	**Income Tax**	6	[redacted]		33.4	32.3	(0.7)	48.0	61.8
10	**Revenue Requirement**		711.9	707.2	605.0	631.9	829.9	860.0	879.8
	(line 1 + line 6 - line 8 + line 9)								
11	**Forecast Production (TWh)**	8	19.8	19.8	19.5	18.5	18.4	20.1	21.0

Notes:
1. From EB-2010-0008 Payment Amounts Order, Appendix A, Table 1, except forecast production which is from Appendix A, Table 3.
2. Actuals and Forecast: Totals from Ex. C1-1-1 Tables 1 through 4 (col. (d)) and Ex. C1-1-1 Table 5 (col. (f)).
   Cost of Capital is allocated to Previously Regulated Hydroelectric operations using rate base financed by capital structure,
   except for 2013 where Return on Equity portion is from I1-1-1 Table 5, line 25.
3. Actuals and Forecast from Ex. F1-1-1 Table 1, updated to reflect changes described in Ex. N1-1-1.
4. Actuals and Forecast from Ex. F1-4-1 Table 1, updated to reflect changes described in Ex. N1-1-1.
5. Actuals and Forecast from Ex. F4-1-1 Table 1.
6. Actuals and Forecast from Ex. F4-2-1 Table 1, updated to reflect changes described in Ex. N1-1-1.
7. Actuals and Forecast from Ex. G1-1-1 Table 1, updated to reflect changes described in Ex. N1-1-1.
8. Actuals and Forecast from Ex. E1-1-1 Table 1, updated to reflect changes described in Ex. N1-1-1.

Table 3
(Updated version of Ex. I1-1-1 Table 3)
Comparison of Revenue Requirement to Board Approved - Nuclear ($M)
Years Ending December 31, 2011, 2012, 2013, 2014 and 2015

Line No.	Description	Note	Board Approved[1] 2011	Board Approved[1] 2012	Actual 2011	Actual 2012	Forecast 2013	Forecast 2014	Forecast 2015
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Total Cost of Capital**	2	260.0	257.4	197.2	214.4	(32.2)	231.4	229.9
	Expenses:								
2	**OM&A**	3	1,965.5	1,976.3	2,116.3	2,230.0	2,493.0	2,491.8	2,531.3
3	**Fuel**	4	240.1	266.2	228.9	265.1	272.6	268.6	260.5
4	**Depreciation & Amortization**	5	235.4	256.4	228.6	341.9	256.5	273.7	288.5
5	**Property Tax**	6	16.0	16.6	13.6	13.3	15.3	15.9	16.4
6	**Total Expenses**		2,457.1	2,515.6	2,587.4	2,850.3	3,037.4	3,050.0	3,096.7
	Less:								
	Other Revenues								
7	**Bruce Lease Revenues Net of Direct Costs**	7	128.1	143.0	84.2	93.2	42.3	39.7	40.6
8	**Ancillary and Other Revenue**	8	[redacted]	[redacted]	85.1	63.8	24.8	33.2	30.5
9	**Total Other Revenues**		[redacted]	[redacted]	169.3	157.0	67.1	72.9	71.1
10	**Income Tax**	6	[redacted]	[redacted]	(25.3)	9.4	(23.9)	132.8	51.9
11	**Revenue Requirement**		2,586.0	2,665.5	2,590.0	2,917.1	2,914.2	3,341.4	3,307.4
	(line 1 + line 6 - line 9 + line 10)								
12	**Forecast Production (TWh)**	9	50.4	51.5	48.6	49.0	48.0	49.0	46.1

Notes:

1 From EB-2010-0008 Payment Amounts Order, Appendix A, Table 2, except forecast production which is from Appendix A, Table 3.

2 Actuals and Forecast: Totals from Ex. C1-1-1 Tables 1 through 4 (col. (d)) and Ex. C1-1-1 Table 5 (col. (f)).
Cost of Capital is allocated to Nuclear operations using rate base financed by capital structure, except for 2013 where Return on Equity portion is from I1-1-1 Table 5, line 25.

3 Actuals and Forecast from Ex. F2-1-1 Table 1, updated to reflect changes described in Ex. N1-1-1.

4 Actuals and Forecast from Ex. F2-5-1 Table 1, updated to reflect changes described in Ex. N1-1-1.

5 Actuals and Forecast from Ex. F4-1-1 Table 2.

6 Actuals and Forecast from Ex. F4-2-1 Table 3, updated to reflect changes described in Ex. N1-1-1.

7 Actuals and Forecast from Ex. G2-2-1 Table 1.

8 Actuals and Forecast from Ex. G2-1-1 Table 1.
Other Revenues included in the determination of the Nuclear revenue requirement are adjusted for sharing of 50 percent of net revenue from sales of heavy water per the OEB Decision in EB-2010-0008, per Ex. G2-1-2 Table 1, Note 1.

9 Actuals and Forecast from Ex. E2-1-1 Table 1, updated to reflect changes described in Ex. N1-1-1.

Table 4
(Updated version of Ex. I1-1-1 Table 4)
Summary of Revenue Deficiency
Test Period January 1, 2014 to December 31, 2015

Line No.	Description	Previously Regulated Hydroelectric 2014	2015	Total	Nuclear 2014	2015	Total
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Forecast Production[1] (TWh)**	20.1	21.0	41.1	49.0	46.1	95.1
2	**Prescribed Payment Amount from EB-2010-0008[2] ($/MWh)**	35.78	35.78	N/A	51.52	51.52	N/A
3	**Indicated Production Revenue ($M)** (line 1 x line 2)	718.6	752.4	1,471.1	2,526.8	2,373.4	4,900.2
4	**Revenue Requirement[3] ($M)**	860.0	879.8	1,739.7	3,341.4	3,307.4	6,648.8
5	**Revenue Requirement Deficiency ($M)** (line 4 - line 3)	141.3	127.3	268.6	814.6	934.0	1,748.6

Notes:
1 Prev. Reg. Hydro from E1-1-1 Table 1, line 3, cols. (e) and (f). Nuclear from E2-1-1 Table 1, line 3, cols. (e) and (f), updated to reflect changes described in Ex. N1-1-1.
2 Prev. Reg. Hydro from EB-2010-0008 Payment Amounts Order, Appendix B, Table 1, line 3.
Nuclear from EB-2010-0008 Payment Amounts Order, Appendix C, Table 1, line 3.
3 Ex. N1-1-1 Table 1, line 24.

Table 5
(Updated version of Ex. I1-1-2 Table 1)
Typical Residential Consumer Impact
(not including Newly Regulated Hydroelectric)

Line No.	Description	Amount
		(a)
1	**Typical Consumption[1] (kWh/Month)**	842
2	**Typical Usage of OPG Generation (kWh/Month)** (line 1 x line 11)	406
3	**Typical Bill[1] ($/Month)**	118.69
4	**Typical Bill Impact ($/Month)** (line 2 x line 8 / 1000)	**5.00**
5	**Typical Bill Impact (%)** (line 4 / line 3)	**4.2%**
6	Current OPG weighted average Hydro & Nuclear Rate[2] ($/MWh)	52.06
7	Proposed OPG test period weighted average Hydro & Nuclear Rate[3] ($/MWh)	64.38
8	Change in OPG weighted average Hydro & Nuclear Rate ($/MWh) (line 7 - line 6)	12.31
9	Forecast 2014-15 OPG Regulated Production[4] (TWh)	136.2
10	Forecast of Provincial Demand[5] (TWh)	282.4
11	OPG Proportion of Consumer Usage (line 9 / line 10)	48.2%

Notes:

1 Average monthly consumption (800 kWh) and average monthly bill are based on the OEB "Bill Calculator" for estimating monthly electricity bills (using Tiered pricing). Typical Consumption includes line losses.

2 Current OPG weighted average Hydro & Nuclear rates are payment amounts for Prev. Reg. Hydro and Nuclear, respectively, from EB-2010-0008 Payment Amounts Order (Prev. Reg. Hydro from App. B, Table 1, line 3; Nuclear from App. C, Table 1, line 3) plus riders from EB-2012-0002 Payment Amounts Order (Hydroelectric Rider 2013-A from pg. 4, para. 3; Nuclear Rider 2013-A from pg. 5, para. 6), prorated for respective Prev. Reg. Hydro and Nuclear production in 2014-15 Test Period (from Ex. E1-1-1 Table 1, line 3 (Prev. Reg. Hydro) and Ex. E2-1-1 Table 1, line 3 (Nuclear)), updated to reflect changes described in Ex. N1-1-1.

3 Proposed OPG Test Period rates are Test Period amounts for Prev. Reg. Hydro revenue requirement plus Nuclear revenue requirement (from Ex. N1-1-1 Table 1, line 24), plus Test Period amounts for Deferral & Variance Account recovery (from Ex. N1-1-1 Table 1, line 25), plus Test Period revenue from Hydroelectric Rider 2014-A (EB-2012-0002 Payment Amounts Order, pg. 5, para. 5) and Nuclear Rider 2014-A (EB-2012-0002 Payment Amounts Order, pg. 5, para. 8), all divided by total Test Period Prev. Reg. Hydro and Nuclear production (from Ex. E1-1-1 Table 1, line 3 (Prev. Reg. Hydro) and Ex. E2-1-1 Table 1, line 3 (Nuclear)), updated to reflect changes described in Ex. N1-1-1.

4 Prev. Reg. Hydro from Ex. E1-1-1 Table 1, cols. (e) and (f), Nuclear from Ex. E2-1-1 Table 1, cols. (e) and (f), updated to reflect changes described in Ex. N1-1-1.

5 Based on IESO May 24, 2013 18 Month Outlook. As the 18 Month Outlook did not provide a demand forecast for 2014 or 2015, OPG used the IESO Energy demand forecast for 2013 (141.2 TWh) and assumed the 2014 and 2015 forecasts to be equal to the 2013 forecast (141.2 TWh + 141.2 TWh = 282.4 TWh).

Numbers may not add due to rounding.

Table 6
(Updated version of Ex. I1-2-1 Table 1)
Payment Amount and Rider - Previously Regulated Hydroelectric
Test Period January 1, 2014 to December 31, 2015

Line No.	Description	2014-2015 Test Period
		(a)
	PAYMENT AMOUNT:	
1	**Revenue Requirement[1] ($M)**	1,739.7
2	**Forecast Production[2] (TWh)**	41.1
3	**Payment Amount ($/MWh)** (line 1 / line 2)	42.31
	DEFERRAL AND VARIANCE ACCOUNT PAYMENT RIDER:	
4	**2015 Payment Rider[3] ($/MWh)**	2.99

Notes:
1 From Ex. N1-1-1 Table 1, line 24.
2 From Ex. E1-1-1 Table 1, line 3, cols. (e) and (f), updated to reflect changes described in Ex. N1-1-1.
3 From Ex. H1-2-1 Table 1, line 13, column (e) divided by updated 2015 Previously Regulated Hydroelectric production of 21.0 TWh per Ex. N1-1-1, Chart 10.

Table 7
(Updated version of Ex. I1-2-1 Table 2)
Payment Amount - Newly Regulated Hydroelectric
July 1, 2014 to December 31, 2015

Line No.	**Description**	**July 1 - December 31 2014**	**2015**	**July 1, 2014 - December 31, 2015 Total**
		(a)	(b)	(c)
	PAYMENT AMOUNT:			
1	**Revenue Requirement[1] ($M)**	277.6	575.8	853.4
2	**Forecast Production[2] (TWh)**	5.5	12.5	17.9
3	**Payment Amount ($/MWh)** (line 1 / line 2)			47.59

Notes:

1 Cols. (a) is 2014 Newly Regulated Hydroelectric Revenue Requirement (from Ex. N1-1-1 Table 1, col. (d), line 24) times 0.5. Col. (b) from Ex. N1-1-1 Table 1, col. (e), line 24.

2 Col. (a) is July to December 2014 Newly Regulated Hydroelectric forecast production from Ex. E1-1-1 Table 2, line 8, cols. (g) through (l). Col. (b) from Ex. E1-1-1 Table 1, col. (f), line 8.

Numbers may not add due to rounding.

Table 8
(Updated version of Ex. I1-3-1 Table 1)
Payment Amount and Rider - Nuclear
Test Period January 1, 2014 to December 31, 2015

Line No.	Description	2014-2015 Test Period
		(a)
	PAYMENT AMOUNT:	
1	**Revenue Requirement[1] ($M)**	6,648.8
2	**Forecast Production[2] (TWh)**	95.1
3	**Payment Amount ($/MWh)** (line 1 / line 2)	69.91
	DEFERRAL AND VARIANCE ACCOUNT PAYMENT RIDER:	
4	**2015 Payment Rider[3] ($/MWh)**	1.59

Notes:
1. From Ex. N1-1-1 Table 1, line 24.
2. From Ex. E2-1-1 Table 1, line 3, cols. (e) and (f), updated to reflect changes described in Ex. N1-1-1.
3. From Ex. H1-2-1 Table 2, line 16, column (e) divided by updated 2015 Nuclear production of 46.1 TWh per Ex. N1-1-1, Chart 10.