Board Staff Interrogatory #178

Issue Number: 6.9
Issue: Is the proposed test period nuclear depreciation expense appropriate?

Interrogatory

Reference:
Ref: Exh F4-1-1 page 6
OPG is undertaking initiatives to extend Pickering operating beyond 2020.

a) Has OPG capitalized projects relating to the extension of Pickering operations? If yes, how much is the related depreciation expense over the test period?

b) OPG will seek OEB's approval of an accounting order related to any future changes to the Pickering EOL date. If OPG is able to extend operations, please explain how this will impact depreciation and amortization expense as well as any gains and losses recognized in the application.

c) If OPG is unable to extend operations, please explain how this will impact depreciation and amortization expense as well as any gains and losses recognized in the application and how OPG plans to address the impacts to rates.

d) How will the Capacity Refurbishment Variance Account or any of the other existing DVAs be impacted, if it is impacted?

Response

a) No, OPG has not and does not expect to capitalize any costs to enable the extension of Pickering operations beyond 2020, as discussed further in Ex. L-6.4-1 Staff-119 b).

   However, as noted in Ex. F2-2-3, section 3.3 and Ex. L-6.5-1 Staff-118 g), OPG's forecasts for the IR term include restoration of project portfolio capital expenditures to levels needed to operate the plant (as opposed to the reduced levels that would have been anticipated based on shut down at year-end 2020). Projected depreciation expense related to these expenditures is nil in each of 2017, 2018 and 2019, $8.1M in 2020, and $50.4M in 2021, based on the December 31, 2020 EOL date as discussed in Ex. L-6.9-1 Staff-177.

b) If OPG is able to extend Pickering operations beyond 2020, OPG would extend the accounting end of life (EOL) dates based on high confidence information supporting the extended life. In accordance with generally accepted accounting principles, OPG would then calculate the revised depreciation and amortization expense as of the effective date of the new EOL date. OPG would do this by dividing the remaining net book value of the

Pickering assets by the remaining life to the new EOL date. All else equal, this would reduce depreciation and amortization expense relative to the forecast in this application for periods beginning on the effective date of the EOL extension. There also may be an impact on depreciation expense resulting from an associated change in the nuclear liabilities. Any such change is expected to be recorded on the effective date of the EOL extension.

Assuming the resulting revenue requirement impact meets the materiality threshold specified in the previously established accounting order requirements related to changes in station service lives and nuclear liabilities, OPG would file an accounting order application. This application would propose that the revenue requirement impact be recorded in a new deferral account similar to the treatment authorized for the Impact Resulting from Changes in Station End-of-Life (December 31, 2015) Deferral Account approved in EB-2014-0370.

There would be no impact on gains or losses if OPG is able to extend the Pickering EOL date. Whatever final EOL date is established, all Pickering assets (other than minor fixed assets transferrable to other parts of OPG's regulated operations) would be fully depreciated by that date. The transferrable minor fixed assets would continue to be depreciated based on their standalone services lives.

c) If OPG is unable to extend Pickering operations beyond 2020, and absent any new information that would require a reassessment of the Pickering EOL dates, OPG would retain the December 31, 2020 EOL date and fully depreciate all Pickering fixed assets (other than transferrable minor fixed assets) by those dates. Since, as discussed in Ex. L-6.9-1 Staff-177, this rate application is based on the December 31, 2020 EOL date, OPG does not anticipate any impact to depreciation and amortization expense or any gains and losses arising from the inability to extend Pickering operations beyond 2020, other than as a result of any differences between actual and forecast in-service additions related to the restoration of project portfolio capital expenditures to normal levels discussed in part a).

Differences related to the restoration of normal levels of project portfolio capital expenditure would not be captured within the scope of the Capacity Refurbishment Variance Account. Pursuant to O.Reg. 53/05, section 6(2)4, this account is defined to include only those expenditures made to increase the output of, refurbish or add operating capacity to a prescribed generation facility. Capital expenditures necessary to restore the project portfolio to normal operational levels do not meet this definition. As such, any differences in these expenditures would be treated like any other variance resulting from forecast risk that is not subject to true up (see Ex. L-06.1-1Staff-98 (b)).

OPG expects that the Capacity Refurbishment Variance Account would capture differences between actual and forecast non-capital costs incurred to enable Pickering extended operations, including the Fuel Channel Life Assurance project. The enabling costs are described in Ex. F2-2-3 section 3.3. This approach was previously approved by the OEB for Pickering Continued Operations costs (for example, see EB-2014-0370, Ex. H1-1-1, pp.11-

12). OPG does not expect that any other existing variance or deferral accounts (or any of the accounts proposed by OPG in this application) will be impacted.

Board Staff Interrogatory #187

Issue Number: 6.10
Issue: Are the amounts proposed to be included in the test period nuclear revenue requirement for income and property taxes appropriate?

Interrogatory

Reference:
Ref: Exh F4-2-1, page 10, and Table 3

Per page 10, OPG can claim a non-refundable ITC for SR&ED. In Table 3, 2014 regulatory income taxes were ($56.0M) mainly as a result of a $61.7M SR&ED ITC.

a) Please confirm that OPG did not receive a refund for the $61.7M SR&ED ITC.

b) Please explain the treatment of the $61.7M SR&ED ITC and whether it was carried forward and applied to the calculation of regulatory income taxes in 2015 or future years.

Response

a) & b)

The $61.7M SR&ED ITC does not constitute a refund and has not been carried forward to future years as explained below.

SR&ED ITCs reported in a given year's regulatory income tax calculation are comprised of two items:

1) Regulated Portion of Utilized SR&ED ITCs: The regulated portion of SR&ED ITCs utilized to reduce OPG's actual corporate income taxes payable for the year, using a 75 percent recognition percentage for taxation years subject to audit. As discussed in Ex. F4-2-1, section 3.4, the 75 percent recognition factor is applied in accordance with generally accepted accounting principles and is based on an assessment of the likelihood of the credits ultimately being allowed. Amounts of SR&ED ITCs utilized in the year include SR&ED ITCs earned in the year as well as any amounts carried over to/from a different year in line with OPG's corporate income tax calculations.

2) Tax Audit Results: Upon resolution of a prior year income tax audit, the regulated portion of the difference between the final amount of actual SR&ED ITCs allowed for that year and the amount previously recognized (i.e. at 75 percent).

The breakdown of the $61.7M is detailed in Ex. L-6.10-1 Staff-188, Attachment 1, Table 1, col. (b). It shows that the recognized portion of utilized SD&ED ITCs was $50.0M for nuclear and $0.2M for regulated hydroelectric, with the remaining $11.5M on account of income tax audit results.

OPG notes that, of the $61.7M, approximately $12M was recorded as a ratepayer credit in the Income and Other Taxes Variance Account in 2014 upon resolution of prior taxation year audits.[1] Other variances between actual reported and forecast SR&ED ITCs, which predominantly relate to differences between actual and forecast levels of underlying qualifying expenditures, are not within the scope of the Income and Other Taxes Variance Account, and the associated forecast risk is borne by the shareholder.

[1] The credit entry into the Income and Other Taxes Variance Account is explained at EB-2014-0370 Ex. H1-1-1, p. 8, lines 19-22 and p. 9, lines 5-10, and EB-2014-0370 Ex. H1-1-2, section 3.6. The credit entry is shown as $9.0M at EB-2014-0370 Ex. H1-1-2, Table 6, line 17, col. (I), which is net of taxes payable on the ITCs.

Board Staff Interrogatory #188

Issue Number: 6.10
Issue: Are the amounts proposed to be included in the test period nuclear revenue requirement for income and property taxes appropriate?

Interrogatory

Reference:
Ref: Exh F4-2-1, Table 3 and Exh I1-2-1, Table 2a

a) The 2015 Nuclear SR&ED ITC included in the EB-2013-0321 Payment Amount Order is $9.4M as seen in Table 2a. Please confirm that there will be no true up to the actual 2015 SR&ED ITC of $31.9M (i.e. it will not be included in the Income and Other Taxes Variance Account).

b) Please provide a continuity schedule of the SR&ED credits available, used against regulatory income tax, carried forward or back from 2013 to 2021.

Response

a) Confirmed.

Exhibit L-6.10-1 Staff-187 explains the two items reported as the SR&ED ITC amount in a given year's regulatory income tax calculation. The regulated portion of utilized SR&ED ITCs of $26.0M for nuclear and $0.1M for regulated hydroelectric and $5.8M related to income tax audits comprise the $31.9M SR&ED ITC amount for 2015, as detailed in Attachment 1, Table 1, col. (c). Of the $31.9M, approximately $5M was recorded as a ratepayer credit in the Income and Other Taxes Variance Account in 2015 upon resolution of a prior year taxation year audit.[1] No other variances between the $31.9M amount and the 2015 OEB-approved amount of $9.4M have or are expected to be recorded in the Income and Other Taxes Variance Account, as these variances relate to differences between actual and forecast underlying qualifying expenditure levels. Such variances are not within the scope of the Income and Other Taxes Variance Account and are borne by (or accrue to) the shareholder.

b) Attachment 1 provides a 2013-2021 continuity schedule of SR&ED ITCs attributed to the regulated business and reported in the regulatory income tax calculations in the pre-filed evidence.

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[1] The credit entry into the Income and Other Taxes Variance Account is explained at Ex. H1-1-1, p. 12, lines 17-24 and is shown as $4.2M at Ex. H1-1-1, Table 6, line 13, col. (c), which is net of taxes payable on the ITCs.

Numbers may not add due to rounding.

Filed: 2016-10-26
EB-2016-0152
Exhibit L
Tab 6.10
Schedule 1 Staff-188
Attachment 1

Table 1
Continuity Schedule of Scientific Research & Experimental Development Investment Tax Credits (SR&ED ITCs) ($M)

Line No.	Particulars	Actual 2013	Actual 2014	Actual 2015	Budget 2016	Plan 2017	Plan 2018	Plan 2019	Plan 2020	Plan 2021
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Nuclear:									
	Amounts Utilized for OPG's Corporate Income Tax Purposes [1]									
1	Earned in the Year	35.5	33.0	19.3	18.7	18.4	18.4	18.4	18.4	18.4
2	2012 ITCs Brought Forward and Other Adjustments	8.1	-	-	-	-	-	-	-	-
3	2013 ITCs (Carried Forward) / Brought Forward	(23.7)	23.7	-	-	-	-	-	-	-
4	2014 ITCs (Carried Forward) / Brought Forward	-	(6.8)	6.8	-	-	-	-	-	-
5	Total Amount Utilized for Corproate Income Tax Purposes	19.8	50.0	26.0	18.7	18.4	18.4	18.4	18.4	18.4
	Previously Unrecognized Amounts Recognized upon Resolution of Tax Audit									
6	2008 Tax Audit (for April to December)	3.5	-	-						
7	2009 Tax Audit	-	5.7	-						
8	2010 Tax Audit	-	5.9	-						
9	2011 Tax Audit	-	-	5.8						
10	Total Amount Related to Prior Year Income Tax Audits	3.5	11.5	5.8	-	-	-	-	-	-
11	**Total Nuclear SR&ED ITCs Reported in Regulatory Income Taxes**	**23.4**	**61.5**	**31.8**	**18.7**	**18.4**	**18.4**	**18.4**	**18.4**	**18.4**
	Regulated Hydroelectric:									
	Amounts Utilized for OPG's Corporate Income Tax Purposes [1]									
12	Earned in the Year	0.1	0.1	0.1	0.1					
13	2012 ITCs Brought Forward and Other Adjustments	0.1	-	-	-					
14	2013 ITCs (Carried Forward) / Brought Forward	(0.1)	0.1	-	-					
15	2014 ITCs (Carried Forward) / Brought Forward	-	0.0	0.0	-					
16	Total Amount Utilized for Corproate Income Tax Purposes	0.2	0.2	0.1	0.1					
	Previously Unrecognized Amounts Recognized upon Resolution of Tax Audit									
17	2008 Tax Audit (for April to December)	0.1	-							
18	2009 Tax Audit	-	0.0	-	-					
19	2010 Tax Audit	-	0.0	-	-					
20	2011 Tax Audit	-	-	0.0	-					
21	Total Amount Related to Prior Year Income Tax Audits	0.1	0.0	0.0	-					
22	**Total Regulated Hydro SR&ED ITCs Reported in Regulatory Income Taxes**	**0.2**	**0.2**	**0.1**	**0.1**					
23	**Total SR&ED ITCs Reported at Ex. F4-2-1 Table 3 Line 27**	**23.6**	**61.7**	**31.9**	**18.8**					
24	**Total SR&ED ITCs Reported at Ex. F4-2-1 Table 3 Line 25**					**18.4**	**18.4**	**18.4**	**18.4**	**18.4**

Note:
1 Amounts are presented at 75% to reflect percentage of recognition in accordance with generally accepted accounting principles

Numbers may not add due to rounding.

Filed: 2016-05-27
EB-2016-0152
Exhibit F4
Tab 2
Schedule 1
Table 3

Table 3
Calculation of Regulatory Income Taxes for Prescribed Facilities ($M)
Years Ending December 31, 2013-2016

Line No.	Particulars	Note	2013 Actual	2014 Actual	2015 Actual	2016 Budget
			(a)	(b)	(c)	(d)
	Determination of Regulatory Taxable Income					
1	**Regulatory Earnings Before Tax**	1	(56.7)	271.6	162.2	162.2
	Additions for Regulatory Tax Purposes:					
2	**Depreciation and Amortization**		319.1	395.8	437.6	458.3
3	**Nuclear Waste Management Expenses**		25.1	31.3	57.7	60.0
4	**Receipts from Nuclear Segregated Funds**		44.7	42.3	41.1	66.1
5	**Pension and OPEB Accrual**		305.3	384.8	439.6	437.9
6	**Regulatory Asset Amortization - Bruce Lease Net Revenues Variance Acct**		62.9	41.9	49.5	165.3
7	**Regulatory Liability Amortization - Income and Other Taxes Variance Acct**		(18.7)	(12.4)	(4.5)	(8.9)
8	**Adjustment Related to Financing Cost for Nuclear Liabilities**		76.8	75.2	70.3	65.8
9	**Disallowance of Niagara Tunnel Project Expenditures**		0.0	77.2	2.1	(21.6)
10	**Taxable SR&ED Investment Tax Credits**		28.4	19.2	62.3	18.7
11	**Other**		20.2	39.4	61.1	61.8
12	**Total Additions**		863.8	1,094.7	1,216.8	1,303.3
	Deductions for Regulatory Tax Purposes:					
13	**CCA**	2,3	307.7	404.3	425.7	513.8
14	**Cash Expenditures for Nuclear Waste Management & Decommissioning**		104.7	109.1	126.3	162.2
15	**Contributions to Nuclear Segregated Funds**		98.1	170.1	172.8	176.7
16	**Pension Plan Contributions**		242.9	322.5	331.3	326.6
17	**OPEB/SPP Payments**		81.9	97.0	108.3	111.3
18	**Reversal of Return on Rate Base Recorded in Deferral and Variance Accounts**		50.9	55.0	0.4	12.0
19	**Deductible SR&ED Qualifying Expenditures**		130.9	174.8	40.3	28.5
20	**Other**		1.6	11.0	6.7	24.2
21	**Total Deductions**		1,018.7	1,343.7	1,211.7	1,355.3
22	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 12 - line 21)	4	(211.6)	22.7	167.3	110.2
23	**Tax Loss Carry-Over**	5	0.0	0.0	0.0	0.0
24	**Regulatory Taxable Income After Tax Loss Carry-Over** (line 22 + line 23)		(211.6)	22.7	167.3	110.2
25	**Regulatory Income Taxes - Federal** (line 24 x line 29)		(31.7)	3.4	25.1	16.5
26	**Regulatory Income Taxes - Provincial** (line 24 x line 30)		(21.2)	2.3	16.7	11.0
27	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		(23.6)	(61.7)	(31.9)	(18.8)
28	**Total Regulatory Income Taxes** (line 25 + line 26 + line 27)		(76.5)	(56.0)	9.9	8.7
	Income Tax Rate:					
29	**Federal Tax**		15.00%	15.00%	15.00%	15.00%
30	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	10.00%	10.00%	10.00%
31	**Total Income Tax Rate**		25.00%	25.00%	25.00%	25.00%

For notes see Table 3b.

Board Staff Interrogatory #189

Issue Number: 6.10
Issue: Are the amounts proposed to be included in the test period nuclear revenue requirement for income and property taxes appropriate?

Interrogatory

Reference:
Ref: Exh F4-2-1, page 10, Table 3a and Exh H1-1-1, pages 11-12

Page 10 indicates that OPG recognizes 75% of the estimated ITCs for taxation years that are subject to audit. To the extent the ultimate percentage of recognition for SR&ED ITCs differs from that applied in reducing regulatory income tax expense reflected in approved payment amounts, OPG records the difference in the Income and Other Taxes Variance Account.

a) Please confirm that the variance account is only to true up the 75% to the percentage of recognition resulting from a tax audit and is not a true up to the actual SR&ED credit claimed.

b) Please indicate how often SR&ED audits occur.

c) OPG has forecasted SR&ED ITCs to be $18.4M for each year from 2017 to 2021.
   i. Is this amount 75% of the total estimated SR&ED ITC?
   ii. Please explain how the $18.4M SR&ED ITC was derived and why OPG proposes that it be the same amount each year from 2017 to 2021.

d) Please provide a comparison of forecasted and actual SR&ED from 2013 to 2015.

e) OPG has forecasted additions for Taxable SR&ED ITCs to be $18.4M each year from 2017 to 2021 and deductions for SR&ED Qualifying Expenditures to be $27.7M each year from 2017 to 2021.
   i. Please explain how these amounts were derived and why OPG proposes it to be the same amount each year from 2017 to 2021.
   ii. Please explain the correlation between the forecasted additions, deductions and ITC amounts relating to SR&ED in Table 3a.

Response

a) Confirmed

b) OPG's income tax returns, which include SR&ED ITC claims, are audited by the Ontario Ministry of Finance for each taxation year.

c)

i. Yes, $18.4M represents 75 percent of total estimated SR&ED ITC amounts attributed to the nuclear operations.

ii. For business planning purposes, OPG estimates future SR&ED ITCs based on actual SR&ED ITCs of a recurring nature earned in the last taxation year for which tax returns have been filed at the time the estimate is prepared, plus forecast amounts of a non-recurring nature (if any) provided by technical personnel for certain identified work. OPG does not rely on historical actuals as the basis for the non-recurring amounts given that the nature and volume of this type of work can change significantly year over year.

The last year for which tax returns were filed at the time OPG developed the estimate reflected in this application was 2014. Actual ITCs of a recurring nature for 2014 (as attributed to the nuclear operations and subject to the 75 percent recognition) were $19.2M. No amounts of a non-recurring nature were identified by technical personnel in the nuclear business unit. Therefore, the amount of $19.2M, as adjusted to $18.4M for the reduction in the Ontario ITC rate from 4.5% to 3.5% effective June 1, 2016 (see Ex. F4-2-1, section 3.4, lines 4-6), was used as the estimate for all years of the IR term.

d) A comparison of the forecasted SR&ED ITCs and actual SR&ED ITCs earned for 2013 to 2015 for the nuclear operations is as follows (pre-tax):[1]

Year	Forecasted ITCs ($M)	Actual ITCs Earned ($M)[2]
2013	14.1[3]	35.5
2014	9.4[4]	33.0
2015	9.4[5]	31.9

e) (i) & (ii)
As discussed at Ex. F4-2-1, section 3.4, OPG is subject to federal and provincial tax on SR&ED ITCs. As such, the Taxable SR&ED ITCs addition to earnings before tax is included in the calculation of regulatory taxable income. The forecasted amount of Taxable SR&ED ITCs reflects the forecasted amount of SR&ED ITCs for the corresponding years. Specifically, the Taxable SR&ED ITCs at Ex. F4-2-1, Table 3a, line 9 were determined by including the Ontario ITCs earned in the current year and the

[1] As discussed at Ex. F4-2-1 section 3.4 and in part (e) of this interrogatory, SR&ED ITCs are taxable. Therefore, the full effect of SR&ED ITC variances on income tax expense would be net of tax on amounts shown in part (d).
[2] For 2013 and 2014, Attachment 1, Table 1, line 1 of Ex. L-6.10-1 Staff-188. The 2015 value is based on the 2015 income tax return which was completed subsequent to the filing of this application.
[3] Nuclear portion of EB-2013-0321 Ex. F4-2-1, Table 5, line 24, col. (a).
[4] EB-2013-0321 Ex. L-6.13-1 Staff-165, Att. 1, Table 1, line 24, col. (c).
[5] EB-2013-0321 Ex. L-6.13-1 Staff-165, Att. 1, Table 2, line 24, col. (c).

federal ITC utilized in the previous year, and therefore are correlated to the SR&ED ITC amounts at Ex. F4-2-1, Table 3a, line 25. The derivation of the $18.4M in forecast SR&ED ITCs is explained in part (c).

The deduction for SR&ED Qualifying Expenditures is on account of SR&ED qualifying expenditures of a current nature that are capitalized for accounting purposes but are deductible for income tax purposes. These amounts are estimated for business planning purposes based on actual historical expenditures of a recurring nature, plus forecast amounts of a non-recurring nature (if any) identified by technical personnel in the nuclear business unit. No amounts of a non-recurring nature were identified as part of the 2016-2018 business planning cycle. The above approach yielded a forecast of $27.7M per year for the IR term. These expenditures, along with qualifying expenditures of a current nature expensed for accounting purposes, are the underlying expenditures giving rise to the SR&ED ITCs.

Board Staff Interrogatory #213

Issue Number: 9.2
Issue: Are the methodologies for recording costs in the deferral and variance accounts appropriate?

Interrogatory

Reference:
Ref: Exh H1-1-1 pages 3-21

OPG proposes that reference amounts used to determine post-2015 hydroelectric additions to Ancillary Services Net Revenue Variance Account, Income and Other Taxes Variance Account, the Pension & OPEB Cash Payment Variance Account and Capacity Refurbishment Variance Account be the forecasts underpinning the hydroelectric payment amounts in 2014 and 2015 approved in EB-2013-0321.

Additions to these accounts are based on revenues, OM&A or some element of revenue requirement.

a) For each of the accounts, please explain why OPG is proposing to use the monthly reference amounts established in the EB-2013-0321 proceeding even though payment amounts recovered will be updated through the Hydroelectric IRM proceeding.

b) Under the hydroelectric IRM price cap proposal, payment amounts are adjusted annually by the price cap formula, with the adjustment to reflect the (I-X) inflation in underlying costs. Furthermore, the price cap adjustments are multiplicative over time. Under OPG's proposal, the variance between actuals over 2017-21 and the average monthly amounts as approved for 2014-15 in EB-2013-0321 will continue to increase.

   Using the Income and Other Taxes Variance Account as an example, why should the reference amount not be the monthly average of the 2014-15 income tax provision as approved in EB-2013-0321 multiplied by the product of the price cap adjustments to each year, reflecting the implicit inflationary increase in the tax provision?

c) Implicitly, for the nuclear payments side, the production forecast also factors into the determination of the reference amount as the revenue requirement reflects the costs which depend explicitly on the production forecast.

   A production forecast for hydroelectric generation is not explicitly required as the payments are a unitized recovery of the revenue requirement and the proposed price cap adjustment accounts for the main two drivers of costs – inflation and productivity – while it is assumed that changes in production (if growth) increases costs in an aggregate sense but also increases revenues so that, all else being equal, rates (payments) remain compensatory, even if costs (including taxes) change due to changes in production.

A closer approximation to the nuclear tax payment would be to account for both the price cap adjustment and the changes in production relative to the 2014-15 base amount as approved in EB-2013-0321. Please provide OPG's views with respect to an adjustment for productivity to the monthly reference amounts.

Response

a) b) & c) OPG's proposal to use the reference amounts reflected in base rates was predicated on the assumption of incentive regulation where revenues are in fact decoupled from costs and revenue offsets. Escalating the reference amounts used to establish revenue requirement by the same price cap index used to establish rates essentially maintains the link between costs and revenues. In addition, while OPG did not review every OEB decision, OPG reviewed a number of decisions and did not find any instances where reference amounts were escalated. As such, OPG proposes that the reference amounts used to determine post-2015 hydroelectric deferral and variance account additions as of the effective date of the payment amounts order in this proceeding will be the forecasts underpinning the hydroelectric payment amounts in 2014 and 2015 approved by the OEB in EB-2013-0321, unless otherwise specified in the account descriptions.

OPG's views with respect to an adjustment for productivity to the monthly reference amounts are provided above. Productivity adjustments are included as part of the price cap index. As incentive regulation decouples revenue and costs as discussed in part, then a productivity adjustment would not apply.

Board Staff Interrogatory #216

Issue Number: 9.8
Issue: Should any newly proposed deferral and variance accounts be approved by the OEB?

Interrogatory

Reference:
Ref: Exh: H1-1-1, pages 31-32

For the Nuclear ROE Variance Account,

a) Please explain how the proposed account would meet the materiality criteria.

b) Please perform a sensitivity analysis on impact to this account, if the ROE was to change by 1% (increase and decrease).

Response

a) As discussed in part b), a 1% change in the OEB prescribed ROE rate would have an impact of over $20M on OPG's nuclear revenue requirement. A variance of 0.1% in the OEB prescribed ROE rate would have an annual impact of approximately $2.2M and would cumulatively exceed OPG's materiality threshold over the 2017-2021 rate term.

b) Attachment 1, Table 1 provides a sensitivity analysis of the annual revenue requirement impact that would be booked to this account given a 1% increase or decrease in the OEB's prescribed ROE. A 1% change to the OEB's prescribed ROE would have over a $20M revenue requirement impact to OPG. This is twice OPG's materiality threshold of $10M.

Numbers may not add due to rounding.

Filed: 2016-10-26
EB-2016-0152
Exhibit L
Tab 9.8
Schedule 1 Staff-216
Attachment 1
Table 1

Table 1
Sensitivity Analysis of ROE Change

		As Filed (2017)	As Filed (2017) +1%	As Filed (2017) -1%	Reference
Nuclear Rate Base Financed by Capital Structure (Nuclear Rate Base - Adjustment for lesser of UNL or ARC)	(a)	3,344.4	3,344.4	3,344.4	*EX. B1-1-1, Table 2* *EX.C1-1-1, Table 5*
ROE %	(b)	9.19%	10.19%	8.19%	*EX.C1-1-1, Table 5*
Common Equity (at 49%) (c) = (a) x 0.49 X (b)	(c)	150.6	167.0	134.2	*EX.C1-1-1, Table 5*
Grossed Up Tax Impacts (at 25%) (d) = [(c) x 0.25] / [1-0.25]	(d)	50.2	55.7	44.7	
Total Revenue Requirement (e) = (d) + (c)	(e)	200.8	222.7	179.0	
Variance from As Filed	(f)	-	21.9	(21.9)	

Board Staff Interrogatory #217

Issue Number: 9.8
Issue: Should any newly proposed deferral and variance accounts be approved by the OEB?

Interrogatory

Reference:
Ref: Exh: H1-1-1, pages 32-33

Please calculate the approximate amounts that would be recorded in the proposed Hydroelectric Capital Structure Variance Account if the OEB approves a capital structure of 49% equity and 51% debt in this application.

Response

OPG has calculated that approximately $114M would be recorded in the proposed Hydroelectric Capital Structure Variance Account between 2017 and 2021 if the OEB approves a capital structure of 49% equity and 51% debt in this application. OPG's calculation is provided in the Table 1 of Attachment 1.

Numbers may not add due to rounding.

Table 1
Calculation of Hydroelectric Capital Structure Variance Account Additions ($M)

Line No.	Description	Board Approved EB-2013-0321			Proposed EB-2016-0152			Variance Account Addition
		2014	2015	Average	2014	2015	Average	
		(a)	(b)	(c)	(d)	(e)	(f)	(g) = (f) - (c)
1	**Regulated Hydroelectric Rate Base**[1]	7,525.7	7,489.6	7,507.7	7,525.7	7,489.6	7,507.7	
2	**Deemed Common Equity**[2]	45%	45%	45%	49%	49%	49%	
3	**Deemed Debt**[3]	55%	55%	55%	51%	51%	51%	
4	**Return On Equity**[4]	9.36%	9.30%	9.33%	9.36%	9.30%	9.33%	
5	**Cost of Debt**[5]	4.81%	4.85%	4.83%	4.81%	4.85%	4.83%	
6	**WACC** (line 2 x line 4) + (line 3 x line 5)	6.86%	6.85%	6.85%	7.04%	7.03%	7.03%	
7	**Cost of Capital** (line 1 x line 6)	516.0	513.3	514.7	529.7	526.7	528.2	13.5
8	**Income Tax Impact** (line 1 x line 2 x line 4 x 25%) / (1-25%)			105.07			114.41	9.3
9	**Total Annual Addition to Variance Account** (line 7 + line 8)							22.9
10	**2017-2021 Total Addition to Variance Account** (line 8 x 5 years)							114.3

Notes

1 Reflects the sum of Previously Regulated Hydroelectric shown in EB-2013-0321 Payment Amounts Order, App. A, Table 1, line 4, col. (c) and (f); and Newly Regulated Hydroelectric shown in EB-2013-0321 Payment Amounts Order, App. A, Table 2, line 4, col. (c) and (f).

2 2014 Board Approved from EB-2013-0321 Payment Amounts Order, App. A, Table 5b, line 5, col. (b).
2015 Board Approved from EB-2013-0321 Payment Amounts Order, App. A, Table 6b, line 5, col. (b).
Proposed EB-2016-0152 capital structure is as outlined in Ex. C1-1-1, Section 2.0.

3 2014 Board Approved from EB-2013-0321 Payment Amounts Order, App. A, Table 5b, line 4, col. (b).
2015 Board Approved from EB-2013-0321 Payment Amounts Order, App. A, Table 6b, line 4, col. (b).
Proposed EB-2016-0152 capital structure is as outlined in Ex. C1-1-1, Section 2.0.

4 2014 Board Approved from EB-2013-0321 Payment Amounts Order, App. A, Table 5b, line 5, col. (c).
2015 Board Approved from EB-2013-0321 Payment Amounts Order, App. A, Table 6b, line 5, col. (c).

5 2014 Board Approved from EB-2013-0321 Payment Amounts Order App. A, Table 5b, line 4, col. (c).
2015 Board Approved from EB-2013-0321 Payment Amounts Order App. A, Table 6b, line 4, col. (c).

Board Staff Interrogatory #218

Issue Number: 9.8
Issue: Should any newly proposed deferral and variance accounts be approved by the OEB?

Interrogatory

Reference:
Ref: H1-1-1, pages 29-33

Please provide a draft accounting order for the four new deferral and variance accounts that OPG proposes to be established in this application.

Response

OPG has never filed an accounting order for the approval of a new deferral and variance account as part of a rate application. OPG has only filed an accounting order to establish a new deferral and variance account as part of an independent application (for example, EB-2015-0374, EB-2011-0432, and EB-2009-0174).

The details required by the OEB to establish the four accounts proposed in this application are set out in Ex. H1-1-1 section 6 (pages 29-33). This evidence provides a description of each account, and the details on how entries are proposed to be recorded. This is the same information that OPG would include in an accounting order application.

To assist the OEB in approving the four proposed accounts, OPG provides details on the entries that would be required to record additions in each proposed account below.

Each of the accounts would also attract interest on the monthly opening outstanding balance, with the Mid-term Nuclear Production Variance Account, the Nuclear ROE Variance Account and the Hydroelectric Capital Structure Variance Account being subject to the OEB-prescribed rate for deferral and variance accounts. Per O. Reg. 53/05, the Rate Smoothing Deferral Account balance will attract interest at a long-term debt rate reflecting OPG's cost of long-term borrowing approved by the OEB from time to time, compounded annually.

Rate Smoothing Deferral Account

The Rate Smoothing Deferral Account is established pursuant to O. Reg. 53/05. Per Ex. H1-1-1, section 6.1, OPG is proposing to record 1/12th of the OEB-approved annual deferral amount each month. Entries into this account will be recorded as follows:

DR *Rate Smoothing Deferral Account*
CR *Revenue*

Mid-term Nuclear Production Variance Account

As noted in Ex. H1-1-1, section 6.2, to determine entries into the account, the monthly production variance will be multiplied by the approved smoothed nuclear payment amount. The resulting amount would then be reduced by an amount determined as the monthly production variance multiplied by the average fuel cost in the approved revenue requirement for the applicable year. Entries into this account will be recorded as follows:

If approved updated production forecast < EB-2016-0152 approved production forecast

DR *Mid-term Nuclear Production Variance Account*
DR *Fuel Expense*
CR *Revenue*

If approved updated production forecast > EB-2016-0152 approved production forecast

DR *Revenue*
CR *Fuel Expense*
CR *Mid-term Nuclear Production Variance Account*

Nuclear ROE Variance Account

Exhibit H1-1-1, section 6.3 states that OPG proposes establishing the Nuclear ROE Variance Account to record the nuclear revenue requirement impact of the difference between the return on equity ("ROE") approved by the OEB for the nuclear business in 2018 to 2021 in this proceeding as part of the revenue requirements for those years and the actual annually updated ROE specified by the OEB. Entries into this account will be recorded as follows:

If OEB-prescribed ROE rate > EB-2016-0152 approved ROE rate of 9.19%

DR *Nuclear ROE Variance Account*
CR *Return on Equity*
CR *Income Tax Expense*

If OEB-prescribed ROE rate < EB-2016-0152 approved ROE rate of 9.19%

DR Return on Equity
DR Income Tax Expense
CR Nuclear ROE Variance Account

Hydroelectric Capital Structure Variance Account

In Ex. H1-1-1, section 6.4, OPG proposes establishing the Hydroelectric Capital Structure Variance Account to record the hydroelectric revenue requirement impact of the difference between the capital structure approved by the OEB in this proceeding and the capital structure approved by the OEB in EB-2013-0321 that is underpinning the 2017-2021 hydroelectric payment amounts in this proceeding. Entries into this account will be recorded as follows:

DR Hydroelectric Capital Structure Variance Account
CR Return on Equity
CR Income Tax Expense

Board Staff Interrogatory #259

Issue Number: 11.5
Issue: Is OPG's proposed mid-term review appropriate?

Interrogatory

Reference:
Ref: Exh H1-1-1, page 30, Exh A1-3-3, page 12

In its evidence, OPG describes the entries to be included in the Mid-term Nuclear Production Variance Account, as follows:

> To determine entries into the account, the monthly production variance will be multiplied by the approved smoothed nuclear payment amount. The resulting amount would then be reduced by an amount determined as a monthly production variance multiplied by the average fuel cost in the approved revenue requirement for the applicable year.

a) Please provide a sample calculation that would show the practical application of methodology outlined in Exh H1-1-1.

b) In Exh A, it's stated that "the regulation does not entitle the OEB to revisit those approved revenue requirement amounts during the five years". How is OPG's proposed adjustment to fuel cost in the Mid-term Nuclear Production Variance Account consistent with the preceding statement?

Response

a) A sample calculation for the year 2020 is provided in Chart 1 below, based on the following assumptions:

   1) The OEB approves a production forecast for July 1, 2019 to July 2021 that is 1 TWh less (the "Mid-term Production") for 2020 than OPG approved in the current application; and

   2) The OEB approves OPG's proposal in the current application, in particular:
      a. that nuclear payment amounts increase at a constant rate of 11% per year in the IR Term, and
      b. the Nuclear production forecast and fuel cost for all years in the IR Term.

The relevant values for 2020 are reflected in Chart 1:

Chart 1 – Sample Calculation

Line	Description	Amount	Evidence Reference
1	Smoothed Rate ($/MWh)	90.01	Ex. A1-3-3, p. 10, Chart 4, line 3
2	Fuel Cost ($M)	223.6	Ex. F2-5-1 Table 1 (line7 – line 6)
3	Production (TWh)	37.36	Ex. A1-3-3, p. 10, Chart 4, line 2
4	Average Fuel Cost ($/MWh)	5.985	Chart (line 2 / line 3)

The approach is described in Ex. A1-3-3, p. 14, lines 6-12. The annual production variance (i.e., 1TWh) will be multiplied by the net of the approved smoothed nuclear payment amount (i.e., $90.01/MWh) and the average fuel cost in the approved revenue requirement ($5.985/MWh) for the applicable year. The amounts determined above (i.e., 1TWh x ($90.01/MWh - $5.985/MWh) = $84.025M) will be recorded in the proposed Mid-Term Nuclear Production Variance Account described in Ex. H1-1-1. The related accounting entries would be:

Mid-Term Nuclear Production Variance Account	$84.0325M	(Debit)
Fuel Expense	$5.985M	(Debit)
Revenues	$90.01M	(Credit)

b) Unlike other costs, Nuclear fuel is a direct marginal cost associated with production. OPG believes it is appropriate that fuel cost be revised to correspond with any update to the Nuclear production forecast as part of the mid-term review. Any approved changes in nuclear fuel cost would be recorded in the Mid-term Nuclear Production Variance Account and would not involve re-opening the approved nuclear revenue requirement.

Board Staff Interrogatory #208

Issue Number: 8.2
Issue: Is the revenue requirement impact of the nuclear liabilities appropriately determined?

Interrogatory

Reference:

Ref: Exh C2-1-1, page 15 of 15

OPG indicates that the proposed period revenue requirement reflects the approved 2012 ONFA Reference Plan. The corresponding revenue requirement impact of the approved 2017 Reference Plan will be recorded in the Nuclear Liability Deferral Account for the prescribed facilities and the Bruce Lease Net Revenue Variance Account for the Bruce facilities.

a) Using the latest draft of the 2017-2021 ONFA Reference Plan, please provide a table that summarizes the estimated revenue requirement impact on the prescribed facilities as well as on the Bruce Net Revenues.

b) Has the reference plan update been finalized for the Province's approval? Based on the process for previous reference plans, has provincial review significantly affected the reference plan?

c) Please identify any limitations to using the draft 2017-2021 reference plan to underpin the payment amounts in the current proceeding.

Response

a) OPG declines to provide the requested table because the draft 2017-2021 ONFA Reference Plan cannot form the basis for the setting OPG's payment amounts and thus is not relevant. Setting payment amounts based on the draft reference plan would be contrary to O. Reg. 53/05. Moreover, as a draft, the plan remains subject to revision upon review by the Province before it is approved. Specifically, O. Reg. 53/05 s. 6(2)8 requires that the "Board shall ensure that Ontario Power Generation Inc. recover the revenue requirement impact of its nuclear decommissioning liability arising from the current approved reference plan."[1] [emphasis added] "Approved reference plan" means a reference plan, as defined in the Ontario Nuclear Funds Agreement, that has been approved by Her Majesty the Queen in right of Ontario in accordance with that agreement." (s.01(1)) [emphasis added]

[1] For purposes of the regulation, "nuclear decommissioning liability" means "OPG's liability for decommissioning its nuclear generation facilities and management of its nuclear waste and used fuel." (s. 0.1(1))

As noted at Ex. C2-1-1, p. 15, the revenue requirement impact arising from the 2017-2021 ONFA Reference Plan, once approved, would be recorded in the Nuclear Liability Deferral Account in accordance with s. 5(2)1 of O. Reg. 53/05. Should the 2017-2021 ONFA Reference Plan be approved by the Province in the course of the proceeding, and result in material changes, OPG would follow the OEB's Rules of Practice and Procedure and bring the matter forward as part of this proceeding, including the impact on revenue requirement.

b) The proposed 2017-2021 ONFA Reference Plan is being finalized for submission to the Province for review and approval. While the Province's review of final submissions of previous reference plans in 2006 and 2011 did not result in significant changes, each reference plan update is distinct and the Province has the right to request changes to the plan based on its review. Thus there is no assurance that the Province's review of the final submission of the current proposed reference plan similarly will not result in significant changes.

c) Refer to part a)

Board Staff Interrogatory #203

Issue Number: 7.2
Issue: Are the test period costs related to the Bruce Nuclear Generating Station, and costs and revenues related to the Bruce lease appropriate?

Interrogatory

Reference:
Ref. Exh G2-2-1, page 4 of 21

Under the Lease Term section, OPG indicates that the lease has been extended by 21 years from December 31, 2043 to December 31, 2064 such that Bruce Power now has options to renew the lease for additional consecutive renewal periods for up to 46 years after the expiry of the initial lease term on December 31, 2018 (the 2015 Amendment). OPG's test period forecasts assume that Bruce Power will exercise the options to renew the lease.

a) Please provide a copy of the Agreement, or the relevant excerpts from the Agreement, that detail each of the renewal periods available after the expiry of the initial lease term on December 31, 2018.

b) Prior to the 2015 Amendment, the lease term for accounting purposes was assessed to be December 2036, but the actual maximum available term of the lease was to December 2043. Why does the period between 2036-2043 now form part of the lease term for accounting purposes if it didn't qualify previously?

c) The 2015 Amendment extended the maximum lease-term by 21 years. On what basis does this additional renewal period qualify to form part of the lease term for accounting purposes?

d) Why does the updated lease term of 2064 extend beyond the useful life of the longest running Bruce station (Bruce B station, which has an end of life date of 2061)?

Response

a) OPG declines to provide a copy of the Bruce Lease Agreement or the requested excerpts for the reasons set out in the OEB's decision in EB-2007-0905 (Decision with Reasons, pages 99-106) where the OEB held, among other things, that the Bruce Lease is an unregulated commercial contract and that "The Board has no authority to set or review the terms of the lease between OPG and Bruce Power." (p.99).

With respect to the renewal periods available after the expiry of the initial lease term on December 31, 2018, the lease can be renewed consecutively for up to 46 years starting on January 1, 2019 and there are 23 renewal periods; the first is for 1 year, the second to twenty-second are for 2 years each and the twenty-third and final renewal period is for 3 years.

b) and c)

According to US GAAP requirements, the lease term for accounting purposes is reviewed only when there is a significant modification to the lease. Prior to the 2015 Amendment, OPG was last required to review the lease term for accounting purposes when a significant change to the lease took place in 2008, as discussed in EB-2010-0008 Ex. G2-2-1 p.3 and EB-2012-0002 Ex. L-1-1 Staff-06. Based on information available at the time, the 2008 lease reassessment determined the most likely outcome to be renewal of the lease to the end of 2036 in line with the assumed end of life for certain of the Bruce A units subject to refurbishment (see EB-2007-0905 Ex. F3-2-1, App. B, p. 6), notwithstanding the available renewal term of the lease to 2043.

The 2015 Amendment and the amended refurbishment agreement between Bruce Power L.P. and the IESO (ARBPRIA) required OPG to reassess the lease term for accounting purposes for the first time since 2008. In line with the end-of-life dates for the Bruce units published in the ARBPRIA and adopted by OPG for depreciation purposes (see Ex. L-1-6.9 Staff-176), OPG determined the most likely outcome to be a continuation of the lease to the end of the amended available renewal term in 2064. This resulted in the extension of the lease term for accounting purposes from 2036 to 2064.

d) The accounting end-of-life date for the Bruce B station of 2061 is computed by averaging the four estimated unit end-of-life dates per the ARBPRIA, which are summarized at Ex. F4-2-1 Att. 1, p. 4, with the last Bruce B unit reaching end of life in 2063. Bruce Power's last available lease renewal period to 2064 extends beyond the estimated end of life of the Bruce B units, reflecting a contractual requirement for Bruce Power to fulfill a number of end of lease obligations before the leased premises are handed back to OPG. As such, it is expected that Bruce Power would extend the lease to the last available renewal period in 2064 to complete these contractual obligations.

Board Staff Interrogatory #10

Issue Number: 3.1
Issue: Are OPG's proposed capital structure and rate of return on equity appropriate?

Interrogatory

Reference:
Ref: Exh C1-1-1, Chart 1

Chart 1, from page 1 of Exh C1-1-1, is replicated below.

Rate Base	2017	2018	2019	2020	2021
Hydro ($B)[1]	7.5	7.5	7.5	7.6	7.7
Nuclear ($B)[2]	3.3	3.5	3.5	7.5	8.0
Total ($B)	10.8	11.0	10.9	15.1	15.6
Nuclear Proportion	31%	32%	32%	50%	51%

1. Reflects OPG's 2016-2018 Business Plan, which includes a projection for 2019-2021 (Ex. A2-2-1 Attachment 1).
2. From Ex. I1-1-1, Table 1, sum of line 5, line 6 and line 7. Nuclear amounts do not include the lesser of unamortized asset retirement costs ("ARC") or unfunded nuclear liabilities ("UNL"). This is consistent with the OEB-approved methodology for determining rate base financed by capital structure, wherein the weighted average cost of capital is applied to OPG's rate base that does not include the lesser of ARC or UNL.

a) Please confirm whether the rate base values shown are: i) beginning of year; ii) mid-year or average of the year; or iii) end-of year.

b) OPG proposes that the equity thickness for the combined hydroelectric and nuclear generating regulated assets be increased to 49% for the whole period of the five- year term, in light of increased risk. The significant capital additions are mainly due to the Darlington Refurbishment Program, which significantly increases the relative percentage of OPG's regulated asset rate base related to nuclear generation. However, from Chart 1, significant additions to the nuclear rate base only begin to occur in 2020, when the nuclear rate base becomes approximately equal to the hydroelectric rate base, and exceeds it only in the last year of the plan 2021. For the first three years of the plan (2017-19), regulated hydroelectric rate base remains more than double the nuclear rate base.

   Please explain why OPG is proposing that the 49% equity thickness apply to all years in the five-year plan. On an assumption that there could be increased risk due to the increased risk from significant nuclear capital investments, why wouldn't the increased thickness only apply, if necessary, beginning in 2020 or 2021?

Response

a) The rate base values in Chart 1, from page 1 of Ex. C1-1-1 Attachment 1, are determined using a mid-year average methodology. As discussed at Ex. B1-1-1 page 4: "for large in-service additions or adjustments, where the in-service addition amount of the amount of an adjustment exceeds $50M, the month in which the addition or adjustment is reflected is used, instead of a mid-year average, to improve accuracy."

b) The following response was prepared by Concentric Energy Advisors:

OPG is proposing that the 49% equity thickness apply to all years in the five-year plan for several reasons. As discussed in Concentric's Common Equity Ratio Report (Ex. C1-1-1 Attachment 1, pages 13 and 14) the cost of capital (including the capital structure) is a forward-looking concept from the perspective of investors. OPG requires ongoing access to capital on reasonable terms in order to finance the Company's significant capital spending program over the 2017 to 2021 period and beyond. Investors and credit rating agencies are aware of OPG's elevated capital spending program and shifting rate base between 2017 and 2021. In order to ensure investors and rating agencies that there is regulatory support for cost recovery and credit quality, OPG's rates should reflect the increased risk profile of its elevated capital spending program and its shifting rate base to a higher percentage of nuclear assets relative to hydroelectric assets.

Although the first refurbished Darlington unit will not be brought into service until late in the test period, OPG will be making substantial capital investments over the next five years that will require access to capital on reasonable terms and that will place pressure on OPG's cash flows and credit metrics during this period. In particular, OPG forecasts total capital expenditures of approximately $5.25 billion on the DRP from 2017-2021 (Ex. D2-2-10, Table 1). DBRS has commented specifically on the risk associated with the DRP as follows:

> *DBRS believes that given the complexity and scale of the Darlington Refurbishment, there is significant execution risk as well as the potential for cost overruns. The high capital expenditures (capex) required, albeit spread over a ten-year period, in addition to ongoing maintenance capex (total capex forecast of approximately $2 billion in 2016), are expected to pressure OPG's key credit metrics.*[1]

DBRS also notes that OPG is expected to generate a free cash flow deficit in 2016 due to the large capital expenditure program.[2]

Credit rating agencies have also commented more generally about the credit risk associated with large capital spending programs. For example, DBRS writes:

[1] Ex. A2-3-1, Attachment 1, at 1
[2] *Ibid.*

For utilities undergoing significant multi-year capital expansion programs, capital spending may be considered a primary rating factor. This would be particularly relevant for companies with significant nuclear generation development.[3]

Moody's has commented on the credit risk associated with capital spending plans:

Given the long-term nature of utility assets and the often lumpy nature of their capital expenditures, it is important to analyze both a utility's historical performance as well as its prospective future performance, which may be different from backward-looking measures. Scores under this factor may be higher or lower than what might be expected from historical results, depending on our view of expected future performance. In the illustrative mapping examples in this document, the scoring grid uses three year averages for the financial strength sub-factors. Multi-year periods are usually more representative of credit quality because utilities can experience swings in cash flows from one-time events, including items such as rate refunds, storm cost deferrals that create a regulatory asset, or securitization proceeds that reduce a regulatory asset. Nonetheless, we also look at trends in metrics for individual periods, which may influence our view of future performance and ratings.[4]

In an August 2016 report, S&P explains the importance of regulatory support for large capital projects:

When applicable, a jurisdiction's willingness to support large capital projects with cash during construction is an important aspect of our analysis. This is especially true when the project represents a major addition to rate base and entails long lead times and technological risks that make it susceptible to construction delays. Broad support for all capital spending is the most credit-sustaining. Support for only specific types of capital spending, such as specific environmental projects or system integrity plans, is less so, but still favorable for creditors. Allowance of a cash return on construction work-in-progress or similar ratemaking methods historically were extraordinary measures for use in unusual circumstances, but when construction costs are rising, cash flow support could be crucial to maintain credit quality through the spending program. Even more favorable are those jurisdictions that present an opportunity for a higher return on capital projects as an incentive to investors[5].

The proposed 49% equity thickness for OPG is conservative as compared to the authorized equity ratios for the operating companies held by Concentric's proxy group,

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3 DBRS, Rating Companies in the Regulated Electric, Natural Gas and Water Utilities Industry, October 2015, at 7.

4 Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, December 23, 2013, at 22.

5 S&P Global Ratings, "Assessing U.S. Investor-Owned Utility Regulatory Environments," August 10, 2016, at 7.

none of which is a pure generation company like OPG. As discussed in Ex. C1-1-1 Attachment 1, page 32, Moody's views power generation as the highest risk component of the electric utility business, as generation plants are typically the most expensive part of a utility's infrastructure (representing asset concentration risk) and are subject to the greatest risks in both construction and operations, including the risk that incurred costs will either not be recovered in rates or recovered with material delays. In addition, nuclear generation is generally considered to be the highest risk generation source. DBRS explains:

> *Nuclear generation faces higher operating risk than other types of generation because of its complex technology (approximately 57% of OPG's production in 2015). Financial implications of forced outages, especially with older units (e.g., Pickering Nuclear Generating Station), are greater given the high fixed-cost nature of these plants as well as the fact that lost revenues from outages are not recoverable through rates.*[6]

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[6] Ex. A2-3-1, Attachment 1, at 2

LPMA Interrogatory #3

Issue Number: 3.2

Issue: Are OPG's proposed costs for the long-term and short-term debt components of its capital structure appropriate?

Interrogatory

Reference:

Ref: Exhibit C1, Tab 1, Schedule 2, Tables 5 through 10

For each year in 2016 through 2021 as shown in Tables 5 through 10, respectively, please show the percentage of long term debt that is currently issued and the percentage of long term debt that is forecast to be issued, but has not yet been issued.

Response

Chart 1

Year		$M	%
2016	Existing Debt	2,994.8	93
	New Debt	210.0	7
2017	Existing Debt	2,580.2	69
	New Debt	1,163.8	31
2018	Existing Debt	1,857.7	44
	New Debt	2,334.5	56
2019	Existing Debt	1,629.6	35
	New Debt	3,065.6	65
2020	Existing Debt	1,177.5	24
	New Debt	3,651.9	76
2021	Existing Debt	779.5	16
	New Debt	3,952.6	84

New debt is cumulative as proposed in Ex. C1-1-2 Tables 5-10

Board Staff Interrogatory #23

Issue Number: 3.2
Issue: Are OPG's proposed costs for the long-term and short-term debt components of its capital structure appropriate?

Interrogatory

Reference:
Ref: Exh C1-1-2
Ref: Consensus Forecasts (January 2009 to date)
Ref: Bank of Canada website – month-end 10 Government of Canada Bond Yields Ref: O.Reg. 53/05

OPG has relied on the methodology accepted by the OEB in its prior payments applications with respect to the methodology for forecasting the long-term debt rate for forecasted new long-term debt that it expects to incur during the test period.

OPG's methodology is similar to that adopted by the OEB for estimating the deemed long-term debt rate that applies or acts as a ceiling on long-term debt costs, in accordance with the OEB's current cost of capital policy as documented in the Report of the Board on the Cost of Capital for Ontario's regulated Utilities (EB-2009-0084), December 11, 2009. However, the methodology differs in two major respects:

- OPG forecasts the rate for new debt "based on the prevailing benchmark Government of Canada bond for the corresponding term of the debt, as published by a verifiable market monitoring service on the day prior to the date funds are advanced, plus a credit margin determined five business days before the date funds are advanced. The credit margin is determined based on a sample of quotes for OPG's credit margin as provided by a selected group of Canadian banks."[4]
- Since OPG's test period has been for two years in all previous payments applications, and the forecast period for the application is longer than the one-year horizon in *Consensus Forecasts* as used by the OEB, OPG uses longer-term estimates of the 10-year Government of Canada bond yield from IHS Global Insights to cover the 2-year test period.

OPG is not proposing any changes to its previously accepted methodology. However, with the longer term period of the current application from 2017-21, in addition to the bridge year of 2016, it is forecasting the cost of new or replacement debt over a forecast period of 6 years, at least double that from previous applications.

OEB staff undertook an analysis to compare the forecasting error of the three-month ahead and 12-month ahead forecasts of the 10-year Government of Canada bond yield as published by *Consensus Forecasts*, and which the OEB relies on for its long-term debt rate and ROE estimates. This analysis calculates the variance between the month- end 10-year Government of Canada bond yield as published on the Bank of Canada website against the 3-month and 12-month ahead forecasts for the 10-Year Government of Canada bond yield published earlier in Consensus Forecasts for that same month-end. OEB staff notes that IHS Global Insights is one of the economic forecasters surveyed by *Consensus Forecasts*, and so has done the analysis based on both the overall Consensus Forecast and on the IHS Global Insights estimates provided to and published by *Consensus Forecasts*. The analysis was done for all months from January 2010 to date, covering the period of the OEB's current cost of capital methodology and also since the recovery from the 2008-2009 global economic downturn and the current period of low interest rates.

The analysis is documented in a separate Microsoft Excel spreadsheet.

The results are summarized in the following table:

OEB Attachment

[4] Exh C1-1-2 page 3

Variance from actual 10-year Government of Canada bond yield month end January 2010 - July 2016

	Consensus Forecasts			IHS Global Insights estimate from *Consensus Forecasts*	
	Difference from actual of 3-month forecast	Difference from actual of 12-month ahead forecast		Difference from actual of 3-month forecast	Difference from actual of 12-month ahead forecast
Mean	0.30	0.90		0.44	0.94
Max	1.21	2.21		1.48	2.1
Min	-0.73	-0.63		-0.91	-0.66

All numbers are percentages

The analysis demonstrates the forecasting errors. First, the forecasting error is generally higher for the 12-month ahead forecast than for the three-month ahead forecast, and the bias is much higher for the longer-term forecast. It would be expected that even longer forecasts – 2-, 3- or 5-years would show even larger forecasting errors.

These results are not surprising in current economic conditions, where persistent low interest rates make the likelihood and magnitude of under-forecasting less than for over- forecasting. Nor does this imply that the forecasts are not credible or should not be used, but that caution is advised. Longer-term forecasts are much more likely to be in error and to be significantly over-forecasted under current conditions.

OPG has proposed that its weighted average cost of long-term debt, applicable to $4,000M in new and replacement debt over the period 2016-2021 be approved in this proceeding. OEB staff also notes that the weighted average long-term debt rate approved is also used to calculate the carrying costs on the rate smoothing deferral account set out in O.Reg. 53/05.

a) Has OPG conducted any similar analysis of the forecasting error of the IHS Global Insights forecast data that it subscribes to? If so, please provide copies of any such analyses.

b) Can OPG undertake to provide an analysis similar to OEB staff's analysis based on IHS Global Insights. If not, please explain.

c) The analysis indicates that there is high risk of forecasting error in the long-term debt rate, and that this increases the farther out the forecasting is. As shown in Charts 1 and 2 of Exh C1-1-2, OPG is forecasting 6-years out. OPG has also proposed a new Nuclear ROE Variance Account to track the impact on the nuclear revenue requirement of the annual update of the ROE. How does OPG propose to mitigate the risk that the long term debt rate and/or that OPG's new or replacement long term debt does not occur as forecasted?, Would it not also be reasonable that an account be used to track the variance of the nuclear revenue requirement in each year from what is approved in this application and what would be the revenue requirement based on actual debt and the actual weighted average cost of long term debt?

d) A variation on c) would be for OPG, in its annual payment application which it proposes to file to update the hydroelectric payments in accordance with the approved hydroelectric Price Cap plan, to also file updated forecasted long-term debt rates based on shorter-term forecasts (3-months and one-year ahead) of its expected debt cost. The forecasting error would be much smaller. The approach would be analogous to what Enbridge Gas Distribution Inc. does with its annual rate applications under its current multi-year rate plan.

   Please provide OPG's views as to whether the account described in c) or that in d) is preferable. Please explain.

Response

Before responding to the above question, OPG wishes to clarify how the rate for new debt issuances is forecasted. As stated in EX. C1-1-2 on page 4, the cost of planned new and refinanced corporate debt and project-related debt for 2016 to 2021 is based on a forecast of the 10-year Long Canada Bond published in January 2016 by Global Insight. OPG's credit spread of 161 basis points (OPG's credit spread at the end of 2015) is added to the bond rates to determine the forecast for OPG's OEFC planned debt in 2016 to 2021.

The preamble to this question erroneously stated that OPG forecasts the rate for new debt "based on the prevailing benchmark Government of Canada bond for the corresponding term of the debt, as published by a verifiable market monitoring service on the day prior to the date funds are advanced, plus a credit margin determined five business days before the date funds are advanced. The credit margin is determined based on a sample of quotes for OPG's credit margin as provided by a selected group of Canadian banks." This quote from OPG's evidence at Ex. C1-1-2 page 3 is describing how a rate is assigned once the debt is issued.

a) No, OPG has not conducted a similar analysis of the forecast data provided by IHS Global Insights.

b) OPG has prepared an analysis of IHS Global Insight forecasts of Government of Canada 10-year bond yields for 2-years ahead, 3-years ahead and 5-years ahead compared to the actual yield on Government of Canada 10-year bonds. The results of this analysis are summarized in Table 1 below:

Table 1: IHS Global Insight Forecasts Variance Analysis

	Difference from actual of 2-years ahead forecast - IHS Global Insight	Difference from actual of 3-years ahead forecast - IHS Global Insight	Difference from actual of 5-years ahead forecast - IHS Global Insight
Mean	1.76	2.52	3.46
Max	3.76	3.80	5.06
Min	0.27	1.53	1.28

c) Since the Nuclear component of new debt issuances makes up relatively small component of OPG's rate base, the actual cost of debt has a relative small impact on OPG's nuclear revenue requirement. As a result, OPG does not believe that the long-term debt forecast poses a significant risk that requires mitigation.

Table 1 below shows the percentage of total Rate Base attributed to the Nuclear business as shown in C1-1-1 Chart 1:

Table 1: Breakdown of Rate Base

Rate Base	2017	2018	2019	2020	2021
Hydro ($B)	7.5	7.5	7.5	7.6	7.7
Nuclear ($B)	3.3	3.5	3.5	7.5	8.0
Total ($B)	10.8	11.0	10.9	15.1	15.6
Nuclear Portion of Total Rate Base	31%	32%	32%	50%	51%

Table 2 below shows the small component of rate base attributed to the cumulative new debt issuances over the 2017-2021 term.

Table 2: Impact of New Debt Issuances Attributed to Nuclear

	2017	2018	2019	2020	2021
Cumulative Total New Debt Issuances[1] ($B)	0.5	1.4	1.9	2.3	2.5
Total Rate Base ($B)	10.8	11.0	10.9	15.1	15.6
Component of Rate Base Attributed to New Debt Issuances	5%	12%	17%	15%	16%
Nuclear Portion of Total Rate Base	31%	32%	32%	50%	51%
Nuclear Component of Rate Base Attributed to New Debt Issuances	2%	4%	6%	8%	8%

In contrast to the small component of rate base that can be attributed to the 2017-2021 new debt issuances, the Nuclear component of rate base attributed to equity ranges from 15% to 25% over 2017-2021. This larger makeup of the overall rate base is what makes it appropriate to track the changes in ROE in a variance account.

d) As discussed in 3.1-Staff-20, OPG agrees that the cost of capital that is implicitly reflected in the hydroelectric payment "rates" will change every year in accordance with the price cap adjustment. As such OPG understands that the option discussed in part d) would apply to Nuclear only.

OPG understands that 4GIRM (and price-cap index-based regulation in general) is premised on the regulatory efficiency that results from the mechanistic nature and the narrow scope of annual adjustment proceedings. To the extent that the nature and scope of those proceedings are expanded to include the review of proposals to change OPG's cost components, those proceedings are made more complex, regulatory efficiency is reduced, and related costs increase.

[1] New issues are weighted in the year issued based on issue date, and allocated to the regulated business based on the allocation percentage identified at Ex. C1-1-2 Table 1, row 13

VECC Interrogatory #9

Issue Number: 3.1
Issue: Are OPG's proposed capital structure and rate of return on equity appropriate?

Interrogatory

Reference:
Reference: C1/T1/S1

Pre-amble: In the 2016 Ontario budget announcement found at http://www.fin.gov.on.ca/en/budget/ontariobudgets/2016/bk9.html, the province stated:
The Province remains committed to building a cleaner and more sustainable energy system for all Ontarians while reducing electricity system cost pressures. Since 2003, more than $34 billion has been invested in cleaner energy generation in Ontario, with Hydro One investing about $15 billion in modern transmission and distribution infrastructure. Other initiatives include:

- Pursuing the continued operation of the Pickering Nuclear Generating Station beyond 2020 up to 2024. By doing this, Ontario Power Generation (OPG) would protect 4,500 jobs across the Durham region, avoid eight million tonnes of GHG emissions, and save Ontario electricity consumers up to $600 million.
- Moving forward with OPG's refurbishment of the four units at the Darlington Nuclear Generating Station. The Independent Electricity System Operator has updated its contract with Bruce Power to refurbish six nuclear units, in addition to two already refurbished units at the Bruce nuclear site. Together, this secures over 9,800 megawatts (MW) of affordable, reliable and emission-free power.

a) Please confirm that in the Ontario Government's infrastructure programme it includes the costs of the Darlington refurbishment programme as provincial government expenditures.

b) Please indicate whether any of the generating plants in the proxy sample are instructed by their owners to follow non-financial objectives such as preserving 4,500 jobs and if their owners put out a release with titles similar to that of Ontario's "Jobs for today and tomorrow". In Concentric's judgement is such an attitude by the shareholder consistent with the stand alone principle.

c) Please indicate the capital structure and allowed ROE for the following 100% provincially owned Canadian electric utilities: New Brunswick Power, Manitoba Hydro Electric System, Saskatchewan Power and BC Hydro.

d) Please explain in detail why the equivalent 100% owned Canadian electric companies are not a better reference point for a fair capital structure than the US private non-government owned entities, particularly since S&P rates the two entities (electric company and province) the same.

e) Is Concentric aware that NB Power also has a CANDU nuclear reactor at Point LePreau?

Response

The following response was provided by Concentric Energy Advisors:

a) Concentric's assessment of OPG's risk profile was performed on a stand-alone basis, consistent with the Board's application of the stand-alone principle in prior OPG payment amount application proceedings. Specifically, as noted in Concentric's report (page 8), the Board stated in EB-2007-0905 that "[t]he stand-alone principle is a long-established regulatory principle," and that "Provincial ownership will not be a factor to be considered by the Board in establishing capital structure." As such, Concentric did not evaluate how the Ontario Government accounts for the Darlington refurbishment program as such an evaluation was not relevant to the analysis.

b) It is not Concentric's understanding that OPG has been instructed to follow non-financial objectives. Concentric is not aware of any specific examples of generating plants in the proxy sample being instructed by their owners to follow objectives such as preserving 4,500 jobs or if their owners have put out releases with titles similar to that of Ontario's "Jobs for today and tomorrow." Many of the generating plants in the proxy group, however, operate in states or regions in which their owners must comply with legislative or regulatory policies such as renewable energy portfolio standards that may be based on objectives that are not related directly to the profitability of the plants. In addition, job preservation and creation is a common benefit cited for large energy-related construction projects.

As stated in response to part a), the stand-alone principle is a "long-established regulatory principle," not a reflection of an owner's "attitude." Therefore, Concentric finds the shareholder's statements in its press release to be neither consistent nor inconsistent with that regulatory principle.

c) Please see the table below. As noted in the table, and unlike OPG, the rates of New Brunswick Power, Manitoba Hydro and Saskatchewan Power are not set based on traditional authorized cost of capital parameters, nor were they as of the time that OPG's initial cost of service payment amounts proceeding was decided (e.g., EB-2007-0905 in November, 2008).

Utility	Capital Structure (Debt/Equity)	Allowed ROE (%)
New Brunswick Power[1]	N.A.	N.A.
Manitoba Hydro Electric System[2]	N.A.	N.A.
Saskatchewan Power[3]	N.A.	N.A.
BC Hydro	70/30[4]	11.84%[5]

[1] New Brunswick Power Corporation's ("NB Power's") rates are not set based on traditional authorized cost of capital parameters. Rather, the New Brunswick Energy and Utilities Board authorizes a revenue requirement that includes a forecasted amount of net income. In addition, NB Power has a goal of achieving a 20% debt-to-capital ratio. For example, per the New Brunswick Energy and Utilities Board, "[f]or the fiscal year 2016/17, the Board approves the amount of $92.4 million for Net Income and is satisfied that this permits NB Power to continue to move towards its target of a 20% equity ratio." *See*, New Brunswick Energy and Utilities Board Decision in the Matter of an Application by New Brunswick Power Corporation Pursuant to Subsection 103(1) of the *Electricity Act*, S.N.B. 2013, c.7, for approval of the schedules of the rates for the fiscal year commencing April 1, 2016, July 21, 2016, at 14. In NB Power's previous rate case, which was decided in 1993, the New Brunswick Energy and Utilities Board applied a "return on equity test," using the embedded cost of debt as an appropriate rate of return on NB Power's equity. Specifically, the New Brunswick Energy and Utilities Board evaluated whether the approved amount of net income for NB Power would exceed the amount required to satisfy the Board's return on equity test, interest coverage test, and debt to equity ratio test. *See*, New Brunswick Energy and Utilities Board Decision in the Matter of an Application by New Brunswick Power Corporation for Approval of Changes in its Charges, Rates and Tolls, April 23, 1993, at 8 and 45.

[2] Manitoba Hydro-Electric Board's ("Manitoba Hydro's") rates are not set based on traditional authorized cost of capital parameters. Manitoba Hydro sets rates based on the objectives of recovering its cost of service and achieving a target capital structure of 75/25 debt/equity. *See, e.g.*, Manitoba Public Utilities Board Order 90/08, June 30, 2008, at 17, and Manitoba Public Utilities Board Order 73/15, July 24, 2015, at 51..

[3] Saskatchewan Power's ("SaskPower's") rates are not set based on traditional authorized cost of capital parameters. SaskPower does, however, have a target debt level of 60-75% and a target ROE of 8.5%. Per SaskPower, "[i]n recent years, SaskPower has attempted to cap its rate increases at 5% per year. The result has been that the Corporation has absorbed some of the required rate adjustments through increased debt rather than passing costs on immediately to [its] customers. These constraints on rate inceases combined with SaskPower's capital program have resulted in SaskPower's debt level reaching the upper limit of [its] 60-75% target," and, "SaskPower's long-term ROE target is 8.5%..." SaskPower Rate Application 2016 and 2017, June 2, 2016, at 14.

[4] Equal to BC Hydro's "deemed equity" from its 2015 to 2016 revenue requirements application. *See*, BC Hydro F2015 to F2016 Revenue Requirements Rate Application (F15-F16 RRRA), March 7, 2014, Appendix C, at 40.

[5] British Columbia Utilities Commission, Order No. G-48-14 in the matter of the Utilities Commission Act, R.S.B.C. 1996, Chapter 473 and British Columbia Hydro and Power Authority Application Regarding its Rates for F2014, F2015 and F2016, Expenditures on Demand Side Measures in F2014, F2015 and F2016 and Retail Access, March 24, 2014, at 6. Note, in 2016 the Province of British Columbia changed the rate regulation of BC Hydro such that starting in fiscal 2018 the company will no longer earn a set ROE as part of its revenue requirement, but rather will have rates designed to earn a specific distributable surplus (*see*, Project No. 3698869, British Columbia Utilities Commission British Columbia Hydro and Power Authority Fiscal 2017 to Fiscal 2019 Revenue Requirements Application Evidentiary Update, August 17, 2016, at 1-15.)

d) S&P does not rate OPG and the Province of Ontario the same. S&P assigns an A+ rating to the Province of Ontario and a BBB+ rating to OPG (i.e., a three notch difference). In addition, S&P states that its stand-alone credit profile for OPG is BBB-.

New Brunswick Power, Manitoba Hydro Electric System, Saskatchewan Power and BC Hydro, in contrast, are either not separately rated from their Provinces (i.e., New Brunswick Power) or receive a "flow-through" of the Province's rating. The reason for this is each of those companies' debt obligations are either direct obligations of the Province or are wholly guaranteed by the Province. The following are excerpts from DBRS regarding each company's credit rating (except New Brunswick Power, which is not separately rated from the Province of New Brunswick):

- BC Hydro: "The ratings assigned to the Long- and Short-Term Obligations of BC Hydro are a flow-through of the ratings of the Province of British Columbia (the Province; rated AA (high) and R-1 (high) with Stable trends; see DBRS's report dated April 28, 2016). Pursuant to the B.C. Hydro and Power Authority Act, the Long- and Short-Term Obligations of BC Hydro are either direct obligations of, or are guaranteed by, the Province." (DBRS Rating Report, British Columbia Hydro and Power Authority, September 30, 2016, at 1.)
- Manitoba Hydro: "The ratings assigned to the Utility's Long-Term Obligations and Short-Term Obligations are a flow-through of the ratings of the Province of Manitoba (the Province; rated A (high) and R-1 (middle) with Stable trends by DBRS). Pursuant to The Manitoba Hydro Act, the Province unconditionally guarantees almost all of Manitoba Hydro's outstanding third-party debt." (DBRS Rating Report, The Manitoba Hydro-Electric Board, November 26, 2015, at 1.)
- Saskatchewan Power: "The ratings assigned to the Company's Long- and Short-Term Obligations are a flow-through of the ratings of the Province of Saskatchewan (the Province; rated AA and R-1 (high) with Stable trends by DBRS; see DBRS's report on the Province dated September 12, 2016). Pursuant to The Power Corporation Act (the Act), SaskPower does not issue debt directly in the capital markets, but obtains funding from the Government of Saskatchewan Ministry of Finance." (DBRS Rating Report, Saskatchewan Power Corporation, September 29, 2016, at 1.)

New Brunswick Power, Manitoba Hydro Electric System, Saskatchewan Power and BC Hydro are not a better reference point for OPG's capital structure because, as described above and in part (c) to this response, rates are set for those utilities on a different basis than they are set for OPG, and the risks for those utilities, as viewed by DBRS, are indistinguishable from their provinces. That is clearly not the case with OPG. In fact, those companies are rated by DBRS to be between three and six notches higher than OPG (or five to eight notches when OPG's stand-alone credit profile is considered). In contrast, the publicly-traded proxy companies analyzed by Concentric were screened to have risk characteristics similar to OPG, consistent with the fair return standard. In addition, precedent in Ontario and other Canadian provinces for considering U.S. data for cost of capital evaluations is set out in Appendix A to Exhibit C1-1-1, Attachment 1. For those reasons, Concentric considers the proxy group to be a better reference point for OPG's capital structure.

In addition, it is important to note that New Brunswick Power, Manitoba Hydro Electric System and Saskatchewan Power are not authorized deemed equity ratios through the ratemaking process, but rather the capital structures referenced in the footnotes in response to VECC-9(c) represent target *actual* capital structures. OPG is significantly underleveraged relative to its deemed capital structure. Reflecting the actual capital structure in OPG's rates would result in an equity ratio of over 70%.[6]

e) Yes.

[6] Calculated by setting the portion of rate base financed by deemed debt in Ex. C1-1-1 Tables 1-5 to the sum of short-term debt (line 1) and existing/planned long-term debt (line 2).

Board Staff Interrogatory #243

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

Interrogatory

Reference:
Ref: Exh A1-3-2 Attachment 1, page 40

LEI States: "the Two Inputs are Capital measured as Capacity (MW) and Non-capital costs measured as total O&M inputs in constant prices..." and "the Labour share of O&M is 63% and the Non-labour share of O&M is 37%"

a) What companies in the sample did not have itemized data on labour expenses?

b) Did the O&M expense data include only salaries and wages or did it also include pension and other benefit expenses?

c) Please report the exact labour price indexes employed in the study. Do these indexes address labour price trends inclusive of pension and benefit expenses?

d) Please describe the EUCG dataset and explain how it was used to calculate the 63% labour cost share. What is this percentage for OPG? Why was a fixed weight used instead of a time-varying weight?

e) Please explain the rationale for combining the US and Canadian O&M price indexes into a North American O&M price index. How was it used? Please clarify how the 22% weight for Canada was determined.

Response

The following responses were provided by LEI.

a) FERC Form 1 data did not include public data specific to labour expenses separately from O&M. Federal and municipal peers O&M data was sourced from annual reports/financial filings as well as information obtained directly from the companies and also didn't provide labour data separate from total O&M.

On page 20 of the report, LEI states:

> "Due to data constraints, LEI could not rely on number of employees or otherwise isolate the labour costs from total O&M costs. However, labour costs are already reflected in O&M costs indirectly through the input price indices..."

b) The FERC Form 1 O&M data does not include pension and other benefit expenses; it includes line items from FERC Form 1 as described on Figure 20 on page 34 of LEI's report.[1]

LEI worked with OPG to ensure O&M data consistent between FERC Form 1 and OPG. However, as noted on page 33 of the report, administration costs (including current pension service costs and other benefits) were included in the OPG OM&A data. These administration costs were found by OPG to be relatively flat historically, and were not a major component of the total OM&A, so their inclusion would not measurably impact TFP trends.

c) For a Canadian labour price index, LEI used Statistics Canada's Average Weekly Earnings (AWE) in current dollars, for Ontario, including overtime, seasonally adjusted, for all employees, by selected industries classified using the North American Industry Classification System (NAICS) from CANSIM Table 281-0027.[2] The OEB is familiar with the industrial aggregate AWE in the context of the electric distributor rate-setting.[3] LEI understands that the AWE data is based on gross payroll before source deductions and does not include pension and benefit expenses.

For US companies, LEI used the US Bureau of Labor Statistics: Wages and salaries for Private industry workers in Utilities Index, accessed as of January 5, 2016.[4] It includes wages, salaries and the following benefits: paid leave, supplemental pay, insurance (health benefits), retirement and savings and what is legally required. Note that LEI relied on the best publicly available data regarding hydroelectric O&M and available industry O&M indexes. LEI notes that the US

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[1] Federal Energy Regulatory Commission. *FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report.* Pages 406 and 408. <https://www.ferc.gov/docs-filing/forms/form-1/form-1.pdf

[2] Statistics Canada. Table 281-0027 - Average weekly earnings (SEPH), by type of employee for selected industries classified using the North American Industry Classification System (NAICS), annual (current dollars), CANSIM (database). <http://www5.statcan.gc.ca/cansim/a26?lang=eng&id=2810027>

[3] Ontario Energy Board. *Filing Requirements For Electricity Distribution Rate Applications – 2015 Edition for 2016 Rate Applications. Chapter 3: Incentive Rate-Setting Applications.* July 16, 2015. <http://www.ontarioenergyboard.ca/oeb/_Documents/2016EDR/OEB_Filing%20Requirements_2016Rates_Chapter%203.pdf>

[4] Bureau of Labor Statistics. *Databases, Tables & Calculators by Subject - Wages and salaries for Private industry workers in Utilities, Index (CIU2024400000000I).* <http://data.bls.gov/timeseries/CIU2024400000000I>

BLS and StatsCan indices do not allow for the inclusion or exclusion of pension and benefits.

d) The EUCG's Hydroelectric Productivity Committee (HPC) dataset provides plant level breakdown of hydro-specific generation data for 18 companies over 2004-2014. The database contains information on about 350 hydro plants on areas such as operations, maintenance, environment and regulatory, land and water rental fees, administration, operations and maintenance investments and capital investments.

LEI used the operations and maintenance data which was broken down into labour, contract and other to develop the labour cost share. EUCG labour costs are comprised of:

- All Regular, Permanent Staff;
- All temporary staff, hiring hall, part-time or casual staff, (this will include long term assigned staff or longer term contract staff or where the individual looks and acts like permanent labour);
- All appropriate loadings, such as benefits, concessions, payroll taxes, etc.; and
- Overtime.

For OPG, the labour share of O&M was 63%, consistent with the industry level of 63% from the EUCG data set. LEI used the average labour share versus non-labour share of O&M from 2004 to 2014. A fixed value was used for each of the years in the TFP study, for purposes of simplicity and consistency. It would not have been possible to use specific annual data from the EUCG data on labour shares, as the EUCG data did not cover the full duration of the study period. In addition to not having data for 2002 and 2003, LEI did not use the EUCG data to calculate TFP trends, since company specific data was not consistently represented for the 2004-2014 period.

e) Consistent with LEI's aggregation approach for the industry, LEI combined the US and Canadian O&M price indices into a North American O&M price index in order to capture the relevant price trends of both countries in the industry peer group. As discussed on page 23 of the report, LEI applied a weight of 22% for the Canadian share of the industry based on OPG's share in total O&M for the industry. The resulting weight of US total O&M price index in the North American total O&M price index is 78%. This North American O&M price index was then used to deflate the annual industry aggregate O&M values. LEI could have applied the US and Canadian O&M price indices to the O&M costs for US peers and OPG before aggregating, which would have yielded the same mathematical results.

Board Staff Interrogatory #247

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

Interrogatory

Reference:
Ref: Exh A1-3-2 Attachment 1

OEB staff would like to make an independent calculation of the productivity trend of OPG. A monetary approach would be used to calculate capital cost and the capital quantity index. Please provide the following information *for as many years as the company has data* to calculate productivity trends. It is quite useful to have the required capital cost data for a lengthy sample period even if the O&M expense data aren't available. If there are noteworthy discontinuities in the data, please explain them. Please indicate whether the Company is providing data only for prescribed generating stations or for all generating stations. The latter is satisfactory if it permits a longer sample period:

a) Value of gross additions to hydroelectric plant.

b) Gross value of hydroelectric plant in service and accumulated depreciation on hydroelectric plant.

c) The typical average service life by type of asset used by OPG to determine depreciation rates. These are not required for each year.

d) Total hydroelectric operation, maintenance, and administration (OM&A) expenses by account, itemized by major expenditure category where possible. Please provide any amounts paid for water for power such that it can be removed as it was for the LEI study.

e) Annual depreciation (amortization) charged for hydroelectric plant.

f) The amount of total hydroelectric OM&A related to compensation of company employees. Should this specific dollar figure be confidential or unavailable, please provide a typical percentage of the total (e.g. "about 60%" based on information over 10 years). Does this amount include the cost of pensions and current employee and other post-employment benefits? If so, approximately what percentage of the total is pension and current and post-employment benefits?

g) The weighted average cost of capital, itemized to the extent practicable.

h) The MWh generated by each unit operated by OPG.

i) Nameplate and operational capacity of each hydroelectric generating station operated by OPG.

j) Please identify which units are conventional and which are pumped storage

k) From previous work done for the OEB in the distribution sector, PEG is aware of the Statistical Yearbooks that Ontario Hydro used to produce annually. PEG believes that these documents also contained operational, capacity, production and financial statistics on generation and specifically for Ontario Hydro's electricity generating plants.
   i. Does OPG possess any summary data publications such as the previous Ontario Hydro Statistical Yearbooks, containing data for Ontario Hydro's generation assets, operations and production prior to the reorganization resulting from the *Energy Competition Act* of 1998?
   ii. For which years are these documents available?
   iii. If available, please provide the documents.

l) Please provide any data on the allocation of corporate costs to hydroelectric O&M (e.g., allocation of Total or Admin & General OM&A). Please describe the methodology by which Corporate A&G costs were allocated between regulated hydroelectric. Nuclear, other (including fossil) generation and, for the predecessor Ontario Hydro, transmission and distribution.

Response

OPG has determined that data dating earlier than 2002 would not provide a meaningful basis of comparison over time or with peers. Moreover, pre-2002 data is not reconcilable with more recent information, due to changes within OPG's accounting systems and major changes in the North American hydroelectric generating industry around the turn of the century. The data provided in this response is from 2002 onward, the same start date used in LEI's TFP study. As noted in Ex. A1-3-2, Attachment 1, p. 16, 2002 is the year that the Ontario competitive electricity market opened, a significant event impacting OPG's business environment. The United States' electricity markets also went through reforms and restructuring phases in the late 1990s and early 2000s. As a result of these changes, data prior to 2002 would not be reconcilable with more recent data, nor would it be representative of OPG or the industry's productivity during the period at issue in this application.

Parts a), b) and e)

Chart 1, below, is a continuity schedule for gross property, plant and equipment for OPG's currently regulated hydroelectric assets for the 2002-2015 period.

Chart 1
Continuity of Gross Property, Plant and Equipment - Regulated Hydroelectric ($M)

Line No.	Year	Opening Balance	In-Service Additions	Retirements, Transfers & Adjustments	Closing Balance
		(a)	(b)	(c)	(d)
1	2002	6,917.0	84.4	8.0	7,009.4
2	2003	7,009.4	26.9	21.0	7,057.3
3	2004	7,057.3	109.6	14.4	7,181.3
4	2005	7,181.3	49.7	15.1	7,246.1
5	2006	7,246.1	54.8	(0.8)	7,300.2
6	2007	7,300.2	81.2	(8.8)	7,372.7
7	2008	7,372.7	48.2	(8.8)	7,412.0
9	2009	7,412.0	82.5	(15.0)	7,479.6
9	2010	7,479.6	105.8	(7.5)	7,577.9
10	2011	7,577.9	134.3	(8.2)	7,704.0
11	2012	7,704.0	59.9	(13.7)	7,750.2
12	2013	7,750.2	1,559.1	(9.0)	9,300.3
13	2014	9,300.3	74.3	(85.6)	9,288.9
14	2015	9,288.9	71.2	(6.9)	9,353.2

Note: numbers may not add due to rounding.

Chart 2, below, is a continuity schedule for accumulated depreciation and amortization for OPG's currently regulated hydroelectric assets for the 2002-2015 period.

Chart 2
Continuity of Accumulated Depreciation and Amortization - Regulated Hydroelectric ($M)

Line No.	Year	Opening Balance	Depreciation and Amortization	Retirements, Transfers & Adjustments	Closing Balance
		(a)	(b)	(c)	(d)
1	2002	(305.2)	(107.9)	(2.5)	(415.7)
2	2003	(415.7)	(109.1)	(2.3)	(527.0)
3	2004	(527.0)	(111.6)	0.0	(638.6)
4	2005	(638.6)	(117.6)	(2.9)	(759.0)
5	2006	(759.0)	(112.1)	(1.5)	(872.7)
6	2007	(872.7)	(114.3)	3.3	(983.6)
7	2008	(983.6)	(113.5)	4.4	(1,092.7)
8	2009	(1,092.7)	(114.0)	5.0	(1,201.7)
9	2010	(1,201.7)	(115.3)	3.8	(1,313.2)
10	2011	(1,313.2)	(118.6)	3.2	(1,428.6)
11	2012	(1,428.6)	(121.3)	6.0	(1,544.0)
12	2013	(1,544.0)	(137.1)	4.9	(1,676.3)
13	2014*	(1,676.3)	(138.4)	8.9	(1,805.8)
14	2015	(1,805.8)	(138.2)	3.7	(1,940.4)

*Amount in col. (c) includes an adjustment to reduce the Niagara Tunnel Project in-service amount to the approved value per EB-2013-0321 Payment Amounts Order, App. A, Table 1a, Note 2.

Note: numbers may not add due to rounding.

Part c)

A list of asset classes and associated service lives for the regulated hydroelectric assets can be found at EB-2013-0321 Ex. F5-3-1, Schedule 1A. More detailed descriptions of the asset classes can be found at EB-2013-0321 Ex. L-6.12-1 Staff-157, Attachment 1.

The overall weighted average service for the regulated hydroelectric assets (excluding the Niagara Tunnel Project) is estimated to be between 80-85 years.

Parts d) and l)

Chart 3, below, presents the total operation, maintenance, and administration costs for the hydroelectric facilities by account. Chart 3 also includes Project OM&A Costs (a subset of Maintenance Costs), HTO Central Support Group Costs, and Corporate Allocated Costs (Corporate Support Services, Centrally Held Costs, Asset Service Fees).

Chart 3 reflects changes to OPG's hydroelectric operations over time, including the following:

1. Business reorganizations in 2006 and 2012.
2. The cost and production associated with approximately 30 MW of capacity was removed from the data starting in 2008-2009, when this capacity became contracted. Prior to that time, OPG did not separately track the cost of this generation.
3. The cost and production associated with approximately 485 MW of capacity was removed from the data set starting in 2011, when this capacity became contracted. Prior to that time, OPG did not separately track the cost of this generation.

Neither the costs provided in Chart 3 nor the costs provided to LEI include Gross Revenue Charges and Water Rentals.

Actual corporate costs allocations are available from 2005 onwards. Corporate cost allocations for 2004 were prepared by applying the 2005 allocation methodology to the 2004 data. The 2002-2003 allocations were estimated by extrapolation from the 2004 data.

OPG's corporate cost allocation methodology is described in the following references:

1. EB-2007-0905, Ex. F3-1-1 and Ex. F3-3-1
2. EB-2010-0008, Ex. F3-1-1, Ex. F3-2-1 and Ex. F4-4-1
3. EB-2013-0321, Ex. F3-1-1, Ex. F3-2-1 and Ex. F4-4-1

Chart 3

Hydroelectric Operations, Maintenance, and Administration Costs ($M) (iv)

Years	Operations Cost, $M	Maintenance Cost, $M	Administration Cost, $M	Project OM&A, $M	Total Plant Group Costs, $M	HTO Central Support Group Cost, $M	Corp Allocated Costs, $M	Total Costs, $M
	A	B	C	(i) D	A+B +C	(ii) (v) E	(ii), (iii) F	A+B+C+E+F
2002	13.7	85.9	18.3	24.3	117.9	26.1	56.8	200.9
2003	14.8	96.7	19.2	30.1	130.7	19.1	58.1	207.8
2004	15.4	96.3	20.5	26.1	132.2	11.2	59.7	203.1
2005	15.4	106.0	21.0	30.1	142.4	15.8	65.4	223.6
2006	16.9	115.1	24.6	34.3	156.6	20.1	84.9	261.6
2007	17.5	123.2	24.3	33.4	165.0	19.8	94.7	279.4
2008	18.1	142.6	25.1	41.6	185.7	22.3	96.3	304.3
2009	20.4	133.9	30.8	33.5	185.1	28.5	85.2	298.8
2010	17.8	142.5	24.4	45.1	184.7	23.1	90.6	298.4
2011	17.6	129.0	28.0	28.4	174.6	24.4	93.5	292.5
2012	17.4	135.9	24.9	34.1	178.1	16.5	110.1	304.8
2013	19.2	138.7	24.7	34.6	182.6	17.2	111.1	310.9
2014	21.0	145.2	21.8	37.7	188.0	20.7	126.0	334.7
2015	21.2	161.7	27.3	52.3	210.2	32.2	140.0	382.4

Notes:
(i) Project OM&A is provided for information only. It is a subset of Maintenance Costs (Column B).
(ii) Classification between Operations, Maintenance, and Administration is not available for HTO Central Support Group and Corporate Allocated Costs.
(iii) Corporate Allocated Costs includes Corporate Support Services, Centrally Held Costs, and Asset Service Fees. IESO non-energy charges are excluded.
(iv) Includes data for currently regulated stations, as well as certain other stations for periods prior to becoming contracted or divested by OPG.
First Nations provision funding amounts are excluded from Plant Group OM&A costs.

Numbers may not add due to rounding.

Part f)

Approximately 60% of regulated hydroelectric OM&A ("Total Costs" shown in Chart 3) is related to the compensation of company employees. This includes the current service cost of pensions and other post employment benefits, and current employee benefits. Approximately 23% of the compensation costs (or 14% of the total OM&A costs) is associated with these benefits. In addition, total costs include the regulated hydroelectric portion of non-current service components of pension and OPEB costs held centrally.

Part g)

Chart 4, below, provides the itemized weighted average cost of capital as approved by the OEB.

Chart 4
Weighted Average Cost of Capital, based on OEB Approved Values

Line No.		2008	2009	2010	2011	2012	2013	2014	2015
1	Debt Ratio (%)[1]	53%	53%	N/A	53%	53%	N/A	55%	55%
2	Debt Cost ($M)[1]	5.76%	5.89%	N/A	5.44%	5.50%	N/A	4.81%	4.85%
3	Equity Ratio (%)[1]	47%	47%	N/A	47%	47%	N/A	45%	45%
4	ROE (%)[1]	8.65%	8.65%	N/A	9.43%	9.55%	N/A	9.36%	9.30%
5	Tax Rate (%)[2]	31.50%	31.00%	N/A	26.50%	25.00%	N/A	25.00%	25.00%
6	**WACC**	**8.99%**	**9.01%**	**N/A**	**8.91%**	**8.90%**	**N/A**	**8.26%**	**8.25%**

Notes
1 2008-2009 from EB-2007-0905 Payment Amount Order Appendix A, Tables 4b, 5b respectively
2011-2012 from EB-2010-0008 Payment Amount Order Appendix A, Tables 4b, 5b respectively
2014-2015 from EB-2013-0321 Payment Amount Order Appendix A, Tables 5b, 6b respectively
2 2008-2009 from EB-2007-0905 Ex. F3-2-1 Table 7, line 32
2011-2012 from EB-2010-0008 Payment Amount Order Appendix A, Tables 6, 7 respectively
2014-2015 from EB-2013-0321 Payment Amount Order Appendix A, Tables 7, 8 respectively

Part h)

Chart 5, below, presents total generation in MWh, including electricity generated in segmented mode of operations. Chart 5 presents the total generation data in MWh, with and without Pump Generating Station (PGS) operation. Generation including PGS is lower due to the reduction in net production that results from the energy costs of pumped storage generation.

OPG does not have consistent generation data for at the unit level, as the energy meters for many stations are installed at station level or IESO/Hydro One Injection points.

Chart 5
Total Hydroelectric Generation (TWh)

Years	Generation	Generation with PGS
2002	33.9	33.8
2003	33.1	33.0
2004	35.3	35.2
2005	33.4	33.2
2006	34.2	34.0
2007	32.9	32.7
2008	37.4	37.3
2009	36.3	36.2
2010	30.5	30.4
2011	31.3	31.2
2012	29.5	29.4
2013	31.4	31.3
2014	31.5	31.4
2015	30.3	30.2

Part i)

The individual units in many stations have undergone several upgrades since the original in-service dates. As a result, the nameplate capacity does not accurately reflect the capacity of the facilities. OPG defines operational capacity as the Maximum Continuous Rating (MCR) in MW for each operating hydroelectric unit, as registered with the IESO.

The current MCR information for OPG's regulated hydroelectric facilities is provided in Ex. A1-4-2, p. 2, Chart 1. The MCR in MW for all hydroelectric stations operated by OPG from 2002 to 2015 is provided in Chart 6, below. Chart 6 is net of any divested, decommissioned or contracted stations from the date of divesture, decommissioning or contract execution.

Chart 6
Maximum Continuous Rating -
Hydroelectric Facilities (MW)

Years	Generation Capacity / MCR
2002	6899
2003	6926
2004	6958
2005	6924
2006	6971
2007	6971
2008	6999
2009	6905
2010	6906
2011	6422
2012	6422
2013	6433
2014	6433
2015	6428

Part j)

OPG only operates one pump generating station, which is listed at Ex. A1-4-2, p. 2, Chart 1: Sir Adam Beck PGS under Niagara Operations. All other regulated hydroelectric generating stations are conventional hydroelectric generating stations.

Part k)

The requested materials all date prior to 2002. For the reasons stated on page 2 of this response, OPG declines to provide these materials.