Board Staff Interrogatory #209

Issue Number: 9.1
Issue: Is the nature or type of costs recorded in the deferral and variance accounts appropriate?

Reference:
Ref: Exh H1-1-1a, Table 1a and Table 8

Interrogatory

Opening balances of the Pension & OPEB Cash Versus Accrual Differential Deferral and Pension & OPEB Cash Payment Variance Accounts for Hydroelectric and Nuclear are presented in Table 1a. These balances were presented in the EB-2014-0170 evidence, however, no further information regarding the balances were provided in that application as the balances were not proposed for disposition. OPG is proposing the Pension & OPEB Cash Payment Variance Account for disposition in this proceeding.

OPG is not proposing the Pension & OPEB Cash Versus Accrual Differential Deferral Account for disposition, but OPG has proposed that the future recovery of this account be limited to the outcome of the generic consultation and not be subject to a future prudence review.

Please provide the derivation of the 2014 opening balances similar to that as in Table 8.

Response

See Attachment 1, Table 1.

Numbers may not add due to rounding.

Table 1
Pension & OPEB Cash Payment Variance Account and Pension & OPEB Cash Versus Accrual Differential Deferral Account
Summary of Account Transactions - November to December 2014 ($M)

Line No.	Particulars	Note	Actual Nov to Dec 2014 Regulated Hydroelectric	Nuclear	(a)+(b) Total
			(a)	(b)	(c)
1	**Forecast Pension Contributions - EB-2013-0321**	1	7.5	46.8	54.3
2	**Forecast OPEB Payments - EB-2013-0321**	2	2.1	13.3	15.5
3	**Total Forecast Pension and OPEB Cash Amounts** (line 1 + line 2)		9.7	60.1	69.7
4	**Actual Pension Contributions**		7.1	47.7	54.8
5	**Actual OPEB Payments**		2.8	18.6	21.4
6	**Total Actual Pension and OPEB Cash Amounts** (line 4 + line 5)		9.8	66.3	76.1
7	**Total Addition to Pension & OPEB Cash Payment Variance Account** (line 6 - line 3)	3	0.2	6.2	6.4
8	**Actual Pension Accrual**		10.4	69.9	80.2
9	**Actual OPEB Accrual**		4.1	27.8	31.9
10	**Total Actual Pension and OPEB Accrual** (line 8 + line 9)		14.5	97.6	112.1
11	**Total Addition to Pension & OPEB Cash Versus Accrual Differential Deferral Account** (line 10 - line 6)	4	4.6	31.3	36.0

Notes:

1 From EB-2013-0321 Payment Amounts Order, App. G, page 14 at $27.15M/month ($3.77M/month for Regulated Hydroelectric, and $23.38M/month for Nuclear).

2 From EB-2013-0321 Payment Amounts Order, App. G, page 14 at $7.73M/month ($1.07M/month for Regulated Hydroelectric, and $6.66M/month for Nuclear).

3 As shown in EB-2014-0370 Ex. H1-1-2 Table 1c, col (b) line 13 for Regulated Hydroelectric and line 31 for Nuclear.

4 As shown in EB-2014-0370 Ex. H1-1-2 Table 1c, col (b) line 12 for Regulated Hydroelectric and line 30 for Nuclear.

Board Staff Interrogatory #210

Issue Number: 9.1
Issue: Is the nature or type of costs recorded in the deferral and variance accounts appropriate?

Interrogatory

Reference:
Ref: Exh H1-1-1, Table 11 and 11a Ref: Exh D2-2-10, Table 5

In the table referenced above the balance of the Capacity Refurbishment Variance Account (CRVA) for DRP is shown as $41.6M-$12.4 = ($10.9M) for non-capital and ($37.5M) for capital, for a total of ($48.2M).

a) Please confirm that the above numbers are correct.

b) Please provide an explanation for the variance between forecast and actual non- capital amounts.

c) Complete the following table with actual additions to rate base for 2014 and 2015:

d) Please reconcile the Net Plant Rate Base Amounts of $116M and $204.6M with the actual in-service capital additions of $43.5M and $147.1M shown in the second reference above.

$M	2014 Forecast	2014 Actual	2015 Forecast	2015 Actual
Darlington Energy Complex	92.0		89.6	
Water and Sewer Project	20.8		26.4	
Heavy Water Storage & Drum Handling Facility			20.3	
Darlington Operations Support Buildin Refurbishment			14.6	
Auxiliary Heating System			17.9	
Electric Power Distribution System	2.2		7.3	
Powerhouse Steam Venting System			5.0	
Third Emergency Power Generator Project			16.0	
Other Miscellaneous Projects	1.0		7.5	
Any other projects?				
Net Plant Rate Base Amount	116.0		204.6	

Response

a) Not confirmed.

The numbers cited in this question do not represent the balance of the Capacity Refurbishment Variance Account (CRVA) for the Darlington Refurbishment Program (DRP) as at December 31, 2015. Instead, Ex. H1-1-1 Table 11 and Table 11a outline additions to the account during 2015.

The amount of ($37.5M) cited in the question and found at Ex. H1-1-1 Table 11, line 34 is the capital portion of the CRVA addition for DRP during 2015. The non-capital (OM&A) portion of the CRVA addition for the DRP during 2015 is ($11.9M), not ($10.9M) cited in the question. The ($11.9M) addition represents ($10.9M) found at Ex. H1-1-1 Table 11, line 11 less $1.1M for the EB-2013-0321 Ex. N1 Impact Statement (Ex. N1) Adjustment. The $1.1M adjustment, found at Ex. H1-1-1, Table 11a, Note 1, line 9a, col. (a) and explained in Note 2 of that table, is embedded in Ex. H1-1-1 Table 11, line 16.

b) An explanation of the variance of ($16.7M) between actual and EB-2013-0321 forecast DRP OM&A for 2015 is found at Ex. F2-7-1, p. 1, lines 26-31. To arrive at the non-capital CRVA addition of ($11.9M) from part (a), offsetting the variance of ($16.7M) is the impact of averaging the 2014 and 2015 annual EB-2013-0321 forecast amounts in determining the reference amounts for calculating CRVA entries, as shown in Ex. H1-1-1 Table 11a, note 1, col. (a), lines 1a to 4a. This averaging approach to determining reference amounts is the same approach approved by the OEB for other variance accounts in the EB-2014-0370 and EB-2013-0321 Payment Amounts Orders (e.g., Ancillary Services Net Revenue Variance Account, Pension & OPEB Cash Payment Variance Account).

c) The requested information is provided in Table 1 of Attachment 1. To facilitate reconciliation with other evidence in this rate application and part (d) of the response, OPG has modified the table to include a sub-total for amounts excluding projects reclassified to Nuclear Operations subsequent to EB-2013-0321. This is discussed further in part (d). The 2014 Actual and 2015 Actual values shown are also found at Ex. L-2.2-1 Staff-9, Attachment 1.

d) The question requests a reconciliation of the forecast net plant rate base amounts to actual in-service capital additions. As in-service capital additions are one of the inputs into the computation of net plant rate base amounts, with other inputs being opening net plant values and depreciation expense, and as the amounts cited are of different vintages (i.e. forecast and actual), it is not possible to provide a direct reconciliation.

To provide further detail on the amounts in question, OPG has prepared the following Tables 2 and 3 in Attachment 1 showing DRP rate base continuities, including in service additions and depreciation, for each of forecast and actual net plant rate base amounts for 2014 and 2015.[1]

The forecast DRP net plant rate base amounts of $116.0M for 2014 and $204.6M for 2015 shown on line 9 of Table 2 in Attachment 1 (and detailed in part (c) of this response) represent the EB-2013-0321 approved forecasts underpinning the reference amounts used to calculate capital additions into the CRVA (Ex. H1-1-1 Table 11a, Note 6, line 1b). As the reclassification of certain projects to Nuclear Operations occurred subsequent to EB-2013-0321, these forecast amounts include the reclassified projects. The reclassified projects are further detailed and discussed in Ex. D2-2-10, section 2.4.4 and Ex. L-4.3-1 Staff-71.

The actual DRP net plant rate base amounts of $121.2M for 2014 and $192.6M for 2015 shown at line 9 of Table 3 in Attachment 1 (and detailed in part (c) above) were used in the calculation of CRVA capital additions at EB-2014-0370 Ex. H1-1-2, Table 12, line 19 for 2014 and EB-2016-0152 Ex. H1-1-1 Table 11, line 19 for 2015. These amounts exclude projects reclassified to Nuclear Operations, which effectively results in a CRVA ratepayer credit for the EB-2013-0321 revenue requirement impact associated with these projects.

[1] Information for 2013 is included to support the 2014 opening net plant amounts.

Numbers may not add due to rounding

Table 1
Net Plant Rate Base Amounts ($M)[1]

Line No.		2014 Forecast	2014 Actual	2015 Forecast	2015 Actual
		(a)	(b)	(c)	(d)
1	Darlington Energy Complex	92.0	77.8	89.6	75.1
2	Water and Sewer Project	20.8	31.6	26.4	41.8
3	Heavy Water Storage & Drum Handling Facility	0.0	7.3	20.3	14.3
4	Electric Power Distribution System	2.2	2.6	7.3	10.1
5	Powerhouse Steam Venting System	0.0	0.0	5.0	2.6
6	Third Emergency Power Generator Project	0.0	0.0	16.0	4.8
7	Retube Feeder Replacement Island Support Annex	0.0	0.0	0.0	0.9
8	Refurbishment Project Office	0.0	0.0	0.0	28.8
9	Emergency Service Water Buried Piping	0.0	0.0	0.0	6.6
10	Other Miscellaneous Projects	1.0	2.1	7.5	7.7
11	**Net Plant Rate Base Amounts without Reclassified Projects**	**116.0**	**121.2**	**172.1**	**192.6**
12	Darlington Operations Support Building Refurbishment	0.0	0.0	14.6	9.1
13	Darlington Auxiliary Heating System	0.0	0.0	17.9	0.0
14	Emergency Service Water Pipe and Component Replacement	0.0	0.0	0.0	2.4
15	**Net Plant Rate Base Amount with Reclassified Projects**	**116.0**	**121.2**	**204.6**	**204.2**

Notes:

1 DRP forecasts approved in EB-2013-0321 included reclassified projects, as the reclassification did not take place until after EB-2013-0321. Actual DRP amounts are reported excluding the reclassified projects.

Numbers may not add due to rounding

Table 2
Darlington Refurbishment Program - EB-2013-0321 Forecast Rate Base ($M)

Line No		Notes	2013 Forecast	2014 Forecast[1]	2015 Forecast[1]
			(a)	(b)	(c)
1	**Gross Plant In-service - opening balance**		5.0	109.2	127.9
2	**Gross Plant In-service Additions**	2	104.2	18.7	209.4
3	**Gross Plant In-service - closing balance** (line 1 + line 2)		109.2	127.9	337.2
4	**Accumulated Depreciation - opening balance**		-	1.0	4.0
5	**Depreciation Expense**	3	1.0	3.0	6.1
6	**Accumulated Depreciation - closing balance** (line 4 + line 5)		1.0	4.0	10.0
7	**Net Plant In-service - opening balance** (line 1 - line 4)		5.0	108.2	123.9
8	**Net Plant In-service - closing balance** (line 3 - line 6)		108.1	123.9	327.2
9	**Net Plant Rate Base**		56.6	116.0	204.6

Notes:
1 As shown in EB-2013-0321 Ex. L-4.9-1 Staff-048, Chart 1 and does not reflect the subsequent reclassification of certain projects to Nuclear Operations.
2 As shown in EB-2013-0321 Ex. D2-2-1, Table 6, line 14.
3 As shown in EB-2013-0321 Ex. F4-1-1, Table 2, Note 1.

Table 3
Darlington Refurbishment Program - Actual Rate Base ($M)

Line No.		Notes	2013 Actual[1]	2014 Actual	2015 Actual
			(a)	(b)	(c)
1	**Gross Plant In-service - opening balance**		5.0	104.2	147.6
2	**Gross Plant In-service Additions**	2	99.2	43.5	147.1
3	**Gross Plant In-service - closing balance** (line 1 + line 2)		104.2	147.6	294.8
4	**Accumulated Depreciation - opening balance**		0.0	2.3	7.0
5	**Depreciation Expense**	3	2.3	4.7	7.0
6	**Accumulated Depreciation - closing balance** (line 4 + line 5)		2.3	7.0	14.0
7	**Net Plant In-service - opening balance** (line 1 - line 4)		5.0	101.9	140.6
8	**Net Plant In-service - closing balance** (line 3 - line 6)		101.9	140.6	280.8
9	**Net Plant Rate Base**	4	60.2	121.2	192.6

Notes:

1 2013 Actual as reported in Ex. B3-3-1, Table 1, line 2; Ex. B3-4-1, Table 1, line 2; and Ex. B3-1-1, Table 1, line 2.

2 2014 Actual and 2015 Actual per Ex. B3-3-1, Table 1, lines 9 and 16; and Ex. D2-2-10 Table 5, line 6. Also detailed in Ex. L-2.21 Staff-008.

3 2014 Actual and 2015 Actual as shown in Ex. B3-4-1, Table 1, lines 9 and 16.

4 As shown in Ex. B3-1-1 Table 1, line 2, cols (c), (f) and (i); and reflects reclassification of certain projects to Nuclear Operations. 2013 Actual also shown in EB-2013-0321 Ex. L-9.1-17, SEC-132 Att. 1, Table 12a, Note 1. 2014 Actual also shown in EB-2014-0370 Ex. H1-1-2, Table 12, line 19. 2015 Actual also as shown in H1-1-1, Table 11, line 19.

Board Staff Interrogatory #211

Issue Number: 9.1
Issue: Is the nature or type of costs recorded in the deferral and variance accounts appropriate?

Interrogatory

Reference:
Ref: H1-T1-S1, page 26

In accordance with EB-2014-0370 payment amounts order, no interest is applied to the sub-accounts of Bruce Lease Net Revenues Variance Account. OPG proposes that the interest on the Non-Derivative Sub-account resume as of the effective date of the payment amounts order in this application.

Please explain why OPG proposes that interest resume.

Response

As per EB-2014-0370 Payment Amount Order, Appendix B (page 13 of 16), the Bruce Lease Net Revenue Variance Account does not attract interest for the period between January 1, 2015 and December 31, 2016. This condition was part of the terms negotiated and agreed between OPG and intervenors in the OEB-approved settlement of EB-2014-0370.

The terms of the EB-2007-0905, EB-2010-0008 and EB-2013-0321 Payment Amounts Orders provide for interest to be recorded on the balances in the Bruce Lease Net Revenue Variance Account in accordance with the OEB's interest rate policy. OPG believes that it is appropriate to resume accumulating interest on the Bruce Lease Net Revenue Variance Account balance starting January 1, 2017, in accordance with the OEB's decision and order in EB-2013-0321 and previous decisions and orders, as the negotiated interest free period will have lapsed.

AMPCO Interrogatory #151

Issue Number: 9.1
Issue: Is the nature or type of costs recorded in the deferral and variance accounts appropriate?

Interrogatory

Reference:

a) Please provide a list of the accounts that currently do not attract interest.

Response

a) Pursuant to the EB-2014-0370 Payment Amounts Order and the EB-2015-0374 Decision and Order, the following deferral and variance accounts currently do not attract interest:

- Pension & OPEB Cash Versus Accrual Differential Deferral Account
- Pension and OPEB Cost Variance Account
- Nuclear Liability Deferral Account
- Bruce Lease Net Revenues Variance (from January 1, 2015 to December 31, 2016)
- Pickering Life Extension Depreciation Variance Account (account terminates on December 31, 2016)
- Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2015) Deferral Account

CCC Interrogatory #39

Issue Number: 9.1
Issue: Is the nature or type of costs recorded in the deferral and variance accounts appropriate?

Interrogatory

Reference:
Reference: Ex. H1/T1/S1 p. 13

a) Please confirm that no matter what capital expenditure and in service addition amounts the OEB approves in relation to the DRP, OPG can and will record the difference between the amounts approved for the purposes of determining the test period revenue requirement and the actual amounts spent (including when those amounts are put into service) in the Capacity Refurbishment Deferral Account for future disposition.

b) Is there any financial difference to OPG between revenue requirement amounts deferred through the use of the proposed rate smoothing deferral account and revenue requirement amounts that are not originally included in the approved revenue requirement but instead are captured in the Capacity Refurbishment Deferral Account, assuming that any amounts captured in the Capacity Refurbishment Deferral Account are ultimately approved? Please illustrate the differences (or the fact that there is no difference) using an example where an in-service amount is approved as part of the test period revenue requirement but is included in the rate smoothing deferral account, vs. the treatment of that same in-service amount (i.e. the same capital spend and in-service date) if it had not been included in the originally approved revenue requirement but instead was entered into the Capacity Refurbishment Deferral Account and subsequently approved and disposed of.

Response

a) As discussed in Ex. H1-1-1 Section 5.6, O.Reg. 53/05 affirms that the scope of the Capacity Refurbishment Variance Account (CRVA) includes the Darlington Refurbishment Program (DRP). As such, OPG confirms that it will record in the account the revenue requirement impact arising from variances between the actual and forecast capital and non-capital costs and firm financial commitments incurred in respect of the DRP. The revenue requirement impact will include the effect of differences between actual and forecast capital in service amounts. The disposition of any balances in the CRVA is subject to a prudence review.

b) The financial difference between deferring revenue requirement amounts in the Nuclear Rate Smoothing Deferral Account (RSDA) and the CRVA relates solely to the interest rates applied on the outstanding balances in the respective accounts. The CRVA attracts interest based on the OEB-prescribed rate applicable to variance and deferral accounts. For the RSDA, O. Reg. 53/05 stipulates that the account shall record 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.

Chart 1 below provides an illustrative example of deferring $100M of revenue requirement in the CRVA versus the RSDA.

Chart 1

$M	CRVA[3]	RSDA[4]	Diff
Forecast Interest Rate[1]			
2020	1.10%	4.49%	3.39%
2021	1.10%	4.48%	3.38%
2020 revenue requirement deferral[2]	100.0	100.0	
2020 Interest	1.1	4.5	3.4
Ending Balance -2020	101.1	104.5	3.4
2021 Interest	1.1	4.7	3.6
Ending Balance -2021	102.2	109.2	7.0

1 Long term debt rates applied to the Nuclear Rate Smoothing Deferral Account (NRSDA) for 2017, 2018, 2019, 2020, and 2021 are as shown in Ex. C1-1-1 Tables 5, 4, 3, 2, and 1, line 2 for each respective year. The OEB-prescribed interest rate applicable to approved regulatory accounts as at September 30, 2016 was 1.10%
2 Additions to the accounts are assumed to be recorded on January 1
3 CRVA balances would be submitted for disposition in the 2022 rates proceeding
4 RSDA balances would be deferred to the post DRP recovery period

Board Staff Interrogatory #212

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, page 6

For the deviations pertaining to newly regulated hydroelectric facilities in the Hydroelectric Water Conditions Variance Account, the corresponding monthly forecasts for January 1 to June 30, 2015 underpinning EB-2013-0321 payment amounts were used and the corresponding average monthly forecasts for 2014 and 2015 underpinning the EB-2013-0321 payment amounts were used. OPG proposes that this method be used to calculate deviations in energy projection after 2015 continue to be used.

a) Please clarify the corresponding years and forecast basis (i.e. monthly forecast or average monthly forecasts) that is proposed to be used to determine deviations from the effective date of the payment amounts order in this proceeding.

b) Please explain OPG's proposed forecast basis.

Response

a) OPG is proposing to continue to use the same methodology approved by the OEB in EB-2014-0370 (as described in the Payment Amounts Order, Appendix B, page 4 and 5) to calculate deviations in production related to water conditions for the purpose of recording entries into the Hydroelectric Water Conditions Variance Account.

Under this approach OPG will use forecast production, determined as outlined below, to determine the deviations:

Previously Regulated
- For January 1 to December 31 of each year, the average of the corresponding monthly forecasts for 2014 and 2015 underpinning the EB-2013-0321 payment amounts.

Newly Regulated
- For January 1 to June 30 of each year, the corresponding monthly forecasts for 2015 underpinning the EB-2013-0321 payment amounts order.
- For July 1 to December 31 of each year, the average of the corresponding monthly forecasts for 2014 and 2015 underpinning the EB-2013-0321 payment amounts.

b) O. Reg. 53/05 established the newly regulated facilities as prescribed facilities as of July 1 2014. The OEB approved the production forecast for the newly regulated facilities as of July 1 2014 and did not approve a forecast for these facilities for January through June of the same year. Because there is no OEB-approved production forecast for the newly regulated facilities for January through June of 2014, OPG proposed to use the 2015 OEB approved production forecast only for January through June. This proposal was accepted by the OEB in EB-2014-0370 (See Appendix B of the Payment Amounts Order).

OPG asserts that it is appropriate to continue using the methodology described in a) above as the production forecast approved in EB-2013-0321 underpins the company's proposed hydroelectric payment amounts.

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.

CCC Interrogatory #40

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

Interrogatory

Reference:
Reference: Ex. A1/T2/S2/p. 5

The evidences states that with respect to the Capacity Refurbishment Variance Account (CRVA) If actual additions to rate base are different from forecast amounts, the cost impact of the difference will be recorded in the CRVA and any amounts greater than forecast amounts added to rate base will be subject to a prudence review in a future proceeding. Please confirm that if the amounts are less than forecast this will result in a credit to the account. Please confirm that OPG will only recover the actual costs of the project, subject to a prudence review by the OEB.

Response

Confirmed.

Board Staff Interrogatory #214

Issue Number: 9.3
Issue: Are the balances for recovery in each of the deferral and variance accounts appropriate?

Interrogatory

Reference:
Ref: Exh H1-1-1, page 9 and Table 4
There were no additions into the Hydroelectric Incentive Mechanism (HIM) Account in 2015 as actual HIM revenues were significantly below the specified threshold of $58M.

Please explain why HIM revenues were significantly below the threshold.

Response

As discussed in EB-2013-0321 Ex. E1-2-1, HIM is intended to provide OPG with an incentive to operate its regulated Hydroelectric facilities in a way that benefits customers. This takes the form of payment to OPG to incent it to time-shift generation from periods of low market price to periods of high market price.

The $58M threshold was set in EB-2013-0321 based on expected net HIM revenue forecasts underpinning the payment amounts order. In 2015, actual net HIM revenues earned were $26.5M (Ex. H1-1-1 Table 4), which were significantly below this threshold as a result of actual market and hydrological conditions which did not meet the forecasted expectations. Specifically:

- Natural gas prices were lower than expected which contributed to a lower than expected market price (HOEP);
- Market demand was lower than expected which resulted in increased Surplus Baseload Generation (SBG) particularly during on peak periods; and
- Water inflow (hydrological) conditions and overall SBG, in both on and off peak periods, were greater than expected.

The result of the combination of these factors is that there were fewer opportunities to time shift energy than expected and where the opportunity existed; less net HIM revenue was earned due to lower than expected market price spreads.

SEP Interrogatory #18

Issue Number: 9.4
Issue: Are the proposed disposition amounts appropriate?

Interrogatory

Reference:
Exh. F4-1-1 p.2 "OPG is not proposing to record additions to this account during the test period. Rather, OPG is proposing to record additions to the Pension & OPEB Cash Payment Variance Account and the Pension & OPEB Cash Versus Accrual Differential Deferral Account. As described at Ex. F4-3-2, this approach is consistent with OPG's proposal to maintain the same treatment for pension and OPEB costs as that resulting from the OEB's EB-2013-0321 Decision, pending the outcome of the OEB's generic proceeding on pension and OPEB costs (EB-2015-0040)."

a) In the event that the OEB delivers its generic decision on EB-2015-0040 in early 2017, does OPG intend to update its position on the disposal of its affected pension and OPEB deferral and variance accounts in the test years?

Response

a) OPG's decision to update its proposal with respect to the clearance of the Pension & OPEB Cash Versus Accrual Differential Deferral Account in this application in the event that the OEB delivers a decision in EB-2015-0040 in early 2017 will depend on a number of factors including:

   - The date the OEB issues its decision in the EB-2015-0040 generic proceeding;
   - The outcome of the OEB's decision;
   - The impact of any transition issues on the disposition of the deferral account; and
   - The requirements of US GAAP for recognition of regulatory assets related to OPEB costs with respect to the commencement of collection, discussed in OPG's September 22, 2016 submission in EB-2015-0040.[1]

   As a general observation, OPG offers that, to the extent possible, it is more administratively efficient to dispose of the year-end balances in all accounts at the same time.

[1] As noted in footnote 20 at page 15 of OPG's September 22, 2016 submission, OPG must begin recovery of amounts recorded for OPEB costs in the Pension & OPEB Cash to Accrual Differential Deferral Accounts within 5 years of the period in which the costs were incurred. For example, amounts recorded during November 2014 must begin to be recovered no later than November 2019.

Board Staff Interrogatory #215

Issue Number: 9.5
Issue: Is the disposition methodology appropriate?

Interrogatory

Reference:
Ref: Exh H1-2-1
Ref: Exh A1-3-1 page 10

OPG is requesting recovery of the audited 2015 year end balances (less 2016 amortization amounts approved in EB-2014-0370) in certain deferral and variance accounts. OPG proposes payment amount riders for the period January 1, 2017 to December 31, 2018.

a) Please explain why OPG has selected a two year disposition period.

b) As noted in Exh A1-3-1, the forecast bill impact in 2017 is a decrease of $1.29 per month. Please determine the bill impacts in 2017 to 2021 if a one year disposition period is used.

c) In the deferral and variance account application, EB-2012-0002, the approved settlement proposal resulted in payment amount riders for two years, but the collection in the first year was 60% of the account balances. Please determine the bill impacts in 2017 to 2021 if 60% of the account balances underpin the 2017 payment amount riders.

Response

a) OPG has proposed a two year disposition period to provide stable riders over 2017 and 2018. The amortization of the Pension and OPEB Cost Variance Account was previously approved for recovery in EB-2012-0002 and EB-2014-0370. These accounts were approved for disposition over 144 months beginning January 1 2013 (Pension and OPEB Cost Variance - Future), and 72 months beginning July 1 2015 (Pension and OPEB Cost Variance - Post 2012 Additions). As a result of these approvals, OPG would propose to recover the previously approved Pension and OPEB Cost Recovery Variance Account balances in the 2017 and 2018 years, even if the 2015 year end balances were recovered through a one year rider. Using a one year rider for the 2015 balances would result in a different rider for the 2017 year and the 2018 year. OPG believes there is more predictability in rates offered to customers by the use of a consistent rider for 2017 and 2018.

b) If OPG used a one year disposition period for the 2015 year end balances in its deferral and variance accounts, this would result in a hydroelectric rider of $2.64/MWh in 2017 (compared to $1.44/MWh) and a nuclear rider of $2.19/MWh (compared to $2.85/MWh). This calculation maintains the treatment of the unamortized portions of the Pension and

OPEB Cost Variance Account previously approved for recovery in EB-2012-0002 and EB-2014-0370.

The resulting one year rider is lower for nuclear than the two year rider because excluding the balances of the Pension and OPEB Cost Variance Account (which as discussed above is amortized as approved in EB-2012-0002), OPG is requesting disposition of a credit balance of $51.3M. Returning this credit balance over a shorter period of time reduces the rider to be collected from customers.

If OPG used a one year disposition of 2015 year end balances in 2017, OPG would propose to continue the previously approved treatment of the Pension and OPEB Cost Account in 2018 which would result in a hydroelectric rider of $0.23 in 2018 and a nuclear rider of $3.50 in 2018.

A calculation of these riders is provided in Attachment 1, Tables 1 and 2.

The bill impact resulting from the riders is provided in Attachment 1, Table 3.

c) As above, OPG would propose to continue the previously approved treatment of the Pension and OPEB Cost Variance Account. As such, OPG has not made a 60%/40% adjustment to the recovery of this account in its reply to this question.

The regulated hydroelectric impact from recovering 60% of the 2015 year end balances in 2017 and 40% of the 2018 year end balances in 2018 is a rider of $1.68/MWh for 2017 and $1.19/MWh for 2018. For nuclear the resulting impact is a rider of $2.72 in 2017 and $2.96 in 2018.

A calculation of these riders is provided in Attachment 1, Tables 4 and 5.

The bill impact resulting from these riders is provided in Attachment 1, Table 6.

Numbers may not add due to rounding.

Table 1

Calculation of Deferral and Variance Account Recovery Payment Rider - Regulated Hydroelectric ($M) Assuming 1 Year Disposition

Line No.	Account	Audited Year End Balance 2015[1]	EB-2014-0370 OEB-Approved Amortization 2016[2]	(a)-(b) 2015 Balance Less 2016 Approved Amortization	Recovery Period (months)	Amortization Jan - Dec 2017	Amortization Jan - Dec 2018	(c)-(e)-(f) Unamortized Balance At Dec 31, 2018
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Hydroelectric Water Conditions Variance**	(23.0)	(5.6)	(17.3)	12	(17.3)	0.0	0.0
2	**Ancillary Services Net Revenue Variance - Hydroelectric**	(24.2)	(11.0)	(13.2)	12	(13.2)	0.0	0.0
3	**Hydroelectric Incentive Mechanism Variance**	(1.7)	(1.7)	(0.1)	12	(0.1)	0.0	0.0
4	**Hydroelectric Surplus Baseload Generation Variance**	114.4	31.9	82.5	12	82.5	0.0	0.0
5	**Income and Other Taxes Variance - Hydroelectric**	(0.1)	(0.1)	(0.0)	12	(0.0)	0.0	0.0
6	**Capacity Refurbishment Variance - Hydroelectric**	83.2	79.9	3.3	12	3.3	0.0	0.0
7	**Pension and OPEB Cost Variance - Hydroelectric - Future**	9.5	1.1	8.4	96	1.1	1.1	6.3
8	**Pension and OPEB Cost Variance - Hydroelectric - Post 2012 Additions**	32.5	5.9	26.6	54	5.9	5.9	14.8
9	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric[3]**	44.2	0.0	44.2	N/A	0.0	0.0	44.2
10	**Pension & OPEB Cash Payment Variance - Hydroelectric**	4.3	0.0	4.3	12	4.3	0.0	0.0
11	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**	16.5	3.0	13.5	12	13.5	0.0	0.0
12	**Total**	255.5	103.4	152.1		79.9	7.0	65.2
13	**Forecast Production[4] (TWh)**					30.2	30.2	
14	**Regulated Hydroelectric Payment Rider ($/MWh)** (line 12 / line 13)					2.64	0.23	

Notes:
1 From Ex. H1-1-1 Table 1, col (b)
2 From EB-2014-0370 Payment Amounts Order App. A Table 1, col (f).
3 Account not proposed for disposition in this application as discussed in Ex. H1-1-1
4 2015 Actual Production of 30.2 TWh (divided by 12 months multiplied by 24 months)

Table 2

Calculation of Deferral and Variance Account Recovery Payment Rider - Nuclear ($M) Assuming 1 Year Disposition

Line No.	Account	Audited Year End Balance 2015[1]	EB-2014-0370 OEB-Approved Amortization 2016[2]	(a)-(b) 2015 Balance Less 2016 Approved Amortization	Recovery Period (months)	Amortization Jan - Dec 2017	Amortization Jan - Dec 2018	(c)-(e)- (f) Unamortized Balance At Dec 31, 2017
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Nuclear Liability Deferral**	190.5	190.5	0.0	12	0.0	0.0	0.0
2	**Nuclear Development Variance**	3.3	1.6	1.7	12	1.7	0.0	0.0
3	**Ancillary Services Net Revenue Variance - Nuclear**	2.1	1.2	1.0	12	1.0	0.0	0.0
4	**Capacity Refurbishment Variance - Nuclear - Capital Portion**	(32.5)	5.0	(37.6)	12	(37.6)	0.0	0.0
5	**Capacity Refurbishment Variance - Nuclear - Non-Capital Portion**	(30.8)	0.8	(31.6)	12	(31.6)	0.0	(0.0)
6	**Bruce Lease Net Revenues Variance - Derivative Sub-Account**	(4.5)	64.1	(68.6)	12	(68.6)	0.0	0.0
7	**Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - EB-2012-0002**	18.7	18.7	0.0	12	0.0	0.0	0.0
8	**Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - Post 2012 Additions**	103.1	82.5	20.6	12	20.6	0.0	0.0
9	**Income and Other Taxes Variance - Nuclear**	(13.1)	(8.8)	(4.3)	12	(4.3)	0.0	0.0
10	**Pension and OPEB Cost Variance - Nuclear - Future**	193.2	21.5	171.7	96	21.5	21.5	128.8
11	**Pension and OPEB Cost Variance - Nuclear - Post 2012 Additions**	622.0	113.1	508.9	54	113.1	113.1	282.7
12	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear[3]**	271.1	0.0	271.1	N/A	0.0	0.0	271.1
13	**Pension & OPEB Cash Payment Variance - Nuclear**	23.4	0.0	23.4	12	23.4	0.0	0.0
14	**Pickering Life Extension Depreciation Variance**	5.2	5.2	0.0	12	0.0	0.0	0.0
15	**Nuclear Deferral and Variance Over/Under Recovery Variance**	81.7	37.6	44.1	12	44.1	0.0	0.0
16	**Total**	1,433.4	533.0	900.5		83.3	134.6	682.6
17	**Forecast Production[4] (TWh)**					38.1	38.5	
18	**Nuclear Payment Rider ($/MWh)** (line 16 / line 17)					2.19	3.50	

Notes:
1 From Ex. H1-1-1 Table 1, col (b)
2 From EB-2014-0370 Payment Amounts Order, App. A, Table 2, col (f).
3 Account not proposed for disposition in this application as discussed in Ex. H1-1-1
4 From Ex. E2-1-1 Table 1, line 3, col. (e) plus col. (f).

Numbers may not add due to rounding.

Table 3
Annualized Residential Consumer Impact Assuming 1 Year Disposition of 2015 Year End Balances

Line No.	Description	2017 Amount	2018 Amount	2019 Amount	2020 Amount	2021 Amount
		(a)	(b)	(c)	(d)	(e)
1	**Typical Consumption[1] (kWh/Month)**	789	789	789	789	789
2	**Typical Usage of OPG Generation (kWh/Month)** (line 1 x line 11)	392	394	397	388	376
3	**Typical Bill[1] ($/Month)**	150.58	150.58	150.58	150.58	150.58
4	**Typical Bill Impact ($/Month)** (line 2 x line 8 / 1000)	**(1.43)**	**2.02**	**0.92**	**1.86**	**1.89**
5	**Typical Bill Impact (%)** (line 4 / line 3)	**-0.9%**	**1.3%**	**0.6%**	**1.2%**	**1.3%**
6	Prior Year weighted average rate with proposed payment amounts and riders[2] ($/MWh)	60.66	57.00	62.13	64.45	69.26
7	Current Year weighted average rate with proposed payment amounts and riders[2] ($/MWh)	57.00	62.13	64.45	69.26	74.27
8	Change in OPG weighted average rate ($/MWh) (line 7 - line 6)	(3.65)	5.12	2.32	4.81	5.02
9	Total OPG Regulated Production[3](TWh)	68.3	68.7	69.3	67.6	65.6
10	Forecast of 2017 Provincial Demand[4] (TWh)	137.6	137.6	137.6	137.6	137.6
11	OPG Proportion of Consumer Usage (line 9 / line 10)	49.7%	49.9%	50.3%	49.1%	47.7%

Notes:

1 Typical monthly consumption (750 kWh) and typical monthly bill are based on the OEB "Bill Calculator" for estimating monthly electricity bills (using Time of Use pricing), available at: http://www.ontarioenergyboard.ca/OEB/Consumers/Electricity/Your+Electricity+Utility
Typical Consumption includes line losses (Assumed loss factor of 1.0525)

2 Uses Nuclear smoothed rate per Ex. I1-3-1 Table 1, IRM Hydro rate (illustrative after 2017) per Ex. I1-2-1 Table 1

3 From Ex. I1-1-2 Table 2, line 5.

4 Based on forecast demand for 2017 (137.6 TWh) from Table 3.1 of IESO 18-Month Outlook Update for April 2016 to September 2017, published March 22, 2016.

Numbers may not add due to rounding.

Table 4

Calculation of Deferral and Variance Account Recovery Payment Rider - Regulated Hydroelectric ($M) Assuming 60% 2017 and 40% 2018 Split

Line No.	Account	Audited Year End Balance 2015[1]	EB-2014-0370 OEB-Approved Amortization 2016[2]	(a)-(b) 2015 Balance Less 2016 Approved Amortization	Recovery Period (months)	Amortization Jan - Dec 2017	Amortization Jan - Dec 2018	(c)-(e)-(f) Unamortized Balance At Dec 31, 2018
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Hydroelectric Water Conditions Variance**	(23.0)	(5.6)	(17.3)	24	(10.4)	(6.9)	0.0
2	**Ancillary Services Net Revenue Variance - Hydroelectric**	(24.2)	(11.0)	(13.2)	24	(7.9)	(5.3)	0.0
3	**Hydroelectric Incentive Mechanism Variance**	(1.7)	(1.7)	(0.1)	24	(0.0)	(0.0)	0.0
4	**Hydroelectric Surplus Baseload Generation Variance**	114.4	31.9	82.5	24	49.5	33.0	0.0
5	**Income and Other Taxes Variance - Hydroelectric**	(0.1)	(0.1)	(0.0)	24	(0.0)	(0.0)	0.0
6	**Capacity Refurbishment Variance - Hydroelectric**	83.2	79.9	3.3	24	2.0	1.3	0.0
7	**Pension and OPEB Cost Variance - Hydroelectric - Future**	9.5	1.1	8.4	96	1.1	1.1	6.3
8	**Pension and OPEB Cost Variance - Hydroelectric - Post 2012 Additions**	32.5	5.9	26.6	54	5.9	5.9	14.8
9	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric[3]**	44.2	0.0	44.2	N/A	0.0	0.0	44.2
10	**Pension & OPEB Cash Payment Variance - Hydroelectric**	4.3	0.0	4.3	24	2.6	1.7	0.0
11	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**	16.5	3.0	13.5	24	8.1	5.4	0.0
12	**Total**	255.5	103.4	152.1		50.7	36.1	65.2
13	**Forecast Production[4] (TWh)**					30.2	30.2	
14	**Regulated Hydroelectric Payment Rider ($/MWh)** (line 12 / line 13)					1.68	1.19	

Notes:

1 From Ex. H1-1-1 Table 1, col (b)

2 From EB-2014-0370 Payment Amounts Order App. A Table 1, col (f).

3 Account not proposed for disposition in this application as discussed in Ex. H1-1-1

4 2015 Actual Production of 30.2 TWh (divided by 12 months multiplied by 24 months)

Table 5

Calculation of Deferral and Variance Account Recovery Payment Rider - Nuclear ($M) Assuming 60% 2017 and 40% 2018 Split

Line No.	Account	Audited Year End Balance 2015[1]	EB-2014-0370 OEB-Approved Amortization 2016[2]	(a)-(b) 2015 Balance Less 2016 Approved Amortization	Recovery Period (months)	Amortization Jan - Dec 2017	Amortization Jan - Dec 2018	(c)-(e)-(f) Unamortized Balance At Dec 31, 2018
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Nuclear Liability Deferral**	190.5	190.5	0.0	24	0.0	0.0	0.0
2	**Nuclear Development Variance**	3.3	1.6	1.7	24	1.0	0.7	0.0
3	**Ancillary Services Net Revenue Variance - Nuclear**	2.1	1.2	1.0	24	0.6	0.4	0.0
4	**Capacity Refurbishment Variance - Nuclear - Capital Portion**	(32.5)	5.0	(37.6)	24	(22.5)	(15.0)	0.0
5	**Capacity Refurbishment Variance - Nuclear - Non-Capital Portion**	(30.8)	0.8	(31.6)	24	(19.0)	(12.6)	0.0
6	**Bruce Lease Net Revenues Variance - Derivative Sub-Account**	(4.5)	64.1	(68.6)	24	(41.2)	(27.4)	0.0
7	**Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - EB-2012-0002**	18.7	18.7	0.0	24	0.0	0.0	0.0
8	**Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - Post 2012 Additions**	103.1	82.5	20.6	24	12.4	8.2	0.0
9	**Income and Other Taxes Variance - Nuclear**	(13.1)	(8.8)	(4.3)	24	(2.6)	(1.7)	0.0
10	**Pension and OPEB Cost Variance - Nuclear - Future**	193.2	21.5	171.7	96	21.5	21.5	128.8
11	**Pension and OPEB Cost Variance - Nuclear - Post 2012 Additions**	622.0	113.1	508.9	54	113.1	113.1	282.7
12	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear[3]**	271.1	0.0	271.1	N/A	0.0	0.0	271.1
13	**Pension & OPEB Cash Payment Variance - Nuclear**	23.4	0.0	23.4	24	14.1	9.4	0.0
14	**Pickering Life Extension Depreciation Variance**	5.2	5.2	0.0	24	0.0	0.0	0.0
15	**Nuclear Deferral and Variance Over/Under Recovery Variance**	81.7	37.6	44.1	24	26.5	17.7	0.0
16	**Total**	1,433.4	533.0	900.5		103.8	114.1	682.6
17	**Forecast Production[4] (TWh)**					38.1	38.5	
18	**Nuclear Payment Rider ($/MWh)** (line 16 / line 17)					2.72	2.96	

Notes:
1 From Ex. H1-1-1 Table 1, col (b)
2 From EB-2014-0370 Payment Amounts Order, App. A, Table 2, col (f).
3 Account not proposed for disposition in this application as discussed in Ex. H1-1-1
4 From Ex. E2-1-1 Table 1, line 3, col. (e) plus col. (f).

Table 6
Annualized Residential Consumer Impact Assuming 60% 2017 and 40% 2018 Split

Line No.	Description	2017 Amount	2018 Amount	2019 Amount	2020 Amount	2021 Amount
		(a)	(b)	(c)	(d)	(e)
1	**Typical Consumption[1] (kWh/Month)**	789	789	789	789	789
2	**Typical Usage of OPG Generation (kWh/Month)** (line 1 x line 11)	392	394	397	388	376
3	**Typical Bill[1] ($/Month)**	150.58	150.58	150.58	150.58	150.58
4	**Typical Bill Impact ($/Month)** (line 2 x line 8 / 1000)	**(1.32)**	**1.78**	**1.04**	**1.86**	**1.89**
5	**Typical Bill Impact (%)** (line 4 / line 3)	**-0.9%**	**1.2%**	**0.7%**	**1.2%**	**1.3%**
6	Prior Year weighted average rate with proposed payment amounts and riders[3] ($/MWh)	60.66	57.30	61.83	64.45	69.26
7	Current Year weighted average rate with proposed payment amounts and riders[3] ($/MWh)	57.30	61.83	64.45	69.26	74.27
8	Change in OPG weighted average rate ($/MWh) (line 7 - line 6)	(3.36)	4.52	2.63	4.81	5.02
9	Total OPG Regulated Production[3](TWh)	68.3	68.7	69.3	67.6	65.6
10	Forecast of 2017 Provincial Demand[4] (TWh)	137.6	137.6	137.6	137.6	137.6
11	OPG Proportion of Consumer Usage (line 9 / line 10)	49.7%	49.9%	50.3%	49.1%	47.7%

Notes:
1 Typical monthly consumption (750 kWh) and typical monthly bill are based on the OEB "Bill Calculator" for estimating monthly electricity bills (using Time of Use pricing), available at:
http://www.ontarioenergyboard.ca/OEB/Consumers/Electricity/Your+Electricity+Utility
Typical Consumption includes line losses (Assumed loss factor of 1.0525)
2 Uses Nuclear smoothed rate per Ex. I1-3-1 Table 1, IRM Hydro rate (illustrative after 2017) per Ex. I1-2-1 Table 1
3 From Ex. I1-1-2 Table 2, line 5.
4 Based on forecast demand for 2017 (137.6 TWh) from Table 3.1 of IESO 18-Month Outlook Update for April 2016 to September 2017, published March 22, 2016.

LPMA Interrogatory #5

Issue Number: 9.5
Issue: Is the disposition methodology appropriate?

Interrogatory

Reference:
Ref: Exhibit H1, Tab 2, Schedule 1

OPG proposes to recover the regulated hydroelectric variance accounts over 24 months beginning January 1, 2017 based on payment rider calculated using 2015 actual hydroelectric output from the regulated hydroelectric facilities.

Given that the actual hydroelectric output in 2017 and 2018 is not likely to be identical to the actual 2015 output, what happens to the variance in the amount to be recovered that results from the output difference under the OPG proposal?

Response

As discussed in Ex. H1-1-1 section 5.8, the Hydroelectric Deferral and Variance Over/Under Recovery account records the differences between the amounts approved for recovery in the hydroelectric deferral and variance accounts and the actual amounts recovered based on the actual regulated hydroelectric production and approved riders.

LPMA Interrogatory #6

Issue Number: 9.5
Issue: Is the disposition methodology appropriate?

Interrogatory

Reference:
Ref: Exhibit H1, Tab 2, Schedule 1

OPG proposes to recover the nuclear variance accounts over 24 months beginning January 1, 2017 based on payment rider calculated using the 2017-2018 forecast nuclear output from the nuclear facilities.

Given that the actual nuclear output in 2017 and 2018 is not likely to be identical to the forecast output over that period, what happens to the variance in the amount to be recovered that results from the output difference under the OPG proposal?

Response

As discussed at Ex. H1-1-1 Section 5.17 The Nuclear Deferral and Variance Over/Under Recovery Variance Account records the difference between the amounts approved for recovery in the nuclear deferral and variance accounts and the actual amounts recovered based on the actual nuclear production and approved riders.

PWU Interrogatory #17

Issue Number: 9.7

Issue: Is the rate smoothing deferral account in respect of the nuclear facilities that OPG proposes to establish consistent with O. Reg. 53/05 and appropriate?

Interrogatory

Reference:
Ref: Exhibit H1-1-1, Page 30

The regulation [O. Reg. 53/05] stipulates that the OEB shall ensure that OPG recovers the balance recorded in the deferral account and shall authorize recovery of the account balance on a straight line basis over a period not to exceed ten years commencing at the end of the deferral period.

a) Please confirm if the 'deferral period' in the reference represents the period January 2017-2026?

b) If (a) is confirmed, please confirm that as per the reference above the Board is expected to authorize recovery of the account by 2036 the latest?

Response

a) As outlined in section 4.1 of Ex. D2-2-1, O. Reg. 53/05 defines the "deferral period" as the period beginning January 1, 2017, and ending when the Darlington Refurbishment Program (DRP) ends. As per Ex. D2-2-8 Attachment 1, the DRP is forecast to be complete when Unit 4 returns to service in February of 2026.

b) The DRP, and therefore the deferral period, is forecast to end in 2026. Pursuant to that forecast, O. Reg. 53/05 would require that the Rate Smoothing Deferral Account be recovered by 2036 at the latest.

SEC Interrogatory #92

Issue Number: 9.7
Issue: Is the rate smoothing deferral account in respect of the nuclear facilities that OPG proposes to establish consistent with O. Reg. 53/05 and appropriate?

Interrogatory

Reference:

Please explain what OPG believes O. Reg 53/05 requires of the Board, and what aspects are a matter of discretion by the Board, with respect to any rate smoothing for nuclear facilities. Please explain the legal basis for OPG's position.

Response

Please refer to section 2.2 of Ex. A1-3-3 for OPG's interpretation of the requirements of O. Reg. 53/05. Please also refer to Ex. L-11.6-1 Staff-264 parts b and c.

SEC Interrogatory #93

Issue Number: 9.7
Issue: Is the rate smoothing deferral account in respect of the nuclear facilities that OPG proposes to establish consistent with O. Reg. 53/05 and appropriate?

Interrogatory

Reference:
[Nuclear Rate Smoothing Proposal Presentation, September 23 2016, slides 5-6]

Please provide similar charts (slides 5-6) and table (slide 5-6) showing the rate smoothing deferral account through the end of the deferral period (as defined in O. Reg 53/05) and the clearance period.

Response

Although the OEB is only required to determine revenue requirement and deferral amounts for the 2017-2021 period, it requires some contextual information beyond that period to assess the full impact of the deferral amounts during the IR term. OPG provided that contextual information in a series of five-year periods in Ex. A1-3-3, Page 7, Chart 2. Chart 2 provides information on three key factors included in the referenced presentation slides: the anticipated unsmoothed revenue requirement, anticipated production, and the resulting unsmoothed payment amount.

The chart below expands Chart 2 to include information consistent with the referenced presentation slides for the 2022-2036 period.

Five-Year Revenue Requirement, Production, Average Rate, and Rate Smoothing Deferral Account Activity

	2017-2021	2022-2026	2027-2031	2032-2036
	(a)	(b)	(c)	(d)
Anticipated Revenue Requirement ($BN)	$ 17.0	$ 18.1	$ 18.2	$ 17.1
Anticipated Production (TWh)	188	130	136	141
Average Rate ($/MWh)	$ 90	$ 139	$ 135	$ 121
Average smoothed rate ($/MWh)	$ 82	$ 138	$ 152	$ 128
Net Revenue Requirement Deferred/Recovered ($BN)	$ 1.6	$ 0.1	$ (2.4)	$ (0.9)
Interest During Period ($BN)	$ 0.3	$ 0.8	$ 0.4	$ 0.1
Period End Rate Smoothing Deferral Account Balance ($BN)	$ 1.9	$ 2.8	$ 0.9	$ 0.0

SEC Interrogatory #94

Issue Number: 9.7
Issue: Is the rate smoothing deferral account in respect of the nuclear facilities that OPG proposes to establish consistent with O. Reg. 53/05 and appropriate?

Interrogatory

Reference:
[Nuclear Rate Smoothing Proposal Presentation, September 23 2016, slide 7]

OPG states that it assessed the rate smoothing proposal against six criteria including its own financial viability, using two metrics, i) Debt-to-Earnings Before Interest Taxes Depreciation and Amortization ratio, and ii) Funds From Operations Adjusted Interest Coverage Ratio:

a. Please provide details regarding the analysis undertaken and the results of metrics based on OPG's proposal.

b. For each metric, please explain what is required to maintain financial viability.

Response

a) The values for the cited financial metrics are shown in Ex. A1-3-3, Chart 3. The row without a label provides the values for the FFO Adjusted Interest Coverage Ratio.

b) As stated at Ex. A1-3-3, p. 9, in OPG's judgment, the assessment of financial viability was based on at least one of the two metrics being within threshold values at all times during each of the two five-year deferral periods (i.e. 2017 to 2021 and 2022 to 2026). If multiple ratio thresholds are exceeded, particularly for multiple years, the risk increases that the company's credit ratings will be negatively affected. Declining credit ratings negatively impact financial viability.

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.

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:

<u>If approved updated production forecast < EB-2016-0152 approved production forecast</u>

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

<u>If approved updated production forecast > EB-2016-0152 approved production forecast</u>

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:

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

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

LPMA Interrogatory #7

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

Interrogatory

Reference:
Ref: Exhibit H1, Tab 1, Schedule 1, pages 32-33

With respect to the Hydroelectric Capital Structure Variance Account, please provide the following:

a) The numerical value of the average 2014-2015 regulated hydroelectric rate base forecast approved by the OEB in EB-2013-0321;

b) The numerical value of the actual average 2014-2015 regulated hydroelectric rate base, and

c) Please provide an example of the calculation of the annual hydroelectric revenue requirement impact of the difference between the 45% equity/55% debt capital structure approved by the OEB in EB-2013-0321and the capital structure proposed in this application of 49% equity/51% debt. Please show all assumptions and calculations used.

Response

Parts a) – c)

See 9.8-Staff-217 for a calculation of the average of the 2014-2015 OEB approved regulated hydroelectric rate base and a calculation of the annual hydroelectric revenue requirement impact of the proposed 49% equity and 51% debt capital structure. The actual 2014-2015 regulated hydroelectric rate base is $7,510.3M.